50 STATES OF ENERGY AFFORDABILITY

Quarterly Report

NC CLEAN ENERGY TECHNOLOGY CENTER | DSIRE insight

June 2026

AUTHORS

Emily Apadula
Rebekah de la Mora
Caitlin Flanagan
Nick Montoni
Autumn Proudlove

CONTRIBUTORS

The authors would like to extend their gratitude for research provided by Justin Lindemann and Brian Lips of NCCETC.

ABOUT THE NC CLEAN ENERGY TECHNOLOGY CENTER

The NC Clean Energy Technology Center is a UNC System-chartered Public Service Center administered by the College of Engineering at North Carolina State University. Its mission is to advance a sustainable energy economy by educating, demonstrating and providing support for clean energy technologies, practices, and policies. The Center provides service to the businesses and citizens of North Carolina and beyond relating to the development and adoption of clean energy technologies. Through its programs and activities, the Center envisions and seeks to promote the development and use of clean energy in ways that stimulate a sustainable economy while reducing dependence on foreign sources of energy and mitigating the environmental impacts of fossil fuel use.

CONTACT

Nick Montoni (npmonton@ncsu.edu)

Autumn Proudlove (afproudl@ncsu.edu)

PREFERRED CITATION

North Carolina Clean Energy Technology Center, *The 50 States of Energy Affordability: June 2026 Report,* June 2026.

COVER DESIGN CREDIT

Cover design by Dawn Haworth

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GLOSSARY OF ABBREVIATIONS

ALJ	Administrative Law Judge
ATT	Advanced Transmission Technology
DER	Distributed Energy Resource
DG	Distributed Generation
GET	Grid-Enhancing Technology
IOU	Investor-Owned Utility
IRP	Integrated Resource Plan
LIHEAP	Low-Income Home Energy Assistance Program
LMI	Low-to-Moderate Income
MYRP	Multi-Year Rate Plan
NWA	Non-Wires Alternative
PBR	Performance-Based Regulation (or Ratemaking)
PIM	Performance Incentive Mechanism
PIPP	Percentage of Income Payment Program
PPA	Power Purchase Agreement
PV	Photovoltaics
REC	Renewable Energy Credit (or Certificate)
RFP	Request for Proposals
RPS	Renewable Portfolio Standard
SNAP	Supplemental Nutrition Assistance Program

INTRODUCTION

WHAT IS ENERGY AFFORDABILITY?

While it has recently worked its way into the political zeitgeist and become a major focus of policymakers at all levels of government, energy affordability is not a new concept. In general, energy affordability refers to the ability of energy and electricity providers, policymakers, and regulators to provide services to customers at low cost and without unnecessary burden or inappropriate allocation of costs. In fact, state lawmakers and regulatory bodies that oversee utilities already dictate rules about how certain costs can be recovered and allocated. This renewed focus on the concept of energy affordability opens up a new question: what can legislatures, utilities commissions, and utilities do to maintain affordability, and are those actions scalable and replicable?

PURPOSE

The purpose of this report is to provide timely, accurate, and unbiased updates to a broad audience of state lawmakers and regulators, state agencies, utilities, consumer advocates, and other energy stakeholders, about how states are choosing to study, adopt, implement, amend, or discontinue policies that are intended in some way to lower electricity costs or decrease energy burden on the ratepayer base. This report catalogues proposed and approved executive, legislative, and regulatory changes affecting oversight of utilities, utility expenditures and revenues, and customer costs.

The 50 States of Energy Affordability report series will provide regular quarterly updates of energy affordability policy updates, keeping stakeholders informed and up to date.

APPROACH

The authors identified relevant policy changes and updates through state utility commission docket searches, legislative bill searches, popular press, and direct communications with industry stakeholders and regulators.

Questions Addressed

- What are legislative, regulatory, and business approaches to reducing or controlling costs to electric customers?
- How are policymakers and utilities approaching the potential cost shifts, including those associated with customer programs and new large load additions?
- How are legislators and regulators rethinking utility business models and oversight?

- What resource acquisition strategies are regulators and utilities considering to help control costs?

Actions Included

This report focuses on cataloguing and describing important proposed and adopted policy and program changes related to energy affordability.

In general, this report considers an “action” to be a relevant (1) legislative bill that has passed at least one chamber, (2) an open or recently decided regulatory docket or rulemaking proceeding, or (3) an executive order or significant state agency initiative. Primarily, statewide actions and those related to investor-owned utilities are included in this report. Specifically, actions tracked in this issue include:

Utility Business Model

The utility business model refers to how utilities generate revenue and earn a profit, including the incentive structure underlying this. The actions tracked include changes to how utilities collect revenues and earn a return, such as implementing performance incentive mechanisms and revenue decoupling. This also includes changes to utility ownership structures and utility participation in wholesale markets.

Utility Oversight and Cost Recovery

Regulatory bodies, legislatures, and consumer advocates have a responsibility to ensure utilities act in the public interest through measurement, data collection, and monitoring. Policy changes in utility oversight may include new cost trackers, audits, consumer representation efforts, and monitoring efforts, as well as changes to cost recovery protocols and rate freezes.

Infrastructure Planning and Procurement

Planning and procurement rules shape how utilities spend money in order to develop or utilize grid resources; while new resource procurement always costs money, the mechanisms for this can lead to varying degrees of cost-effectiveness. This can mean changing how utilities plan for new resources, instructing utilities to make better use of existing resources, or leveraging innovative financing mechanisms.

Customer Cost Allocation

When a utility incurs costs in order to provide services, it may generally recover those costs from its customers. How those costs are distributed across the customer base is a matter of rate design. Customer cost allocation includes both efforts to reduce cost-shifting overall, as well as efforts to intentionally shift cost away from energy-burdened customers, with both approaches having benefits for near-term or long-term affordability. These also include policies that explicitly place cost burden onto large load customers. Additionally, customer cost allocation looks at direct payments or rebates, bill assistance programs, percentage of income payment plans, arrearage management, and disconnection policies, as these are all costs borne by the broader ratepayer (or taxpayer) base in order to alleviate energy burden.

Customer Cost-Saving Programs

This report differentiates between cost allocation and cost-saving programs by defining a cost-saving program as an initiative that explicitly provides technology, equipment, services, or information to a customer. To be clear: if a cost is incurred, someone pays for it somewhere down the line. Cost allocation, above, refers to costs shared or moved between ratepayers or between taxpayers. On the other hand, cost-saving programs in this sense refer to state or utility programs that allow customers to install energy efficiency or weatherization improvements or build their own generation or battery infrastructure, like community solar or distributed energy programs In other words, customer cost-saving programs refers to programs that pay a customer for taking some action or provide some service or tool to a customer at low or no cost. The report considers these as energy affordability actions for two reasons: first, they provide some direct benefit to customers, allowing them to save money through efficiency or self-generation or receive bill credits via exports; second, they provide some benefit to the utility through system-wide cost savings.

Studies and Investigations

Studies and investigations are efforts by legislatures or utilities commissions to acquire more technical information on an issue. Legislatures can direct executive branch departments and agencies to produce studies, utilities commissions can require studies from utilities or open investigatory proceedings and host technical conferences, and Governors can ask their administrations for studies to be conducted. This report examines state- or utility-led efforts to study issues related to energy affordability, including any of the topics listed above.

Actions Excluded

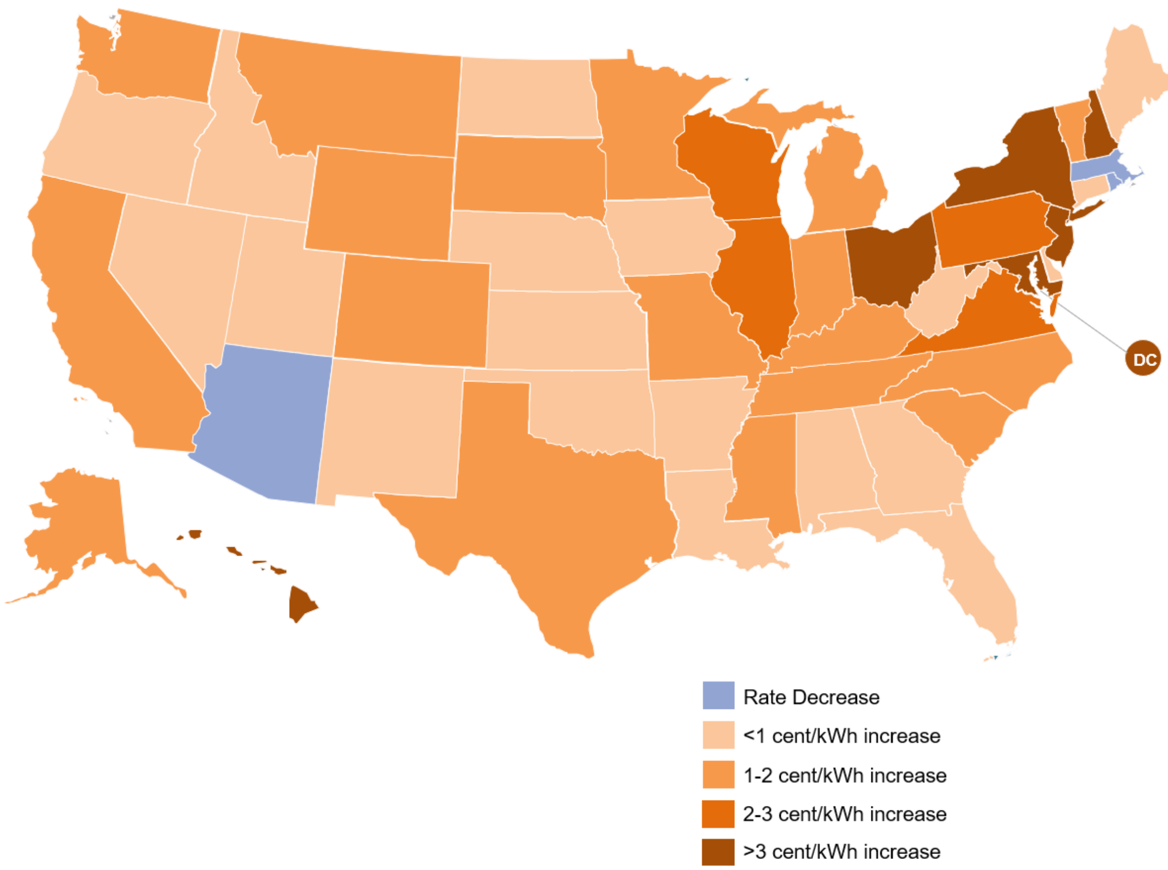
Energy affordability can be a broad category and can be affected by a range of non-energy factors like wages, housing, water, climate, and more; this report excludes actions that are not explicitly related to energy and would only have downstream impacts on energy affordability. Energy can also be inclusive of both electricity and heating; most tracked actions focus on the electricity system and not on gas. The only notable exceptions to this are thermal resources for electricity generation and low- and moderate-income programs focused on weatherization or home heating that are funded in part through thermal resources budgets or focus on electrification efforts. Finally, utilities and regulatory bodies are often considering affordability in their annual or otherwise regularly scheduled proceedings; this report attempts to exclude any “business-as-usual” actions in favor of those that are representative of major changes or major new initiatives.

This report also excludes actions that are specifically to deploy new generation and grid infrastructure. The report authors recognize that there are numerous important policy and regulatory issues related to procurement of new generating capacity and building new transmission and distribution infrastructure, and that by certain metrics these changes stand to make energy more affordable. However, in order to maintain a well-defined scope of content, the report focuses on *policy* actions rather than *technological* actions to maintain a throughline around "how we do business" and "who pays for it." Also excluded are policy mechanisms that are not new. Many utilities already offer low- and moderate-income programs or implement revenue and cost control mechanisms in their rates that benefit the ratepayers. Unless there have been significant changes to those mechanisms or a legislature, regulatory body, or utility are creating new mechanisms, this report does not mention them. The report also excludes all bills introduced in one chamber of their legislature that have not undergone any significant action, and action taken by federal agencies or the United States Congress.

ENERGY AFFORDABILITY IN THE UNITED STATES

In recent years, electricity costs across the U.S. have been on the rise, with few exceptions. In the past year, the national average price of residential electricity increased by around 7.3%, bringing the national average price of electricity to 18.83 cents/kWh.[1] States like Ohio, and much of the mid-Atlantic experienced similar or larger percentage increases over the last year, while a few states, such as Arizona, Massachusetts, and Rhode Island saw slight decreases.[2]

Figure 1. Average Electricity Price Changes (April 2025 to April 2026)



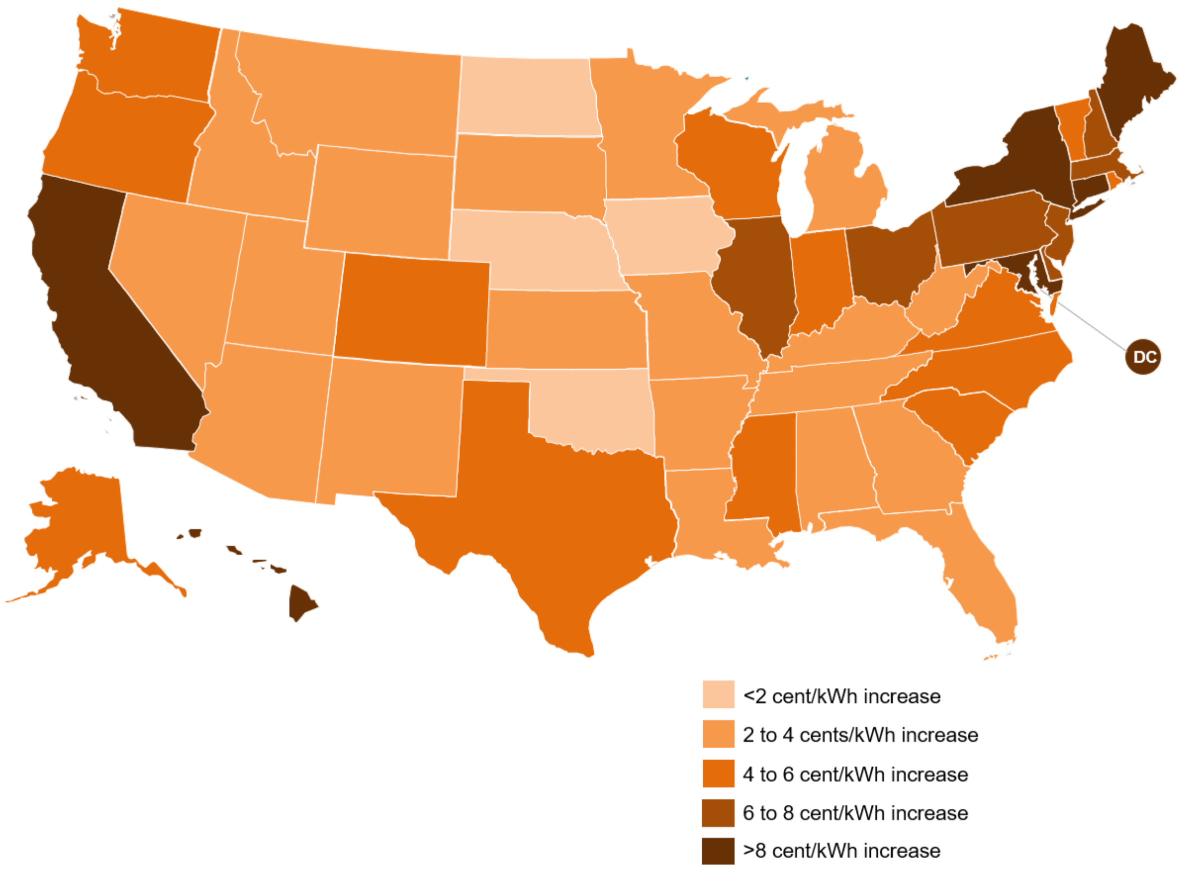
Data Source: U.S. Energy Information Administration – Electric Power Monthly, Average Price of Electricity to Ultimate Customers by End-Use Sector, by State, April 2026 and 2025.

When looking back even further, to the past five years, average electricity prices have increased across the board. However, states like Iowa, Nebraska, North Dakota, and Oklahoma have seen minimal increases, while states like California, Connecticut, Hawaii, Maine, Maryland, New York,

[1] U.S. Energy Information Administration, Electricity Monthly Update: End Use, April 2026, https://www.eia.gov/electricity/monthly/update/end-use.php
[2] U.S. Energy Information Administration, Electricity Monthly Update: End Use, April 2026, https://www.eia.gov/electricity/monthly/update/end-use.php

and the District of Columbia have seen the steepest price increases, in terms of cents per kWh.[3] On a price per kWh basis, New England states and California still see the highest prices, while the Mountain West sees the lowest prices.

Figure 2. Average Electricity Price Changes (April 2021 to April 2026)



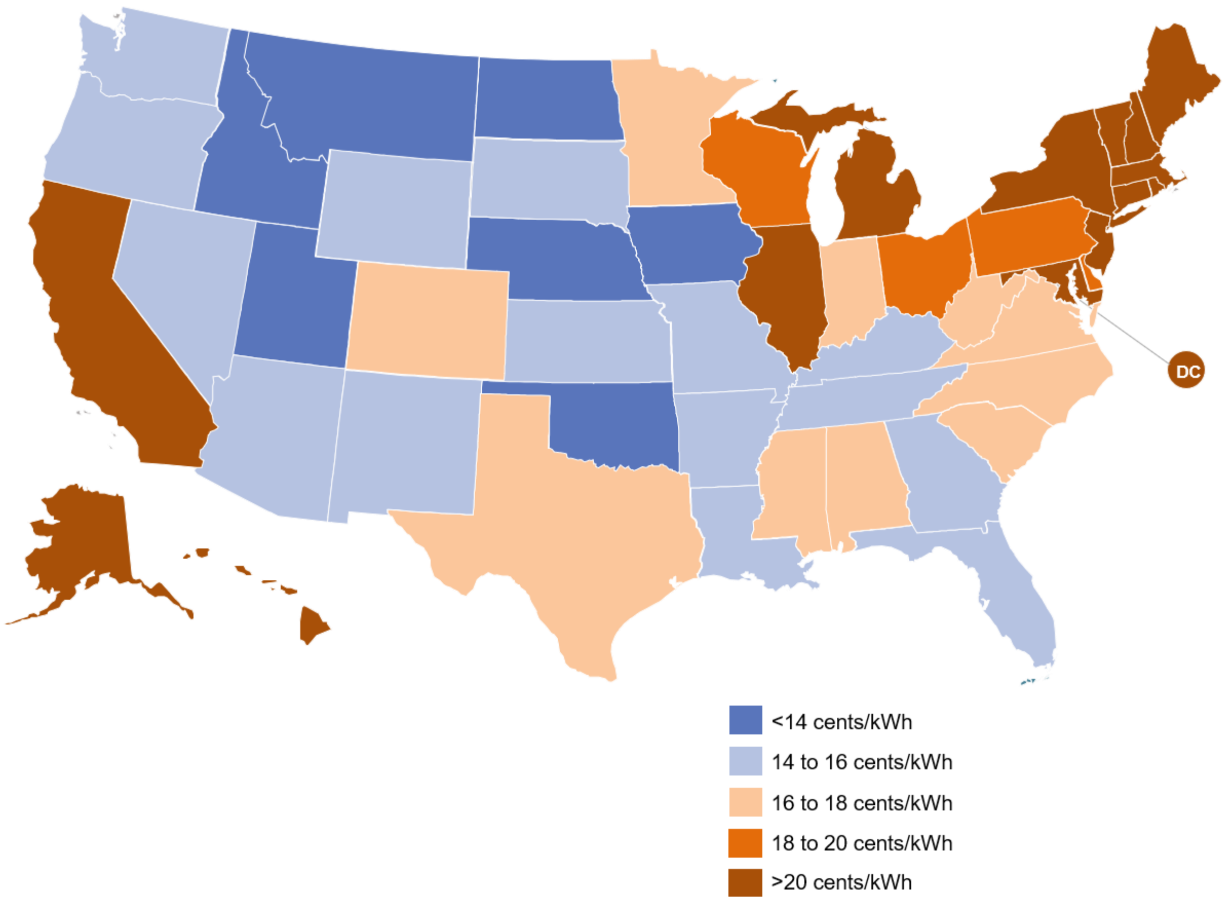
Data Source: U.S. Energy Information Administration – Electric Power Monthly, Average Price of Electricity to Ultimate Customers by End-Use Sector, by State, April 2026 and 2021.

Further, these increases in electricity prices are not felt equally by all ratepayers in the country. The level of energy burden is also on the rise in the U.S. A high energy burden household is one that spends at least 6% of its income on energy, including both electricity and fuel, while any spending higher than 10% of household income is considered severe energy burden.[4,5] On average, low-income households spend 17.8% of their income on energy bills and transportation fuel, more than three times the national average. By different metrics and measures of energy burden, the estimate of energy burdened households in the U.S. ranges from 13% to 21%.[6]

[3] U.S. Energy Information Administration, Electric Power Monthly, Average Price of Electricity to Ultimate Customers by End-Use Sector, by State, April 2026 and 2021, https://www.eia.gov/electricity/data/browser/
[4] U.S. Department of Energy, Low-Income Energy Affordability Data (LEAD) Tool, https://www.energy.gov/cmei/scep/low-income-energy-affordability-data-lead-tool
[5] American Council for an Energy-Efficient Economy, Energy Burden Research, https://www.aceee.org/energy-burden
[6] Federal Reserve Board, Energy Consumption and Inequality in the U.S.: Who are the Energy Burdened?, April 2025, https://www.federalreserve.gov/econres/feds/files/2025026pap.pdf

Regardless of persistent measures, in a 2023 survey, the U.S. Census found that 27% of households reported facing some type of energy insecurity, and around 30% of respondents gave up basic necessities to pay their energy bill.[7] The problems of energy burden and increasing electricity prices are neither new nor slowing down. Recent survey results suggest that over 50% of households have seen their electricity bills increase and 31% have experienced increases over $50 per month.[8]

Figure 3. Average Residential Electricity Price by State (April 2026)



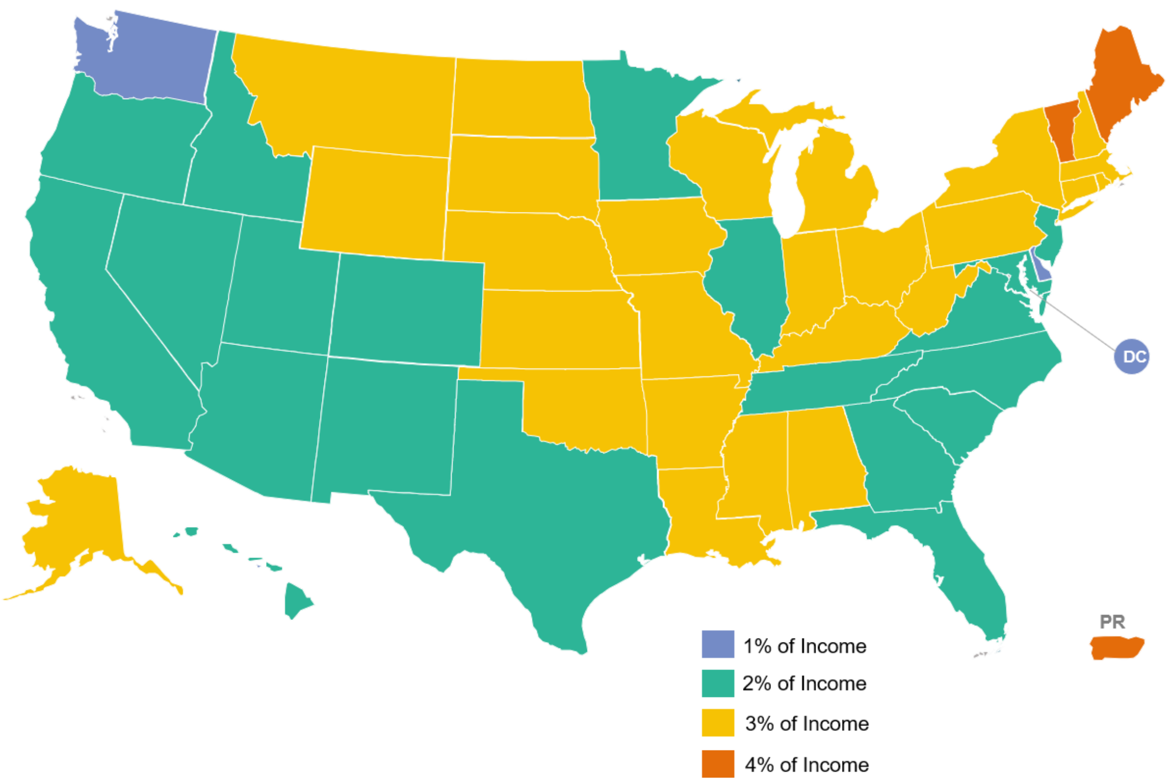
Data Source: U.S. Energy Information Administration – Electric Power Monthly, Average Price of Electricity to Ultimate Customers by End-Use Sector, by State, April 2026.

With this context, policymakers and ratepayers alike are asking two big questions: why is this happening, and what can be done about it? Myriad analyses point to a variety of causes: certain actors use rising prices as an impetus to attack the deployment of clean energy or state clean energy policies, others point to the explosion of large load additions to the grid in the past few years, and still others call out investor-owned utility profit margins. However, identifying causality

[7] Federal Reserve Board, Energy Consumption and Inequality in the U.S.: Who are the Energy Burdened?, April 2025, https://www.federalreserve.gov/econres/feds/files/2025026pap.pdf
[8] Smart Energy Consumer Collaborative, 2026 State of the Consumer Report, February 2026, https://smartenergycc.org/2026-state-of-the-consumer-report/

when it comes to electricity prices is quantitatively challenging (and this report leaves this to other researchers).

Figure 4. Average Energy Burden by State



Data Source: U.S. Department of Energy, Low-income Energy Affordability Data (LEAD) Tool, June 2026.

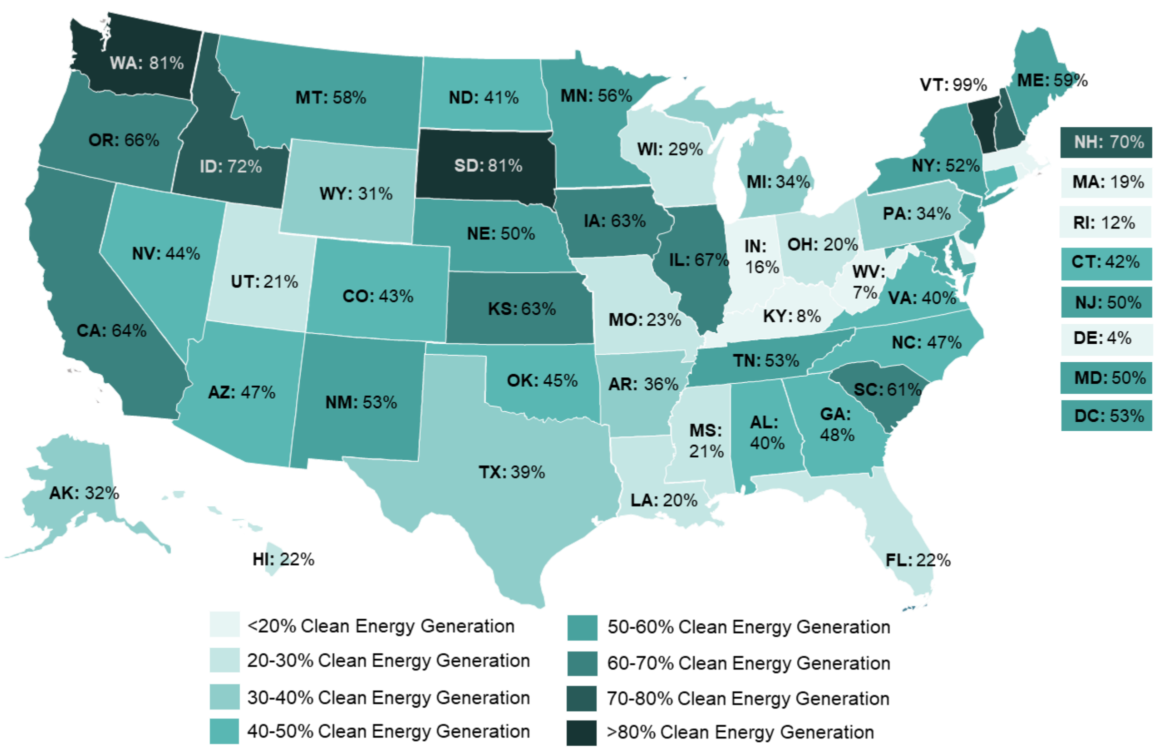
Large load additions can raise electricity demand and require new infrastructure to supply that demand, but some evidence suggests that certain large loads in some markets can actually put downward pressure on rates.[9] Additionally, investor-owned utilities have always been profit-making enterprises, and so there isn't necessarily a direct causal relationship between utility profits and electricity prices.[10] And there is not direct causal evidence that clean energy policies or clean energy deployments necessarily raise or lower prices. All of these factors together play a role, and whether or not clean energy policies and deployment, large load additions, and utility business practices and oversight raise or lower rates is not predetermined but rather is a matter of intentional policy design to socialize, allocate, reduce, or otherwise eliminate costs. Research points to a range of factors influencing prices, working in concert.[11]

[9] Energy Systems Integration Group, Impacts of Large Loads on Electricity Rates: A Primer, May 2026, https://www.esig.energy/reports-briefs/rate-impacts-of-large-loads-primer/
[10] Energy and Policy Institute, Utility Profit Report, March 2026, https://energyandpolicy.org/utility-profit-report/
[11] Lawrence Berkeley National Laboratory, Factors Influencing Recent Trends in Retail Electricity Prices in the United States, October 2025, https://emp.lbl.gov/publications/factors-influencing-recent-trends

While the answer to "what is causing this" is very difficult to ascertain, what can be done about it is not. State legislatures and utilities commissions, as well as the utilities they govern, have been taking a variety of actions that mitigate costs both to utilities and to energy burdened customers. This report seeks to categorize, track, and analyze those policy design considerations in order to provide information to policymakers and utilities looking to expand and assess their own affordability options.

There are longstanding efforts to address energy burden and rising energy and electricity prices. Federal programs, like the Department of Health and Human Service's Low-Income Home Energy Assistance Program (LIHEAP) and the Department of Energy's Weatherization Assistance Program (WAP), have long been part of the portfolio of affordability programs administered by state governments. These two in particular are so ubiquitous that enrollment in these programs is often used to determine eligibility for other affordability or low-income programs.

Figure 5. Percentage of Clean Electricity Generated by State (2025)



Data Source: U.S. Energy Information Administration – Electric Power Monthly, Net Generation by State by Type of Producer by Energy Source (Jan. – Dec. 2025). Map represents percent of total MWh generated in each state from clean energy sources (biomass, geothermal, hydroelectric, nuclear, solar, and wind).

Recognizing that energy prices have long been a focus of federal and state efforts and that the fundamental drivers of costs are varied and deeply intertwined, this report provides a view of the recent energy affordability policy landscape. A number of other organizations have built playbooks[12] and interviewed policymakers[13] in order to understand this landscape and provide recommendations on how to continue providing affordability benefits. This report is mean to be a supplement and catalogue of those policy options. It does not seek to resolve any particular drivers of cost nor does it seek to provide answers outside of energy policy and regulation, but instead to suggest a menu of options that policymakers can choose from in order to keep costs lower for ratepayers in a time of rising prices and growing uncertainty. This can be thought of as a template for policy innovations and an attempt to benchmark where the country is at this point halfway through 2026, and keep track of the efficacy, usefulness, and prevalence of these policy options as energy affordability conversations continue to develop.

[12] Rocky Mountain Institute, Electricity Affordability Toolkit, Accessed June 2026, https://affordability-toolkit.rmi.org/
[13] Federation of American Scientists, States are Plugging into Experimental Electricity Policy to Find Cost-Saving Success, May 2026, https://fas.org/publication/states-experimental-electricity-saving/

OVERVIEW OF 2026 ENERGY AFFORDABILITY ACTION

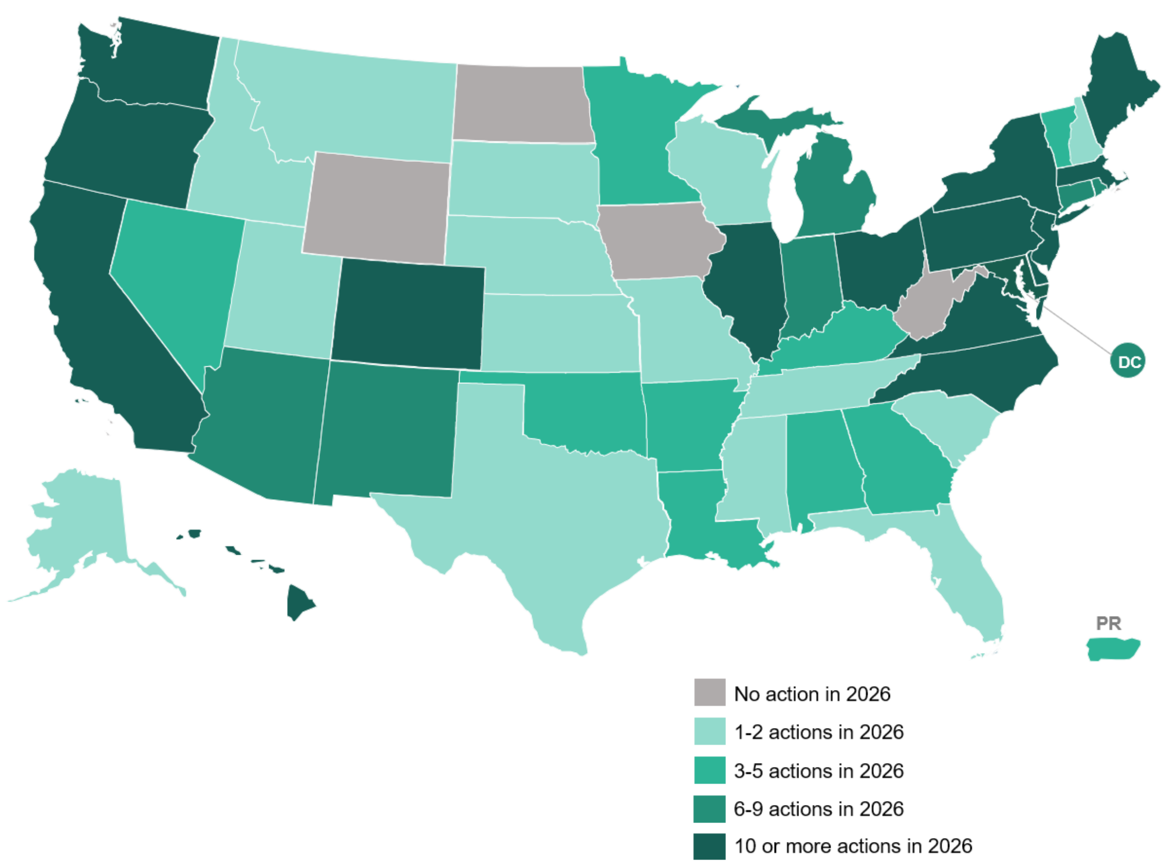
As of June 2026, 46 states, DC, and Puerto Rico took a total of 362 actions related to energy affordability, as scoped by this report. Table 1 provides a summary of state and utility actions on these topics. Of the 362 actions tracked, the most common were related to customer cost allocation (138), utility oversight and cost recovery (60), and studies and investigations (50).

Table 1. Summary of 2026 Energy Affordability Actions

Type of Action	# of Actions	% by Type	# of States
Customer Cost Allocation	138	38%	42 + DC
Utility Oversight and Cost Recovery	60	17%	19 + DC, PR
Studies and Investigations	50	14%	22 + DC
Customer Cost-Saving Programs	48	14%	18
Utility Business Model	36	10%	21 + PR
Planning and Procurement	30	8%	20
Total	**362**	**100%**	**46 States + DC, PR**

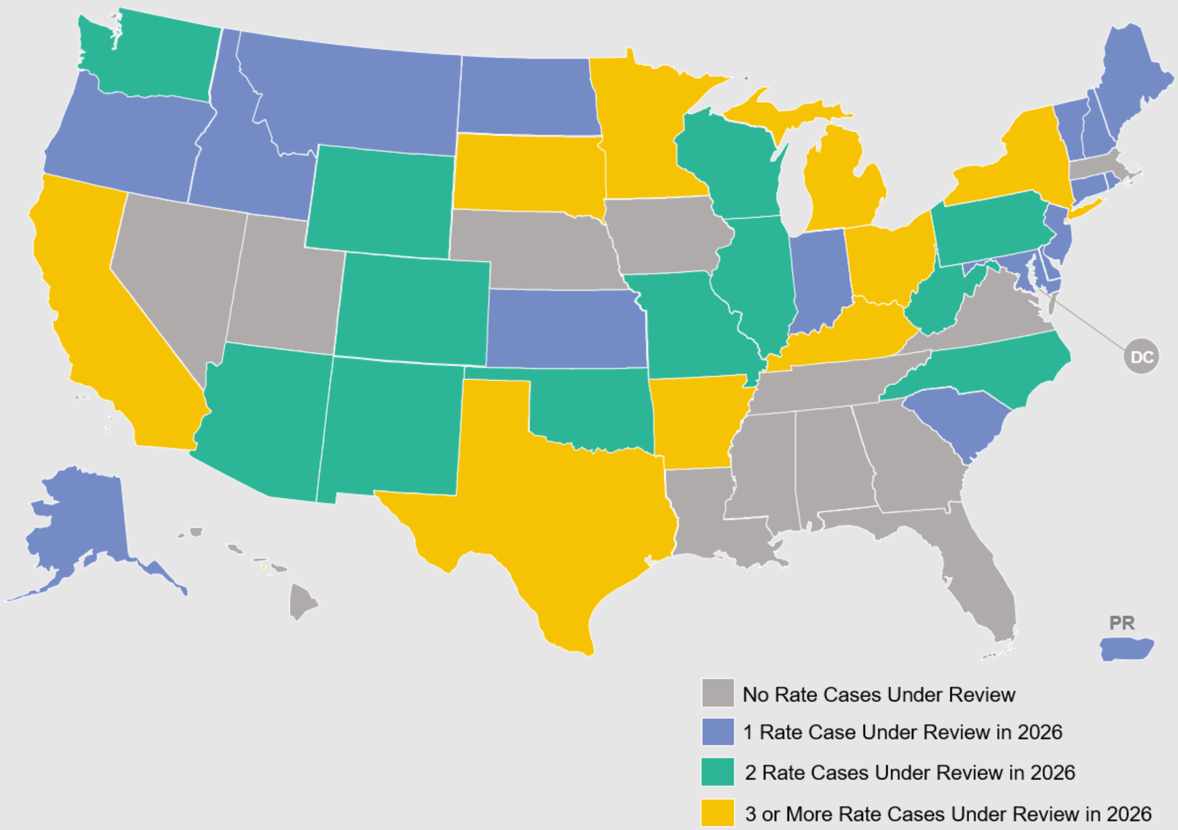
Note: The "# of States/ Districts" total is not the sum of the rows because some states have multiple actions. Percentages are rounded and may not add up to 100%.

Figure 6. 2026 Action on Energy Affordability (as of June 2026)



State and utility activity related to energy affordability is widespread across the U.S., with the vast majority of states taking or considering actions. The most active regions of the country on energy affordability so far in 2026 have been the Mid-Atlantic, West Coast, and Northeast, and the individual states taking the greatest number of actions related to energy affordability so far in 2026 are Pennsylvania, New Jersey, California, and Maryland, followed by Illinois, Maine, New York, and Virginia.

Figure 7. Utility Rate Cases Under Review During 2026 (as of June 2026)



While not tracked in detail by this report, Figure 7 shows states in which utilities had rate case applications under consideration during 2026. Rate cases are formal regulatory proceedings in which utilities propose changes to their rates, and utilities commissions review the utility's costs, revenue requirements, and rate design to determine just and reasonable rates for customers. Utilities commissions in a total of 37 states were in the process of reviewing at least one utility rate case so far this year.

Figure 8. Most Common Energy Affordability Actions in 2026 (as of June 2026)

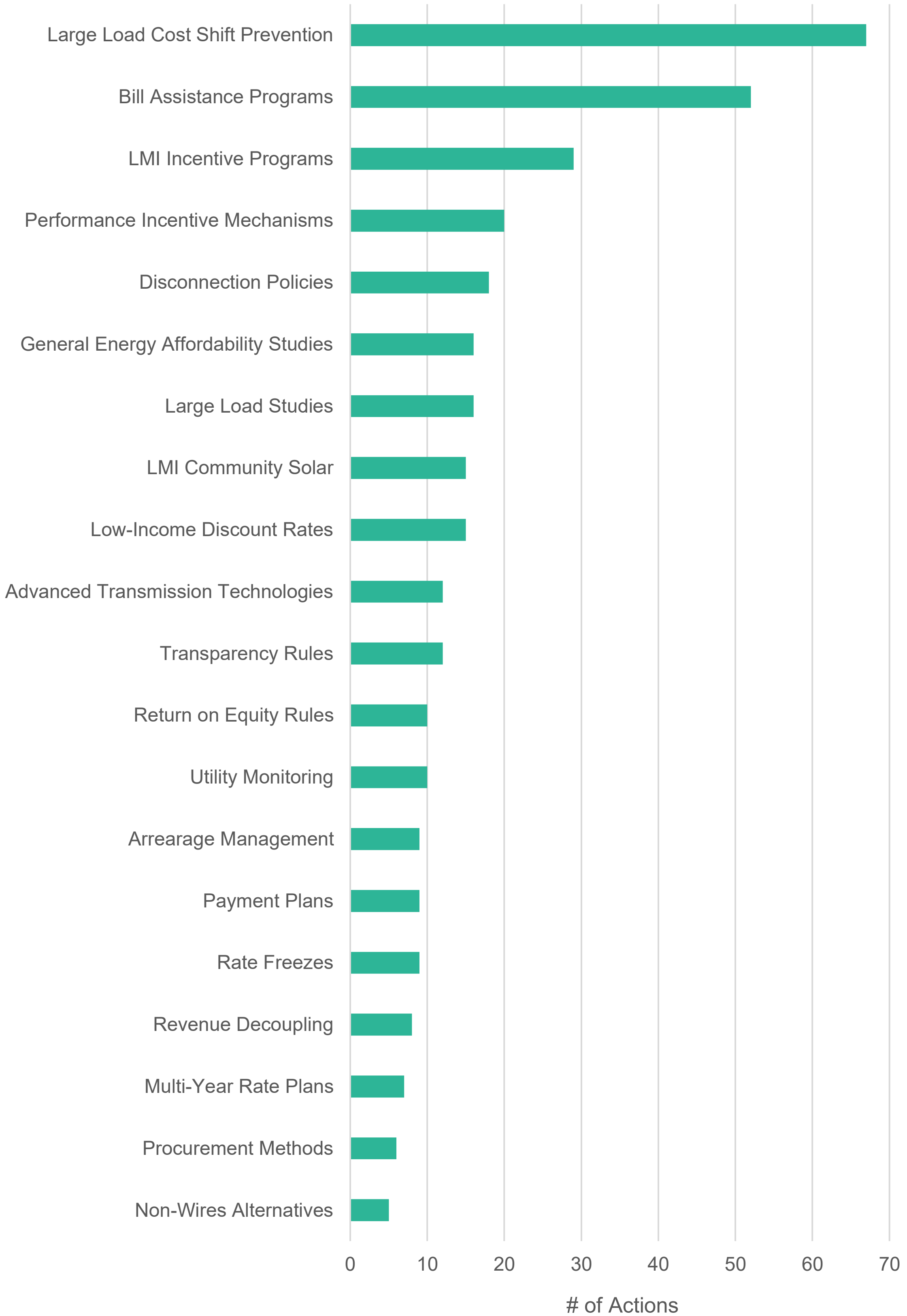
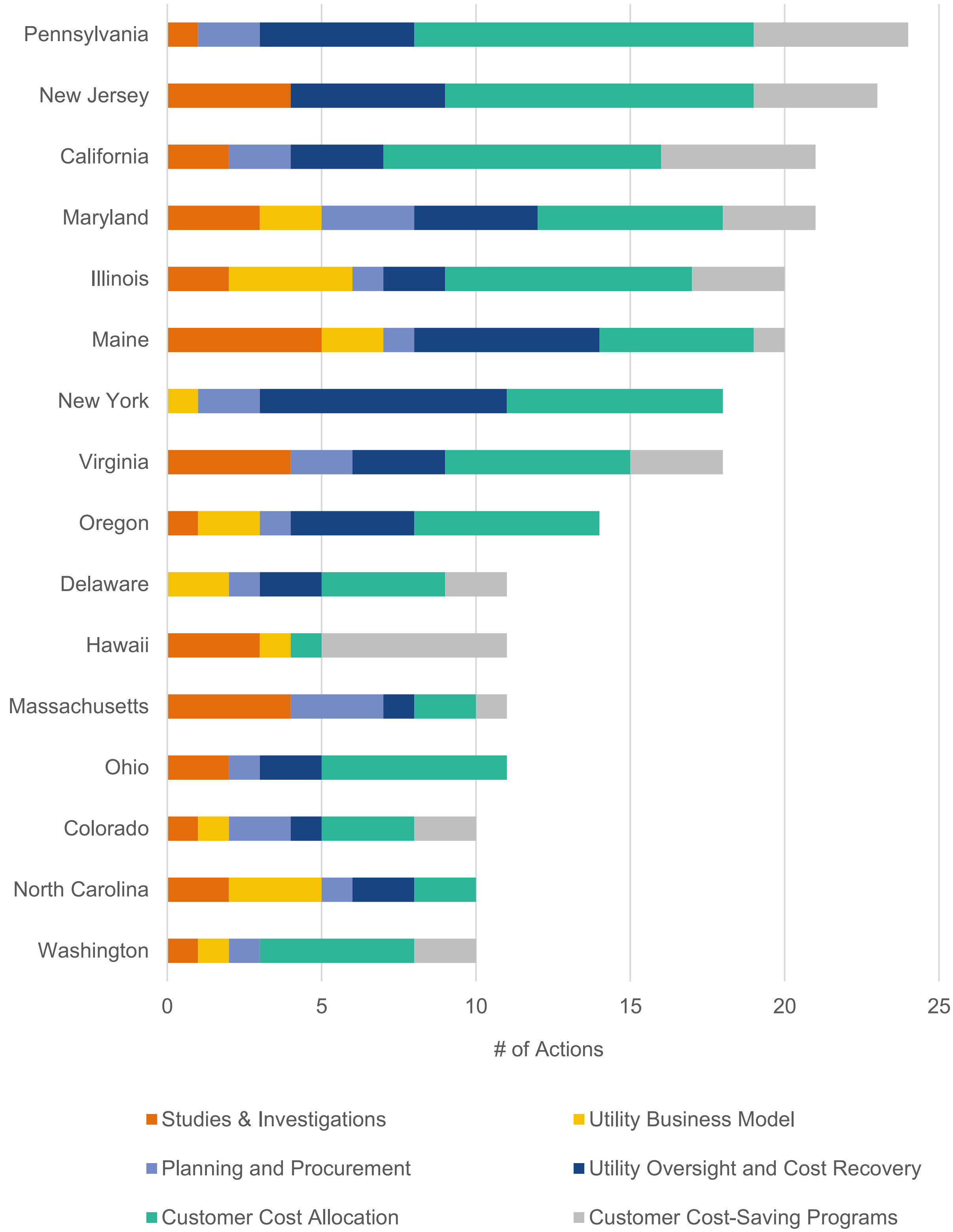


Figure 9. Most Active States of 2026 (as of June 2026)



Box 1. Top Five Energy Affordability Actions

Omnibus Maryland Utility RELIEF Act Makes Changes Across Affordability Levers

In May 2026, Maryland policymakers enacted an omnibus energy affordability bill. The bill initiates a study on automatic community solar enrollment, reduces utility energy efficiency program goals, and directs large load registration fees to residential customer programs. The bill also requires advanced transmission technology assessments and a new renewable energy procurement auction. Further, it promotes oversight in multi-year rate plan proceedings and utility business expenses.

New Jersey Executive Order Initiates Examination of Electricity Costs and Utility Business Model

In January 2026, the Governor of New Jersey signed an executive order directing the Board of Public Utilities to investigate the modernization of the utility business model and address the connection between the traditional model and current affordability issues. The Board must also examine processes for issuing bill credits, consider reducing certain customer charges while preserving funding for direct energy assistance programs, and evaluate pausing rate increase and reconciliation schedules.

New York State Budget Introduces Affordability Index and New Utility Oversight

In its budget bill, signed into law by the Governor in late May 2026, New York took a number of steps to address the rising costs of energy. Among these is a provision requiring utilities to design an affordability index that assesses the energy burden of their customers and to submit that index with each rate increase request. Additionally, the law allows the Public Service Commission to install an independent affordability monitor in each utility.

Indiana Lawmakers Pass Energy Assistance and Performance-Based Regulation Bill

Indiana lawmakers enacted an expansive bill targeting energy affordability in February 2026. The legislation requires utilities to seek rate changes through multi-year rate plans including a new customer affordability performance incentive mechanism. The bill also directs utilities to offer a low-income customer assistance program and adopts a new prohibition on summer electricity shutoffs for low-income customers, among other provisions.

Virginia General Assembly Enacts Suite of Energy Affordability Legislation

The Governor of Virginia signed several pieces of legislation into law addressing energy affordability topics during the 2026 legislative session. Among those bills were provisions limiting fees for disconnection or non-payment, reducing the maximum charge for percentage of income payment plan participants, growing funding commitments for weatherization programs, directing utilities to create low-income distributed energy programs, and initiating studies on grid utilization and performance-based ratemaking.

Box 2. Top Energy Affordability Trends

Governors Take Action on Energy Affordability

Governors across the country are taking actions to support or encourage ratepayer energy affordability. So far this year, Governors in four states - Massachusetts, New Mexico, Rhode Island, and Virginia - have signed executive orders calling for investigations to be conducted and reports and recommendations to be produced on topics such as energy affordability and independence, cost shift avoidance, and cost-reduction policies. The Governor of New Jersey issued another executive order, directing the Board of Public Utilities to take concrete action to increase energy affordability by issuing bill credits to residential customers in order to offset increases in the cost of electricity. Meanwhile, the Governor of Delaware called on the Public Service Commission to freeze electric rates and reset the utility's profit model. Finally, the Governor of Pennsylvania penned a letter to utility leaders, encouraging the consideration of cost-effective forms of capital and transparency.

Policymakers Address Cost Shifts for Customer Programs and Large Loads

Cost shifts are a recurring theme in energy affordability discussions. Cost shifts have long been discussed as part of cost allocation for customer programs like energy efficiency incentives and net metering, but in more recent years these discussions have also focused on the socialization of cost due to new large load additions that require significant infrastructure investments. Policymakers in 41 states and DC took or considered actions to address these issues, either initiating studies on large load additions, opening proceedings on or approving new large load tariffs, reducing energy efficiency budgets to provide short-term bill relief, or re-examining net metering and other rate designs to reduce cost burden on non-participating customers. These actions reflect the urgency with which policymakers are approaching energy affordability as they both grapple with new sources of surging demand and attempt to provide short-term relief, sometimes to the detriment of long-term, system-wide benefit.

Lawmakers and Regulators Examine Utility Business Models and Profit

Lawmakers in Illinois, Indiana, Maryland, Maine, New York, and Rhode Island all passed legislation seeking to shape utilities' business models and profit-earning mechanisms. The provisions vary in mechanism and impact: in Illinois and Indiana, utilities will have their return on equity modified based on performance incentives related to energy affordability; in Maryland, Maine, and Rhode Island, lawmakers are removing a return on equity adder by mandating utility participation in a RTO or ISO; and in New York, the budget law directs the Public Service Commission to consider changes to utilities' return on equity based on affordability and energy burden metrics. Additionally, the Governor of Delaware has called for a proceeding to examine utilities' profit models, Virginia legislators enacted a bill to evaluate a performance-based regulatory framework, and the New Jersey Board of Public Utilities opened a docket to conduct a study of the utility business model.

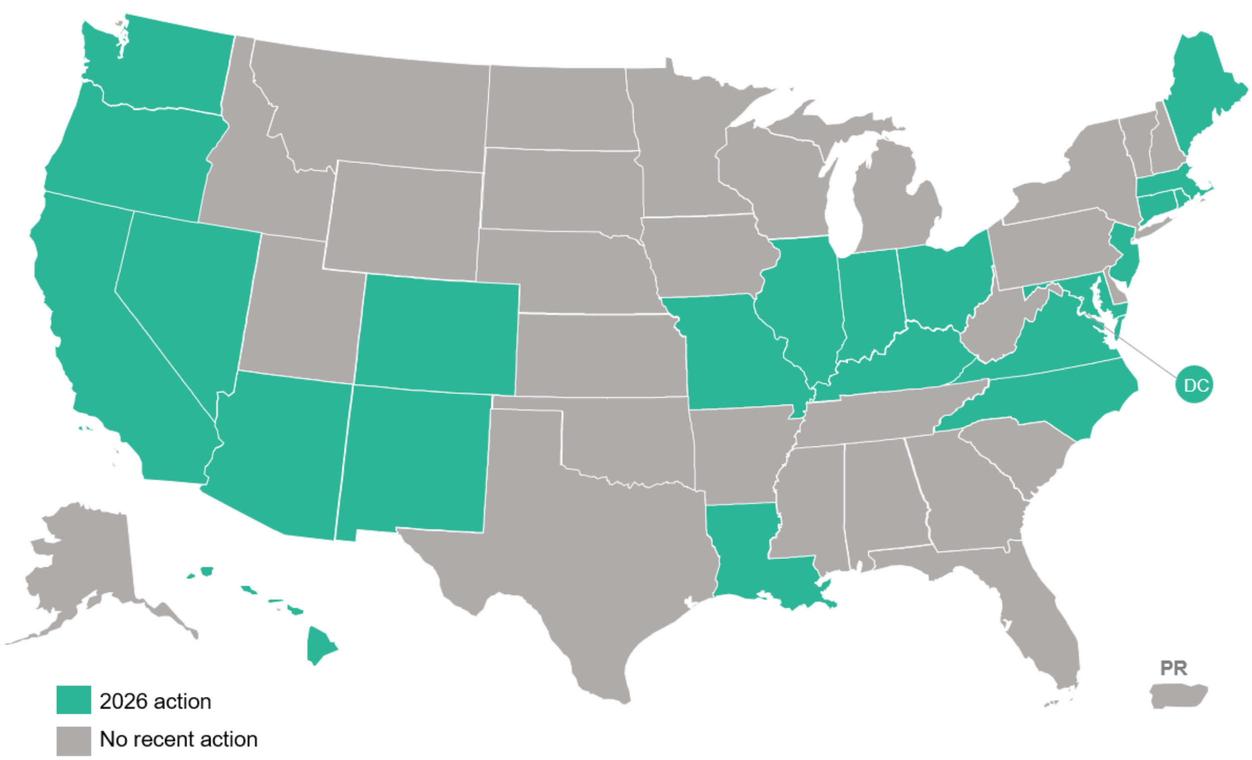
STUDIES AND INVESTIGATIONS

Key Takeaways:

- So far in 2026, 22 states and DC took actions to study or investigate issues related to bill assistance programs, cost shift prevention, utility business models, and energy affordability.
- Maine lawmakers enacted legislation directing the Public Utilities Commission to conduct a comprehensive review of electric delivery rates and consider changes that would support affordability.
- Regulators in Indiana initiated an investigative inquiry on energy affordability to better understand the drivers behind this issue and recommend solutions.

While a number of states are starting to move beyond studies and investigations and toward policy and regulatory changes, several states are engaged in various studies examining specific policies, programs, or regulatory practices related to energy affordability. So far in 2026, 22 states and DC have taken action related to studies and investigations. The majority of these actions focused on topics related to bill assistance programs, cost shift prevention, energy affordability, and utility business model reforms.

Figure 10. Action on Energy Affordability Studies and Investigations



The Indiana Utility Regulatory Commission began an investigative inquiry on energy affordability, with the goal of better understanding the drivers behind energy affordability and identifying shortand long-term solutions. This first phase of a larger strategy included participation from the state's investor-owned utilities. Topics covered in the first session included how usage and rates lead to bills, the impact of growth on affordability, and steps that can be taken in the short-term to increase bill transparency and address rising energy costs.

Meanwhile, in Kentucky, newly enacted legislation requires a review of energy costs, grid reliability, and opportunities and mechanisms to reduce energy cost burdens, specifically on eastern Kentucky households and businesses. Potential opportunities include, but are not limited to, policy intervention, infrastructure investment, rate design modifications, and efficiency approaches.

Lawmakers in Maine directed the Public Utilities Commission to develop an affordability metric. The metric will be used to assess the impact of electricity bills on the energy burden of residential customers. Additionally, the Commission must conduct a comprehensive review of each component of electricity delivery rates to consider whether changes should be made to ensure customer affordability and increase transparency.

Newly enacted legislation in Colorado directs the Public Utilities Commission to conduct a study regarding the barriers utilities face in jointly procuring resources. Jointly procuring resources may increase affordability by lowering per-unit prices and reducing administrative and transitional costs. The study should identify barriers and examine how participation in a wholesale market affects barriers to joint resource procurement.

The Governor of New Mexico established the Energy Affordability and Reliability Council. The Council was created in response to the state's growing electricity demand, mostly stemming from new large load customers, as well as the high number of recent wildfires. The main responsibility of the Council is to make recommendations related to ratepayer protections, affordable rate designs, and advancing clean energy progress. Additionally, the Council must assess a number of different factors to design a framework to appropriately adjust permitting to accelerate low-carbon impact projects and ensure alignment with applicable innovation, infrastructure, and economic development funding.

In February 2026, the Governor of Rhode Island signed an executive order requiring a comprehensive review of the state's net metering program (behind-the-meter and virtual) and the Renewable Energy Growth Program. The goal of this order is to control costs to ratepayers and ensure the programs do not impose an undue financial burden on households and businesses, while remaining aligned with the state's emission reduction policies. The review should evaluate ratepayer impacts, state fiscal implications, and energy system effects, assessing potential program modifications when appropriate. In addition, a longer-term review of behind-the-meter net metering and the Renewable Energy Growth Program must be completed, providing key findings and potential policy and legislative options.

Finally, legislation signed into law in Virginia directs the State Corporation Commission to consider whether a performance-based regulatory framework, which would evaluate electric utility performance and cost control incentives, are in the public interest of the Commonwealth. The Commission is also directed to conduct a comprehensive analysis of existing electric utility infrastructure to identify cost-saving opportunities that improve or preserve electric system reliability as an alternative or supplement to greenfield infrastructure projects

Many states began or ordered studies while studies in other states are still under consideration. In Massachusetts, lawmakers advanced legislation that would establish an Electric Rates Taskforce. The Taskforce would be charged with advising the state government on the current and future costs of electricity in the state. The Taskforce must report on: each cost component for electric bills for residential and commercial customers of investor-owned utilities, current cost per-kWh and per month for average users, annual rate increases over the previous ten years, projected increases over the next five years, and recommended short- and long-term rate relief. The report is also to benchmark ratepayer affordability in Massachusetts against all other New England states.

Box 3. Categorizing Studies and Investigations

Actions included within Studies and Investigations do not include a defined policy proposal or a directive to make a specific policy or regulatory change. Once a specific proposal is introduced, that action is included in the more specific category pertaining to that particular type of change, such as Utility Business Model Reforms, Utility Oversight and Cost Recovery, Planning and Procurement, Customer Cost Allocation, or Customer Cost-Saving Programs.

An additional provision within this proposed legislation directs the Inspector General to perform a comprehensive review of the Mass Saves program to ensure ratepayer funds are being used effectively and efficiently. The Mass Saves program is a collaboration amongst electric and natural gas utilities and energy efficiency service providers, providing a range of services, rebates, incentives, training, and information for energy efficiency upgrades. The program is funded by mandatory energy efficiency charges on customers' electric and gas bills. The inspector's review must include methods of supporting energy efficiency goals while increasing ratepayer affordability.

In California, the Senate advanced legislation that would begin the first phase analysis of a potential transition away from the investor-owned utility model. California lawmakers previously enacted legislation authorizing an in-depth study to assess the practical, financial, legal, regulatory, labor, and technical aspects of a smooth and just transition away from the investor-owned utility model to one that prioritizes the needs of people and the ecology of the state.

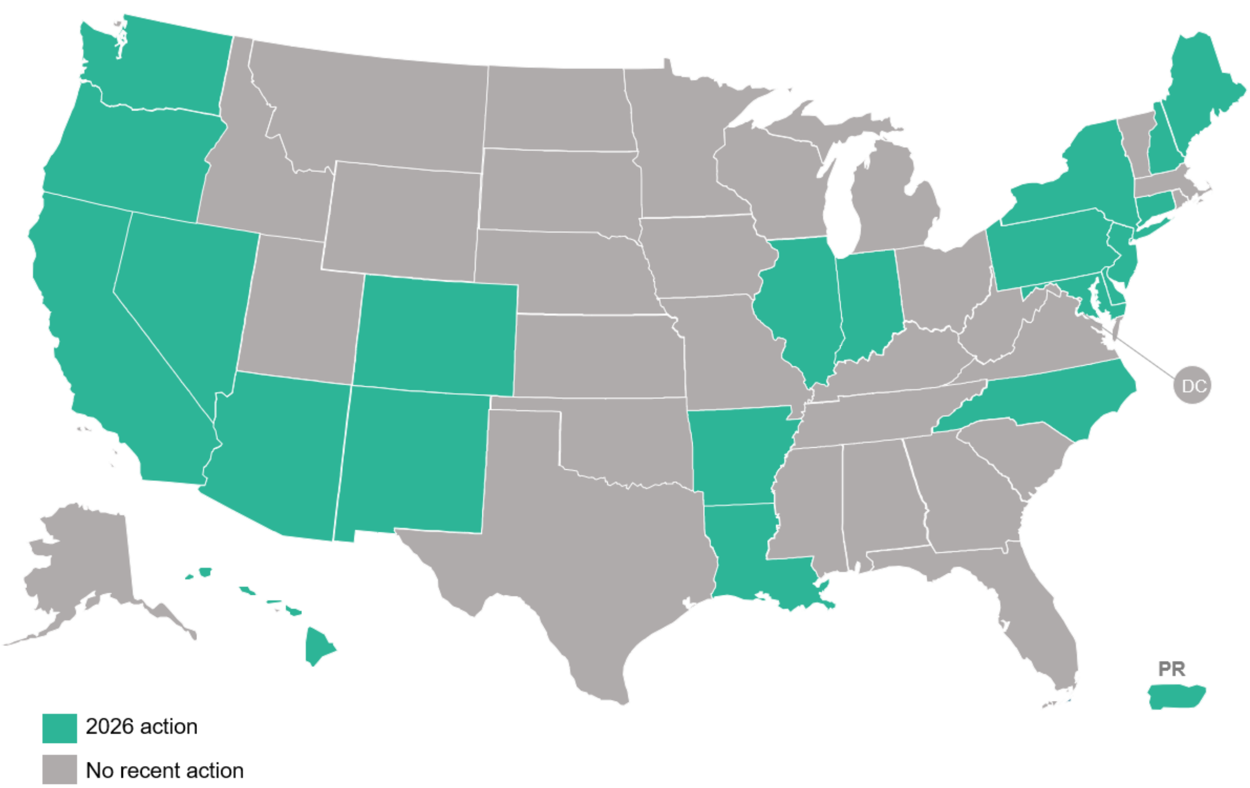
UTILITY BUSINESS MODEL REFORM

Key Takeaways:

- So far in 2026, 21 states and Puerto Rico took actions related to utility business model reforms impacting energy affordability.
- Indiana lawmakers enacted legislation requiring utilities to submit multi-year rate plans with performance incentive mechanisms focused on affordability and service restoration.
- Oregon regulators released straw proposals to implement 2025 legislation requiring multi-year rate plans and performance incentive mechanisms.

The connection between utility business models and affordability revolves around utilities' incentive structure and profit models. While the purpose of a typical business is to maximize profit, utilities must also serve the public interest. As a result, lawmakers and regulators take an interest in how much money utilities can make from their customers, rewarding utilities for achieving non-monetary goals, or developing mechanisms to reinvest earnings into customer programs. These policies can promote affordability by attempting to rein in profits and enable or require utilities to provide more public services using customer revenues. As of June 2026, 21 states and Puerto Rico took actions related to utility business model reforms.

Figure 11. Action on Utility Business Model Reforms



A significant portion of actions addressing utility business model reforms so far in 2026 focused on performance-based regulation, including multi-year rate planning, performance incentive mechanisms, and revenue decoupling. The Arkansas Public Service Commission began an investigation into strategies, efficiencies, and cost containment measures to facilitate electric and gas affordability, including performance-based ratemaking. Meanwhile, the Puerto Rico Energy Bureau approved a temporary decoupling mechanism for PREPA.

In 2025, Oregon legislation required the state's Public Utility Commission to establish a multi-year rate plan framework and a performance-based ratemaking framework; the Commission then opened various rulemakings to create the frameworks. This year, Commission Staff released two straw proposals for multi-year rate plans. The first focuses on the transition from current rate plans and the first multi-year rate plan for utilities, while the second outlines the design elements of a multi-year rate plan framework. Indiana lawmakers also considered multi-year rate plans, implementing requirements for utilities. Duke Energy must file its first plan by 2027, and other utilities by 2029.

The Indiana legislation also adopts rules for performance incentive mechanisms, performance metrics, and return on equity. A utility's rate of return can change up to 1% based on the results of the performance metrics, including a metric for customer affordability. The New York Senate passed a bill requiring the New York Public Service Commission to annually set a standardized common equity ratio for each regulated utility and a single authorized rate of return on equity for all utilities. Utilities must also return excess return on equity to customers as a bill credit.

The Illinois Commerce Commission approved performance and tracking metrics for Ameren Illinois and Commonwealth Edison for 2028-2031; Ameren's metrics include one for affordable customer delivery costs, while Commonwealth Edison's includes two for reduced disconnections. Meanwhile, the Washington Utilities and Transportation Commission released a policy statement clarifying performance metrics and providing guiding principles for performance-incentive mechanisms. In addition, Hawaii lawmakers enacted legislation clarifying that performance-based incentives can include revenue adjustment mechanisms, cost control mechanisms, and reward and penalty mechanisms.

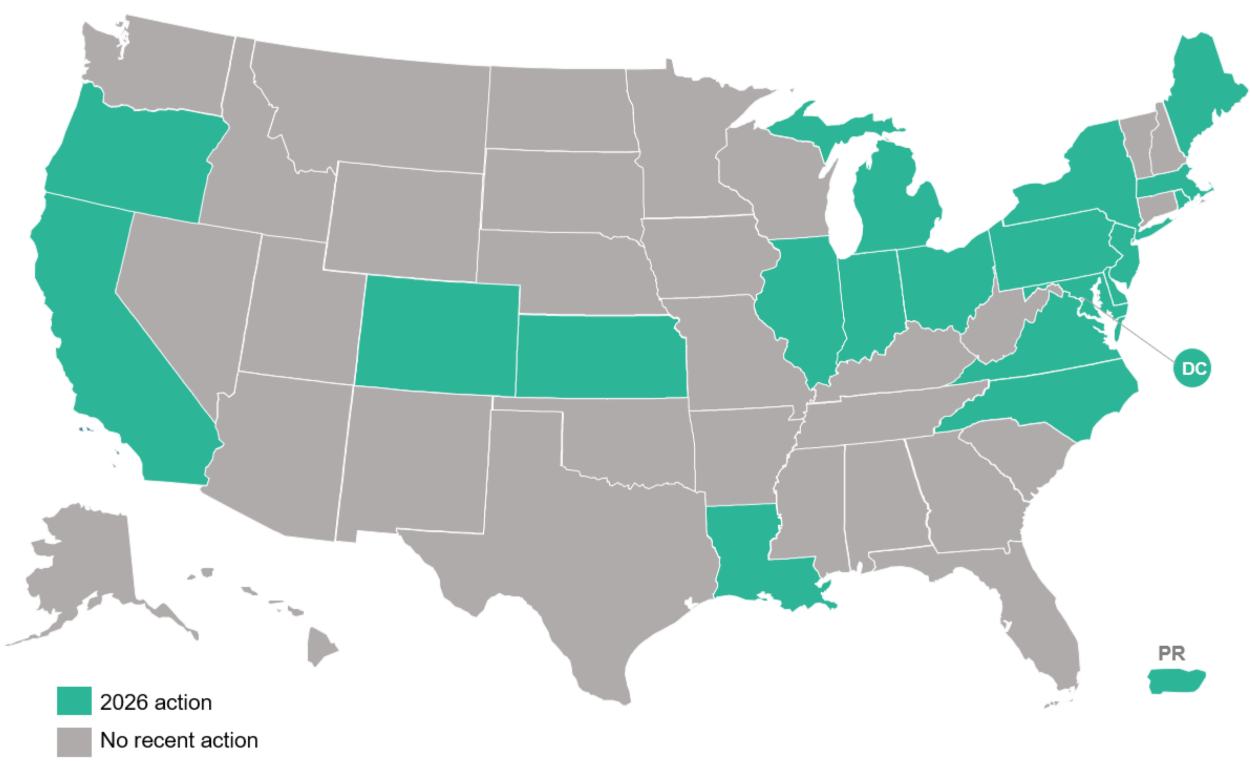
UTILITY OVERSIGHT AND COST RECOVERY

Key Takeaways:

- So far in 2026, 19 states, DC, and Puerto Rico took actions related to utility oversight and cost recovery.
- Oregon regulators adopted rules implementing utility oversight provisions from a recently enacted bill, including a winter rate increase moratorium and rate case reporting and analysis requirements.
- New York lawmakers enacted legislation requiring utilities to report on the energy burden of their customers and create an affordability index, and allowed regulators to install independent affordability monitors at utilities requesting large rate increases.

Utility oversight, or actions taken to ensure that utilities act in the public interest, can help control or reduce costs by providing direction for, limits on, or consequences for utility business practices. Utility oversight actions tracked in this report range from audits and monitoring, to reforms to cost recovery rules and outright rate freezes, to providing additional avenues for consumer representation. These kinds of actions promote affordability by empowering regulators to hold utilities accountable when needed, giving consumers more power, and improving transparency into utility practices. Thus far in 2026, 19 states, DC, and Puerto Rico have taken action on utility oversight and cost recovery practices. Several states focused on tracking costs, freezing rates, auditing utilities and programs, and consumer representation.

Figure 13. Action on Utility Oversight and Cost Recovery



Multiple states focused their oversight on gauging energy affordability. In Maine, lawmakers enacted a bill that requires the Public Utilities Commission to develop an affordability metric to assess the impact of electricity bills on residential energy burden. New York's budget, signed by the Governor in March 2026, includes a provision requiring utilities to design an affordability index that assesses customer energy burden and to submit the index with each rate increase request. The law also allows the New York Public Service Commission to install an affordability monitor in each utility, who will report to the Commission on affordability activities.

In March 2026, the Oregon Public Utility Commission adopted rules implementing provisions from recently enacted legislation that prohibit residential rate increases in winter months, address general rate case impact analysis requirements, require visual representations of cost drivers, and require annual reports on expected rate increases. In May 2026, the Commission filed its proposal for the winter rate increase moratorium, addressing effective dates, allowing rate changes that do not increase rates or negatively impact customers, addressing revenue and interest treatment, and outlining customer communication requirements.

Actors in several other states promoted utility oversight by limiting rate increases. The new Governor of New Jersey began her term in 2026 by directing the Board of Public Utilities to consider a pause or modification of the schedule governing electric utility rate increases and cost recovery. Elsewhere, following the DC Court of Appeals order vacating and remanding Pepco's recent multi-year rate plan, the DC Council adopted a resolution directing the Public Service Commission to restore Pepco's rates to those last approved in December 2024.

Lawmakers in other states provided for overarching procedures to modify or freeze rates. Kansas legislators enacted a bill requiring the Kansas Corporation Commission to consider petitions from utility customers protesting rate changes if they are signed by at least 5% of the utility's customers or 3% of customers from one rate class. If the Commission finds the rates to be unjust, unreasonable, discriminatory, or preferential after investigation, it may change the rates.

Legislators in Michigan's House passed a bill requiring utilities to report property tax exemption savings to the Michigan Public Service Commission. Within a month of the reports, the Commission must subsequently begin conducting reconciliation proceedings. The Commission must issue orders decreasing residential utility rates by the amount of property tax exemption savings, and utilities cannot apply for rate increases for two years thereafter.

Meanwhile in Maine, legislators also moved to promote cost transparency by enacting a bill that prohibits utilities from labeling rate-recoverable expenses as "public policy charges." Instead, utilities will be required to objectively label and describe any charges other than those for supply, delivery, and transmission. The Massachusetts House passed a bill requiring more comprehensive oversight through management and operations audits for electric utilities every five years by the Department of Public Utilities (DPU) or an independent auditor. The utilities would be required to submit a plan to implement the DPU's findings and recommendations and may receive penalties for non-compliance.

Finally, regulators in Pennsylvania directed West Penn Power to make financial contributions and changes to customer assistance protocols in response to a complaint spurred by the death of a customer shortly following a service shutoff. The complaint alleged that West Penn violated regulations by terminating service during a winter moratorium and without considering the resident's federal poverty level, failing to provide information about universal service programming and eligibility, and failing to explain emergency medical procedures. The Pennsylvania Public Utility Commission ordered double the civil penalty and hardship fund contribution that was proposed in the case settlement and directed West Penn to improve training and customer income review.

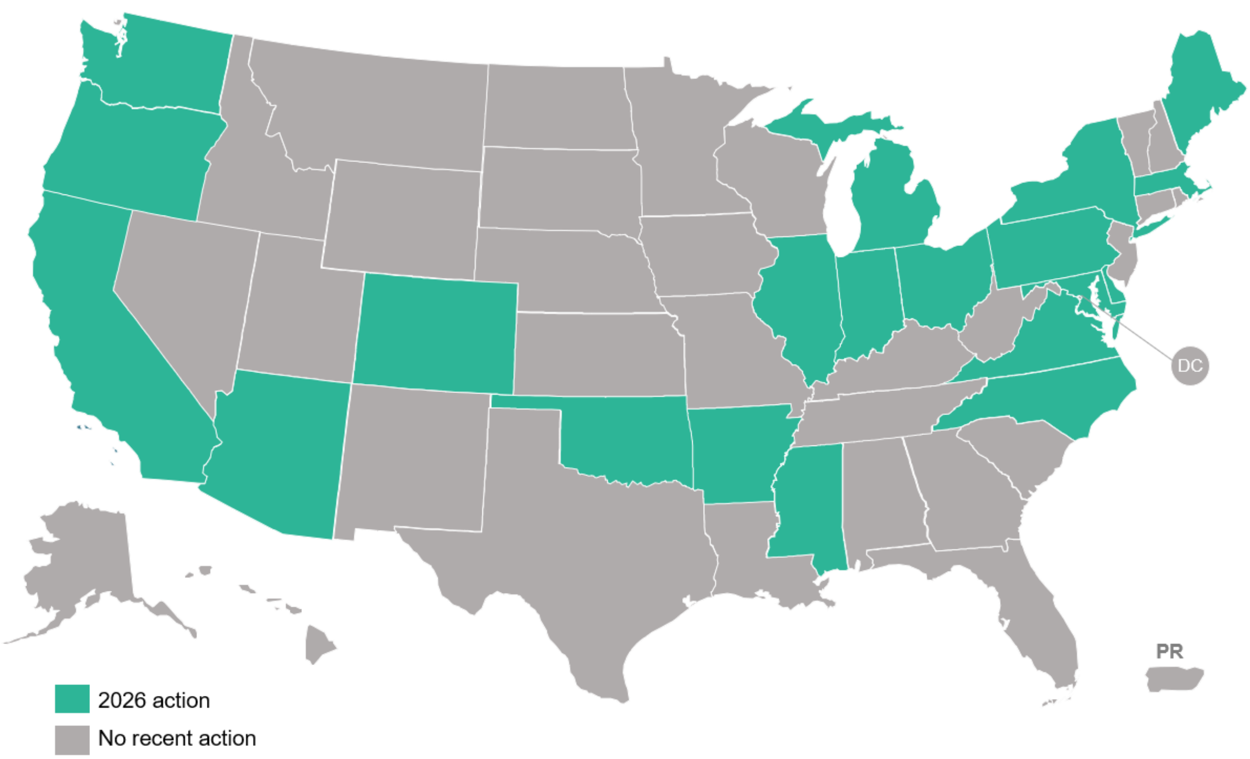
INFRASTRUCTURE PLANNING AND PROCUREMENT

Key Takeaways:

- So far in 2026, 20 states have considered infrastructure planning and procurement actions related to energy affordability.
- Lawmakers in Colorado enacted legislation requiring utilities to consider advanced transmission technologies in planning processes.
- Virginia legislators adopted new requirements for utilities to develop grid utilization metrics and evaluate non-wires alternatives.

The majority of utilities are required to file some form of planning document on a regular basis, outlining projected capacity growth and what resources they will procure in order to meet this growth. Securing least-cost or low-cost resources, integrating affordability into planning rules, and more fully utilizing existing utility infrastructure are just some ways the planning and procurement process can be used to control costs and positively impact energy affordability. So far in 2026, 20 states have considered infrastructure planning and procurement actions related to energy affordability. These actions include procurement methods, innovative financing, evaluation of advanced transmission technologies and non-wire alternatives, and more.

Figure 12. Action on Infrastructure Planning and Procurement



Across several states, regulators and legislators directed the inclusion of advanced transmission technology (ATT) evaluations in future planning reports. In Colorado, lawmakers enacted legislation requiring utilities' ten-year transmission plans to include an evaluation of the potential of ATTs, such as dynamic line ratings, advanced power flow controllers, topology optimization, stationary and other technologies that increase grid reliability, flexibility, and capability. The evaluation must include a cost-effectiveness analysis and an assessment of the technologies' ability to increase the transmission system cost-effectiveness. If ATTs offer a more cost-effective strategy but the utility does not include them in its plan, then it must explain why the technologies should not be deployed.

Similarly, legislators in Pennsylvania advanced a new requirement for the consideration of ATTs in certain applications relating to the Public Utility Commission's review of siting and construction of transmission lines. Applicants would be required to provide a report demonstrating that the use of ATTs for existing transmission infrastructure and proposed transmission infrastructure in the application were assessed and evaluated. The Commission may order the applicant to integrate ATTs to help partially or fully resolve the need identified in the application as a condition of approval.

In North Carolina, the Utilities Commission approved Duke Energy's plan to conduct an 18-month prototype of dynamic line rating (DLR) for its transmission lines. DLR involves attaching sensors to power lines that measure ambient environmental factors like temperature and wind speed to assess whether the lines will cool faster or slower when operated at higher capacity. With DLR, utilities can improve transmission line capacity by 10-50%. Duke Energy will test these sensors across four transmission lines and will report back to the Commission every six months.

In Virginia, newly enacted legislation requires investor-owned utilities in the state to petition the State Corporation Commission for approval of grid utilization metrics. The petition must include assessments comparing current electric grid system performance with optimal utilization of existing electric grid assets. The bill also requires the Commission to include in an existing annual report its findings on each applicable utility's assessment of relevant grid utilization metrics, which must include an analysis of the potential for each applicable utility to increase electric grid utilization through the deployment of non-wires alternatives.

In Maryland, legislators enacted new legislation amending the requirements to be included for an application of a certificate of public convenience and necessity for the construction of a transmission line. In the planning process, applicants must consider alternatives to the proposed transmission line and analyze ATTs that will enhance the value of the new lead line, as well as technologies or modifications to electric distribution systems that could avoid the need for the transmission line. Cost to ratepayers must also be considered within the process.

The new Maryland law also requires each owner or operator of transmission lines to submit a report that identifies the following: areas of transmission congestion for the preceding three years and coming five years; the cost to ratepayers as a result of past and projected congestion; the feasibility and cost of using alternative means of addressing congestion, including advanced transmission technologies; and the social, environmental, and economic issues posed by the use of each alternative. The report must also propose an advanced transmission technology plan if feasible.

Meanwhile, in Mississippi, lawmakers established a new mechanism for the Public Service Commission to authorize utility financing to cover the costs associated with storm damage repairs. Utilities are now allowed to recover storm-related repair costs via system restoration bonds issued by the State Bond Commission. The proceeds of such bonds will be used to securitize the system restoration costs and storm damage reserve levels, with the goal of providing customers relief from traditional methods of recovering these costs.

Finally, in Delaware, a resolution adopted by the House urges the PJM regional transmission organization to extend its price collars for two years at the current rate and encourages the organization to reform its interconnection queue to allow new generation to come online faster and prevent the need for future price collars. PJM's price collars have saved customers more than $8 billion and the current collar is set to expire at the end of 2026.

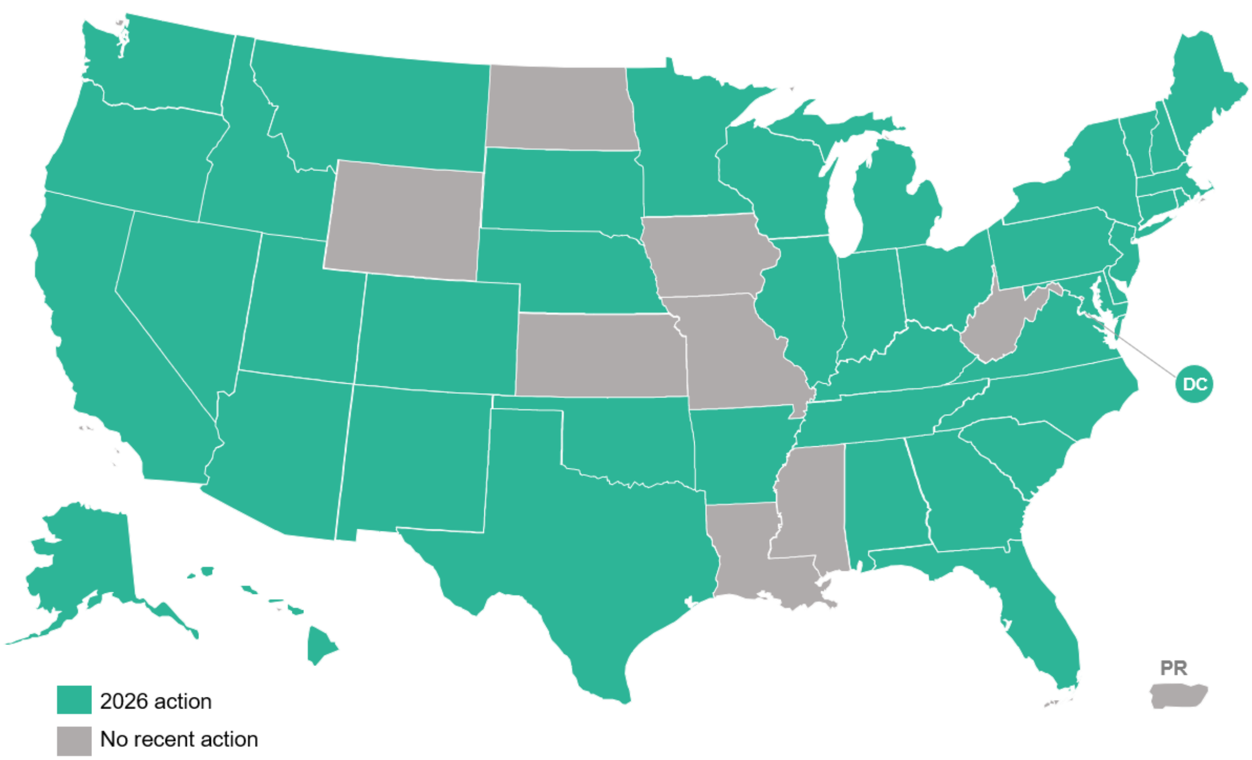
CUSTOMER COST ALLOCATION

Key Takeaways:

- So far in 2026, 42 states and DC took actions related to customer cost allocation, including bill assistance programs, large load tariffs, and low-income discount rates.
- Thirty-six states took actions specifically focused on allocation of costs associated with serving new large load customers.
- Regulators in Maryland and Massachusetts approved tiered frameworks for low-income discount rates, while Washington legislators established a new supplemental low-income energy assistance program.

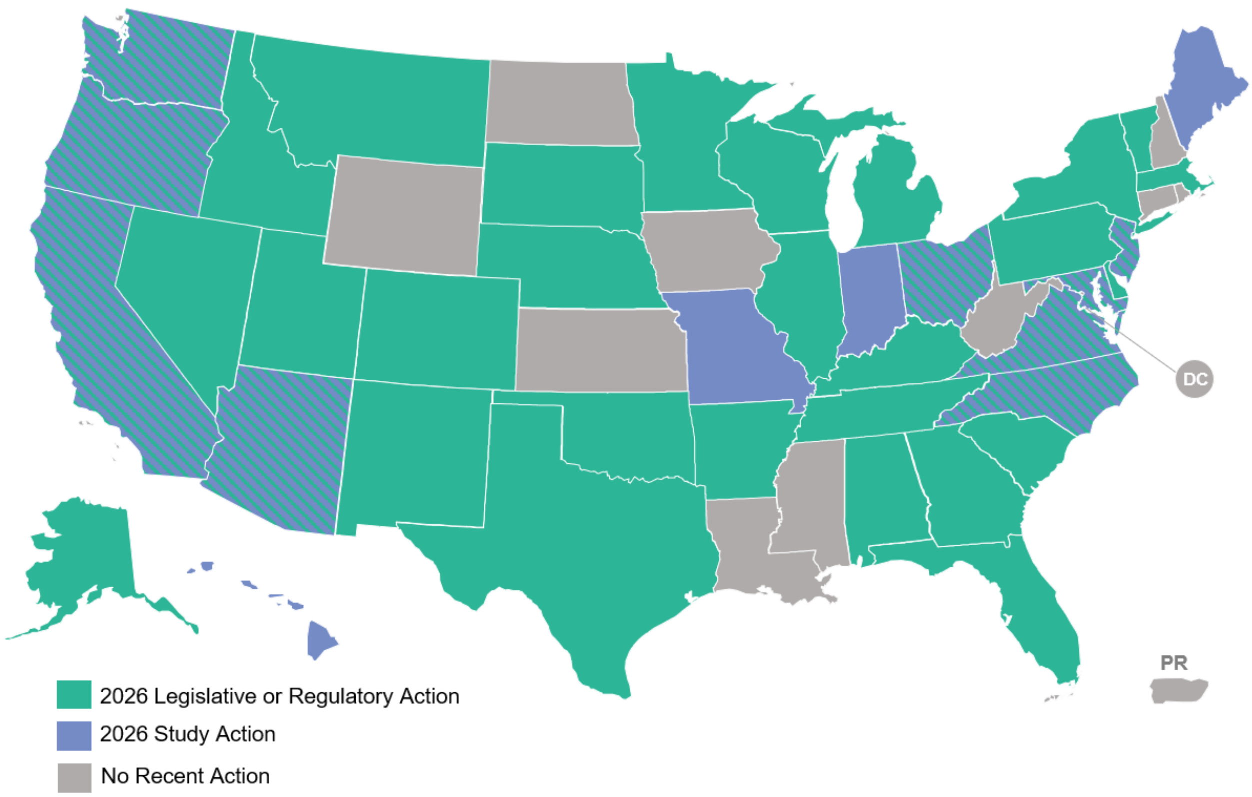
Customer cost allocation, or the way in which a utility's costs are distributed amongst customer classes for recovery, has significant implications for energy affordability. These largely boil down to (1) preventing costs caused by one customer class from being shifted to others and (2) intentionally allowing for cost shifts that reduce costs for energy-burdened customers. Note that for this report, customer cost allocation also refers to how costs may be shifted between the ratepayer base and taxpayer base - for example, through state-funded bill assistance programs. So far in 2026, 42 states and DC took actions related to customer cost allocation, including consideration of bill assistance programs, large load tariffs, low-income discount rates, and percentage of income payment plans.

Figure 14. Action on Customer Cost Allocation



Unsurprisingly given the amount of public attention on data centers, the most common type of action taken by states and utilities so far in 2026 has been developing large load tariffs or taking other steps to prevent costs required to serve new large load customers from being borne by other ratepayers. A total of 36 states considered specific actions to prevent cost shifts associated with new large load customers. Lawmakers in several states - including Alabama, Florida, Idaho, Maryland, Nebraska, Oklahoma, South Dakota, and Tennessee - have enacted legislation related to large load customer cost allocation so far in 2026.

Figure 15. Action on Large Load Customer Cost Allocation



Some states have also been addressing potential cost shifts due to customer programs, including net metering. Maine lawmakers enacted legislation establishing a Net Energy Billing Cost Stabilization Fund, which will help to offset ratepayer costs associated with Maine's net energy billing program. In Rhode Island, the Governor issued an executive order requiring the Office of Energy Resources to review the state's net metering and renewable energy incentive programs, with the goal of controlling costs to ratepayers and ensuring the programs do not place under financial burden on households and businesses.

Another major area of activity this year has been around customer bill assistance programs, which provide financial relief to low-income or otherwise vulnerable customers to help them afford their energy bills and avoid service disconnections. In Indiana, lawmakers enacted legislation requiring regulated utilities to offer a low-income customers assistance program by July 1, 2026, while Washington legislators established a statewide low-income energy assistance program as a supplement to utility-provided energy assistance programs. In Michigan, the Public Service Commission expanded low-income energy assistance in the state by increasing non-bypassable charges that support these programs.

Some states also took actions to move toward auto-enrollment in customer assistance programs for eligible customers. In Pennsylvania, Duquesne Light Company filed for approval of its plan to auto-enroll eligible customers with an outstanding balance of $250 or more in the utility's customer assistance program. Taking a bit of a different approach, the Governor of New Jersey signed an executive order directing the Board of Public Utilities to issue residential universal bill credits (RUBCs) to offset increases in the cost of electricity in 2026, building upon the initial RUBC initiative approved in August 2025.

Other states and utilities addressed customer cost allocation through low-income discount rates or percentage of income payment plans (PIPPs). The Massachusetts Department of Public Utilities issued an order in February 2026, establishing a low-income discount rate framework. The framework contains six income tiers, with discounts tied to energy burden; utilities are required to implement the new framework by November 1, 2026. The Massachusetts State House also passed a bill that would establish requirements for LMI rate discounts and fund these through a non-bypassable monthly fixed charge. In Maryland, regulators approved the design for a tiered discount mechanism targeting low-income customers, and in New Mexico, El Paso Electric proposed a new low-income rider that would waive the monthly fixed charge for income-qualified customers. Meanwhile in Colorado, legislators enacted a bill requiring investor-owned utilities to establish PIPP programs for residential income-qualified customers.

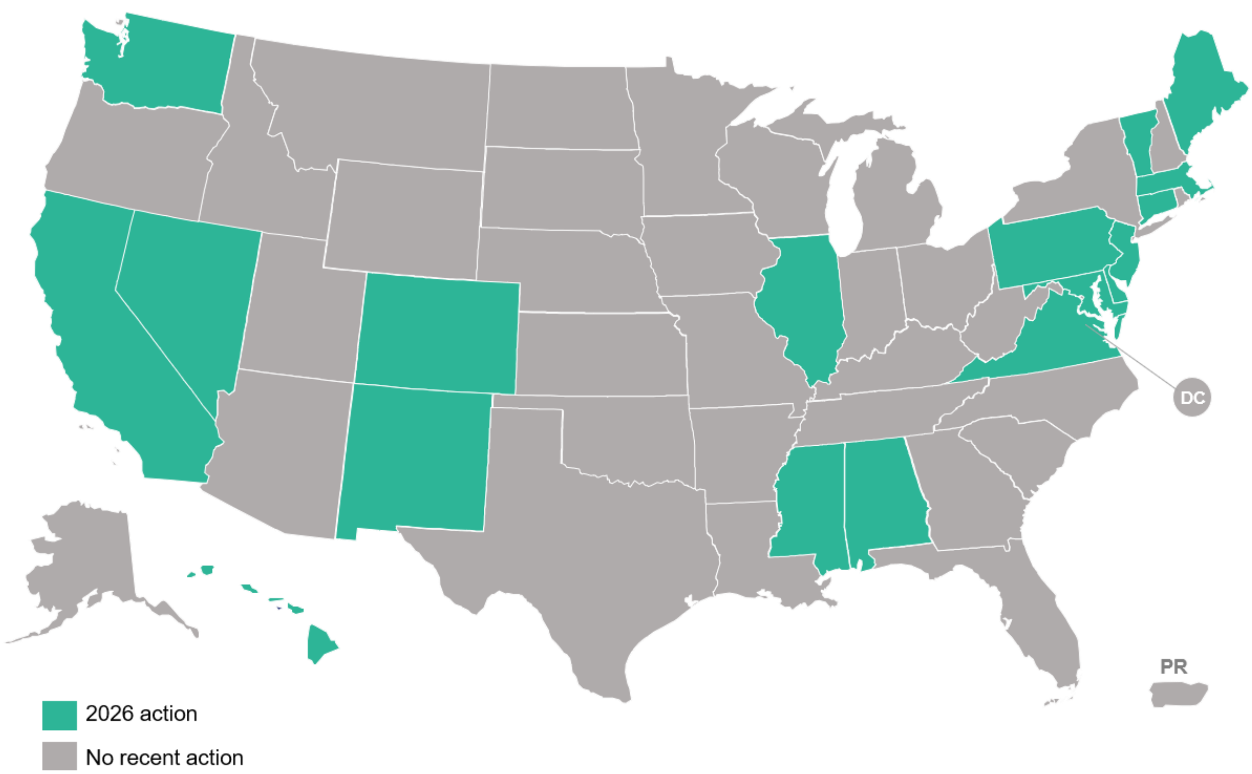
CUSTOMER COST-SAVING PROGRAMS

Key Takeaways:

- So far in 2026, 18 states took actions related to customer cost-saving programs, including low- and moderate-income (LMI) community solar programs, LMI incentive programs, and on-bill financing.
- New Jersey regulators opened new capacity for the state's Community Solar Energy Program and revised rules to require a guaranteed bill discount of at least 25% for LMI customers.
- Illinois lawmakers enacted legislation establishing a new Storage for All program, which will be available to the low-income subprogram of the state's Solar for All program.

Customer cost-saving programs are programs that empower customers to reduce their costs through the provision of weatherization, energy efficiency upgrades, or distributed energy resources (DERs). These cost-saving programs promote energy affordability through two mechanisms: first, they enable customers to directly save money through energy efficiency or on-site consumption, or receive bill credits by selling energy back to the grid; second, they provide utility-wide or system-wide benefits that can be socialized to all customer classes by avoiding utility energy, capacity, transmission, distribution, or other costs.

Figure 16. Action on Customer Cost-Saving Programs



In March 2026, the New Jersey Board of Public Utilities opened additional Community Solar Energy Program capacity and adopted Staff recommendations to require that community solar projects provide a guaranteed bill credit discount of no less than 20% to subscribers, and no less than 25% for LMI subscribers. Before the Board's order, the amount of the credit discount offered was used as a tiebreaker between otherwise identical programs competing for limited capacity; project owners may still offer a greater discount to increase their project competitiveness. Lawmakers in Maryland also moved to change LMI community solar program design by enacting a bill that requires the Maryland Public Service Commission to examine the feasibility and barriers of establishing an automatic community solar enrollment to provide bill credits to LMI subscribers.

Meanwhile in Colorado, regulators approved revisions to several of Xcel Energy's Renewable Energy Plan programs with income-qualified (IQ) provisions in April 2026. The previous Solar*Rewards Community program will be replaced with the Inclusive Solar Community Program in 2026, with at least 51% of a facility's subscriptions reserved for IQ customers and subscription charges limited to at most 75% of the subscriber's credit. The decision also approved changes to the Solar*Rewards subprogram to have an increased IQ incentive. Further, the Renewable Battery Connect program will see an IQ/disproportionately impacted (DI) capacity allocation for its 2026 solicitation and enhanced incentives for IQ/DI customers.

As directed by H.B. 5232, enacted in 2024, Connecticut regulators filed a final report on reforming several renewable and clean energy programs in February 2026. The study recommends that the Residential Renewable Energy Solutions successor program reserve the buy-all compensation method for multifamily affordable housing customers and customers enrolled on the low-income discount rate. Additionally, the Shared Clean Energy Facilities (SCEF) successor program should have eligibility and selection limited to LMI customers.

Connecticut lawmakers subsequently enacted a bill directing regulators to establish successors for certain programs, including SCEF. For community solar, regulators can limit subscriber eligibility to low-income customers and may give priority for participation to low-income customers with an arrearage; the program may also include incentives or financing mechanisms to encourage low-income customer participation. Further, regulators may require utilities to develop enrollment plans, including auto-enrollment and opt-out mechanisms.

In addition to amending community solar programs, several state policymakers took actions to increase LMI accessibility to cost-saving DERs. In Illinois, lawmakers passed an omnibus bill including a new Storage for All program, which will provide incentives to encourage development of energy storage co-located with solar devices developed under the low-income single-family and multifamily subprogram, as well as the non-profit and public facility subprogram. Maine legislators passed a bill initiating a clean energy and energy efficiency program navigator hub focused on helping residents in low-income, rural, and underserved areas affordably meet their energy needs.

Virginia lawmakers enacted a bill requiring American Electric Power and Dominion Energy to petition the State Corporation Commission to conduct a pilot program for energy conservation, solar, and storage for low-income, elderly, and disabled customers. Further, the Commission must convene a technical conference on creating a program modeled after Pay As You Save, a financing mechanism in which utilities provide the upfront cost of energy efficiency upgrades and customers pay that cost back using their energy savings. Certain utilities must petition the Commission to implement such a program if it is found to be feasible and in the public interest.

Relatedly, several utilities also proposed LMI-focused DER programs. In alignment with the Maryland DRIVE Act’s provisions, Potomac Edison proposed a Bring Your Own Device pathway with a connectivity incentive of $150/connected year plus a $50/year LMI adder. Additionally, the utility proposed an Energy Savings Rewards Smart Thermostat program with a one-time enrollment bonus of $50 for summer plus a $25 LMI adder or $100 for year-round plus a $25 LMI adder. Elsewhere, El Paso Electric filed an application with New Mexico regulators to implement a demand response and DER pilot that would install a third-party owned and operated 20 kW solar-plus-storage system, a smart panel, and an inverter. In addition to being implemented in 250 new build homes, the program would include 10 existing LMI homes.

APPENDIX A:
Table of Actions

State	Category	Sub-Topic(s)	Description	Source				
AK	Customer Cost Allocation	Cost Shift Prevention	S.B. 250, as passed by the Senate in May 2026, requires utilities providing electricity to a data center to enter into a contract with the data center, and to have that contract approved by the Regulatory Commission of Alaska. The terms of a contract must include an accounting of all costs for infrastructure necessary to provide the electricity and directly assign those costs to the customer. The bill did not pass the House by the end of the legislative session in May 2026.	S.B. 250 (D)				
AL	Customer Cost Allocation	Cost Shift Prevention	H.B. 403, as passed by the House in March 2026, states that when the Alabama Public Service Commission makes a determination regarding a service contract between a utility and a large load data center customer (one with a total peak energy demand of at least 100 MW), the Commission must consider whether the contract allows for full cost recovery for service to the data center's premises and whether it produces positive benefits for all other utility customers. Such benefits may include lower costs for other customers, improvements in the efficiency of the utility's power system resulting from the large load data center's operations, and whether the customer furthers economic growth in the community in which an applicable data center is sited. The bill did not pass the Senate by the end of the legislative session in April 2026.	H.B. 403 (D)				
AL	Customer Cost Allocation	Cost Shift Prevention	S.B. 270, enacted in April 2026, provides that when the Alabama Public Service Commission makes a determination regarding a service contract between a utility and a large load data center customer (one with an expected total peak demand of at least 150 MW), the Commission must consider whether the contract allows for full cost recovery for service to the data center's premises and whether it produces positive benefits for all other utility customers. Such benefits may include lower costs for other customers, improvements in the efficiency of the utility's power system resulting from the large load data center's operations, and whether the customer furthers economic growth in the community in which an applicable data center is sited.	S.B. 270 (E)				
AL	Customer Cost-Saving Programs	LMI Incentives	H.B. 609, as enacted in April 2026, revises the income eligibility limit for the state's weatherization assistance funding, Neighbors Helping Neighbors Fund, from a maximum of 125% of the federal poverty level to a maximum of 200% of the federal poverty level. The bill also revises which non-state organizations can implement the program, changing this from community action agencies and county governments to statewide resiliency organizations. Statewide resiliency organizations are defined as Alabama non-profits that improve the resiliency, energy efficiency, and safety of LMI residential housing by participating in large-scale residential energy efficiency programs.	H.B. 609 (E)				
AR	Customer Cost Allocation	Low-Income Discount Rates	As part of a general rate case filed on February 27, 2026, Entergy Arkansas proposed a new Low-Income Qualified Discount Rider for single-family and multifamily residential customers eligible for LIHEAP, which provides a 50% reduction in the monthly customer charge.	Docket No. 26-001-U				
AR	Customer Cost Allocation, Planning and Procurement, Utility Business Model	Arrearage Management, Bill Assistance, Cost Shift Prevention, Performance-Based Regulation, Procurement Methods	On June 3, 2026, the Arkansas Public Service Commission opened a proceeding to explore potential strategies, efficiencies, and cost containment measures to facilitate electric and gas affordability via mechanisms such as arrearage management programs, low-income assistance measures, large load tariffs, sleeved PPAs, and performance-based ratemaking.	Docket No. 26-042-U				
AZ	Customer Cost Allocation	Cost Shift Prevention	In April 2025, the Arizona Corporation Commission opened a new proceeding to review the existing rate classifications and the possible creation of more transparent rates for data center customers and the public. The proceeding may also consider utility mechanisms being implemented with data center customers, as well as behind-the-meter and in-front-of-the-meter solutions, and user-funded utility-scale generation to help large customers, such as data centers, meet their power needs. The Commission hosted a workshop on large load customers in mid-April 2026.	Docket No. E-00000A-25-0069				
AZ	Customer Cost Allocation, Utility Business Model	Cost Shift Prevention, Formula Rates	As part of a general rate case filed on June 13, 2025, Arizona Public Service (APS) proposed a new cost allocation method due to the increase in large loads. APS proposed directly assigning new generation costs to serve load growth based on the level of increased load each class experiences; therefore, the increased generation costs incurred by APS to serve high load factor customers like data centers would be recovered specifically from those customers. APS also proposed an alternative formula rate proposal to reduce regulatory lag by implementing more regular and efficient base rate adjustments. APS will continue its Energy Support Program (i.e. its low-income discount rate) and its Crisis Bill Program (i.e. its bill assistance program, administered by third parties) without modification, only requesting deferral accounting treatment for the programs.	Docket No. E-01345A-25-0105				
AZ	Customer Cost Allocation, Utility Business Model	Formula Rates, Low-Income Discount Rates	As part of a general rate case filed on June 17, 2025, Tucson Electric Power (TEP) proposed a new formula rate mechanism, the Annual Rate Adjustment Mechanism (ARAM). The ARAM is intended to smooth out potential bill changes between rate cases, mitigate the regulatory lag of capital investments, and ensure that TEP is not exceeding its authorized rate of return. The ARAM will update rates annually based on historical changes in the utility's revenue requirement using a framework similar to FERC's approach on formula rates. TEP also proposed modifications to its limited income tariffs. For residential customers at or below 100% of the federal poverty level, TEP will provide a 50% monthly discount on their bills. For customers with an income between 101% and 200% of the federal poverty level, TEP will provide a 20% monthly discount on their bills. TEP is also proposing two alternative mechanisms if the ARAM is not approved. The first is a System Resource Benefit Mechanism (SRB), which would help recover the costs for investments in significant generation resources (more than $50 million) needed to meet growing demand. The second mechanism is a Limited Income Rate Adjustment (LIRA) to track and recover (or refund) the difference between the actual costs of the limited income tariffs and the amount included in base rates.	Docket No. E-01933A-25-0103				
AZ	Planning and Procurement	Competitive Procurement, Planning Rules	H.B. 2912, as passed by the House in March 2026, requires utilities to file IRPs every three years. As part of the planning process, utilities must use the ratepayer impact measure test to determine the combination of electric generation plants and ownership structures that result in: (1) the lowest overall lifetime revenue requirement for the utility over the useful life of the plant, (2) the safest and most reliable electric service for customers in each of the next 15 years, and (3) the intent or design not being meant to satisfy any carbon or emissions reduction goal. In addition, utility RFPs must be approved by the Arizona Corporation Commission; RFPs should prioritize reliability and affordability, and they should result in contracts for resources that provide reliable electricity at the lowest cost. The bill did not pass the Senate by the end of the legislative session in June 2026.	H.B. 2912 (D)				
AZ	Studies and Investigations	Large Load Cost Shift Prevention, Planning and Procurement	The Governor of Arizona signed an executive order in September 2025 to facilitate energy affordability for customers. The executive order established the Arizona Energy Promise Taskforce to develop three separate sub-reports by March 1, 2026. The three reports should provide recommendations for (1) facilitating data center load growth while minimizing the impact on other ratepayers, (2) taking advantage of emerging energy technologies including geothermal and advanced nuclear, and (3) streamlining the deployment of necessary generation and transmission projects. The Taskforce released its final report on March 1, 2026. Between the three sub-reports, it includes 31 specific recommendations. There are four overarching recommendations, including a recommendation to accelerate energy generation, transportation, and transmission project timelines to reduce project cost through a centralized permitting coordination council. There are six recommendations for managing large load additions, including one to support the Arizona Corporation Commission's existing Docket No. E-00000A-25-0069 process and workshops to prevent cost shifts, mitigate stranded asset risks, and increase development transparency. There are seven recommendations for strategic energy, including to promote new resource energy deployment and reduce system costs through clean repowering, and to encourage deployment of cost-effective, readily-deployable utility-scale wind and solar energy projects and new transmission lines by reforming and streamlining permitting processes. The report also recommends encouraging increased deployment and adoption of low carbon- and water-use firm capacity and energy storage technologies to maintain and promote enhanced affordability, reliability, and system flexibility. There are seven recommendations for geothermal energy, including the creation of an Arizona geothermal playbook for industry to decrease barriers to market, and, when economically feasible and market-ready, include next-generation geothermal potential in long-term energy resource planning. There are two recommendations for nuclear energy, including the identification of pathways for project finance certainty and the implementation of financing guardrails to decrease project costs and protect affordability for Arizonans. It also suggests support for project development at the state level to accelerate project timelines and decrease costs.	Executive Order 2025-13	Arizona Energy Promise Taskforce Report (Mar. 2026)			

State	Category	Sub-Topic(s)	Description	Source				
AZ	Studies and Investigations	Utility Ownership Structure	The City of Tucson is exploring the potential of acquiring the electric distribution assets owned and operated by Tucson Electric Power (TEP) and forming its own municipal electric utility. In February 2026, TEP released a study into the potential impacts of municipalization. The study finds that it would cost the city more than $4 billion to acquire the assets and establish a new utility, and electric service under the city would cost approximately $290 million more per year, on average, over the next 20 years compared to the same service being provided by TEP. The additional costs to average residential bills would also increase over time from $160 per year in Year 1, to $900 per year in Year 20. Overall, the benefits of lower financing costs would be significantly offset by the costs to acquire, operate, and maintain the electric distribution system.	Preliminary Feasibility Study (Feb. 2026)				
CA	Customer Cost Allocation	Arrearage Management, Disconnection Policies, Payment Plans	A.B. 1945, as passed by the Assembly in May 2026, adds provisions to the law that allows a district furnishing electrical service to fewer than 100,000 customers to offer customers a prepay option for electrical service. The district must provide the customer with all information related to the mechanisms and policies to return to standard billing and provide information on any differences in consumer protection rules between the prepay option and standard billing. Additionally, the district must issue automated low-balance alerts to customers at least 10 days before the forecasted service suspension and again at least 24 hours before the forecasted service suspension. Before the prepay option takes effect, and if the customer has eligibility for an arrearage payment plan offered by the district, the district must offer the customer an opportunity to participate in an arrearage payment plan. Additionally, the prepay option requires the district to refund the customer any unexpended balance from the customer's account within 10 business days after the customer has terminated electrical service and the district has withdrawn the payment from the customer's final bill. The district must also adopt a policy to minimize service disruptions to residential customers who elect to participate in the prepay option who are 65 years of age or older, customers who are medically vulnerable, and customers who are dependant adults.	A.B. 1945 (P1)				
CA	Customer Cost Allocation	Bill Assistance	On July 24, 2025, the California Public Utilities Commission initiated a rulemaking proceeding to consider ways to improve the effectiveness of the California Climate Credit for supporting customer affordability. The state's Cap-and-Trade program requires power plants, fuel providers, and large industrial facilities that emit greenhouse gases to retire allowances or a limited quantity of offsets equal to their emissions. Investor-owned utilities are allocated annual allowances under this program. The sale of these allowances must be used to benefit residential and small business customers and fund certain clean energy and efficiency programs. This Climate Credit is delivered as a twice-per-year lump-sum bill credit, automatically provided to all bundled and unbundled residential customers and certain qualifying small business customers. The Commission is considering a number of actions to maximize the effectiveness of this program including: adjusting the eligibility criteria to increase the impact of the bill assistance program; adjusting the number of distributions or time-of-year of distributions; allocating the credit on the basis of usage; and increasing outreach. On May 4, 2026, the Commission issued an order directing the investor-owned utilities to implement immediate changes to the residential electric Climate Credits to improve customer bill affordability. The order directs that, starting this year, credits be moved to high-usage months to lower customers' highest electricity. The Commission will still consider broader changes to this program.	Docket No. R-25-07-013	Order (May 2026)			
CA	Customer Cost Allocation	Cost Shift Prevention	A.B. 222, as passed by the Assembly in June 2025, requires the California Public Utilities Commission to minimize the shifting of costs attributable to the construction or alteration of the data center to ratepayers who do not directly benefit from the data center.	A.B. 222 (P1)				
CA	Customer Cost Allocation	Cost Shift Prevention	S.B. 886, as passed by the Senate in May 2026, requires the California Public Utilities Commission, by July 1, 2027, to establish a rate structure for data centers taking transmission-level electrical service with an estimated peak demand of at least 25 MW. In designing the rate structure, the Commission should evaluate the risks and benefits of an electrical corporation tariff to non-participating customers, ensure that it prevents the creation of stranded costs for, or cost shifts to, non-participating customers, and ensure that charges generally included in the generation component of the customer's bill are assessed separately from charges generally included in the transmission and distribution components of the customer's bill. Resulting utility tariffs to serve these customers should assign participating customers any unique wholesale energy costs, including ancillary and reliability services costs attributable to rapid fluctuations in demand by the participating customer. They should also include a reasonable share of the costs relating to wildfire mitigation, wildfire liability, electrification and environmental programs, and other societal cost obligations typically collected from distribution-level ratepayers. The resulting tariffs should also require participating customers to prefund a contract of at least 15 years in duration through a utility for the installation of new, incremental, zero-carbon energy resources that provide at least 50% of the customer's hourly energy needs and provide dispatchable assets to the utility. They must also require participating customers to participate in a new demand response program authorized by the Commission that does not result in any net costs to a non-participating customer and supports load shifting, reliability, resource adequacy, and greenhouse gas emission reduction objectives.	S.B. 886 (P1)				
CA	Customer Cost Allocation	Cost Shift Prevention	S.B. 887, as passed by the Senate in May 2026, prohibits categorical exemptions under the California Environmental Quality Act (CEQA) for data center development and operation projects, requiring full environmental review. The bill also establishes criteria for data centers and geothermal power plants to qualify as environmental leadership development projects with streamlined CEQA benefits. To qualify, a data center must pay the full cost of interconnection to prevent cost shifts to other ratepayers, not increase fossil fuel consumption within the state, include zero-carbon energy storage with at least four hours of capacity at 100% of forecasted peak demand for the facility, use on-site zero-carbon energy storage to provide demand response services to the electrical grid, rely on zero-carbon generation located behind the meter to the maximum extent feasible, use recycled water and water-efficient technology or waterless cooling systems, and rely on 100% zero-carbon electricity resources to serve hourly energy needs within five years of initial operations, of which 75% shall be newly developed.	S.B. 887 (P1)				
CA	Customer Cost Allocation	Cost Shift Prevention	S.B. 1168, as passed by the Senate in May 2026, requires the California Public Utilities Commission to assess opportunities for rate structures to ensure data centers pay a reasonable share of their costs associated with transmission and distribution needs, identify mechanisms to ensure that data centers pay for their proportionate share of load increases and procurements needed to reliably serve their loads using non-emitting resources, and structure rates to alleviate cost pressures on residential ratepayers.	S.B. 1168 (P1)				
CA	Customer Cost Allocation, Customer Cost-Saving Programs	Bill Assistance, LMI Incentives, Low-Income Discount Rates	On January 16, 2026, San Diego Gas & Electric (SDG&E) filed a request for approval of income-qualified programs and budgets for program years 2028-2033. The utility requests a continuation of the six-year program cycle for its Energy Savings Assistance (ESA), California Alternate Rates for Energy (CARE), and Family Electric Rate Assistance (FERA) programs. ESA provides no-cost weatherization and energy saving services. CARE offers a 30% - 35% discount on electricity bills and a 20% discount of natural gas bills. FERA is available for customers whose income exceeds the eligibility for CARE and offers an 18% discount on electricity bills. SDG&E requested budgets of around $195 million for ESA, $1.32 billion for CARE, and $96.8 million for FERA. SDG&E also requested changes for each program. For ESA, the utility is requesting the addition of an electrification pilot program and transitioning the Multifamily Whole Building program from a regional model to a local administration model. The pilot program is designed to deliver electrification measures to income-qualified customers, with a focus on achieving bill neutrality or bill savings while enhancing energy efficiency, long-term affordability, and health, comfort, and safety. Changes to CARE would include increasing the annual post-enrollment verification cap from 6% to 20%. Finally, changes to FERA would include modifying the automatic enrollment requirement for LIHEAP to CARE to include LIHEAP to FERA automatic enrollment via data sharing and increasing the capitation fee for FERA from up to $30 to up to $60 per enrollment.	Docket No. A-26-01-010				

State	Category	Sub-Topic(s)	Description	Source				
CA	Customer Cost Allocation, Customer Cost-Saving Programs	Bill Assistance, LMI Incentives, Low-Income Discount Rates	On January 9, 2026, Pacific Gas & Electric (PG&E) filed a request for approval of income-qualified programs and budgets for program years 2028-2033. The utility requests a continuation of the six-year program cycle for its Energy Savings Assistance (ESA), California Alternate Rates for Energy (CARE), and Family Electric Rate Assistance (FERA) programs. The utility requested a combined budget of around $1.03 billion for the three programs. PG&E also requested changes for each program. ESA provides no-cost weatherization and energy saving services. CARE offers a 30% - 35% discount on electricity bills and a 20% discount of natural gas bills. FERA is available for customers whose income exceeds the eligibility for CARE and offers an 18% discount on electricity bills. For CARE, the changes would include: (1) adding a new third-party platform to assist customers with uploading income documentation to assist with post-enrollment verification; (2) moving the Community Help and Awareness of National Gas and Electricity Services (CHANGES) evaluation process to the California Public Utilities Commission; (3) increasing CARE Community Outreach Contractor Capitation fee from $30 to $40 per enrollment; (4) and modifying and/or sunsetting a subset of compliance items that have become obsolete. The requested changes for FERA include: (1) setting FERA enrollment goals, starting at 30% in 2028 and increasing to 35% by 2033; (2) following a similar post-enrollment verification process as proposed in CARE, including communication methods and frequency; (3) using customer-facing tools developed for CARE, including outbound calling for FERA post-enrollment verification and a potential new platform for customers to provide income documentation; (4) based upon the anticipated success with its 2026 outbound calling effort, using third-party vendor partnership to continue the coubound calling effort, or other acquisition services; and (5) increasing FERA Community Outreach Contractor Capitation fee from $30 to $60 per enrollment. Finally, the changes for ESA would include: (1) a portfolio-level energy savings goal for the program cycle with annual targets; (2) annual households treated targets; (3) a new targeted deep savings tier; (4) retiring High Energy Usage, Medical Baseline, and High Fire Threat Customer Need States, while adding High Heat Area Need State; (5) modifying the repair and replace program to incorporate electrification; (6) establishing direct contractor requirements for local/disadvantaged communities hiring and on the job training; open and competitive solicitations for program implementation; (7) standardizing fund shifting and carryover rules across the ESA portfolio; (8) adding a tier 2 advice letter process to adjust programs based on impact and process evaluation results; and (9) modifying and/or sunsetting a subset of compliance items that have become obsolete.	Docket No. A-26-01-003				
CA	Customer Cost Allocation, Studies and Investigations	Cost Shift Prevention, Rate Design	On April 9, 2026, the California Public Utilities Commission initiated a rulemaking on advanced electric rate design to update residential and non-residential rate structures and their underlying cost inputs so that rates more accurately reflect the cost of providing service, send price signals that support efficient use of grid infrastructure, and allocate costs fairly across all customers. As part of this order, the Commission stated, "In many decisions and forums, the Commission has identified the need to address electric rate affordability. Addressing affordability continues to be a priority and particularly urgent given rate increases from wildfire-related costs and cost impacts from rapid load growth, including from data centers. This proceeding will consider how advanced rate design policies can support equitable and affordable electric rates for Californians and advance the Commission's Environmental and Social Justice Action Plan." Among the preliminary issues to be addressed in the proceeding are residential income-graduated fixed charges, demand and non-bypassable charges, and tariffs for large load customers to prevent cost-shifting. This proceeding will also address the study directive in S.B. 57, enacted in October 2025. S.B. 57 authorizes the California Public Utilities Commission to assess the extent to which utility costs associated with new loads from data centers result in cost shifts to other utility customers. The Commission is to submit its assessment to the relevant policy committees of the Legislature and publicly post a copy of the assessment on the Commission's website on or before January 1, 2027.	Docket No. R-26-04-009	S.B. 57 (2025)			
CA	Customer Cost-Saving Programs	LMI Community Solar	Existing law required the California Public Utilities Commission, on or before March 31, 2024, to evaluate each customer renewable energy subscription program to determine if the program meets specified goals and to determine whether it would be beneficial to ratepayers to establish a new tariff or program. The Commission carried out this requirement, eventually adopting rules for a new community solar program. However, the program has not been fully developed yet. A.B. 1813, as passed by the Assembly in May 2026, changes the year throughout this section of the statutes from 2024 to 2027, making the Commission redo its evaluation. One of the goals of this bill is to promote participation by low-income customers.	A.B. 1813 (P1)				
CA	Customer Cost-Saving Programs	LMI Community Solar	In May 2024, the California Public Utilities Commission issued a decision in several ongoing cases surrounding the review of Pacific Gas & Electric's (PG&E), San Diego Gas & Electric (SDG&E), and Southern California Edison Company's Disadvantaged Communities-Green Tariff (DAC-GT), Community Solar Green Tariff (CSGT), and Green Tariff Shared Renewables (GTSR) Programs. The decision expanded the existing DAC-GT Program from 60 MW to 144 MW and adopted a new Community Renewable Energy Program. The new program will be available to customers of all income levels as well as commercial customers.The decision also commits the Commission to using $33 million appropriated to the Commission, as well as federal funding associated with the Solar For All program, to help make the program more attractive to participants. Participating projects must ensure that at least 51% of the capacity is reserved for low-income customers. Rather than receiving a volumetric monetary credit based on a cents-per-kWh basis, subscribers will receive a flat monetary credit on their bills based on the percentage of resource revenue for the project. In June 2026, the Commission issued a decision adopting a process to implement the customer community renewable energy tariff it adopted in May 2024. The decision was necessitated by the termination of California's Solar for All award, which was a key part of the May 2024 decision, in addition to other factors. The Commission is maintaining the general structure it adopted in 2024, whereby utilities will use existing procurement mechanisms for community renewable energy projects, and layer on a subscription model. The decision also directs the investor-owned utilities to file a Tier 2 advice letter within 90 days, outlining the details of their proposed community renewable energy tariffs. If any community choice aggregators or electric service providers wish to offer a community renewable energy program, they must submit a Tier 1 advice letter to notify the Commission when they begin or end participation in the program. The decision also addresses Green Tariff program oversight and cost recovery, Disadvantaged Communities-Green Tariff funding and program evaluation.	Docket No. A-22-05-022	Docket No. A-22-05-023	Docket No. A-22-05-024	Decision (May 2024)	Decision (June 2026)
CA	Customer Cost-Saving Programs	LMI Incentives	On January 13, 2026, Southern California Edison (SCE) filed a request for approval of income-qualified programs and budgets for program years 2028-2033. The utility requests a continuation of the six-year program cycle for its Energy Savings Assistance (ESA), California Alternate Rates for Energy (CARE), and Family Electric Rate Assistance (FERA) programs. The utility requested a combined budget of around $782 million for the three programs. SCE also requested changes for the ESA program. For ESA, the changes include: (1) closing the Building Electrification pilot in 2027 and transitioning the installation of building electrification measures to the ESA program and integrating all such offerings to all eligible single-family, mobile, and multifamily homes; (2) closing the regionally administered Southern Multifamily Whole Building program and transition all aspects of the multifamily ESA to the ESA program; (3) providing HVAC offerings to customers in additional climate zones, while also providing cooling measures for more customers; (4) enhancing coordination with other agencies and programs to maximize program impact, efficiency, and customer satisfaction; and (5) establishing a supplemental solicitation approach that will allow the utility to pre-qualify additional vendors and expand access to contracting needs not initially identified at the beginning of the program cycle.	Docket No. A-26-01-005				
CA	Planning and Procurement	Non-Wires Alternatives	S.B. 1295, as passed by the Senate in May 2026, requires utilities to consider NWAs. For any proposed distribution or transmission infrastructure investment above a threshold to be determined by the California Public Utilities Commission, the utility must evaluate whether distributed energy storage systems or other NWAs can meet the identified reliability or capacity need. The evaluation should include the cost of the proposed infrastructure investment, the cost of procuring deploying storage or other NWAs, avoided or deferred infrastructure costs, and reliability and operational benefits. The Commission may not approve rate recovery for a proposed infrastructure investment unless the utility demonstrates NWAs are not feasible within the required timeframe or cost effective.	S.B. 1295 (P1)				

State	Category	Sub-Topic(s)	Description	Source				
CA	Planning and Procurement, Utility Business Model, Utility Oversight	Grid Utilization, Innovative Financing, Return on Equity Rules	S.B. 905, as passed by the Senate in May 2026, requires the California Public Utilities Commission, on or before January 1, 2028, to initiate a proceeding to investigate, develop, and adopt a framework for performance-based metrics for the large investor-owned utilities. At minimum, the framework should require electrical corporations to track the performance over time of a variety of metrics, including distribution system utilization, timely completion of transmission and generation interconnections for generation and energy storage projects, and utilization of demand response resources or other distributed resources to serve during periods of peak demand as a means of reducing the need for additional investment in both generation resources and transmission and distribution infrastructure. The Commission may establish targets for each of the performance metrics. The bill also directs the Commission to initiate a rulemaking proceeding to evaluate opportunities for alternative methods of financing capital investments in electrical generation, transmission, and distribution that reduce costs for ratepayers. The proceeding should consider options for substituting alternative financing for shareholder equity and other financing mechanisms that could lower the cost of capital recovered in retail rates. Additionally, the bill includes a provision where during the establishment of a reduced return on equity for certain types of capital costs - including those recovered through a balancing account, exempted from a reasonableness review, and relating to undergrounding of the electrical system - shall not be considered by the Commission in making any determination regarding the reasonableness of the authorized rate of return on equity for the utility.	S.B. 905 (P1)				
CA	Studies and Investigations, Utility Oversight	Executive Compensation, Utility Business Model	California lawmakers previously enacted legislation authorizing an in-depth study to assess the practical, financial, legal, regulatory, labor, and technical aspects of a smooth and just transition away from the investor-owned utility model to one that prioritizes the needs of people and the ecology of the state. S. B. 332, as passed by the Senate in June 2026, directs the research institute, to be determined at a later date, to conduct the first phase of the comparative analysis and submit an interim report by the end of 2026. This analysis must include: (1) legal parameters generally associated with each corporate from listed as a successor entity; (2) all legal obligations currently applicable to electrical corporations under federal and state law and regulations, including obligations imposed by the California Public Utilities Commission; (3) legal barriers and legally permissible pathways to transition an electrical corporations assets, operations, and legal obligations to each successor entity corporate form; (4) changes in the law necessary to ensure all electrical corporation legal obligations would apply to each type of successor entity, without jeopardizing the provision of safe, reliable, and affordable service; and (5) recommendations for narrowing the scope of the remainder of the comparative analysis based on conclusions from the initial analysis. Additionally, the bill requires that any utility's executive incentive compensation structure is designed to ensure public safety, ratepayer affordability, and utility financial stability. The compensation structure is to include performance metrics, and ratepayer affordability is to include review of data related to customer disconnections, arrears, and uncollectibles.	S.B. 332 (P1)				
CA	Utility Oversight	Cost-Effectiveness Standards	On March 16, 2026, Southern California Edison (SCE) filed its Energy Efficiency 2028-2031 Portfolio Plan and 2032-2035 Business Plan. As part of this submission, SCE proposed several policy changes that, if adopted, would enable SCE to better manage costs, reduce unnecessary administrative complexity, deliver more cost-effective energy efficiency, and advance the state's clean energy objectives. One such policy change is prioritizing affordability by apply the same cost-effectiveness and other regulatory requirements to all program administrators that use ratepayer funds for energy efficiency portfolios. According to SCE, inconsistent requirements across program administrators risks perpetuating a patchwork energy efficiency management structure in which ever-expanding portions of the ratepayer-funded portfolio budgets are insulated from the cost-effectiveness and oversight standards. The utility suggests that the California Public Utilities Commission establish minimum cost-effectiveness standards for all program administrators managing resource acquisition energy efficiency programs utilizing ratepayer funds.	Docket No. A-26-03-010				
CO	Customer Cost Allocation	Arrearage Management, Payment Plans	S.B. 2, as enacted in June 2026, requires investor-owned utilities (gas and/or electric) to establish a percentage-of-income payment plan (PIPP) program for residential income-qualified customers. Participants would have their utility bills tied to their income, ensuring their monthly bill does not exceed an affordable percentage of income. The affordable percentage of income for investor-owned utilities up to 500,000 customers (functionally, Black Hills Energy) cannot exceed: 6% of household income for electric accounts with electricity as the primary heating fuel, 3% for electric accounts with another primary heating fuel, 5% for dual gas and electric accounts, 5% for accounts with neither gas nor electricity as the primary heating source, and 3% for accounts with gas as the primary heating fuel. The affordable percentage of income for investor-owned utilities with more than 500,000 customers (functionally, Xcel Energy) cannot exceed: 4% of household income for electric accounts with electricity as the primary heating fuel, 2% for electric accounts with another primary heating fuel, 5% for dual gas and electric accounts, and 5% for accounts with neither gas nor electricity as the primary heating source. If a customer's annual household income is $0, then the Colorado Public Utilities Commission must determine the percentage. Based on this percentage, the participant would receive a fixed credit, either annually or monthly, equal to their total project full annual bill minus the percentage, as calculated at the start of participation each year. Income eligibility criteria for the PIPP program would be based on existing statute: up to 200% of the federal poverty level, up to 80% of the area median income, or other criteria established by the Colorado Department of Human Services. To participate, a customer must either submit an application to their utility or be referred by the Colorado Department of Human Services, the Colorado Energy Office, Energy Outreach Colorado, or other energy assistance programs. The utility must approve or deny an application within 30 days. Participants would be enrolled for two years and would not lose their spot if they move within the utility's territory; if they move outside the utility's territory, they must reapply to their new utility's PIPP program (if applicable). Customers could dual-enroll in the PIPP program and other energy assistance programs. A utility must apply arrearage credits to, when combined with a participant's arrearage payments, reduce the existing arrearage to $0 within 1-24 months. A utility could implement conditions on the arrearage credits, either (1) timely payment of current bills or (2) payment towards existing arrearage, as long as the payments do not exceed 1% of annual household income. If a participants leaves the program and still haves arrearage, then the customer must pay the arrearage in line with existing utility tariffs. A utility could not terminate a participant due to partial or late payments on their bill or arrearage, though it could pursue collection efforts. To recover program costs, a utility could implement a PIPP charge on customers; if imposing a PIPP charge, a utility is encouraged to annually contribute shareholder profits to the program.	S.B. 2 (E)				
CO	Customer Cost Allocation	Cost Shift Prevention	On April 2, 2026, Xcel Energy filed an application for two new large loads tariffs - a Transmission Large (TL) Service rate and a Clean Transition Tariff (CTT) rate - and updates to its transmission line extension policy. The transmission line extension policy changes create new provisions specifically for TL rate customers. These customers must pay for the entire cost of constructing, operating, and maintaining new transmission and interconnection infrastructure associated with their service; these costs would be recovered through the TL rate. The CTT rate is an optional service for customers under the new TL rate to support the development of clean resources in Xcel Energy territory. Participating customers must assume financial responsibility for the resource and cover all project costs via a CTT Charge; multiple customers could support a single resource. The service agreement between Xcel Energy and the customer would lay out the contract term (tied to the asset life of the resource), the ability for subscriptions to transfer to other customers, pathways for Xcel Energy to replace the customer if they exit early, and an exit fee payment obligation if not replacement is found; the agreement could also include additional terms to ensure full financial responsibility on the part of the customer.	Docket No. 26AL-0137E				

State	Category	Sub-Topic(s)	Description	Source				
CO	Customer Cost Allocation, Utility Oversight	Bill Assistance, Cost Trackers, Disconnection Policies	As part of a Phase 1 general rate case filed on November 21, 2025, Xcel Energy proposed changes to its Energy Affordability Program (EAP). The changes allow customers to enroll via self-attestation of eligibility, as long as they already participate in certain other income-based assistance programs. The changes also amend the Percentage of Income Payment Plan (PIPP) option. The payment rate based on the percentage of household income would decrease from 3-6% to 1.5-2.5% for electric-only customers, from 3-5% to 1.5-2.5% for electric/gas (primary electric heating) customers, and from 2-3% to 1-2.5% for electric/gas (primary gas heating) customers. PIPP customers would no longer be subject to involuntary disconnections. For income-qualified customers 65 years or older who do not qualify for PIPP, they can instead receive a $20/month bill reduction. Xcel Energy also proposed a new cost tracker for Customer Information System modernization and a new cost tracker for electric damage prevention. Xcel Energy filed a settlement agreement on June 2, 2026, approving the changes to the EAP, with minor modification. Xcel agreed to not conduct any involuntary disconnections for customers referred to EAP through the Low-Income Energy Assistance Program, Energy Outreach Colorado, or the Colorado Energy Office, even if the customers are not actually enrolled in the EAP. Xcel also agreed to provide $5 million in shareholder funds to the program in 2027. The settlement did not approve the new cost trackers. The settlement allows the upcoming Phase 2 general rate case to address the topic of a low-income residential rate. On June 9, 2026, Energy Outreach Colorado filed a settlement agreement specific to the EAP in conjunction with the Utility Consumer Advocate, City of Boulder, and AARP; these participants are not party to the June 2nd settlement filed by Xcel Energy. The purpose of this EAP settlement is to show the parties' support for the EAP terms of Xcel's settlement without endsoring other portions of the settlement.	Docket No. 25AL-0494E	Settlement Agreement (June 2026)	EAP Settlement Agreement (June 2026)		
CO	Customer Cost-Saving Programs	LMI Community Solar	H.B. 1225, as enacted in June 2026, allows community solar subscriber organizations to require utilities to provide income-qualified subscribers with fixed bill credits and other subscribers with a bill credit that changes annually. Initially, the fixed bill credit's value would be determined by the subscriber organization, while the period of applicability would be determined by the Colorado Public Utilities Commission. After the initial period, the fixed bill credit would be adjusted annually by the Commission to ensure it aligns with changes in electric rates.	H.B. 1225 (E)				
CO	Customer Cost-Saving Programs	LMI Community Solar, LMI Incentives	On May 12, 2025, Xcel Energy filed its 2026-2027 Renewable Energy Plan. As part of the plan, Xcel Energy will implement revisions to its Solar*Rewards incentive subprograms. The Residential Income Qualified/Disproportionately Impacted (IQ/DI) Community subprogram would double from 0.5 MW annually to 1 MW annually and have a new tiered upfront incentive structure: $2/W for IQ customers and $0.50/W for DI community customers. The C&I subprogram (formerly the Medium subprogram) would provide a new Standard Offer upfront adder of $0.15/kW for standard offer systems that service IQ/DI communities. The IQ On-Site subprogram would double from 250 kW annually to 500 kW annually. Xcel Energy will also continue its Renewable Battery Connect program, of which 2.5 MW annually would be dedicated to IQ/DI customers (up from 2 MW annually). While the standard incentives would stay the same, the IQ/DI Community offering would switch to a tiered incentive structure of $800/kW for IQ customers and $500/kW for DI customers. The plan would sunset the utility's Solar*Rewards Community Program and replace it with a new Inclusive Community Solar Program starting in 2026, as created by S.B. 24-207. At least 51% of a facility's subscriptions must be reserved for IQ customers. A subscriber is limited to 120% of their reasonably expected average annual total consumption; IQ customers are limited to 200%. Excess credits will roll over indefinitely; when a subscriber cancels their utility service, any unused credits will be donated to IQ customers as energy assistance. At any point, a subscriber organization, subscription coordinator, or subscriber can donate their banked/rollover credits to IQ customers for energy assistance. IQ subscribers will receive a discount on their bill, by limiting the subscription charge to 75% of the value of the subscriber's credit; if a facility receives Inflation Reduction Act (IRA) funding for its location in an energy community, the limit is 70%; if a facility receives IRA funding to provide utility bill savings, the limit is 50%; if a facility receives IRA funding for both of these, the limit is 45%. Xcel Energy filed a settlement agreement on November 17, 2025, approving the application with modification. The settlement approved the Inclusive Community Solar Program with modifications unrelated to the IQ provisions. The settlement partially approved the Solar*Rewards subprogram capacities and incentives. It approved the IQ/DQ capacity increase, but increased the IQ incentive to $3/W; it did not directly mention the DI community incentive. It kept the IQ On-Site subprogram's original capacity of 250 kW, but did not mention the change to system size. The settlement partially approved the changes to the Renewable Battery Connect program; instead of annual solicitations, Xcel will have one solicitation in 2026, of which 11 MW would be dedicated to IQ/DI customers. The settlement approves the new tiered structure for IQ/DI incentives, but with different values: $1,000/kW for IQ customers and $500/kW for DI customers. The settlement did not mention the Solar*Rewards C&I subprogram. The ALJ filed its recommendation on January 28, 2026, approving the settlement agreement in full and ruling on contested issues related to cost recovery and bill assistance. Energy Outreach Colorado had proposed that Xcel Energy allocate $5 million/year to energy assistance programs (for $25 million over five years), to offset the lost benefits of unbuilt IQ/DI capacity and provide short-term relief to IQ households while the new inclusive community solar facilities are built. The ALJ denied the request, on the grounds that this proceeding is not the appropriate venue and that S.B. 24-207 is already meant to address the IQ/DI shortfalls that this proposal seeks to offset. The Colorado Public Utilities Commission filed a decision on April 7, 2026, adopting the ALJ recommendation in full.	Docket No. 25A-0194E	S.B. 24-207 (2024)	ALJ Recommendation (Jan. 2026)	Decision (Apr. 2026)	
CO	Planning and Procurement	Advanced Transmission Technologies	H.B. 1081, as enacted in May 2026, requires utilities' ten-year transmission plans to incorporate an evaluation of the potential of advanced transmission technologies (i.e. advanced conductors and grid-enhancing technologies). Grid-enhancing technologies include dynamic line ratings, advanced power flow controllers, topology optimization, stationary or mobile energy storage (when used as a T&D resource), and other technologies that increase grid reliability, flexibility, and capability. The evaluation must include a technical feasibility assessment, a cost-effectiveness analysis and timetable for potential deployment, and an assessment of the technologies' ability to: (1) increase transmission system capacity, cost-effectiveness, reliability, or resilience; (2) reduce transmission system congestion; (3) reduce the timeline to connect new generation or load to the grid; (4) reduce the risk of igniting wildfires; (5) increase capacity to connect new renewable and clean resources; or (6) increase the transfer capability of electricity between Colorado and neighboring states. The evaluation should also describe any additional potential benefits - like meeting short-term transmission needs or reducing impact on high-priority environmental areas. If advanced transmission technologies offer a more cost-effective strategy but the utility does not include them in its plan, then it must explain why the technologies should not be deployed.	H.B. 1081 (E)				

State	Category	Sub-Topic(s)	Description	Source				
CO	Planning and Procurement, Studies and Investigations, Utility Business Model	Joint Procurement, Performance Incentive Mechanisms, Planning Rules	Existing law requires the Colorado Public Utilities Commission to account for and help correct historical inequities in disproportionately impacted (DI) communities. H.B. 1326, as enacted in May 2026, requires the Commission to take reasonable actions to benefit affected communities and workers, including net benefits like high-quality jobs, workforce development in energy transition communities, and decisions that allow residents to share in the benefits of new energy facilities. As part of this, the Commission must identify equity impact proceedings that could impact the distribution of benefits and burdens to DI communities, workers, and income-qualified customers. Equity impact proceedings must include procedural and substantive requirements to promote equity. The Commission must adopt rules that (1) minimize impacts on and prioritize benefits to DI communities, (2) implement equitable and inclusive practices, and (3) engage DI communities and just transition communities. It must also establish an Equity Task Force to provide input and recommendations. By December 2026, the Commission must open a proceeding(s) to investigate potential barriers and opportunities for streamlining energy planning proceedings, integrating gas and electric system planning, and maximizing the efficiency and effectiveness of customer programming. The Commission should identify and evaluate recommendations regarding: (1) revising the timing and order for planning to achieve regulatory efficiency, reduce litigation costs, and maintain high standards of regulatory oversight; (2) integrating gas and electric system planning to reduce ratepayer costs and advance air quality and decarbonization goals; and (3) improving the cost-effectiveness and effectiveness of utility customer programs, including demand-side management, beneficial electrification, clean heat, customer-sited renewables and storage, and income-qualified service programs. When evaluating gas and electric planning, the Commission must consider: (1) implementing emerging forecasting and modeling practices to allow for system optimization; (2) aligning planning processes, forecasts, assumptions, programs, and/or initiatives across gas, electric, and steam; (3) facilitating secure data sharing between gas utilities, electric utilities, and non-utility entities; (4) improving collaboration between utilities with overlapping territories; (5) implementing geographically-targeted zonal electrification; (6) minimizing stranded asset risks; and (7) modifying cost-recovery methods to reduce ratepayer risk or to align utility incentives with relevant public policy objectives. The Commission must submit a final report summarizing its findings and recommendations by November 30, 2027. The bill also requires the Commission to conduct a study regarding barriers utilities face in jointly procuring resources. The study should: (1) identify barriers to joint procurement; (2) identify how barriers differ between regulated utilities, electric cooperatives that opted out of regulation, and municipal utilities; and (3) examine how participation in a wholesale market affects barriers to joint resource procurement. The study is due within 18 months. Separately, the Commission must establish minimum quality-of-service metrics for electric and gas investor-owned utilities. The rules must include requirements for customer-specific incentives and penalties associated with customer-experienced service quality; the metrics should specifically address equity for DI communities, and the incentive/penalty could be symmetrical. The bill also allows regulated investor-owned utilities to engage third parties via competitive bidding to administer or facilitate customer-facing programs aimed at reducing energy bills, reducing energy consumption, or supporting the transition to lower- or zero-carbon generation.	H.B. 1326 (E)				
CT	Customer Cost Allocation	Arrearage Management, Bill Assistance, Cost Shift Prevention, Disconnection Policies, Low-Income Discount Rates	On November 26, 2025, the Connecticut Public Utilities Regulatory Authority (PURA) opened a proceeding for its 2026 review of affordability programs and offerings; formal action began in January 2026. The docket covers Eversource (including its electric and gas subsidiaries) and Avangrid (including its electric subsidiary United Illuminating and its gas subsidiaries). PURA will review programs - including but not limited to reasonable amortization agreements, the Matching Payment Program, and the residential Low-Income Discount Rate (LIDR) - and their impact on uncollectibles. It will also review utilities' 2026-2027 Joint Arrearage Forgiveness Program Plan. On June 1, 2026, the utilities filed their 2026-2027 Joint Arrearage Forgiveness Program. The plan noted that the utilities implemented semi-annual auto-enrollments in November 2025 for the Matching Payment Program - customers will now be auto-enrolled in February and December, instead of just February. The utilities proposed improvements to the data matching and verification process for enrolling eligible customers. To reduce arrears, the utilities argued that the cost of unpaid bills is borned by all customers, so efforts to decrease these costs make all customers' bills more affordable; therefore, they proposed (1) removing customers from the payment plan if they miss one monthly payment (the current rule is two consecutive monthly payments) and (2) requiring customers to pay a 50% of their past due balance (20% for financial hardship customers) to reconnect service (the correct rule is a percentage or a fixed amount, whichever is lower: 20% or $400 for financial hardship customers, and 50% or $1,000 for non-financial hardship customers).	Docket No. 26-05-01				
CT	Customer Cost-Saving Programs	LMI Community Solar, LMI DER Programs, LMI Incentives	H.B. 5340, as enacted in May 2026, requires the Connecticut Public Utilities Regulatory Authority (PURA) to establish successor programs to the Residential Renewable Energy Solutions, Non-Residential Renewable Energy Solutions, and Shared Clean Energy Facilities (SCEF) programs by April 2028; it must begin the development proceedings by July 2027. The successor programs should consider the findings from the existing study of the value of DERs and the impact of DERs on the state's goals to reduce greenhouse gas emissions. When establishing tariffs for all three successors, PURA must consider (1) the average cost of installation of a DER, (2) costs and benefits to program participants and non-participants, (3) the state's Comprehensive Energy Strategy, and (4) the value or benefits of DERS to grid reliability. PURA should also consider whether to incorporate time-varying rates or other dynamic pricing and which type (real-time, one-day, less than one day, or more than one day but less than one month). Utilities must begin offering the successor programs starting July 2028 and continue offering to new customers through June 2036; once enrolled, customers would stay enrolled for 20 years. After June 2036, PURA can establish tariffs to purchase electricity from non-residential systems and SCEFs. Under the residential successor, for standard residential customers, utilities must offer a tariff to purchase excess energy and RECs (similar to the existing Netting option). For low-income residential customers or residential customers in multifamily affordable housing, utilities must offer two tariff options: (1) a tariff to purchase all energy and RECs (similar to the existing Buy-All option) or (2) a tariff to purchase excess energy and RECs (similar to the existing Netting option). Under the non-residential successor, utilities must offer a tariff to purchase excess energy and RECs (similar to the existing Netting option). Under the SCEF successor, utilities must offer a tariff to purchase excess energy and RECs (similar to the existing Netting option). PURA must determine the billing credit for subscribers and establish consumer protections. PURA could limit subscriber eligibility to low-income customers or residential customers in environmental justice communities, or prioritize low-income customers who have an arrearage with their utility; it could also create incentives or other financing mechanisms to encourage low-income participation. Alternatively, PURA could implement a minimum 40% capacity carve-out for low-income and environmental justice customers, or implement a maximum 40% capacity limit on commercial customers. PURA could also require utilities to develop enrollment plans, including auto-enrollment/opt-out structures. PURA must also examine how to incorporate preferences for DER projects in distressed municipalities and brownfields. The annual program limit would be $16 million/year for procured energy products; unused budget would rollover to the next year. Under all three programs, PURA must examine how to incorporate preferences for DER projects in distressed municipalities and brownfields. Separately, the bill requires the Connecticut Department of Energy and Environmental Protection to establish a two-year pilot to support the installation of residential solar for residents of environmental justice communities; the program should provide systems at low- or no-cost to 100 households in any environmental justice community.	H.B. 5340 (E)				

State	Category	Sub-Topic(s)	Description	Source				
CT	Customer Cost-Saving Programs	LMI Incentives	**Background:** In October 2024, the Connecticut Public Utilities Regulatory Authority (PURA) opened a docket regarding Year 5 of the Energy Storage Solutions Program. In May 2025, the Connecticut Green Bank, Eversource, and United Illuminating filed a proposal for a performance-based incentive model, recommending keeping the existing incentive model and instead exploring changes to the active-only performance incentive. **Recent Action:** PURA filed a final decision on December 17, 2025. PURA elected to adopted an alternative performance-based incentive model that Eversource proposed in July 2025, which the Green Bank later modified in September 2025. The upfront per-kW incentive would become a flat enrollment incentive, similar to the state's managed charging program: $30/kWh for residential customers, $130/kWh for residential customers at the grid edge, and $10/kWh for priority commercial customers. The new model would not use a declining block incentive, and the enrollment incentive would only be paid out after the system shows up in the utility's DERMS platform. The performance incentive for residential customers would be fixed for all 10 years of enrollment: $300/kW-yr for standard residential, $450/kW-yr for underserved residential, and $550/kW-yr for low-income residential. On a voluntary basis, the Green Bank could advance a portion of a residential customer's future performance payments to contractors, who would then apply the funds as an installation cost reduction; in return, the customer would repay the Green Bank via their received performance incentives until the advance is paid off. PURA noted that this model will only apply to new customers starting April 1, 2026; existing customers will stay on the existing incentive model. On April 24, 2026, the program administrators filed a motion to allow third parties (e.g. original equipment manufacturers, contractors, financing entities) to repay the prorated upfront incentive on behalf of the customer and subsequently enroll the system into the program without receiving an enrollment incentive. PURA approved the request with minor changes on May 5, 2026.	Docket No. 25-08-05	Decision (Dec. 2025)			
CT	Customer Cost-Saving Programs	LMI Incentives	**Background:** The Innovative Energy Solutions (IES) Program is a statewide initiative designed to identify, pilot, and scale innovative ideas that support a decarbonized, affordable, and equitable electric grid. The program opens a new Cycle annually, and each Cycle goes through four Phases. Phase 1 (ideation and screening) and Phase 2 (prioritization and selection) applications are submitted in Q1 Year 1 of each Cycle. The Connecticut Public Utilities Regulatory Authority (PURA) then selects projects in Q4 Year 1 to move onto Phase 3 (project development), with project deployment starting in Q1 Year 2 to last 12-18 months. At the end of the project, the project organization must submit a final report to the program administrator, after which Phase 4 (assessment and scaling) will decide which projects should be deployed at-scale. Cycle 1 opened in early 2023 targeting demand-side flexibility, while Cycle 2 opened in early 2024 targeting projects that empower electrification. **Cycle 3:** The theme for Cycle 3 is Smart Energy Communities, i.e. neighborhoods, districts, towns, or cities that strategically enhance local energy infrastructure or energy end-uses in ways that improve quality of life for their citizens. Phase 1 and Phase 2 applications were filed in early 2025. The program administrator and the IES Advisory Council filed their Phase 2 (prioritization and selection) recommendations on July 31, 2025, recommending 6 of the 19 projects to move on to Phase 3 (project development); three of the projects relate to smart grid technologies/grid modernization, one to multifamily electrification, one to EV charging, and one to microgrids. PURA filed an interim decision on December 17, 2025, detailing the selected Phase 2 projects. All six of the recommended projects were chosen. For Phase 3, project deployment is expected by the end of January 2026, and projects should finish within 12-18 months. **Cycle 4:** The theme for Cycle 4 is Residential Affordability, i.e. cost-effective, reliable energy solutions that ease financial burdens for households; projects should showcase equitable access to innovative grid technologies and pricing models that keep energy affordable for all residential customers. Phase 1 (ideation and screening) applications were due by February 16, 2026.	Docket No. 25-08-07 (Cycle 4)	Innovative Energy Solutions Program Website			
CT	Customer Cost-Saving Programs	Tariffed On-Bill Financing	On November 21, 2025, the Connecticut Department of Energy and Environmental Protection (DEEP) filed an application requesting that the Connecticut Public Utilities Regulatory Authority (PURA) initiate a docket to determine whether it should require Eversource and United Illuminating to implement an on-bill financing program for customers served by DEEP's energy efficiency procurement released on October 1, 2025. DEEP's procurement specifically focuses on demand response measures installed at residential, commercial, and industrial properties by third parties. The measures can be passive or active, and include both electricity and gas. The procurement explicitly includes on-bill financing as a possible financing mechanism, as approved by PURA, and DEEP is filing this application to comply with PURA's orders to address the on-bill financing proposal in a formal docket. PURA filed a decision on May 13, 2026, denying the request, as DEEP received no proposals that requested the use of on-bill financing, and there are significant financial barriers to updating utility systems to implement the proposal.	Docket No. 25-11-09	Final Decision (May 2026)			
CT	Customer Cost-Saving Programs, Studies and Investigations	LMI Community Solar, LMI DER Programs	On February 19, 2025, the Connecticut Public Utilities Regulatory Authority (PURA) opened a proceeding to study the Residential Renewable Energy Solutions (RRES), Non-Residential Renewable Energy Solutions (NRES), and Shared Clean Energy Facilities (SCEF) programs, as required by 2024's H.B. 5232. Under H.B. 5232, the study should include whether the programs should be extended, potential processes to avoid stranded projects, and potential successor programs. Potential processes and successor analyses should include a review of programs without a MW cap, different criteria and procedures for choosing projects (e.g. lottery or first-come first-serve), and alternative bidding frameworks (e.g. preferences for projects with a sooner deployment date). The current RRES and NRES programs provide higher incentives for LMI customers and customers in distressed municipalities, while the current SCEF program utilizes opt-out participation for low-income residential customers, with utilities automatically enrolling income-qualified customers. PURA filed a revised notice of proceeding in late June 2025 to integrate 2025's S.B. 4, which adds three additional analyses for potential processes and successors: a framework to encourage DER aggregation, an evaluation of how non-participating electric customers are impacted by these programs and strategies for minimizing duplication of incentives between participating and non-participating customers (including an evaluation of costs and benefits of the programs and methods to maximize benefits for non-participating customers), and consideration of different compensation structures to encourage deployment in areas of grid underutilization. PURA filed its final legislative report on February 27, 2026. Overall, it recommends a shift from current structures to a unified eight-year program (2028-2035) for long-term market stability. For all programs, it recommends comprehensive consumer protections through the Consumer Protection Task Force and a front-of-the-meter storage program through legislative authorization. The RRES successor should have a reduced export compensation (i.e. below the retail rate), instantaneous netting (instead of monthly), the Buy-All option reserved specifically for multifamily affordable housing customers and customers enrolled on the low-income discount rate, and storage alignment (i.e. incentivize storage through lower export rates instead of creating a storage adder within the program). The NRES successor should have "first-ready" selection and standard offer compensation rates (instead of the reverse auction method), adders (instead of bid preferences) for existing bid preference categories (including for projects in disadvantaged communities), and an annual budget-based cap (instead of an annual MW cap). The SCEF successor should have customer eligibility and selection limited to low-income subscribers, higher compensation than the NRES successor, and alignment with the NRES successor's project selection methodologies. As a result, PURA does not recommend continuing the existing RRES, NRES, and SCEF programs.	Docket No. 25-02-14	H.B. 5232 (2024)	S.B. 4 (2025)	Final Legislative Report (Feb. 2026)	

State	Category	Sub-Topic(s)	Description	Source				
CT	Utility Business Model	CapEx/OpEx Equalization, Earnings Sharing Mechanisms, Multi-Year Rate Plans, Revenue Decoupling	On May 3, 2023, the Connecticut Public Utilities Regulatory Authority (PURA) opened a sub-docket regarding revenue adjustment mechanisms (RAMs) for a performance-based regulation (PBR) framework, as required by the final decision in Docket No. 21-05-15. PURA requested proposals on changes to the four RAMs under review: multi-year rate plan (MYRP), earning sharing mechanism, revenue decoupling mechanism, and CAPEX/OPEX equalization mechanisms. On July 14, 2025, PURA filed a draft decision that would approve a February 2025 straw proposal with modification. The straw proposal summarized various financial mechanisms for the MYRP, earning sharing mechanism, revenue decoupling mechanism, and CAPEX/OPEX equalization mechanisms. MYRP included an externally-indexed revenue cap attrition relief mechanism, a four-year plan duration, going-in rates based on a modified historical test year approach, a new revenue cap formula, catastrophic storm costs, a capital funding mechanism (including cost trackers and an incremental mechanism called a CT-Bar), and standard filing requirements; PURA excluded a return on equity/performance incentive mechanism (ROE/PIM) nexus and an efficiency carryover mechanism. It also included a stay-out provision that prevents a utility from requesting a rate amendment during the term of a PBR plan, and off-ramp exceptions to the stay-out provision to account for unforeseen circumstances. Earning sharing included an upside-only asymmetrical mechanism, a new return on equity methodology, and an earning sharing calculation that does not include PIMs or non-rate recovered costs; PURA excluded dead bands for return on equity and tiered earnings deviation. Revenue decoupling included the existing annual true-up mechanism; it will determine which categories should be excluded from the revenue decoupling calculation within each utility's next rate case. CAPEX/OPEX equalization included revisions to regulatory asset treatment; PURA excluded TOTEX (total expenditures) ratemaking, but noted it may open a future docket to further investigate the issue. It also excluded third-party solution providers, but it will begin tracking relevant Non-Wires Solutions performance mechanisms for visibility into their use. Utilities must implement these components into their next rate case (with the exception of the CT-Bar, as that will not be available until a utility files an integrated distribution system plan).	Docket No. 21-05-15RE01	Draft Decision (July 2025)			
CT	Utility Business Model	Performance Incentive Mechanisms, Shared Savings Mechanisms	On May 3, 2023, the Connecticut Public Utilities Regulatory Authority (PURA) opened a sub-docket regarding performance mechanisms for a performance-based regulation framework, as required by the final decision in Docket No. 21-05-15. PURA filed a straw proposal on March 14, 2024. The proposal includes four performance incentive mechanisms (PIMs), 16 scorecards, and 19 reported metrics across the nine priority outcomes adopted in the main docket. The four PIMs are a non-wires solutions (NWS) shared savings mechanism, an equitable reliability PIM, a DER interconnection PIM for Level 1 projects, and an avoided service terminations outcome PIM. The NWS mechanism would encourage utilities to evaluate NWS resources when beneficial; this mechanism is currently under development in Docket No. 24-08-08. The equitable reliability PIM would encourage utilities to provide reliable service through customer-centric measures. The DER PIM would improve the interconnection process for Level 1 projects (projects under 25 kW); the incentive would be based on the number of days it took for the pre-construction and post-construction application reviews. The terminations PIM would encourage utilities to reduce the total number of residential service terminations for non-payment. On February 28, 2025, PURA filed a revised straw proposal. The revised proposal includes the same PIMs with a new fifth PIM and amendments to some metrics. The new system reliability PIM would provide accountability for system-wide utility reliability performance. The revised straw proposal adds sub-metrics for avoided costs from DERs less than 500 kW and deferred costs from implementing NWS, shifts the peak demand metric benchmark from a 5-year to a 3-year historical average, and adds a new metric for reliability. On July 14, 2025, PURA filed a draft decision that would approve the revised straw proposal with modification. It would adopt four PIMs, 13 scorecards, and 21 reported metrics across the nine priority outcomes with minor changes. PURA approved the NWS, system reliability, equitable reliability, and DER PIM with minor changes, and excluded the terminations PIM.	Docket No. 21-05-15RE02	Draft Decision (July 2025)			
DC	Customer Cost Allocation	Disconnection Policies	Bill 630, as enacted in April 2026, prohibits an electric company from disconnecting electric service for non-payment of a bill or fees during the remand interim period, or the time period after vacating a multi-year rate plan and before a new rate plan is approved, or for 15 calendar days after the remand interim period, unless the household has an average outstanding balance of $1,000 for any residence where the usage can be measured, or per unit for any multifamily resident at which each unit's electricity usage cannot be measured.	B26-0630 (E)				
DC	Customer Cost Allocation, Utility Oversight	Bill Assistance, Cost Shift Prevention, Monitoring	On November 25, 2025, the Office of the People's Counsel (OPC) DC filed a public petition for the DC Public Service Commission to establish a docket to perform a holistic evaluation of energy affordability for ratepayers and to take affirmative actions to adopt measures to protect and improve energy affordability for ratepayers. Specifically, the OPC requested that the Commission perform an evaluation of affordability in the District, develop an affordability metric, and apply best practices to improve energy assistance programs and consumer protections. The OPC further recommended implementing methodologies from an energy affordability assessment that it commissioned; the report includes an affordability metric that may be used in rate cases and reporting. On January 15, 2026, the Commission granted the petition, opened Formal Case 1186, and invited stakeholders to comment on the petition, as well as provide feedback on topics including the Commission's authority over affordability, existing programs and proceedings related to affordability, affordability metrics, creation of a specific rate for large loads that impact ratepayer costs, and recommendations such as best practices and new legislation. Several comments were filed in response to the notice. On May 15, 2026, the Commission filed a notice of a legislative-style hearing to be held on June 3, 2026 addressing potential cost mitigation measures for the "generation" portion of customer bills.	Formal Case No. 1186				
DC	Customer Cost Allocation, Utility Oversight	Disconnection Policies, Rate Freezes	In March 2026, the DC Council adopted Resolution 25-0583 in March 2026. On March 5, 2026, the DC Court of Appeals vacated and remanded the orders approving Pepco's multi-year rate plan and $123.4 million increase over two years. The resolution states that given the rate vacate and remand, the DC Public Service Commission should restore Pepco rates to those last approved in December 2024, since these are the most recent rates that maintain legal standing. The resolution further states that it is necessary to pause electricity disconnections and that the Council determines that the given circumstances make it necessary that the Rate Plan Vacatur Interim Provisions Emergency Amendment Act of 2026 (Bill 630) be adopted after a single reading.	PR26-0583 (Adopted)				
DC	Studies and Investigations	Energy Affordability	From May 27-29, 2026, the DC Public Service Commission held the District of Columbia Energy Action Summit, focused on increasing energy conservation, addressing increasing energy costs, and expanding access to consumer assistance programs. Several panels addressed general affordability while progressing clean energy goals, and one focused directly on the role of the utility companies in affordability. The event also included a community outreach and engagement day, where local organizations provided information on bill assistance, payment programs, and weatherization referrals.	District of Columbia Energy Action Summit (May 2026)				

State	Category	Sub-Topic(s)	Description	Source				
DE	Customer Cost Allocation	Cost Shift Prevention	On October 15, 2025, the Delaware Public Service Commission issued an order opening a docket to require Delmarva Power & Light to promulgate a large load tariff for customers and further requiring the tariff to be in place before interconnecting any large load customers who were not already interconnected by September 3, 2025. On December 19, 2025, the utility proposed a new service class, General Service - Large Demand (GS-LD) for large demand customers. The utility notes the same structure for GS-LD as existing tariff GS-T (General Service - Transmission). The utility also proposed revisions to its Rules and Regulations applicable to large load customers, including a new definition of large load customers as those with projected new load or load additions of at least 50 MW over a 10-year load ramp period. Through a cash deposit for engineering reviews, applicants must pay for the costs of a system impacts analysis and a subsequent detailed engineering analysis. The revisions additionally require a deposit for long lead time equipment, financial assurances for expected distribution extension costs, and a transmission security agreement. Deposits over $2 million must be backed by a letter of credit. On April 28, 2026, Delmarva Power & Light revised the new service classification terms and renamed it General Service - Large Load (GS-LL). Contracts are modified to have an initial period of 10 years, with early termination resulting in exit fees equal to any unrecovered distribution project extension costs, as well as those specified in the transmission service agreement. The revision clarifies that expected distribution extension costs in the rules and regulations may include all associated engineering work and clarifies the company's protocol for returning or releasing delivery revenue and financial assurances.	Docket No. 25-0826				
DE	Customer Cost Allocation, Customer Cost-Saving Programs	Bill Assistance Program, Cost Shift Prevention, LMI Incentives	H.B. 233, as substituted and passed by the House in June 2026, requires Delaware Public Service Commission-regulated utilities to establish a service classification and tariff for large energy use facilities, separate from other commercial or industrial customers. Any tariff or electric service agreement (ESA) approved by the Commission directly assign the costs of serving a large energy consumer to the consumer and ensure that the costs of serving the class of large energy use facilities are borne by that class of customers. The tariff must require large energy use facilities to contribute to the Low-Income Charge at a rate of $0.000190 per kWh; the charge is deposited into the state agency-administered Low-Income Program Fund to, which is used for low-income fuel assistance and weatherization programs in Delmarva Power & Light's service territory. The bill outlines protocols for assigning infrastructure, PJM capacity procurement, and study costs. Further, it outlines provisions for minimum contract term lengths, minimum distribution charges, exist procedures and fees, incremental cost tests, and financial security. In determining whether to approve an ESA, the Commission must consider whether the ESA and underlying tariff ensures that all applicable costs attributed to the large energy use facility are directly assigned to the facility and use the incremental cost test referenced above to make this determination. Additionally, the Commission must consider if the ESA and tariff provides protections necessary to ensure that other customers of the utility are not placed at risk for paying stranded costs associated with the utility serving the large energy use facility. The House passed the bill in June 2026.	H.B. 233 (P1)				
DE	Customer Cost Allocation, Utility Business Model	Low-Income Discount Rates, Revenue Decoupling	On December 9, 2025, Delmarva Power & Light filed an application for an increase in electric base rates. The application includes an income-based rate discount available to ratepayers enrolled in LIHEAP or the Delaware Energy Assistance Program; the rate and associated costs are authorized by H.B. 116 (enacted in 2025). Enrollment in one of the programs qualifies the customer for a 20% discount on the total electric delivery charge. The utility also requested Delaware Public Service Commission approval to recover budgeted program costs as an additional charge to the existing low-income rate. The application also requests a Bill Stabilization Adjustment (BSA) Rider to decouple electricity use and distribution revenue; the BSA would lower customer rates if the company earned above its target revenue distribution revenue per customer and raise rates if the company earned less than the target revenue. The company would seek an annual adjustment to collect or return the balance and propose a revised rate based on forecasted usage.	Docket No. 25-1555				
DE	Customer Cost-Saving Programs	LMI Incentives	On December 9, 2025, Delmarva Power & Light filed its application for approval of its 2027-2029 Affordability and Load Flexibility Portfolio. The portfolio includes five programs and two pilots; the total estimated 2027-2029 plan period budget is estimated to be $36.95 million. The new Direct Load Control (DLC) 2.0 program is an update to Delmarva's legacy A/C control program, supplying utility-provided switches (two-way communication load control devices) that enable direct cycling. Customers can receive annual incentives of $40 for 50% cycling, $60 for 75% cycling, and $80 for 100% cycling. Delmarva claims that DLC 2.0 will focus on affordability and equitable participation for LMI access due to the no-cost, turnkey nature of the program and states plans for outreach in collaboration with community organizations.	Docket No. 25-1554				
DE	Planning and Procurement	Wholesale Capacity Market Rules	H.C.R. 94 urges PJM to extend its price collars for two years at the current rate of $325/MW-day and encourages PJM to reform its interconnection queue to allow generation to come online faster to prevent the need for future price collars. The House and Senate passed the resolution in January 2026.	H.C.R. 94 (Adopted)				
DE	Utility Business Model, Utility Oversight	Rate Freezes, Return on Equity Rules	On June 16, 2026, Delaware Governor Matt Meyer called on several state actors to address energy affordability. First, Governor Meyer called on the Public Advocate to file a petition with the Delaware Public Service Commission asking the Commission to act within the next six months to reset the utility's profit model. The Governor requested that the review examine Delmarva Power's rate of return and consider whether a competitive determination is more appropriate than allowing a set return. Further, the Governor called on the Commission to initiate a review to freeze rates. Finally, the Governor called on the legislature to pass S.B. 326 and H.B. 233.	Delaware Governor's Office Press Release (June 2026)				
DE	Utility Oversight	Audits, Cost Recovery, Monitoring, Transparency	S.B. 326, as passed by the Senate in June 2026, directs the Delaware Public Service Commission to conduct management audits of Commission-regulated electric distribution companies, which must include an examination of management effectiveness and operating efficiency. Audits would be conducted every five years, unless the Commission finds that a specific management audit is unnecessary. The bill further allows the Commission to require an audit to be performed by independent audit or consulting firms, with stipulations that the firms must be paid by the utility for relevant expenses and that no entity other than the firm will have input or editorial control of the firm's findings and recommendations. The bill also requires each public utility to prepare, maintain, and file with the Commission for approval, a rate summary table for each rate class, showing the total effective rate and itemizing each rate element. Each element will be displayed numerically, using the same units in which the customer is billed and include a schedule that identifies the components of rates that change on a predictable schedule. The Commission may reject or require revisions to the table to align with approved rates. The utility will include the table in its tariff, post the table for each customer class in an easily accessible place on its website, include the table in customer bills, and file the table in the above locations at least 30 days prior to the effective date of any rate change. The bill also outlines a plain language standard in public facing and customer communications and any submissions to the Commission, public utilities, Commission Staff, and Division of the Public Advocate. Pertaining to rate cases, the bill requires that for changes to base rates, notice to the Commission must include the test period and test year applicable. Further, as a part of any base rate filing, a public utility may be subject to a regulatory accounting review of transactions included on the utility's books and records for ratemaking purposes. Current law allows utilities to place their proposed rates into effect if the Commission has not made its decision within seven months after the filing, on the condition that the utility files a bond in a reasonable amount to refund entitled parties the excess if the rate is finally determined to be excessive, provided that the increase does not constitute an increase in excess of 15% of the utility's gross intrastate operating revenues; a utility may put a rate into a bond 60 days after the filing. The bill revises current law to to state that only 50% of the increase may be put into effect, and 75% after 12 months; a utility may put a rate into a bond 90 days after the filing. The bill also stipulates that for any public utility with more than 25,000 customers, the utility will not recover from its customers expenses related to distribution rate cases for attorneys' fees and to engage external expert witnesses incurred after the filing date that exceed the amount spent by Commission Staff and the Division of the Public Advocate on attorneys' fees and fees to engage expert witnesses or consultants. Additionally, the bill stipulates that all orders issued by the Commission must contain adequate support and rationale for any conclusions, including specific facts and factors on which the conclusion is based, and major elements of the settlement when issuing an order accepting or denying certain settlement agreements. Finally, each Commission-regulated utility may not recover in rates annual non-mandatory spending in excess of $70,000,000 for 2026 and 2027, and for year 2028 and continuing thereafter.	S.B. 326 (P1)				

State	Category	Sub-Topic(s)	Description	Source				
DE, IL, MD, NJ, PA	Customer Cost Allocation	Bill Assistance	In summer of 2025, Exelon, parent company to utilities Atlantic City Electric, Baltimore Gas & Electric, Commonwealth Edison, Delmarva Power & Light, PECO, and Pepco, partnered with local non-profits to determine eligibility for and administer the $50 million Customer Relief Fund, a one-time temporary assistance program. In January 2026, Exelon committed an additional $10 million in temporary funds for the program.	Exelon Customer Relief Fund				
FL	Customer Cost Allocation	Cost Shift Prevention	S.B. 484, as passed by the Senate and House in March 2026, establishes minimum tariff and service requirements for large load customers in public utility tariffs. Tariffs must ensure each large load customer bears its full cost of service (e.g., connection, transmission, generation, infrastructure, operations, and maintenance) with no cost shifting to general ratepayers, who also may not bear the risk of nonpayment. The Governor signed the bill in May 2026.	S.B. 484 (E)				
FL	Customer Cost Allocation	Cost Shift Prevention	On April 22, 2026, Duke Energy Florida filed a petition to approve a Large Load Customer Policy (LLCP) and Large Load Customer Agreement (LLCA), following a similar 2025 filing (Docket No. 20250113). The utility plans to propose a new large load rate schedule in its next rate case. The petition reflects changes driven by S.B. 484 of 2026, which requires large load customers to fully cover service costs without shifting risk to other ratepayers. It also prohibits service to foreign entities and prevents load-splitting to avoid classification, while allowing the Florida Public Service Commission to use standard ratemaking tools such as demand charges and financial guarantees. The policy applies to new or expanded facilities with expected demand of at least 50 MW, excluding sites already interconnected as of December 31, 2025. Customers must pay a $150,000 non-refundable system impact study fee (plus $150,000 for updates) and, within three months, execute an LLCA or reimbursement agreement. Service requires a 20-year minimum term and may include a load ramp period (75–85% of contract capacity). Customers must provide financial security and cover all incurred costs if service is not taken or is terminated early, including specified termination fees. Two years' notice is required for termination, while Duke Energy may terminate for cause with 90 days' notice. The utility may require upfront payment of extension costs (refundable over five years). Until a new rate is approved, service will be taken under existing GSD-1 or GSADT-1 rates.	Docket No. 20260064				
GA	Customer Cost Allocation	Cost Shift Prevention	H.B. 1027, as passed by the House in February 2026, states that the sale of electric power must include contract terms requiring that a specific customer pay for any new power plant needed to serve them during the initial PPA term. Where a new facility's output is shared between a large load customer (with an expected peak demand of at least 100 MW) and a local government, construction costs must be allocated so the local government is only responsible for their pro rata share. Contracts between the Municipal Electric Authority of Georgia or local governments and a large load customer must protect residential and retail customers from costs associated with serving that customer, including minimum billing requirements, terms that may exceed the applicable service tariff, and performance, credit, and termination provisions to protect retail customers in the event of default or termination. The large load customer is responsible for all costs associated with establishing the additional generating capacity needed to serve them during the initial contract term. The bill did not continue to advance before the end of the legislative session.	H.B. 1027 (D)				
GA	Customer Cost Allocation	Cost Shift Prevention	H.B. 1063 requires electric utilities to protect other customers from costs associated with data centers, specifically those with a demand of at least 100 MW. Each contract between a utility and data center must include specific terms and condition, such as minimum billing requirements to recover incremental costs, a contract term that may exceed the length of the associated tariff, performance and credit provisions to protect retail customers, and termination provisions. The bill applies to data center agreements entered into on or after the bill's enactment. The House passed the bill in February 2026 with minor changes. However, the bill did not continue to advance before the end of the legislative session.	H.B. 1063 (D)				
GA	Customer Cost Allocation	Cost Shift Prevention	S.B. 410, as passed by the Senate in early March 2026, requires electric utilities to protect other customers from costs associated with data centers, specifically those with a demand of at least 100 MW. Each contract between a utility and data center must include specific terms and condition, such as minimum billing requirements to recover incremental costs, a contract term that may exceed the length of the associated tariff, performance and credit provisions to protect retail customers, and termination provisions. The bill failed to progress before the end of the legislative session.	S.B. 410 (D)				
HI	Customer Cost Allocation	Bill Assistance	S.B. 191 and S.B. 3103, as passed by the Senate in March 2026, establish the Hawaii Home Energy Assistance Program to assist households with the cost of home energy needs. Eligibility requirements would be established by the Hawaii Department of Human Services, including income limits. The bills did not pass the House by the end of the legislative session in May 2026.	S.B. 191 (D)	S.B. 3103 (D)			
HI	Customer Cost-Saving Programs	Education, LMI Incentives	H.B. 1774, as passed by the House in March 2026, requires the Hawaii Climate Change Mitigation and Adaptation Commission to maintain a centralized resource website to connect residents to programs, services, discounts, and assistance that address affordability, health, safety, and the impacts of climate change. The website should be the main starting point to access and apply to these resources. Applicable resources include those that improve household energy efficiency, reduce utility costs, and promote long-term cost savings for working families. The bill also appropriates a yet-to-be-determined amount of money to the website. The bill did not pass the Senate by the end of the legislative session in May 2026.	H.B. 1774 (D)				
HI	Customer Cost-Saving Programs	Financing	H.B. 977, as passed by the House in February 2025, limits the Clean Energy and Energy Efficiency Revolving Loan Fund to underserved ratepayers, which includes state and local governments, LMI homeowners, renters, non-profits, small businesses, and multifamily rental projects. The Fund provides low-cost loans at below-market rates for clean energy investments or other authorizes uses. The bill also appropriates a yet-to-be-determined amount of money to the Fund. The bill did not pass the Senate by the end of the legislative session in May 2026.	H.B. 977 (D)				
HI	Customer Cost-Saving Programs	LMI Community Solar	**Background:** Legislation enacted in 2015 established the Community-Based Renewable Energy (CBRE) program. The Hawaii Public Utilities Commission then developed a CBRE program framework and model tariff language. The framework includes island-specific capacity additions, credit rates, project size stipulations, and time-differentiated pricing. The CBRE framework features a phased approach, where future phases will incorporate lessons learned from the first phase. **Recent Action:** In October 2025, HECO filed its proposed framework for a CBRE Phase 3, which is a utility-resourced model composed entirely of LMI subscribers. In doing so, HECO agreed with a 2024 assessment from the Commission that Phase 2 of the CBRE program has attracted only a fraction of the 235 MW program cap, and most developers working on project have struggled to meet the program's complex requirements and schedules. In its proposed model, the utility manages the systems for the program and serves as the subscriber organization. Customers could subscribe directly with the utility and all the fees and credits would be accounted for on one bill. The proposed framework does not propose specific bill credit amounts, but rather identifies that HECO needs to conduct a fresh analysis to determine appropriate subscriber credit rates for each island under a utility-resourced model, as well as a framework for application fees, meter fees, and treatment of unsubscribed energy, reflecting the utility's new role. It also presents three options for acquiring the projects to support the program, including converting a portion of an existing as-is utility operated renewable generation facility on a leased site to a CBRE project, upgrading and converting existing renewable systems owned by the HECO companies to CBRE projects, and partnering with state government entities to develop new CBRE projects operated by the utility. In May 2026, the Commission denied HECO's proposed CBRE Phase 3 framework, arguing that the application lacked sufficient detail for the Commission to determine whether it is reasonable and in the public interest. The Commission provided a non-exhaustive list of questions to illustrate the type of details that were missing in the proposal when compared to HECO's proposals for other Phases. The order invited HECO to resubmit its application, but cautioned the utility to provide more detail.	Docket No. 2015-0389	CBRE Phase 3 Proposed Framework (Oct. 2025)	Order (May 2026)		
HI	Customer Cost-Saving Programs	LMI Incentives	H.B. 2241, as passed by the Senate in April 2026, limits the state's individual income tax credit for solar PV systems on single-family residential properties to taxpayers with an adjusted gross annual income up to $170,000 if filing as an individual, $262,500 if filing as head of household, or $350,000 if filing jointly. Taxpayers with an adjusted gross annual income up to $40,000 individually or $60,000 jointly could have excess credits refunded. Systems using third-party financing, regardless of the taxpayer's income, are still eligible. The House did not concur with the Senate version and sent the bill to conference committee; the bill did not pass conference committee by the end of the legislative session in May 2026.	H.B. 2241 (D)				

State	Category	Sub-Topic(s)	Description	Source				
HI	Customer Cost-Saving Programs	LMI Incentives	S.B. 3183, as passed by the Senate in March 2026, limits the state's individual income tax credit for solar PV systems on single-family residential properties to taxpayers with an adjusted gross annual income up to $250,000 individually or jointly; tax credits that meet this income requirement would not have a maximum. Taxpayers with an adjusted gross annual income up to $40,000 individually or $60,000 jointly could have excess credits refunded. Systems using third-party financing, regardless of the taxpayer's income, are still eligible. The bill did not pass the House by the end of the legislative session in May 2026.	S.B. 3183 (D)				
HI	Customer Cost-Saving Programs	LMI Incentives	On April 21, 2026, the Hawaii Public Utilities Commission opened a proceeding to design and implement a virtual power plant (VPP) grid-services program to improve upon the Hawaiian Electric Companies' (HECO) existing scheduled dispatch grid services programs. The Commission hopes the new program will expand new customer-sited DER adoption for all customer income levels and ultimately gather nearly all legacy and future DER into a single framework to maximize the benefits of DERs. In opening the proceeding, the Commission presented VPP program design elements it believes are better suited for Hawaii. By listing these design elements up front, the Commission hopes to expedite the development of the VPP program. As part of its proposed design elements, the Commission requires incentive adders for LMI participants; it is open to diverse proposals for appropriate incentive and compensation terms, but prefers performance-based incentives.	Docket No. 2026-0084				
HI	Studies and Investigations	Cost Savings Strategies	H.R. 192, adopted by the House in April 2026, establishes the Legislative Task Force on Hawaii's Future Energy Pathways to examine strategies to maximize cost savings while minimizing risk to ratepayers over the next three decades and achieving the state's energy goals and providing affordable, reliable, and resilient energy. The Task Force will evaluate potential pathways for Hawaii's energy transition, including strategies for integrating high levels of renewable energy and DERs into the power grid, reducing long-term energy costs for residents and businesses, strengthening energy independence and resilience, and examining the potential risks, costs, and benefits associated with proposed fossil fuel infrastructure investments, including liquefied natural gas. It must consider lessons learned from other jurisdictions pursuing rapid energy transitions and identify policy recommendations to help maximize cost savings and minimize risk to ratepayers while achieving statutory clean energy goals. The Task Force must submit an initial report of its finding to the Legislature no later than 20 days prior to the convening of the 2027 session, and a final report no later than 20 days prior to the convening of the 2028 session.	H.R. 192 (Adopted)				
HI	Studies and Investigations	Large Load Cost Shift Prevention	H.C.R. 206, H.R. 196, and S.R. 90, as adopted in April 2026, request that the Hawaii State Energy Office convene a working group to study the potential impacts of large data centers requiring electricity of 5 MW or more in instantaneous demand on Hawaii's electric utilities, ratepayers, natural resources, and climate goals. The working group should examine (1) mechanisms to ensure that data center developers bear the full cost of any new electricity generation, transmission, distribution, or grid infrastructure required to serve their facilities; (2) measures to protect residential and small business ratepayers from increased electricity costs associated with large new electricity loads; (3) requirements for transparency and reporting regarding electricity consumption, water usage, and greenhouse gas emissions associated with data center operations; (4) strategies to ensure that data centers operating in Hawaii are powered by renewable energy and do not undermine the state's statutory clean energy goals; (5) consideration of water use and other environmental impacts associated with data center cooling systems; (6) grid reliability considerations related to large electricity loads on Hawaii's island grids; and (7) any other regulatory safeguards that may be necessary to ensure that data center development, if it occurs in Hawaii, provides net benefits to the state and its residents. The working group is requested to submit a report of its findings and recommendations, including any proposed legislation or regulatory actions, to the Legislature no later than 20 days prior to the convening of the Regular Session of 2027.	H.C.R. 206 (Adopted)	H.R. 196 (Adopted)	S.R. 90 (Adopted)		
HI	Studies and Investigations	Utility Ownership Structure	S.B. 3326, as passed by the Senate in March 2026, requires the Hawaii Public Utilities Commission to conduct a study of the desirability of the separation of ownership and control of electric energy generation services from transmission and distribution (T&D) services. The study should examine how this separation would, among other things, create savings for ratepayers and ensure customer rate stability. It must submit its initial report to the legislature no later than 20 days prior to the convening of the regular session of 2027 and its final report no later than 20 days prior to the convening of the regular session of 2028. Following the completion of the final report, the Commission may adopt rules to require separate ownership and control of generation from T&D for investor-owned utilities; cooperatives are explicitly excluded. If implementing this structure, then the Commission must, among other things: implement requirements to promote transparency and prevent cross-subsidization, undue preference, or discrimination between generation and T&D; ensure fair and reasonable recovery of costs, consistent with the public interest and ratepayer protection; ensure power purchase agreements minimize financial risk to ratepayers; and consider the impacts of the separation on ratepayer affordability. The bill did not pass the House by the end of the session in May 2026.	S.B. 3326 (D)				
HI	Utility Business Model	Performance Incentive Mechanisms, Revenue Adjustment Mechanisms	S.B. 2487, as enacted in June 2026, clarifies that performance-based incentives can include revenue adjustment mechanisms, cost control mechanisms, and reward and penalty mechanisms. It also authorizes the Hawaii Public Utilities Commission to adopt alternative ratemaking procedures to establish electricity rates and performance-based incentives, provided that the rates must be derived from a performance-based model for determining utility revenues. The Commission must adopt performance-based incentives by 2027; the current adoption deadline is 2020.	S.B. 2487 (E)				
ID	Customer Cost Allocation	Cost Shift Prevention	H.B. 911, enacted in April 2026, requires public utilities to provide service to a new large load only pursuant to an Idaho Public Utilities Commission-approved service contract. Service contracts must be approved by the Commission prior to providing service to a new large load and such filing must include a no harm test. A no harm test is an assessment by the Commission to determine the impact a new large load will have on the rates of existing utility customers. Service contracts may be approved if the utility demonstrate that: it is reasonably expected to maintain the same or higher level of service quality and reliability available to other customers as would have been expected had the utility not served the new large load; and the new large load is responsible for funding its full cost of service, including its share of generation, transmission substation, and distribution infrastructure investment that would not be placed in service or be required by the utility if not for the new large load. Approval of service contacts is conditional on the new large load furnishing financial security in a form and amount approved by the Commission, that is reasonably sufficient to protect the utility and its other customers from risk of stranded costs, unrecoverable costs or investments. Additionally, in each general rate case, the Commission must review the rates, charges, and recovery mechanisms applicable to an approved service contract as part of a comprehensive public utility cost study to ensure the new large load is assigned its full cost of service and may adjust these items if necessary. A new large load is any electrical load associated with a new service entrance, any additional service associated with a chance, enlargement, or other modification of a service entrance, or utilization of an existing entrance that: results in an increase in a cumulative power requirement of such entrance of 50 MW or more in any consecutive 60 month period; and is subject to a service contract with a utility that was entered into on or after July 1, 2026. A new large load may not change its status by splitting its load among more than one entrance or adding additional connections, meter, or entrances to serve an otherwise single entity or enterprise.	H.B. 911 (E)				
ID	Customer Cost Allocation	Cost Shift Prevention	On March 31, 2026, Idaho Power opened a new proceeding to review and determine the appropriate cost of service for new large load customers to ensure that other customer classes are not adversely affected. The petition does not propose tariff changes and does not request any specific class cost of service methodology.	Docket No. IPC-E-26-07				
IL	Customer Cost Allocation	Cost Shift Prevention	On March 19, 2026, the Illinois Commerce Commission filed a final order adopting Commonwealth Edison's (ComEd) proposed revisions to its General Terms & Conditions (GT&C), collectively designed to memorialize existing practices and create new ones to ensure that new service requests by large demand applicants and customers, "neither harm, nor unjustly shift costs to, other customers." The revisions include: using deposits or security to ensure recovery of engineering costs of large demand project applications; facilitating the procurement of long-lead materials in ways that do not place cost and risk on other consumers; memorializing utility requirements for applicant letter of credit, as well as utility practices related to transmission revenue requirements and to conducting "cluster" studies for multiple applicants in a joint process. The order adopted the transmission security agreement (TSA) provision with a modification effectively requiring the use of a TSA.	Docket No. P2025-0677	Order (Mar. 2026)			

State	Category	Sub-Topic(s)	Description	Source				
IL	Customer Cost Allocation	Cost Shift Prevention	On March 19, 2026, the Illinois Commerce Commission filed a final order adopting Commonwealth Edison's (ComEd) proposed revisions to Rider DE, finding the proposed modifications to Rider DE necessary to strengthen deposit and collateral protections for new large load customers. The revisions clarified requirements and procedures for large load customers' new service requests, requesting an effective date of August 7, 2025. In its filing to the Illinois Commerce Commission, ComEd explained that the revisions were designed to help ensure that such requests, "neither harm, nor unjustly shift costs to, other customers." Revisions included deposits or security to ensure recovery of on-property distribution costs, in addition to off-property extension distribution costs; and revisions to the definition of and conditions for a letter of credit or nonrefundable payment to provide standard electric services. While applicable to all customers seeking new or expanded service, ComEd noted that for customers expected to require 50 MW or more within 10 years, the proposal included a customer deposit for utility facilities on customer premises. Applicable customers with a deposit amount of $2 million or more will be required to provide a qualifying Acceptable Letter of Credit in lieu of a deposit.	Docket No. P2025-0679	Order (Mar. 2026)			
IL	Customer Cost Allocation	Low-Income Discount Rates, Payment Plans	H.B. 4456, as passed by the House and Senate in May 2026, allows the Illinois Commerce Commission to approve a low-income discount for electric and natural gas residential customers that applies to the entirety of a qualifying customer's bills; a qualifying customer is a residential customer of a utility serving more than 100,000 customers that has a low-income discount program for residential customers (1) who been deemed eligible for assistance under LIHEAP or who receives energy assistance under the Energy Assistance Act and (2) whose household income does not exceed 300% of the federal poverty level. It further allows utilities to fund the discounts through a surcharge on both residential and non-residential customers' bills; any cost recovery mechanisms must be assessed on a fixed, per-customer basis. It further requires any electric or natural gas public utility serving more than 100,000 customers in the state that does not have a low-income discount for residential customers or that chooses to implement a low-income discount that complies with the requirements above on or after the effective date of the bill to to file a new or amended tariff within 30 days of the effective date and for the Commission to issue a final order on the tariff within 90 days of the utility's filing; if the tariff is approved the utility will implement the low-income discount within 12 months and an additional 12 months upon filing a notice with the Commission. The Commission must consider the effect of the low-income discount on, and work to maximize, the allocation and funds under LIHEAP, the Supplemental Low-Income Energy Assistance Fund under the Energy Assistance Act, or other state and federal energy assistance grants. The discount may include, but is not limited to, tiered discounts or a Percentage of Income Payment Plan (PIPP) program. The calculation of the discount will be applied after any federal or state energy assistance funds are applied to a qualifying customer's bill. Additionally, the bill stipulates that in setting the annual eligibility level for the use of state funds from the Supplemental Low-Income Energy Assistance Fund under the Energy Assistance Act, the limit may not be set higher than 300% of the federal non-farm poverty level. Finally, the bill states that beginning January 1, 2027, the Base Energy Assistance Charge will be $0.80 per month for each utility that is required to implement a low-income discount program and $0.40 per month for each utility that is not required to implement a low-income discount program and that contributes to the Supplemental Low-Income Energy Assistance Fund.	H.B. 4456 (P2)				
IL	Customer Cost Allocation	Low-Income Discount Rates, Payment Plans	In August 2025, the Illinois Commerce Commission filed a final order approving a Low Income Discount (LID) program for Ameren Illinois through Rider ESDA (Electric Service Discount Adjustment). The Commission approved "Option 2," a percentage of income payment (PIPP)-like program designed to limit a participant's energy burden to 3% of household income for non-electric heating households or 6% for electric heating households. The Commission also set a target implementation date of June 2026 for rider ESDA. Finally, the Commission directed Ameren to file quarterly implementation status reports. On January 8, 2026, pursuant to its November 2025 status report and alternative timeline with a revised implementation date of no later than October 1, 2026, Ameren submitted a tariff filing to the Commission reflecting these changes. On April 1, 2026, Ameren filed its most recent status report, outlining progress and changes including the January filing.	Docket No. 25-0083	Order (Aug. 2025)	Revised Tariff (Jan. 2026)		
IL	Customer Cost Allocation, Customer Cost-Saving Programs, Planning and Procurement, Studies and Investigations, Utility Business Model	Competitive Procurement, Cost Shift Prevention, LMI Community Solar, LMI Incentives, Performance Incentive Mechanisms, Planning Rules	S.B. 25 (the Clean and Reliable Grid Affordability Act, or CRGA Act), as enacted in January 2026, makes revisions to several energy-relevant provisions of Illinois statute. Pertaining to Beneficial Electrification Plans, the bill adds a requirement that utilities demonstrate methods of minimizing ratepayer impacts and exempting or minimizing low-income ratepayers from the costs associated with facilitating the expansion of electric vehicle charging. The bill also authorizes the Illinois Power Agency to direct up to 25% of the low-income single-family and small multifamily, non-profits and public facilities, and large multifamily solar incentives under the Illinois Solar for All program to be used towards a newly established Illinois Storage for All program, which provides incentives to encourage the development of energy storage co-located with distributed PV devices developed through the Illinois Solar for All program. The bill also outlines development, eligibility, and the stakeholder process for the Illinois Storage for All program. It also allows for income verification to rely on self-attestation of low-income applicants to reduce process burden. Additionally, the bill modifies energy efficiency resource standards for utilities. Electric utilities must use at least 25% of total energy efficiency program spending approved by the Illinois Commerce Commission (ICC) on energy efficiency measures targeting low-income households. For utilities that serve less than 300,000,000 but more than 500,000 retail customers in the state, the incremental annual energy savings requirements outlined in the bill may be reduced by 0.025 percentage points for for every percentage point increase, above the 25% minimum to be targeted at low-income households, in the portion of total program spending that is on LMI efficiency programs; the requirement may not be reduced to a level less than 0.25 percentage points less than the requirement applicable to the calendar year. The bill also requires that at least 33% of all costs of offering and promoting electrification measures under the given subsection must be for supporting the installation of electrification measures through programs exclusively targeting low-income households; if achieving this percentage is demonstrated not to be attainable and the percentage is reduced, the utility must prioritize support for low-income electrification over non-low-income spending. Energy efficiency cost recovery must include a cost of equity that is equal to the baseline cost of equity approved by the Commission for the utility's electric distribution rates effective during the applicable year. The bill further outlines a performance incentive mechanism for utilities that serve greater than 500,000 retail customers in the state; beginning on January 1, 2027, the utility will have its return on equity modified for performance on the energy savings and peak demand goals. Related to community renewable energy subscriptions, the bill adds a provision that electric utilities must use the same net crediting format for subscribers on payment plans and subscribers participating in budget billing programs. Net crediting is defined as the utility remitting the cash value of the subscription fee to the owner or operator of the community renewable generation facility without regard to whether the subscriber has paid the subscriber's monthly electric bill and places the cash value of the remaining bill credit on the subscriber's bill. The bill also outlines requirements for a new virtual power plant program, including a requirement for upfront payment or performance payment compensation mechanisms. The program must enable LMI customers and community-driven community solar projects to receive a higher upfront payment. Further, ICC Staff now must coordinate with state agencies including the Illinois Power Agency to propose the state's first IRP by November 15, 2026. The portfolios within the development process must include a comparison of total system cost on a net-present-value basis and customer rate and bill impacts. Also related to planning and procurement, the bill outlines a process for procurement for the delivery year beginning June 1, 2027, to potentially facilitate additional supply through a competitively neutral cost allocation mechanism upon need identified in the IRP process. The Illinois Power Agency is directed to propose long-term contract structures for new clean energy resources that do not create contractual obligations on utilities that are not contingent on full and timely cost recovery, that avoid negative financial impacts on the utilities, and that are agreed upon by the utilities. In approving the contract structures, the ICC must prioritize structures that ensure stable, reliable, and competitively neutral allocations of costs and responsibilities. Further, purchases made under contracts awarded will be funded in a competitively neutral manner as determined by the ICC. Finally, the bill requires that the ICC conduct and publish the findings of a policy study to evaluate the costs and benefits, including affordability, over time of establishing a single state-operated independent system operator.	S.B. 25 (E)				

State	Category	Sub-Topic(s)	Description	Source				
IL	Customer Cost Allocation, Studies and Investigations	Cost Shift Prevention	On March 20, 2026, the Illinois Commerce Commission released a press release stating that the Commission intends to open an investigation into how Commonwealth Edison (ComEd) should address data center issues and cost risks, prompted by consideration of deposit protection in the case ComEd's newly approved data center tariff. The recent decision requires the Commission to initiate an investigation to examine if data centers warrant a separate tariff structure; the extent to which Rider Nonstandard Service (NS) and Rider Zero Standard Service (ZSS) may need modification to function as companions to, or substitutes for, Rider Distribution System Extension (DE); whether refinements to Rider DE are needed to define standard service, collateral requirements, and methods for assignment of interconnection costs to data centers; and discussion of costs and benefits of infrastructure attributable to large load projects and facilities. The investigation should be completed within eight months of initiation; the Commission is directed to initiate the investigatory docket by April 23, 2026. On April 8, 2026, a Commission Staff report recommended that the Commission initiate an investigation for the purpose of identifying, examining, and potentially adopting appropriate ratepayer protections and cost recovery mechanisms to mitigate rate base impacts, allocate costs, and address affordability concerns related to large load tariffs. The report further recommended that the proceeding consider topics including cost allocation of infrastructure to serve large load customers and make ComEd a respondent. On April 23, 2026, the Commission concurred in and accepted the recommendations of the Staff report, and initiated the investigation proceeding.	Docket No. 26-0364	ICC Press Release (Mar. 2026)			
IL	Customer Cost Allocation, Utility Business Model, Utility Oversight	Cost Recovery, Low-Income Discount Rates, Revenue Decoupling	On March 20, 2026, MidAmerican Energy Illinois filed a proposed increase in electric rates. The proposal contains testimony addressing affordability concerns, including a low-income discount rate. MidAmerican declined to file a low-income discount rate, citing a small customer base and limited customer count, which would result in a disproportionate impact on other customers. However, MidAmerican proposed Rider PI, a phase-in adjustment rider over year one of its rate increase with the rationale of decreasing the customer affordability impacts that would have come from an immediate rate increase. As part of this general rate case, MidAmerican Energy proposed Rider EBA - Electric Balancing Adjustment to separate its revenue from its electricity sales. Rider EBA will allow the company to determine an annual adjustment under the rider, based on the difference in actual revenue and the rate case revenue amounts approved by the Illinois Commerce Commission in the most recent rate case. The EBA factor would be determined through a delivery EBA and a supply EBA, separately calculated for residential and non-residential classes. Rider EBA also includes provisions for revision of factors, annual filing of information and reconciliation sheets, an annual audit, and compliance documents. For the first billing cycle beginning April 2027, Rider EBA will be set at $0 per kWh across classes. A hearing is scheduled for October 13, 2026.	Docket No. 26-0331				
IL	Customer Cost-Saving Programs	LMI Incentives	On July 17, 2025, Commonwealth Edison (ComEd) proposed three new tariffs: Rider BYODLR - Bring Your Own Device Load Reduction (BYODLR) Program, Rider VPP - Virtual Power Plant Program, and Rider CSS - Community Solar Plus Storage Program. These tariffs are intended to comply with the requirements of the order from Docket No. 22-0486, ComEd's Multi-Year Grid Plan docket. On November 18, 2025, ComEd filed a motion to withdraw its application. ComEd cited the Illinois legislature passing the Clean and Reliable Grid Affordability (CRGA) Act (S.B. 25) as rationale, since the CRGA Act touches on CSS and VPP program components such as device eligibility, compensation levels, and measurement of participant performance and could be cause for rider revision. ComEd intends to revise its proposals in response to the CGRA Act and additional feedback. On February 17, 2026, in line with the withdrawal order, ComEd filed a new BYODLR program, including enhanced LMI incentives, to allow load response devices while ComEd develops its VPP program, with the intention to eventually incorporate the BYODLR program into the VPP program. The proposal expands eligibility to residential retail customers with a smart thermostat or thermal storage device, and device eligibility may be expanded in the future. The event parameters for smart thermostat load reduction (STLR) include up to 184 events per year between 9 AM and 9 PM lasting no more than four hours. ComEd would provide 24-hour notice for planned events and 30-minute notice for emergency events. The compensation structure for STLR would be $30 for enrollment, with a $50 enhancement for income-eligible customers, and $30/kW for an annual performance incentive.	Docket No. 25-0678				
IL	Customer Cost-Saving Programs	Tariffed On-Bill Financing	Public Act 102-0662 directs the Illinois Commerce Commission to carry out a process that will establish "Equitable Energy Upgrade Programs" that Commonwealth Edison and Ameren Illinois must offer to eligible retail electricity customers. The statute stipulates that the programs are intended to provide immediate financial savings to lower-income residential and environmental justice community residents who finance the installation of renewable energy generation systems, energy efficiency upgrades, energy storage systems, and demand response equipment through an on-bill finance mechanism modeled after "Pay As You Save (PAYS)." Once the Commission adopts guidelines for the programs, the utilities must submit informational filings within 120 days. On September 18, 2025, the Commission filed an order initiating a docket to establish guidelines for equitable energy upgrade programs. Parties have filed initial comments, response comments, reply comments, and sur-reply comments. The ALJ's proposed order has not yet been filed.	Docket No. 25-0863				
IL	Utility Business Model	Performance Incentive Mechanisms	On May 15, 2025, Commonwealth Edison (ComEd) proposed seven performance metrics (PMs) and 32 tracking metrics as described in its performance and tracking metrics plan for 2028-2031. The metrics are the same as those in ComEd's first plan, with only minor changes. The performance metrics include a reduced disconnections metric. The metrics are paired with a symmetrical incentive/penalty mechanism for significant deviations from the expected performance, which step up each year. On November 10, 2025, an ALJ filed a proposed order approving PMs 2 through 7 with minor modifications. On February 5, 2026, the Illinois Commerce Commission filed an order approving the PMs with minor modification and direction for further refinement before implementation. For the reduced disconnections metric, the Commission implemented two submetrics - one to reduce the disconnection ratio to below 12% in identified ZIP codes and one to reduce the disconnection ratio to below 4% for all residential customers.	Docket No. 25-0514	Order (Feb. 2026)			
IL	Utility Business Model	Performance Incentive Mechanisms	On June 6, 2025, Ameren Illinois proposed eight performance metrics (PMs) and 49 tracking metrics as described in its performance tracking metrics plan for 2028-2031. The metrics include PM6, affordable customer delivery costs. The metrics are paired with a symmetrical incentive/penalty mechanism for performance goals under or over the applicable metric. On February 2026, the Illinois Commerce Commission filed a final order approving the PMs with minor modification. The Commission modified the PM 6 metric to align with an intervenor's proposed two-part metric with modifications; the utility will be able to earn or be penalized three basis points if the it achieves a four-year 15% cumulative reduction in the disconnection ratio in the 20 zip codes with the highest disconnection ratios; only after that, the company may earn (or be symmetrically penalized by) two basis points if it achieves a four-year cumulative reduction sufficient to lower the overall residential disconnection ratio to 4.81%.	Docket No. 25-0574	Order (Feb. 2026)			
IL	Utility Oversight	Consumer Representation	H.B. 4514, as passed by the House and Senate in May 2026, requires that when any electric public utility proposes a general rate increase, the public utility must notify its customers of their right to request a public forum. A group of customers must make a written request to the Illinois Commerce Commission for the public forum, which the Commission will schedule at its discretion unless staffing or funding is inadequate for a timely convening. The public utility must, to the best of its ability, provide 30 days advance notice of the public forum to any units of local government affected by the rate increase. The day and location of the public forum will be selected to encourage the greatest public participation and reports and comments made during or as a result of the convening must be made available to hearing officials and reviewed when drafting a recommended or tentative decision, finding, or order. However, failure to comply will not affect the validity of any order entered by the Commission in a general rate proceeding.	H.B. 4514 (P2)				

State	Category	Sub-Topic(s)	Description	Source				
IN	Customer Cost Allocation, Utility Business Model, Utility Oversight	Bill Assistance, Disconnection Policies, Performance Incentive Mechanisms, Rate Design, Rate Freezes	H.B. 1002, as enacted in February 2026, aims to support energy affordability in multiple ways. First, the bill requires electric utilities subject to Indiana Utility Regulatory Commission (IURC) jurisdiction to automatically enroll residential customers that have applied for home energy assistance in a levelized billing plan, beginning June 30, 2026. Customers may opt out without penalty, and utilities may not market these plans as "budget billing plans" unless they allow for deferred or reduced payments. The bill also requires Commission-regulated utilities to offer a low-income customer assistance program to customers that are eligible for and have applied for assistance through LIHEAP. Utilities must offer programs by July 1, 2026, which provide financial assistance to these customers for the payment of electric bills. Additionally, the bill expands existing winter electricity shutoff prohibitions (December 1 - March 15) for LIHEAP-eligible customers of all electric utilities to also include a summer prohibition: utilities may not shut off service to these customers on days when the National Weather Service forecasts a heat index of 95 degrees or higher in the customer's area. Beginning in 2027, utilities are to fund their low-income customer assistance programs at a level equal to at least 0.2% of the utility's jurisdictional revenues for residential customers, plus any government or third-party contributions. Furthermore, the bill limits the IURC's ability to temporarily adjust or suspend existing electric rates to governor-declared disaster emergencies resulting from a national economic depression, an act of war, or a disaster of unprecedented size and destructiveness resulting from manmade or natural causes. The bill also requires utilities to seek rate changes through multi-year rate plans with several performance incentive mechanisms, including a customer affordability metric based on the difference between the utility's average monthly residential bill change over the past five years and the national average annual percentage change in seasonally adjusted electricity prices, as measured by the Consumer Price Index. Utility rates of return could be altered by up to 1% depending on the results of performance reports. The requirement to file multi-year rate plans phases in, starting from the beginning of 2027 for Duke Energy, and up through the beginning of 2029 for the other utilities.	H.B. 1002 (E)				
IN	Planning and Procurement, Studies and Investigations	Surplus Interconnection	S.B. 240, enacted in March 2026, requires utilities, in IRPs filed after December 31, 2029, to include an analysis of the potential for surplus interconnection service to meet immediate needs for capacity and energy at facilities owned by the utility. Additionally, when considering any certificate of public convenience and necessity petition for a generation resource submitted after December 31, 2029, the Indiana Utility Regulatory Commission (IURC) is to consider whether the petitioner conducted an analysis of the use of surplus interconnection service as an alternative to or in conjunction with the facility, and whether the facility will make use of or allow for surplus interconnection service. The bill also directs the IURC to conduct a study evaluating the potential use of surplus interconnection service by October 1, 2027.	S.B. 240 (E)				
IN	Studies and Investigations	Advanced Transmission Technologies	S.B. 422, enacted in March 2025, requires the Indiana Utility Regulatory Commission to conduct a study to evaluate the potential use or deployment of advanced transmission technologies (ATTs) by public utilities to enable them to safely, reliably, efficiently, and cost effectively meet electric system demand; and provide safe, reliable, and affordable electric utility service to customers. The Commission should evaluate attributes, functions, costs, and benefits of various ATTs, including grid-enhancing technologies and advanced conductors. The report that includes the Commission's findings is due October 1, 2026. The Commission entered into a contract with Electric Power Engineers, who will be drafting the study report. The Commission provided utilities, stakeholders, and the RTO with a series of questions to inform the study, and requested responses by June 3, 2026.	IURC Advanced Transmission Technologies Study Website	S.B. 422 (2025)			
IN	Studies and Investigations	Energy Affordability	On March 24, 2026, the Indiana Utility Regulatory Commission held an investigative inquiry on energy affordability, with the state's five largest investor-owned utilities providing presentations and answering Commission questions. The Commission notes that this is the first phase of a larger strategy that it will lead to better understand the drivers behind energy affordability and identify short- and long-term solutions. The second phase of this process was hearing directly from customers through community listening sessions across the state, which were held during March and April 2026.	Investigative Inquiry on Energy Affordability				
IN	Studies and Investigations	Energy Affordability, Load Growth	Executive Order 25-66, issued by the Governor of Indiana in June 2025, creates a Strategic Energy Growth Task Force to oversee development of a State Energy Growth Plan. The plan will focus on energy reliability and affordability to meet power needs. The plan has four objectives: (1) energy development to meet current and future demand; (2) energy affordability for all Hoosiers; (3) energy diversity through an "all-of-the-above" approach to energy policy; and (4) energy collaboration and innovation between state and industry to deploy technology to meet the unique opportunities that lie ahead with unprecedented demand and development. The full plan is due by May 29, 2026. The Task Force provided the Governor with an interim report in December 2025, describing the meetings held by the Task Force in 2025. As of June 2026, the final report is not publicly available.	Executive Order 25-66	Interim Report (Dec. 2025)			
KS	Utility Oversight	Consumer Representation	S.B. 348, as enacted in March 2026, requires the Kansas Corporation Commission to consider petitions from utility customers protesting rate changes; petitions must reach at least 5% of a utility's total customers or at least 3% of a utility's customers from the same rate class to be considered. If, after investigating, the Commission finds the rates are unjust, unreasonable, discriminatory, or preferential, then it can change the rates.	S.B. 348 (E)				
KY	Customer Cost Allocation	Cost Shift Prevention	H.B. 593, as passed by the House in March 2026, establishes rules for municipal utility tariffs for data center customers with loads of 15 MW or greater and a load factor of 60% or greater. The Senate did not pass the bill before the session ended.	H.B. 593 (D)				
KY	Customer Cost Allocation	Cost Shift Prevention	On May 30, 2025, Kentucky Utilities filed a rate case application including a request for approval of a new Extremely High Load Factor (EHLF) Service tariff for customers with a contract capacity greater than 100 MVA and an expected load factor above 85%. It requires a 15-year contract period, though the initial contract term, load ramp, load ramp period, contract capacity, and other terms of service will be prescribed in the electric service agreement executed between the customer and the utility. The tariff also includes provisions related to financial assurances required of the customer and ways the contract may be modified. Kentucky Utilities and Louisville Gas & Electric filed a stipulation in October 2025, in which the utilities agreed to modify the proposed tariff to reduce the minimum contract capacity to 50 MVA, clarify that it applies only to new customers, and clarify that customers cannot circumvent the minimum capacity threshold by siting multiple smaller facilities. The Kentucky Public Service Commission issued its final order in February 2026, approving the new EHLF tariff as amended by the stipulation.	Docket No. 2025-00113	Order (Feb. 2026)			
KY	Customer Cost Allocation	Cost Shift Prevention	On May 30, 2025, Louisville Gas & Electric filed a rate case application including a request for approval of a new Extremely High Load Factor (EHLF) Service tariff for customers with a contract capacity greater than 100 MVA and an expected load factor above 85%. It requires a 15-year contract period, though the initial contract term, load ramp, load ramp period, contract capacity, and other terms of service will be prescribed in the electric service agreement executed between the customer and the utility. The tariff also includes provisions related to financial assurances required of the customer and ways the contract may be modified. Kentucky Utilities and Louisville Gas & Electric filed a stipulation in October 2025, in which the utilities agreed to modify the proposed tariff to reduce the minimum contract capacity to 50 MVA, clarify that it applies only to new customers, and clarify that customers cannot circumvent the minimum capacity threshold by siting multiple smaller facilities. The Kentucky Public Service Commission issued its final order in February 2026, approving the new EHLF tariff as amended by the stipulation.	Docket No. 2025-00114	Order (Feb. 2026)			
KY	Studies and Investigations	Energy Affordability	S.B. 100, enacted in April 2026, requires the Energy Planning and Inventory Commission to conduct a review of energy costs, grid reliability, and opportunities and mechanisms to reduce energy cost burdens on eastern Kentucky households and businesses, including potential policy interventions, infrastructure investments, rate design modifications, efficiency programs, and other approaches.	S.B. 100 (E)				

State	Category	Sub-Topic(s)	Description	Source				
KY	Studies and Investigations	Energy Affordability	S.J.R. 75, as passed by the Senate in March 2026, directs the Kentucky Public Service Commission to open administrative cases to address affordability and reliability of electric service. The administrative case or cases would have: (1) examines strategies to provide consistent access to utility service for low and fixed-income customers; (2) examined strategies to protect consumers from payment delinquencies, late fees, and disconnections that could threaten their health, safety, and well-being; and (3) evaluated potential solutions to address affordability such as rate design, financial assistance programs, water and wastewater utility regionalization, and other regulatory and non-regulatory approaches and innovations. The resolution did not pass the House before the end of the legislative session in May 2026.	S.J.R. 75 (D)				
LA	Studies and Investigations	Bill Assistance	S.R. 148, as adopted in May 2026, is a resolution creating the Utility Assistance Coordination Task Force, charged with improving coordination between federal, state, utility, and non-profit bill assistance programs. The Task Force should consider and make recommendations regarding: (1) an inventory of bill assistance programs; (2) opportunities to improve coordination of intake, referrals, eligibility verification, customer communications, vendor payments, and program outreach; (3) opportunities to reduce unnecessary duplication, address gaps in assistance, and improve interactions among bill assistance, arrearage management, disconnection prevention, and related energy assistance programs; (4) opportunities to improve access to assistance for vulnerable households; and (5) any policy changes necessary to improve coordination. The Task Force must submit a final report by March 2027.	S.R. 148 (Adopted)				
LA	Utility Business Model	Performance Incentive Mechanisms	On May 30, 2025, Entergy Louisiana filed an application for a suite of demand response (DR) programs, including a performance incentive mechanism for the DR programs, based on the utility's achievement of DR targets. The proposed targets are 0 MW in program Year 1, 95 MW in Year 2, 145 MW in Year 3, 150 MW in Year 4, and 155 MW in Year 5. If Entergy meets less than 80% of its DR target in a given year, it would not receive an incentive. If it meets 80%-90% of its target, it would receive 2% of DR portfolio costs for the program year. If it meets 90%-105% of its target, it would receive 4% of DR portfolio costs for the program year. If it meets 105%-120% of its target, it would receive 6% of DR portfolio costs for the program year. If it meets over 120% of its target, it would receive 8% of DR portfolio costs for the program year. Entergy filed a settlement agreement on February 9, 2026, excluding the performance incentive mechanism. The Louisiana Public Service Commission filed an order on April 17, 2026, approving the settlement agreement in full.	Docket No. U-37595	Settlement Agreement (Feb. 2026)	Order (Apr. 2026)		
LA	Utility Oversight	Cost Recovery	On March 16, 2026, the New Orleans City Council's Utility, Cable, Telecommunications and Technology Committee adopted a resolution approving changes to Chapter 158, which governs utility regulation. The amended rules include a new section requiring a utility to receive Council approval for any full-scale demand-side program whose rate base value exceeds 2% of the ratemaking value of the utility's property. The City Council adopted the resolution on March 26, 2026.	City Council Docket No. UD-25-01	Proposed Rules (Mar. 2026)	Resolution No. R-26-129 (Mar. 2026)		
LA	Utility Oversight	Monitoring	H.B. 478, as enacted in May 2026, requires utilities to reimburse overcharged customers within 90 days of discovery.	H.B. 478 (E)				
MA	Customer Cost Allocation	Low-Income Discount Rates	**Background:** In January 2024, the Massachusetts Department of Public Utilities (DPU) launched an inquiry into innovative solutions to address energy affordability for residential ratepayers, with a focus on tiered discount rates (TDR) and percentage-of-income payment plans (PIPPs). In September 2024, the DPU issued an interlocutory order outlining areas of consensus from the comment period. These included capping energy burden at 6% of household income, basing eligibility on household income and size, extending the program to both heating and non-heating customers, and ensuring that customers in arrears remain eligible. The order also emphasized outreach to environmental justice communities and extended disconnection protections to periods of extreme heat and poor air quality. Based on these findings, the DPU decided to focus the inquiry on developing tiered discount rates rather than PIPPs, with costs to be recovered through utility-specific residential assistance adjustment factors (RAAF). Several questions remain open, including the specific design of the TDR program, enrollment and verification processes, arrearage management, and disconnection policies for nonpayment. **Recent Action:** On May 16, 2025, the DPU initiated the Phase II stakeholder working group to discuss the aforementioned areas of inquiry. On February 17, 2026, the DPU issued an order regarding the TDR, establishing a low-income discount rate framework based on its stakeholder inquiry process. In the order, the DPU directed utilities to implement a six-tier rate on a statewide basis to avoid creating separate frameworks for each utility, thereby increasing efficiency and reducing administrative challenges. The rates should include the following tiers: households earning up to 100% of the Federal Poverty Level (FPL); households earning 100-125% of the FPL; households earning 125-150% of the FPL; households earning 150-175% of the FPL; households earning 175-200% of the FPL; and households earning greater than 200% of the FPL and up to 60% of the State Median Income. Each utility must implement the new rate framework by November 1, 2026, and cease charging low-income discount customers for RAAF. The model also assumed a six-tier structure consistent with those used by the state's Home Energy Assistance Program (HEAP), and the DPU intends to reassess these tiers in the future. In terms of the actual measured discounts, utilities must develop discounts for the lowest tier that achieve a 4% total energy burden and a 2% electric energy burden; the other tiers should achieve a 6% total energy burden and 3% electric energy burden. Recognizing that this approach could result in no discount for some customers in the highest tiers, there would also be a discount floor of 25% for electric customers. In addition, although the DPU has not yet commenced the moderate-income discount rulemaking, the information gathered thus far will inform that proceeding, including determinations regarding how to define eligible moderate-income customers and how to recover the associated revenue shortfall. As part of that rulemaking, the DPU will also consider the appropriate framework for determining discount levels for eligible moderate-income customers.	Docket No. 24-15	Order (Feb. 2026)			

State	Category	Sub-Topic(s)	Description	Source				
MA	Customer Cost Allocation, Customer Cost-Saving Programs, Planning and Procurement, Studies and Investigations, Utility Oversight	Audits, Cost Shift Prevention, Electricity Costs, LMI Incentives, Low-Income Discount Rates, Planning Rules, Procurement Methods, Tariffed On-Bill Financing, Transparency	H.B. 5175, as passed by the House in late February 2026, requires the Massachusetts Department of Public Utilities (DPU) to create a real-time online dashboard showing a visual breakdown of the components of residential utility bills, including explanations of each charge. The dashboard is also to quantify the benefits of clean energy, energy efficiency, and demand response programs. Additionally, the bill requires 70% of alternative compliance payments associated with the state's renewable portfolio standard, alternative energy portfolio standard, and clean peak standard to be returned to ratepayers as annual bill credits until July 1, 2029. Beginning July 1, 2029, this will be required in years where fund balances exceed predicted levels by 2% and energy costs are a substantial burden to residents. The bill also directs the DPU to develop and publish a resource solicitation plan identifying the state's clean energy generation and energy service needs sufficient to meet greenhouse gas emission limits. The plan must evaluate residential energy affordability - including impacts on low- and fixed-income households - and the economic competitiveness of Massachusetts businesses. Clean energy solicitations must utilize a competitive bidding process. After approval, the DPU must require utilities to file tariffs reflecting the plan to recover ratepayer costs, with cost allocation shared among utilities. The bill also authorizes the state's Department of Transportation to permit installation and maintenance of high-voltage transmission lines along state highway rights-of-way to allow to avoid the need for new land acquisition. Furthermore, the bill establishes requirements for discounted electricity rates for low-income customers and eligible moderate-income customers. These discounts are to be funded through a non-bypassable monthly fixed charge, with the charge being determined separately for each customer class. Statewide cost recovery for these discounts will be allowed across electric distribution companies to promote rate equity across the state. Eligibility for the discount rates will be established by the DPU, and income re-verification will be limited to no more than once every two years. Distribution companies are to conduct substantial outreach efforts to make the discount rates available to eligible customers and may presumptively enroll eligible customers, with the option for them to withdraw from the program without penalty. The bill allows the DPU to order management and operations audits of electric distribution companies once every five years by Department staff or an independent auditor. Supplemental audits may be ordered on specific aspects of operations and performance as necessary. Audited companies are to submit a plan to to implement the DPU's findings, and the DPU may issue penalties for non-compliance with an approved plan. Upon a request by an electric distribution company for a general rate increase or to make capital improvements, the DPU is to review the company's compliance with the directions and recommendations made previously by the DPU as a result of the most recently completed management and operations audit. The bill also directs the Massachusetts Department of Energy Resources to develop a new statewide solar incentive program utilizing market-based mechanisms. The program is to include differing incentive levels by installation type, including low-income solar. The bill also specifies that the program administrators of the approved three-year energy efficiency investment plan are not to require household income verification for low-income eligible customers and renters. Income verification will remain in place for moderate-income rebates and incentives. Additionally, electric distribution companies will be required to develop inclusive utility investment program proposals to help customers finance energy efficiency upgrades, high-efficiency electric heat pumps, energy storage systems, demand response equipment, and on-site solar energy systems. Agreements for leasing distribution or transmission asset entitlements between a distribution utility and a non-utility third party may permit the third party to sublease those entitlements to the utility's projects, provided each lease includes the following protections: a binding commitment to contribute a share of annual after-tax profits derived from ratepayer use of the entitlements to charitable purposes, with not less than 50% directed to energy affordability for low- and moderate-income families. Regarding large load cost allocation, the bill requires each utility to file a proposed data center tariff with the DPU designed to protect other ratepayers from increased costs and to incentivize energy efficiency, including technologies that capture and reuse waste heat. The bill also establishes an electric rates taskforce to advise the state government on the current and future cost of electricity in the state. No later than September 30, 2027, the task force must report on each cost component of electric bills for residential and commercial customers of investor-owned distribution companies serving more than 100,000 customers, including statewide revenue by component, utility, and customer class, current costs per-kWh and per month for typical users, annual rate increases over the prior ten years, and projected increases over the next five years. The report shall also recommend short- and long-term rate relief and benchmark ratepayer affordability against all other New England states. Finally, the bill directs the inspector general to conduct a comprehensive review of the Mass Save program to ensure ratepayer funds are being used efficiently and effectively. The inspector general is to review methods of supporting the energy efficiency goals of the program while increasing ratepayer affordability. The inspector general must submit a report of its findings and recommendations by July 1, 2027.	H.B. 5175 (P1)				
MA	Planning and Procurement, Studies and Investigations	Advanced Transmission Technologies	On June 2, 2025, the Massachusetts Department of Public Utilities (DPU) opened an investigation into the use of advanced conductors, grid-enhancing technologies (GETs), and other advanced transmission technologies (ATTs) to improve the performance of the state's transmission system in areas under federal jurisdiction. On September 25, 2025, the Advanced Transmission Solutions Report was filed, outlining federal and state policies, market trends, and key grid-enhancing technologies (GETs), including dynamic line rating (DLR), advanced power flow control (APFC), advanced conductors, and energy storage. In February 2026, the Hearing Officer filed a memorandum seeking additional information regarding utilities' compliance with a requirement to conduct a cost-effectiveness and timetable analysis of the emerging grid solutions, as well as plans to develop performance incentive mechanisms to deploy ATTs.	Docket No. 25-69	Advanced Transmission Solutions Report (Sept. 2025)			
MA	Planning and Procurement, Studies and Investigations	Energy Affordability, Non-Wires Alternatives	Governor Maura Healey signed Executive Order No. 654 in March 2026, to support energy affordability and independence, strengthen community resilience, and meet growing power needs. The order sets a capacity targets for the end of 2035 of 3.5 GW of new demand reduction through load management strategies. The Massachusetts Department of Energy Resources must publish a review of existing demand and customer supply programs by September 1, 2026. Additionally, the order directs the Massachusetts Department of Public Utilities to investigate strategies to ensure energy independence and affordability for electric customers in the state with the growth of large commercial customers. The order also directs the Office of Environmental Justice and Equity to conduct an analysis into the energy system and resilience benefits that accrue to residents of burdened areas, with a focus on programs designed to convey benefits to LMI customers. This analysis is to identify any eligibility gaps in these programs and whether the programs sufficiently address energy burden.	Executive Order 654				

State	Category	Sub-Topic(s)	Description	Source				
MA	Studies and Investigations	Energy Affordability	On December 15, 2025, the Massachusetts Department of Public Utilities (DPU) opened an investigation to conduct a comprehensive review of gas and electric delivery rates and charges, aiming to contain customer costs, reduce bill volatility, and increase bill transparency. Specifically, through Phase I of the proceeding, the DPU is focusing on: (1) identifying electric and gas reconciling mechanisms that can be eliminated or included in base distribution rates going forward, (2) determining whether certain electric and gas reconciling mechanism costs should be collected from customers through fixed charges rather than volumetric charges, (3) determining whether certain electric reconciling mechanisms should be included in utilities' annual retail rate filings fore review and approval rather than filed in separate dockets, (4) determining how the value of net metering credits and bill impacts to electric customers in the state compare to similar programs in other jurisdictions and whether the value of these credits should be adjusted, and (5) determining the feasibility of creating a maximum threshold for the amount that charges assessed to customers may change from one month to another. Phase II of the proceeding will focus on utility bill redesign to improve customer knowledge, agency, and responsiveness to price and policy signals. The DPU requested that utilities file reports with specific information related to the Phase I topics. The DPU also accepted comments through March 31, 2026 and held a technical conference in early April 2026.	Docket No. 25-200				
MD	Customer Cost Allocation	Bill Assistance	H.B. 648, as enacted in April 2026, amends statute requiring the Office of Home Energy Programs to develop a redetermination process to assist eligible energy customers in enrolling in energy assistance programs; the bill lowers the relevant age from 65 years to 60.	H.B. 648 (E)				
MD	Customer Cost Allocation	Cost Shift Prevention	On June 26, 2025, in compliance with the "Next Generation Energy Act" or H.B. 1035 of 2025, the Maryland Public Service Commission initiated a new public conference and formed a work group to investigate regulations regarding large load customers and utility tariffs. The Commission is required to adopt regulations which will (1) establish notice requirements, deadlines, and contract requirements related to large load customer study requests; (2) if necessary, specify common forms of acceptable financial surety or collateral to meet requirements; and (3) establish study deadlines and fees. Final regulations must be adopted by June 1, 2026. Further, investor-owned utilities and cooperatives are required to submit to the Commission a rate schedule for electric large loads by September 1, 2026. On December 8, 2025, the Commission Technical Staff filed a request that the Commission open a rulemaking to consider the proposed regulations required as outlined above. On the same day, Commission Staff filed a progress report on the status of the development of regulations by the working group. The report documents the utilities' responses to information requests and major points of discussion in the work group. They include current utility collateral requirements; transmission jurisdiction on federal and state levels, especially pertaining to cost recovery of large load transmission buildout; and certain transmission-related customer protections that can be included in the state jurisdiction large load tariff. The report also includes additional key issues discussed, including how utility tariffs should address H.B. 1035's requirement that the Commission consider whether the tariff requires the large load customer to cover distribution or transmission upgrades necessary for interconnection and how utility tariffs should address H.B. 1035's requirement that the Commission consider whether the tariff protects residential electric customers from large load customer financial risks through various financial and contractual means. The work group also submitted proposed regulations denoting proposed language from the Commission Staff, utilities, and Amazon. On December 9, 2025, the Commission initiated Rulemaking 93 to consider the proposed regulations. On February 4, 2026, the Commission moved to publish the subtitle 20.96 Large Load Customers in the Maryland Register for comment. As of June 2026, final approval of regulations has not been published in the Maryland Register or relevant dockets.	Public Conference No. 72	H.B. 1035 (2025)	Rulemaking No. 93		
MD	Customer Cost Allocation	Low-Income Discount Rates	On October 1, 2025, Public Conference 59's Work Group on Energy Burdens filed a report on a proposed Limited Income Mechanism for Utility Customers. On February 12, 2026, the Maryland Public Service Commission filed an order approving utilities' ability to develop systems to provide discounted rates to limited-income customers, approving the general design of the proposed Limited Income Mechanism (LIM), and approving Phase II of the Work Group; utilities will need to update their billing systems, marketing materials, and tariffs accordingly by January 1, 2027. The Commission also approved the tiered discount mechanism general program design, which will categorize customers based on the Office of Home Energy Programs' (OHEP) poverty level identification standards, as well as the customer's heating source; customers at poverty level 6 and below would be eligible for the LIM year-round. The credit would be calculated by subtracting the Target Energy Burden Threshold (Average Income multiplied by the Energy Burden Percentage) from the Applicable Bill Net of OHEP assistance; customers will receive the credit as a rider or surcharge. The Commission approved a percent-of-rate discount mechanisms for all utilities except for Southern Maryland Electric Cooperative, which will employ a flat bill credit. The Commission did not make a final determination on the target energy burden, stating that the Commission would return to this determination when the utilities file their updated proposals and tariffs, and that such proposals should be developed with the 6% goal recommended by the Work Group in mind. Further, the Commission approved the application of the LIM to both supply and distribution charges. On May 26, 2026, the Commission approved a proposal from the Work Group to extend the 12-month LIM enrollment period to address concerns about gaps in coverage while applicants re-apply for financial assistance with OHEP; the Commission ultimately approved an 18-month enrollment period.	Public Conference No. 59				

State	Category	Sub-Topic(s)	Description	Source				
MD	Customer Cost Allocation, Customer Cost-Saving Programs, Planning and Procurement, Studies and Investigations, Utility Business Model, Utility Oversight	Advanced Transmission Technologies, Arrearage Management, Bill Assistance, Cost Recovery, Cost Shift Prevention, Executive Compensation, LMI Community Solar, LMI Incentives, Monitoring, Multi-Year Rate Plans, Program Reviews, Return on Equity Rules, Transparency	H.B. 1532, enacted in May 2026, requires the Maryland Public Service Commission to examine under an existing directive for a study on automatic community solar enrollment for local jurisdictions the feasibility and technical barriers to establishing an automatic community solar enrollment process to provide bill credits for LMI subscribers. The Commission must consider eligibility criteria for LMI subscribers, opt-out procedures, the amount of bill savings for LMI subscribers, and the amount of energy generated that should be dedicated to for LMI subscribers. The bill also outlines requirements for a successor net metering program, which must balance, on a statewide basis across technologies and sectors participating net metering, fair compensation and the benefits of reduced load on the system with ratepayer costs and impacts and potential impacts on customers, including LMI customers, who do not participate in the net metering program resulting from customer-generators' reduced contributions to the distribution system. The bill further stipulates that beginning on January 1, 2027, the Office of Home Energy Programs, rather than the Commission, will authorize benefits under the electric universal service program for an electric customer who meets the eligibility requirements for the program of having income at or below 200% of the federal poverty level but who does not meet the requirements for LIHEAP. The bill also states that residential electricity suppliers may not exceed the electric company's standard offer service rate in its service territory more than 100% for a term of 23 months, 105% for a term of 24 to 35 months, and 110% for a term of 36 months. After changes transitioning energy efficiency targets to greenhouse gas emission reduction targets through efficiency measures, EmPOWER was previously targeted to achieve a 2.5% reduction in emissions every year. With the rationale of short-term affordability, the bill sets the target at 1.75% for the next three years, eventually increasing back up to 2.5% by 2036. Further, the bill requires a process to determine if EmPOWER should be run by a third-party administrator rather than by each individual utility for purposes of cost efficiency. The bill modifies past requirements set by the Next Generation Energy Act that new large load energy users pay a higher electricity price for a new tariff; the past threshold was large load customers of 100 MW and an 80% utilization rate and the new provisions set the threshold at 25 MW and 60% utilization. The bill also requires that the tariff allocates to large load customers any increased or avoided costs caused by the customer, including any costs assigned to data centers by PJM as a part of its capacity auction to data center customers, as well as transmission costs. Additionally, the tariff must allocate any direct or indirect costs, fees, and obligations normally applied to retail customers in the relevant service territory if the Commission determines that such costs are attributable to the large load customer. The Commission will charge a registration fee of at least $1,000 per MW of peak load, of which 50% will be used for the electric universal services program and 50% for the low-income EmPOWER programs. Additionally, the bill outlines situations in which construction related to an existing transmission line that is designed to carry a voltage above 69,000 volts may have good cause for the Commission to waive the requirement for a certificate of public convenience and necessity. The reasons include whether the applicant gave due consideration to alternatives to the proposed construction, including advanced transmission technologies (ATTs), and the extent to which the cost of the facilities will be allocated to ratepayers. Further, it requires an applicant for a certificate of public convenience and necessity for the construction of a transmission line to include in its application evidence that the applicant considered in its planning processes alternatives to the proposed transmission line, an analysis of ATTs will enhance the value of the new lead line, alternative routings, technologies or modifications to electric distribution systems that could avoid the need for the transmission line, the cost to ratepayers, resource adequacy, energy efficiency and demand response, environmental impacts, a review of an integrated transmission-distribution system to address the need for the transmission line, and any other information deemed necessary by the Maryland Public Service Commission; it also requires an analysis of the transmission line routes. Additionally, by December 1, 2026, and every four years thereafter, each owner or operator will submit to the Commission a report that (1) identifies areas of transmission congestion for the preceding three years and coming five years, (2) identifies the cost to ratepayers as a result of past and projected congestion, (3) identifies the feasibility and cost of using alternative means of addressing congestion, including ATTs, (4) identifies the social, environmental, and economic issues posed by the use of each alternative, and (5) proposes an advanced transmission technology plan if feasible. Further pertaining to procurement and planning, the bill outlines an auction process using alternative compliance fees in order to meet a capacity target, defined as the lesser of the amount of renewable energy generation needed in a given year to satisfy the renewable energy portfolio standard for a specific year minus the amount already procured from other sources or the amount of renewable energy that can be procured using alternative compliance fees available for the auction. For 2027 and 2028, the Maryland Energy Administration will conduct an annual, competitive alternative compliance fee auction to award grants to eligible bidders to offset a portion of project costs associated with the development of renewable energy in the state using revenue from the alternative compliance fees. The competitive auction may require the administration to solicit bids from renewable energy project developers to develop renewable energy projects in a cost-effective manner. Additionally, before a nuclear energy generation project begins commercial operation, the Commission may approve an increase of the total cost of a nuclear energy generation project under a long term pricing permit agreement, but the total cost may not be increased by more than 15% of the original project cost. The bill also makes changes to rate case proceedings. When a utility initiates a base rate proceeding or another proceeding that may lead to a distribution cost increase above 3% for residential customers, the utility must provide those customers physical or digital notice that the utility is initiating the proceeding and make information about the proceeding available on its website. Additionally, in each residential customer bill and email payment, the utility must include a statement directing customers to the Commission website for information on how to participate in or observe a proceeding. Pertaining to multi-year rate plans, the bill adds provisions that the Commission may approve such a plan only if the plan does not allow for reconciliation if it would result in additional charges to customers or the use of cost-sharing mechanisms that would result in additional charges to customers above the approved revenue component used by the Commission. Further, utilities that have filed an application for a multiyear rate plan may not subsequently file for reconciliation that would result in additional charges to customers due to the utility spending more than the approved revenue component unless the filing for reconciliation was made before January 1, 2025. For multi-year rate plans approved after January 1, 2026, the Commission may require a utility to include a reconciliation procedure in its plan to refund customers the difference between the approved revenue requirement and the actual revenue requirement during the term of the plan. Further, private utilities may not recover costs associated with compensation for a supervisor that exceeds 110% of the maximum salary of the Chair of the Commission. Additionally, the Board of Directors of each utility must adopt a company-wide policy placing reasonable cost limitations on expenditures that the utility intends to recover through rates for entertainment and events, office and facility renovations, transportation/aviation services, staff development activities or events, performance incentives, and other activities outside the scope of normal business operations. Each utility will send a copy of the policy to the Commission as soon as practicable, each time the policy it updated, and at least every five years. The Commission may review in a base rate proceeding the reasonableness of the cost limitations in the policy. The bill also requires the Commission to conduct a proceeding and determine whether the use of forecast test years, historic test years, or a hybrid model is in the best interest of and protects ratepayers; the Commission may not approve a requested rate increase based on a forecast test year in a base rate proceeding until the required proceeding is completed or April 1, 2027. Finally, the bill requires all utilities to participate in a local RTO market, though they all voluntarily participate in PJM currently. Voluntary participation in a regional transmission organization or independent system operator market allows a 0.5% return on equity adder under the Federal Regulatory Commission's rate-setting policies, which can be recovered from customers. Mandating participation makes the utilities ineligible for the adder.	[H.B. 1532 (E)]				

State	Category	Sub-Topic(s)	Description	Source				
MD	Customer Cost-Saving Programs	LMI Community Solar	On October 6, 2025, the Maryland Public Service Commission accepted a recommendation from its Staff on next steps for addressing non-critical elements of Maryland's permanent Community Solar program, including policies for unsubscribed LMI credits. Staff did not recommend a new formal rulemaking at this time, but instead recommended a period of monitoring and data collection of the community solar billing launch wherein Staff would continue to facilitate the Work Group and provide a formal recommendation for a subsequent rulemaking proceeding by April 1, 2026. In November 2025, Baltimore Gas & Electric (BGE), Delmarva Power & Light, and Pepco, filed their revised tariff pages for community solar/community net energy metering tariffs. Potomac Edison (PE) filed revised tariff pages proposing revisions to its community solar energy generation systems (CSEGS) program, including provisions that address requirements for subscription percentages for LMI customers. On December 23, 2025, the Commission filed a letter accepting PE's proposed revisions, excluding language allowing PE to discontinue service to projects that do not maintain a 40% kWh output to LMI requirement. On January 6, 2026, the Commission filed an order directing the Net Metering Working Group to address LMI allocation adherence, subscriber fluctuation, and banked credit allocations to subscribers in its forthcoming recommendations by April 1, 2026, regarding a potential new rulemaking on community solar. On March 27, 2026, Commission Staff filed a status report on the implementation of the permanent community solar program and recommendation for rulemaking. The Net Metering Working Group has developed drafts regarding certain program elements, but paused work on LMI compliance and the 3,000 MW capacity limit while the General Assembly makes possible statutory amendments. On June 5, 2026, the Net Metering Working Group submitted a suite of draft regulations for the Commission's consideration as a proposed rulemaking. For certain areas where the Working Group did not reach consensus, several proposals per area were submitted. There are three versions of LMI Regulations concerning tracking, banking, and enforcing compliance for projects with minimum LMI subscriber requirements.	Rulemaking No. 56				
MD	Customer Cost-Saving Programs, Planning and Procurement	LMI Incentives, Non-Wires Alternatives	On July 1, 2025, Maryland's Public Service Commission-regulated electric utilities filed proposals for virtual power plant (VPP) programs, as required by the 2025 Distributed Renewable Integration and Vehicle Electrification (DRIVE) Act. The DRIVE Act stipulates that it is reasonable to provide additional incentives and protections to LMI participants. On October 21, 2025, the Commission filed an order in response to the utilities' proposed VPP programs, denying the proposals and ordering the utilities to re-file with various modifications. On January 29, 2026, the utilities filed their revised VPP proposals. Pepco and Delmarva Power & Light's proposal mentioned the possibility of providing enhanced incentives to LMI customers, but did not specify any enhanced incentives. Potomac Edison's Bring Your Own Device pathway provides that for qualified batteries and bidirectional electric vehicles, customers will be paid a connectivity incentive of up to $150/connected year (with a $50/year LMI adder) and a performance incentive up to $300/kW-year based on event participation (full compensation for participation in at least 75% of events) and estimations of device performance. For its Energy Savings Rewards Smart Thermostat program, the utility proposed that customers receive $25 for summer or $50 for year-round, plus a $25 bonus in targeted locations where peak loading is nearing distribution limits, as well as one-time enrollment bonuses of $50 for summer (plus a $25 enhancement for LMI) or $100 for year round (plus a $25 LMI enhancement). On May 29, 2026, the Commission filed an order on common metrics for DRIVE Act July 2026 reporting. The Commission-directed metrics for the July reporting incorporate both the recommendations from the utilities focused on deferring capital investments for currently-forecasted system constraints and Staff and Office of People's Council recommendations focused on a broader understanding of and screening for overall avoidance and deferral potential into the future.	Case No. 9761				
MD	Planning and Procurement, Utility Oversight	Cost Recovery, Procurement Methods	On October 2, 2023, the Maryland Public Service Commission issued an order initiating a workgroup to develop an energy storage program for Maryland. In November 2025, the Commission-regulated electric utilities filed their proposals for energy storage projects. On April 8, 2026, the Commission filed an order on the energy storage plan proposals. Regarding procurement model, the Commission directs the utilities to utilize an RFP model for this first tranche of distribution-connected energy storage deployments. The Commission will also hold pre-award confidential conferences for the sake of procurement transparency. The Commission also noted that more standardization of benefit-cost analysis (BCA) methodology is necessary before these conferences; it stated that Potomac Edison's BCA methodology was not acceptable. Bill impacts must be re-analyzed following RFPs, and cost recovery decisions are deferred pending new bill impact analyses. On April 9, 2026, a memo reviewing the BCAs was submitted; a meeting with the goal of achieving consensus on a standardized BCA approach was scheduled for April 23, 2026. On May 11, 2026, Pepco and Baltimore Gas & Electric jointly requested that the Commission approve their request for a regulatory asset for a limited amount of pre-award development and launch costs for the projects.	Case No. 9715				
MD	Studies and Investigations	Data Center Ratepayer Impacts	H.B. 270 and S.B. 116, both enacted in December 2025, require an analysis from the Department of the Environment, the Maryland Energy Administration, and the University of Maryland School of Business, in conjunction with the Department of Legislative Services, of the likely environmental, energy, and economic impacts of data center development in the state. The analysis must include an assessment by the Maryland Energy Administration of the potential energy impacts of the data center industry, including an evaluation of ratepayer impacts. By September 1, 2026, the Department of Legislative Services will submit the report to the Governor. Further information on the report is not yet available as of June 2026.	H.B. 270 (2025)	S.B. 116 (2025)			
MD	Studies and Investigations	Energy Affordability	Executive Order 01.01.2025.27, issued on December 19, 2025, creates an Energy Subcabinet to coordinate interagency actions and align energy policy with state policy goals, including affordability. The bill also creates a Maryland Energy Advisory Council to provide external stakeholder input to the Subcabinet. The Council must identify barriers to the deployment of generation facilities and affordability and provide recommendations to the Subcabinet. Within 180 days of the order, the Council must submit a memorandum to the Subcabinet identifying the most urgent challenges to energy affordability and reliability. As of June 2026, the Council has posted slides outlining challenges and solutions for topics of (1) Supply and Demand Challenges, (2) Insufficient Transmission and Distribution, (3) Energy Burden, (4) Disconnect Among Policy Goals, and (5) Financing and Market Design. The slides outline common themes, areas of disagreement, particularly interesting points, and potential solutions identified by working group participants in a survey. The Energy Burden group identified potential solutions of creating a low-income rate class, targeted energy efficiency program deployments, and value-added products like incentives for smart home investments. The Financing and Market Design group identified solutions related to rate classes and cost allocation for high-demand users.	Executive Order 01.01.2025.27	Energy Advisory Council Website			

State	Category	Sub-Topic(s)	Description	Source				
MD	Utility Business Model, Utility Oversight	Performance Incentive Mechanisms, Program Review, Shared Savings Mechanisms	On January 9, 2026, the Cost Recovery Work Group filed its status report regarding decisions on Baltimore Gas & Electric and the PHI Utilities' (Pepco and Delmarva Power & Light) alternative performance incentive mechanism (PIM) proposal. The original proposal was a shared savings proposal, which raised stakeholder concerns about evaluation, measurement, and verification, along with potentially contentious decisions about incentive amount. The alternate proposal also uses a shared savings mechanism, but with pre-defined incentives that utilities may earn at the start of the 2027 to 2029 EmPOWER Maryland program cycle, calculated as a percentage of the net benefits over the prior three years on a rolling basis. The status report refers to the alternate proposal in its discussion. The parties have not come to a consensus about performance levels, thresholds of savings, incentive/penalty amounts, or total expenditures. On February 6, 2026, the Maryland Public Service Commission filed an order in response to EmPOWER Semi-Annual and Work Group reports, where it decided to table discussion of PIMs in the Cost Recovery Work Group. On April 15, 2026, the Future Programming Work Group filed a status report contemplating several topics. Regarding whether a single third-party administrator would be more effective than utility-led programs, non-utility parties largely supported a third-party administrator to increase cost-effectiveness and program effectiveness. On May 22, 2026, the Future Programming Work Group filed revised EmPOWER Goals for 2027 to 2029 in response to the Utility RELIEF Act, outlining party perspectives on methodologies for calculating savings goals and their potential bill impacts. The Act changes the minimum EmPOWER goal specified to be based on a percentage of baseline 2016 electricity sales from 2.5% to 1.75% for the 2027-2029 EmPOWER cycle. The parties disagreed on the methodology to translate the 1.75% goal into a lifecycle greenhouse gas emission reduction metric, with Commission Staff advocating for an estimated useful life bin methodology and major utilities supporting a statewide weighted average metric resulting in lower savings goals. The utilities provided estimates of surcharge reductions for the revised goal using their methodology and Staff's methodology, compared to the 2026 EmPOWER surcharge, claiming that their methodology would yield greater surcharge savings and thus greater affordability. The Maryland Energy Administration noted that the utilities failed to discuss any of the lost customer benefits and fewer opportunities to reduce energy consumption resulting from the smaller goals they advocated for, which were not calculated using the already approved estimated useful life bin methodology.	Case No. 9705				
MD	Utility Oversight	Cost Recovery, Monitoring	On March 31, 2026, The Maryland Public Service Commission denied a significant portion of Pepco's request for reconciliation for the third and final year of its first multi-year rate plan. Citing Pepco's overspend of its budget and poor forecasting, the Commission approved a true-up for $13.36 million, rather than the full requested $30.6 million. The Commission also highlighted affordability concerns surrounding approving Pepco's full requested amount and stated that the proposed reconciliation would have a residential net monthly bill impact of $2.42, as opposed to the approved reconciliation net monthly bill impact of $0.64.	Case No. 9655				
ME	Customer Cost Allocation	Bill Assistance	L.D. 995, as passed by the House in April 2025, amends the definition of low-income household as it pertains to the state's Low-Income Home Energy Assistance program. The bill adds language that specifies a low-income household has an income of no more than 150% of the federal poverty level. The bill was then placed in legislative files in late April 2026.	L.D. 995 (D)				
ME	Customer Cost Allocation	Bill Assistance	On August 19, 2025, the Maine Public Utilities Commission opened a docket to amend Net Energy Billing (NEB) rules (Chapter 313) and filed a notice of rulemaking on August 26, 2025. Beginning in 2026, unused kWh credits must be remitted annually to statewide low-income assistance programs, and new NEB tariff program rates will apply. The Commission issued an order on February 3, 2026, finalizing and approving the amended rules with modifications. The final rules retain the provision regarding the remittance date for unused kWh credits, but change the date to April 1 of each year.	Docket No. 2025-00264	Proposed Rules (Aug. 2025)	Order (Feb. 2026)		
ME	Customer Cost Allocation	Cost Shift Prevention	L.D. 839, as passed by the House in early June 2025, establishes the Net Energy Billing Cost Stabilization Fund as a non-lapsing fund to offset costs to ratepayers under the Net Energy Billing (NEB) program. The fund is designed to absorb NEB-related costs, shifting them from individual electricity bills to a centralized pool, potentially funded by state appropriations. This mechanism helps stabilize consumer electricity costs and prevents sudden rate increases caused by fluctuations or growth in NEB program participation. The Senate approved the bill in late June 2025; the Governor held the measure in early July 2025, and it ultimately became law in early January 2026 without her signature.	L.D. 839 (E)				
ME	Customer Cost Allocation	Tax Exemption	L.D. 2078, as passed by the House in mid-March 2026, expands the sales tax exemption for the sale and delivery of residential electricity to cover all sales of residential electricity beginning July 1, 2026. The bill was then placed in legislative files in late April 2026.	L.D. 2078 (D)				
ME	Customer Cost Allocation, Utility Oversight	Arrearage Management, Bill Assistance, Monitoring	L.D. 2112, as enacted in April 2026, outlines community choice aggregation (CCA) program provisions. The bill provides that a customer receiving financial assistance for low-income households or participating in an arrearage management program may not receive electricity supply under a CCA if the customer would pay a supply rate that is at any time higher than the default services supply rate. The bill also outlines additional protections for low-income and electric assistance program customers. It states that enrollment in a CCA does not affect benefits under an electric assistance or other income assistance program administered by the state, that the provisions of an arrearage management program continue to apply, and that utilities may not charge any person enrolled in an electricity assistance program or any other low-income customers additional fees, charges, or penalties as a result of participation in a CCA.	L.D. 2112 (E)				
ME	Customer Cost-Saving Programs	Education	L.D. 2220, as passed by the House and Senate in April 2026, creates the Maine Home Energy Navigator and Coaching Resource Hub within the Maine Department of Energy Resources. The hub will promote energy coaching services to residential customers, especially those in low-income, rural, and underserved communities, to navigate clean energy and energy efficiency options to affordably meet their home energy needs. The Department will make curricula and training materials available so that communities may implement their own hubs. The Governor signed the bill in April 2026.	L.D. 2220 (E)				
ME	Planning and Procurement	Non-Wires Alternatives	On October 17, 2025, the Maine Public Utilities Commission opened an inquiry regarding a review of the NWA investigation and recommendation process, as a result of a requirement in L.D. 1726 (enacted in 2025). On February 10, 2026, Commission Staff filed a draft report in the proceeding's inquiry, setting forth several conclusions and recommendations. The report suggests that legislative clarification may be needed regarding the role of NWA's definition and whether the legislature intends for the Commission to evaluate the need for utility incentives to encourage NWA development. The report also recommends that the Commission further examine whether the current exclusion criteria for certain projects from the NWA investigation should be expanded. The Commission emphasized the need for a more holistic review of the various issues and topics examined in this proceeding, as well as related matters currently before the Commission, including those focused on the NWA process, flexible interconnections, storage, and grid resilience and reliability.	Docket No. 2025-00307	Draft Report (Feb. 2026)			
ME	Studies and Investigations	Cost Shift Prevention	On June 25, 2025, the Maine Public Utilities Commission opened a proceeding to inquire about opt-in programs to reduce net energy billing (NEB) costs. The Commission filed a notice of inquiry on April 13, 2026, with a request for comment by May 13, 2026, for the following questions: what kinds of long-term financial mechanisms and buy-down arrangements would encourage a DG project sponsor to voluntarily leave its existing NEB agreement; and what potential mechanisms can create savings for low-income customers that could provide savings to other ratepayers. Central Maine Power filed comments on May 13, 2026, stating that it supports savings initiatives for low-income customers as long as they are cost-neutral or beneficial for other customers.	Docket No. 2025-00193				
ME	Studies and Investigations	Large Load Cost Shift Prevention	L.D. 307, as passed by the House in early April 2026, directs the Maine Department of Energy Resources to convene the Maine Data Center Coordination Council to provide strategic input, facilitate coordinated state planning, and evaluate policy tools to address data center opportunities and related benefits and risks. The Council's charge is to evaluate issues related to data centers located or proposed to be located in Maine, with the goals of protecting ratepayers, maintaining grid reliability, minimizing environmental impacts, and enabling responsible and appropriately sited economic development. In carrying out its work, the Council would be directed to examine the following topics related to cost shift prevention: (1) review data center legislation adopted or considered in other states; evaluate projections of load growth, infrastructure needs, and reliability and resource adequacy impacts in Maine and the ISO-New England region; (2) identify ratepayer protection strategies, including cost allocation approaches, rate design changes, impact fees, efficiency standards, energy supply obligations, and demand response mechanisms; and (3) review applicable state programs and financial tools. The Council must submit a final strategy report - including findings, recommendations, and any proposed legislation - to the state government by February 1, 2027. The committee may report out a bill based on the report to the 133rd Legislature in 2027. The Governor vetoed the bill in late April 2026.	L.D. 307 (V)				

State	Category	Sub-Topic(s)	Description	Source				
ME	Studies and Investigations	Large Load Cost Shift Prevention	On May 27, 2026, the Maine Public Utilities Commission initiated an informal investigation into large data center development. A notice was filed on June 5, 2026, to identify and implement strategies to: (1) safeguard customers against increased energy supply costs, including the risks associated with overbuilding new generation; (2) safeguard customers against increased transmission and distribution costs, including by mitigating the risk of stranded utility assets; and (3) promote the development of market and regulatory mechanisms to ensure that costs attributable to data center development are fully borne by the entities responsible for creating those costs.	Docket No. 2026-00142				
ME	Studies and Investigations	Large Load Cost Shift Prevention	On April 29, 2026, Governor Mills signed Executive Order No. 5, establishing the Maine Data Center Advisory Council. The Council is charged with addressing large-scale data center opportunities and their associated benefits and risks by evaluating policy tools and state planning considerations, while accounting for existing clean energy and emissions reduction objectives. A final report must be submitted to the state government by January 29, 2027. The order also directs the Maine Department of Energy Resources to coordinate with the Public Utilities Commission to identify and implement strategies that protect ratepayers from increased energy costs resulting from data center development.	Executive Order 5				
ME	Studies and Investigations, Utility Oversight	Cost Containment, Monitoring	L.D. 1949, as signed by the Governor in late March 2026, requires the Maine Public Utilities Commission to develop an affordability metric to assess the impact of electricity bills on the overall energy burden for residential customers of investor-owned transmission and distribution utilities. The Commission must submit an interim report on its progress to the joint standing committee having jurisdiction over energy matters by January 15, 2027, and a final report by December 15, 2027, including any recommendations or proposed legislation. The bill also directs the Commission to conduct a comprehensive review of each component of electric delivery rates and consider whether changes to the current design and composition of rates could be implemented in order to (1) contain customer costs, (2) reduce utility bill volatility, and (3) increase utility bill transparency. The Commission is to submit an interim report to the legislature by January 31, 2027 and a final report by December 15, 2027, including any recommendations or proposed legislation.	L.D. 1949 (E)				
ME	Utility Business Model	Multi-Year Rate Plans, Performance Incentive Mechanisms, Revenue Decoupling	On December 5, 2025, the Maine Public Utilities Commission filed a notice of inquiry to receive input and develop guidance related to its preferred approach to multi-year rate plans and associated performance metrics. A staff proposal filed on January 20, 2026, outlines a four-year price cap, a multi-year rate plan, and an advanced metering infrastructure (AMI) utilization performance incentive mechanism (PIM) designed to encourage greater enrollment in demand response programs, time-of-use rates, and potential new peak reduction initiatives. The proposal does not recommend direct financial incentives tied to Central Maine Power's affordability performance or PIMs focused exclusively on low-income customers. On February 17, 2026, the Commission's Advisory Staff filed recommendations that support maintaining the current PIMs, with further development to occur within a rate case, and conclude that a revenue-cap multi-year rate plan framework with a revenue decoupling mechanism is reasonable for the state's investor-owned utilities. On March 13, 2026, the Commission issued guidance concluding that a revenue cap multi-year rate plan with a revenue decoupling mechanism is reasonable for Maine's investor-owned transmission and distribution utilities. PIMs should encourage new policy objectives or counter negative incentives inherent in the current ratemaking model, and should be developed and maintained through rate cases. Remaining issues, including rate plan terms, earnings sharing mechanisms, off-ramps, and storm costs, are best resolved in rate cases.	Docket No. 2025-00354	Maine PUC Guidance (Mar. 2026)			
ME	Utility Business Model, Utility Oversight	Cost Recovery, Earnings Sharing Mechanisms, Multi-Year Rate Plans, Performance Incentive Mechanisms	On April 17, 2026, Central Maine Power filed a general rate case, including a request to eliminate a cap on recovery of costs incurred for shared services from Avangrid service companies. Finally, the utility requested the possibility of a potential phase 2 filing to establish a multi-year rate filing, which may include performance mechanisms and earnings sharing, in addition to the one-year filing.	Docket No. 2026-00043				
ME	Utility Oversight	Monitoring	L.D. 2203, as enacted in April 2026, prohibits a utility from charging a customer receiving low-income assistance a generation service rate exceeding the standard-offer service rate otherwise applicable to that customer. The Maine Public Utilities Commission may adopt routine technical rules to implement this requirement, including rules governing the sharing of low-income customer data between transmission and distribution utilities.	L.D. 2203 (E)				
ME	Utility Oversight	Return on Equity Rules	L.D. 2038, enacted in April 2026, requires utilities to participate in an RTO, except for consumer-owned utilities and those located in an area of the state where the retail market is administered by the independent system operator for northern Maine. Voluntary participation in a regional transmission organization or independent system operator market allows a 0.5% return on equity adder under the Federal Regulatory Commission's rate-setting policies, which can be recovered from customers. Mandating participation makes the utilities ineligible for the adder and cost recovery from customers.	L.D. 2038 (E)				
ME	Utility Oversight	Transparency	L.D. 1966, as passed by the House and Senate in early April 2026, directs the Maine Public Utilities Commission to prohibit investor-owned transmission and distribution utilities from labeling rate-recoverable expenses as "public policy charges" or any substantially similar term on customer bills, and must require instead that such expenses be labeled in an objective manner that helps customers understand them. The Commission must also require, where practicable and without additional cost to ratepayers, that utilities include a brief, objective description of each such expense or a link to a publicly accessible website where customers may obtain such descriptions. For purposes of this bill, expenses that may be recovered in rates means charges or costs paid by a customer other than those for electricity supply, delivery, and transmission, including charges for energy efficiency, renewable energy, and low-income energy assistance programs. The bill became law without the Governor's signature in late April 2026.	L.D. 1966 (E)				
MI	Customer Cost Allocation	Bill Assistance	On April 17, 2026, the Michigan Public Service Commission filed an order increasing the Low-Income Energy Assistance Fund (LIEAF) funding factor from \$1.00 to \$1.50 per meter per month for the September 2026 through August 2027 billing months. The LIEAF funding factor (funding factor) is a nonbypassable surcharge to be added to each retail billing meter (but not charged on more than one residential meter per residential site), payable monthly by every customer that receives retail distribution service. An electric utility, municipally owned electric utility, or cooperative electric utility shall remit the LIEAF payments to the Michigan State Treasurer for deposit in the LIEAF on a monthly basis no later than 30 days after the last day of each calendar month. Each utility identified in this order as opting out of the funding factor shall establish and fund an energy assistance program consistent with the Michigan energy assistance program year October 1, 2026 through September 30, 2027, for their eligible residential customers that provides assistance to their residential customers for both their electric and home heating needs consistent with the eligibility requirements of the Michigan energy assistance program. The increased funding surcharge is expected to raise about \$90 million for the year beginning with the September 2026 billing month, estimated to provide energy security for a year for about 90,000 Michigan households. On May 1, 2026, the Commission issued an RFP for non-profits, units of local or state government, and Tribal governments for the administration of funding and provision of services for assisting income-qualified households in the reduction of home energy insecurity and the resolution of energy crisis situations. The deadline for submitting a grant proposal is June 12, 2026, with grant awards expected to be announced in July 2026. The grant period is expected to begin October 1, 2026, and end no later than September 30, 2027. The amount available is estimated to be \$93,000,000, consisting of an estimated amount of \$88,000,000 from the LIEAF and \$5,000,000 from federal LIHEAP Assurance 16 funds. Projects should have the following goals: (1) reduce energy insecurity by assisting eligible low-income households in meeting their home energy costs; (2) develop household plans to reduce energy insecurity and enable participants to become self-sufficient; (3) prioritize vulnerable populations for energy assistance including certain low-income households; (4) collaborate with relevant state agencies and energy providers to ensure statewide access and that all funds collected from a geographic region are prioritized for that geographic region; and (5) promote education and outreach on availability of assistance programs and funding.	Docket No. U-17377	Michigan PSC Press Release on Increase to Funding Factor (Apr. 2026)	Michigan PSC Press Release on LIEAF RFP (May 2026)	Michigan Energy Assistance Program RFP (May 2026)	
MI	Customer Cost Allocation	Cost Shift Prevention	On October 17, 2025, Indiana Michigan Power (I&M) filed an application to modify its Large Power tariffs to incorporate specific terms and conditions to accommodate large load customers whose contract demands equal or exceed 50 MW. I&M seeks to balance the obligation to serve these customers with the risk they pose to the utility's system and other customers. I&M proposes a contract term of 15 years with a five-year load ramp period, an exit fee that would apply if the customer permanently closes, takes service from an alternate electric supplier, or reduces contract capacity by more than 20%, provisions that allow the customer to reduce its contract capacity by up to 20% with 60 months notice, a 90% monthly minimum billing demand, a 65% monthly minimum energy, and an increased amount of minimum collateral.	Docket No. U-21986				

State	Category	Sub-Topic(s)	Description	Source				
MI	Customer Cost Allocation	Disconnection Policies	On March 27, 2026, the Michigan Public Service Commission Staff filed a report, in response to an order issued in August 2025. The report makes recommendations for improvements to the critical care shutoff protection rule, which prohibits utilities from shutting off electric service to patients for whom a loss of power would be life threatening and provides other protections and transparency requirements around electricity shutoff for medically vulnerable customers. The recommendation amends the existing rule: (1) by removing the stipulation that this rule only applies due to inability to pay and by requiring critical care customers to identify themselves to the utility annually; (2) by prohibiting a utility from requiring payment of an after-hours reconnect fee or a deposit as a condition of restoring service; (3) and making other changes to how the customer and utility enroll in and operate the program. On May 14, 2026, the Commission filed an order inviting comments on the proposed rule change.	Docket No. U-21939	Report on Critical Care Shutoff Protection Rule (Mar. 2026)	Michigan PSC Press Release (May 2026)		
MI	Planning and Procurement	Securitization	On May 8, 2026, DTE Electric submitted an application for authority to securitize the costs of converting two coal plants to natural gas plants and for cost recovery for vegetation management. The Michigan Public Service Commission previously approved securitization of the coal handling costs at the Belle River generating facility in Docket No. U-21193 and the securitization of unrecovered balances from the company operating Belle River in Docket Nos. U-21543 and U-21860. The Commission approved securitization of the costs of tree trimming as a regulatory asset in Docket No. U-20162. Securitization has been found to be the least cost method of financing these infrastructure projects. Customers will initially receive bill credits that go into effect coincident with the securitization charges. The bill credits will reflect the current revenue requirement associated with the portions of the above-identified costs that are included in DTE Electric's retail electric rates, and will remain in effect until such time as the company's rates are reset. The residential bill credits range from 0.0371 cents to 0.0704 cents per kWh.	Docket No. U-22109				
MI	Planning and Procurement, Utility Oversight	Consumer Representation, Planning Rules	H.B. 5710, passed by the House in May 2026, requires energy utilities in Michigan to remit specified amounts to the utility consumer representation fund before filing energy cost recovery proceedings, with amounts varying based on customer count. Companies serving at least 100,000 customers pay proportional shares of $2,500,000 adjusted annually, while smaller companies pay proportional shares of $150,000 adjusted annually. The bill also requires the Michigan Public Service Commission to consider affordability and net cost to ratepayers when evaluating utilities' IRPs, including the relationship between affordability and factors like reliability and diversity of generation and whether peak load reduction is cost-effective. In evaluating affordability, the Commission should consider capital, fuel, operation and maintenance, and decommissioning costs, levelized cost of energy or capacity, projected impacts on customer bills and overall rate stability, and long-term cost escalations, contingencies, and revenue requirements. The bill defines "affordability" as the capacity of a generation resource or portfolio to deliver electricity at a cost that minimizes the total financial burden on ratepayers over the resource's expected operational life.	H.B. 5710 (P1)				
MI	Utility Oversight	Ratemaking, Rate Freezes	H.B. 5879, as passed by the House in May 2026, requires utilities to provide the Michigan Public Service Commission with property tax exemption savings amounts within 60 days of the bill's effective date. Within 30 days of receiving this information, the Commission is to begin reconciliation proceedings. The bill requires that the Commission issue orders decreasing residential utility rates by the amount of property tax exemption savings and utilities cannot file rate increase applications for two years after such orders.	H.B. 5879 (P1)				
MN	Customer Cost Allocation	Bill Assistance	H.F. 2433, as passed by the House in 2026, establishes a supplemental energy assistance grant program within the Minnesota Department of Commerce to assist low-income households experiencing energy burden to pay the costs of heating, cooling, and other home energy costs throughout the year. Residents whose household incomes is below the income eligibility threshold identified in the Minnesota LIHEAP Detailed Model Plan submitted to the U.S. Department of Health and Human Services for the applicable program year is eligible to receive a grant. The Commissioner of Commerce may award grants for the following: (1) crisis grants to low-income households to prevent shut-off of residential energy services, reinstate residential energy services, or enable delivery of residential fuels to households that received a LIHEAP primary energy grant from federal funds but did not receive the maximum crisis grant amount while federal funds allocated for crisis grants were available; (2) primary energy grants to help low-income households maintain and continue affordable energy service and crisis grants to eligible households that did not receive LIHEAP primary energy and crisis from federal funds; (3) emergency heating system repair or replacement; and (4) outreach activities. The Senate passed the bill in mid-May 2026, removing these provisions; the House concurred with the amendments. The Governor signed the bill in late May 2026.	H.F. 2433 (E - Relevant Provisions Amended Out)				
MN	Customer Cost Allocation	Bill Assistance	H.F. 2442 changes the definition of "low-income" for the existing low-income electric rate discount and the low-income affordability programs. Currently, the definition for "low-income" for the low-income electric rate discount describes a customer who is receiving assistance from the federal LIHEAP. For the low-income affordability programs, "low-income residential ratepayers" are defined as ratepayers who receive energy assistance from LIHEAP. The new definition of "low-income" for both provisions means a household: (1) that is approved as qualified for energy assistance from LIHEAP; (2) with a household income that is 50% or less of the state median income; or (3) that meets another qualification established by the Minnesota Public Utilities Commission. The bill also changes the definition of "low-income household" under the state's energy savings and optimization policy goal. The current definition is a household whose household income is 80% or less of the area median household income for the geographic area in which the low-income household is located, as calculated by the U.S. Department of Housing and Urban Development. The new definition removes the "U.S. Department of Housing and Urban Development" and replaces it with a body of the state or federal government. The House passed the bill in May 2025. The Senate passed an amended version of the bill in May 2025, in which the House refused to concur and the bill was later laid on the table. The bill failed to pass before the end of the 2026 legislative session.	H.F. 2442 (D)				
MN	Customer Cost Allocation	Bill Assistance, Disconnection Policies, Payment Plans	An ALJ filed recommendations in Xcel Energy's ongoing rate case on April 29, 2026. While the ALJ summarized an ongoing dispute over a disconnection moratorium and rate study alternative, but did not provide recommendations on the issue. Intervenors in this case have recommended that the Minnesota Public Utilities Commission implement an indefinite moratorium on disconnections for all customers based on the claim that disconnections do not serve any purpose. Instead, the intervenors recommend that the Commission authorize a randomized control trial to test the impact of disconnection practices by testing different ramifications for real customers that are otherwise subject to disconnection. The moratorium would exist until Xcel Energy could demonstrate that the benefits of disconnection outweigh the costs. Xcel argued that such a moratorium would negatively impact arrearages and customers in the long run by eliminating opportunities for the utility to connect with customers and make them aware of affordability programs and payment plans, in addition to making some customers eligible for some forms of crisis assistance that require a disconnection notice. Additionally, the ALJ recommended approving a proposal to expand the utility's existing PowerOn assistance program by implementing an auto-enrollment provision that would apply to the utility's LIHEAP-enrolled electric only customers. The PowerOn program is currently tailored to households that have received federal LIHEAP funding but are still paying more than 3% of income towards electricity bills. The program offers assistance in the form of monthly payments as a percentage of household income and past-due bill forgiveness.	Docket No. 24-320	ALJ Recommendation (Apr. 2026)			
MN	Customer Cost Allocation	Cost Shift Prevention	On July 16, 2025, Xcel Energy filed a proposal for a new tariff, the Large General Time of Day Service tariff. The tariff would serve customers that meet the demand threshold of at least 100 MW and be open to all industries. Qualifying demand would be determined by an interconnection agreement and will be inclusive of any load ramp-up period, which is limited to five years and a contract term length of at least 15 years. Early termination would require at least 24 months' notice and require the customer to pay an exit fee based on a calculation of the current effective demand charges, times 75%, times the lesser period of ten years or the remainder of the term. The pricing of this tariff would shift more cost recover through demand charges and less from energy costs. The utility also proposes a Form Electric Service Agreement that details the specific terms and conditions governing service to the customer. On June 12, 2026, the Commission issued an order approving the tariffs with several modifications. These modifications include: creating a standalone customer class for large load customers, rather than housing the tariffs under the existing Commercial and Industrial class; requiring all transmission and distribution upgrades needed to serve very large customers be paid directly by these customers; and requiring that for each new customer, Xcel Energy must demonstrate that the electricity provided will meet the state's renewable and carbon fee energy benchmarks without delaying statewide progress.	Docket No. 25-289	Order (June 2026)			

State	Category	Sub-Topic(s)	Description	Source				
MN	Customer Cost Allocation	Cost Shift Prevention	On May 18, 2026, Otter Tail Power filed an application for approval of a new class for very large customers, generally, for customers above 25 MW. The new class would be designated as Large General Service - Tier II - Time of Day. Customers under this service must have a demand of at least 25 MW within the most recent 12 months and will have the option to select this rate schedule for an optional trial service. The tariff is designed to protect all non-participating customers from cross-subsidy and stranded cost risk.	Docket No. 26-211				
MO	Studies and Investigations	Large Load Cost Shift Prevention	Executive Order 2, signed by the Governor in January 2026, directs the Missouri Department of Natural Resources, in collaboration with the Missouri Public Service Commission, to initiate an investigation and review of energy regulations and infrastructure planning in light of the growing demand for power from data centers supporting AI. The Department is directed to review the current regulations and practices to ensure the construction and operation of large power users do not result in higher energy rates for residential and small business customers and project the current and future energy needs of the state, including the impact of large power customers, and develop strategies to address these needs. Findings must be completed by November 30, 2026.	Executive Order 26-02				
MS	Customer Cost-Saving Programs	LMI Incentives	On June 17, 2025, the Mississippi Public Service Commission opened a rulemaking to consider removing the provision governing customer programs for public schools and low-income customers from the Commission's DG rules. This provision does not mandate these programs, but does outline certain rules utilities must follow if they implement these programs. As part of the proceeding, the Commission stayed the associated utility programs, including Entergy Mississippi's and Mississippi Power's LMI rebate programs. Comments on the proposed rules were due within 45 days.	Docket No. 2025-AD-61	Proposed Rules (June 2025)			
MS	Planning and Procurement	Innovative Financing	S.B. 3229, as enacted in April 2026, establishes a mechanism for the Mississippi Public Service Commission to authorize an electric utility financing order to cover the costs of storm repairs due to Winter Storm Fern. Utilities could recover storm repair costs via system restoration bonds issued by the Mississippi State Bond Commission. Eligible system restoration activities and costs include mobilization, logistical support staging, housing, fueling, contracting and construction, removal, reconstruction, replacement or repair of electric generation, transmission or distribution facilities, the recovery of fuel costs related to the operation of electric generation facilities in advance of and through the duration of the storm, and related activities. Utilities could implement system restoration charges on all customer bills to recover the costs of the bonds. The Commission can approve up to $275 million in aggregate costs.	S.B. 3229 (E)				
MT	Customer Cost Allocation	Cost Shift Prevention	On March 31, 2026, NorthWestern Energy filed a proposals for a Large Load Service Tariff Rule (Rule No. 24) to establish minimum terms for each electric service agreement. The rule will apply to customers who will take new or expanded service with an expected average monthly demand of at least 5 MW and provide a tiered approach for very large customers, those whose average monthly demand is at least 50 MW. The rule will include a development deposit to pay for any study costs in addressing the ability to serve the customer, a five year minimum contract, a load ramp-up period not to exceed five years, a minimum demand and load factor, a minimum termination cost, and a curtailment provision. The tiered approach for very large customers will include stricter guardrails such as a 15-year minimum contact length and a minimum demand payment of 75%.	Docket No. 2026.04.023				
NC	Customer Cost Allocation, Studies and Investigations, Utility Oversight	Cost Shift Prevention, Energy Affordability, Monitoring	S.B. 730, as passed and amended by the House in June 2026 and under consideration by the Senate, establishes certain requirements for electric service agreements (ESAs) entered into between utilities and data centers (defined as those with a peak monthly electricity demand of 100 MW or greater). Each contract must (1) include terms and conditions designed to protect residential, other retail, and wholesale electricity customers from costs incurred or reasonably anticipated to be incurred by the utility to provide service to the data center, and (2) prevent, to the maximum extent reasonably feasible, the subsidization of data center electric service costs by other retail customers. Contracts must include minimum billing requirements, a contract term sufficient to recover all of the utility's incremental costs, performance and credit provisions designed to protect retail customers in the event of contract default, and termination provisions. Additionally, the bill directs the North Carolina Collaboratory to issue an RFP for a study to be conducted that examines the current and project impacts to customer bills of the 2050 carbon neutrality goal and whether any changes to this policy or other policies are advisable to improve customer affordability. The study is also to provide recommendations for effective policies to prevent rate impacts from large load customers on other customer classes. The study would be due by May 1, 2027. The bill also institutes a cooling-off period for North Carolina Utilities Commissioners and Commission Staff, prohibiting these individuals from intending to influence on behalf of an employer or client, any communication to or appearance before the Commission within a period of six months following the end of their service or employment with the Commission.	S.B. 730 (P1)				
NC	Customer Cost Allocation, Utility Business Model, Utility Oversight	Cost Shift Prevention, Cost Trackers, Monitoring, Utility Structure	In July 2025, Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) filed a joint application to merge their operations into one entity called Duke Energy Carolinas. The utilities entered into an agreement and stipulation of settlement with other parties in February 2026 resolving all the issues with the proceeding. One condition in the settlement is that the utilities commit to engaging with Google to receive and consider in good faith a more detailed proposal related to a new customer clean energy program structured similarly to the Clean Transition Tariff in Nevada cited by Google in its direct testimony. The settlement also includes plans by DEC and DEP to provide around $286 million in customer benefits to North Carolina. If this benefit to the state is not achieved, DEC's and DEP's shareholders will fund the resulting shortfall, unless the shortfall is due to some other unforeseen economic circumstances, subject to North Carolina Utilities Commission approval. The settlement also commits the utilities and the Public Staff to developing a tracking methodology to measure benefits to NC from the merger. In May 2026, the Commission filed an order approving the merger and the settlement agreement in its entirety.	Docket No. E-2 Sub 1383	Docket E-7 Sub 1332	Settlement Agreement (Feb. 2026)	Order (May 2026)	
NC	Planning and Procurement	Advanced Transmission Technologies	On March 16, 2026, Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) filed a notice with the North Carolina Utilities Commission for approval of Dynamic Line Rating ("DLR") prototypes. Duke Energy suggested that with the significant surge in load growth, DLR technologies were becoming a more attractive solution for the near term as large customers and renewable energy sites put pressure on utility planners to evaluate an extensive list of applications for interconnection requests. Duke stated that the DLR prototypes would test and aim to identify whether DLR technologies could help maximize capacity of the existing power grid by taking in various weather and conductor parameters to accurately provide near-time ratings. Duke Energy outlined the specific research questions and objectives of the DLR prototypes, which are to: (1) test grid enhancement technologies (GETs) in efforts to meet goals related to clean and reliable sources for GETs; (2) test the accuracy of each DLR technology compared to objective weather data or current weather technologies; (3) seek to show the usefulness of DLR compared to ambient adjusted ratings and seasonal ratings; (4) determine whether the use of DLR technologies will increase line ratings that can help maximize the capacity of the preexisting infrastructure; and (5) determine whether DLR technologies can affordably increase Duke's transmission capacity while increasing resilience and helping with constraints during peak demand compared to traditional infrastructure upgrades. Duke Energy stated that the DLR prototypes would impact all customer classes since they would be tested on four specific locations across the utility's system and that there would be no direct customer impact since the prototypes would be attached to transmission circuits. The utility went on to note that the DLR prototypes would not acquire customers and that there were no expected revenues for the DLR prototypes. Duke stated that the expected costs were $1.5 million for DEP and $1.5 million for DEC. On May 11, 2026, the Commission approved the prototypes for 18 months and directed Duke Energy to file status reports every six months and work with the Public Staff at the conclusion to evaluate the costs and benefits of DLR technologies.	Docket No. E-2 Sub 1403	Order (May 2026)			
NC	Studies and Investigations	Large Load Cost Shift Prevention	On August 26, 2025, the Governor of North Carolina created the NC Energy Policy Task Force, an advisory body made up of legislators, state officials, electricity customers, investor-owned utilities, municipal and cooperative utilities, research organizations, and advocacy organizations. The Task Force's goal is to provide policy recommendations to the Governor, General Assembly, Utilities Commission, and other policymakers on pressing energy issues. Its first issue to address is load growth in North Carolina. On February 15, 2026, the Task Force published its interim report, in which it made a number of recommendations for further investigation. Specifically, the Task Force recommended further development of policy options for large load tariffs in order to address the potential for cost shift from large load additions in the state.	Executive Order No. 23	Interim Report (Feb. 2026)			

State	Category	Sub-Topic(s)	Description	Source				
NC	Utility Business Model	Earnings Sharing Mechanisms, Performance Incentive Mechanisms, Revenue Decoupling	In its November 2025 multi-year rate plan (MYRP) application, Duke Energy Progress (DEP) proposed an earnings sharing mechanism (ESM) by which the utility pays customers back any revenues that exceed 0.5% over the utility's return on equity. Returned revenues will appear as a rider or credit on customers' bills. The MYRP also proposes a residential decoupling mechanism (RDM), which would distribute to or collect from residential customers funds based on the difference between actual and target revenues. The RDM includes net lost revenues due to DEP's demand side management and energy efficiency programs; as a result, this kind of mechanism encourages continued investment in these programs. DEP is also proposing a set of performance incentive mechanisms (PIMs): Time Differentiated and Dynamic Rate Enrollment, Reliability, Renewables Integration, and Customer Service. Notably, the Time Differentiated and Dynamic Rate Enrollment PIM is identical to DEP's existing PIM, with changes to the incentive amounts. The PIM is designed to reduce peak load and is based on winter peak load reductions from customer enrollments in time differentiated rates. The changes increase the potential reward from $5 to $10 per enrolled customer and decreases the customer enrollment cap from 250,000 to 50,000.	Docket No. E-2 Sub 1380				
NC	Utility Business Model	Earnings Sharing Mechanisms, Performance Incentive Mechanisms, Revenue Decoupling	In its November 2025 multi-year rate plan (MYRP) application, Duke Energy Carolinas (DEC) proposed an earnings sharing mechanism (ESM) by which the utility pays customers back any revenues that exceed 0.5% over the utility's return on equity. Returned revenues will appear as a rider or credit on customers' bills. The MYRP also proposes a residential decoupling mechanism (RDM), which would distribute to or collect from residential customers funds based on the difference between actual and target revenues. The RDM includes net lost revenues due to DEC's demand side management and energy efficiency programs; as a result, this kind of mechanism encourages continued investment in these programs. DEC is also proposing a set of performance incentive mechanisms (PIMs): Time Differentiated and Dynamic Rate Enrollment, Reliability, Renewables Integration, and Customer Service. Notably, the Time Differentiated and Dynamic Rate Enrollment PIM is identical to DEC's existing PIM, with changes to the incentive amounts. The PIM is designed to reduce peak load and is based on winter peak load reductions from customer enrollments in time differentiated rates. The changes increase the potential reward from $5 to $10 per enrolled customer and decreases the customer enrollment cap from 250,000 to 50,000.	Docket No. E-7 Sub 1329				
NE	Customer Cost Allocation	Cost Shift Prevention	L.B. 1010, as enacted in April 2026, creates the Large Load Customer Regulation Act. The bill allows a utility to create new rates for each large load customer that fairly allocate electricity system costs to the customer and mitigate risks to operational adequacy, resource adequacy, and other customers.	L.B. 1010 (E)				
NH	Customer Cost Allocation, Utility Business Model	Arrearage Management, Revenue Decoupling	In its 2025 multi-year rate plan, Unitil proposed modifications to its revenue decoupling mechanism (RDM) and implementation of an arrearage management program. In a February 25, 2026 settlement agreement, Unitil agreed to transition from the Revenue-Per-Customer ("RPC") methodology to a total revenue methodology that is calculated based on the total authorized base revenue for each customer group. The RDM has also been expanded to include the company's electric vehicle customer classes as well as outdoor lighting. The settlement lays out a methodology for computing a new revenue decoupling adjustment factor, based on monthly variances from expected revenues per customer class. The factor is a charge or credit applied to the bills of each customer class. The utility must cap the adjustment at 3.0% of authorized base revenues; any adjustments needed in excess of 3.0% will be deferred to the next billing cycle. The settlement also includes implementation of the arrearage management program (AMP). The AMP will be open to all customers coded as "Financial Hardship." Those financial hardship customers are eligible for the AMP if they have past due balances of $200 or greater, 60 days or more past due. Financial Hardship customers will be offered enrollment in a budget billing payment plan to pay their average bill each month. For customers enrolled in, and complying with, the AMP, the company will forgive up to $400 per month, for a maximum annual arrearage of $4,800. The utility's base rates can include $449,000 in annual revenue attributable to the implementation of the AMP. On May 28, 2026, the New Hampshire Public Utilities Commission approved the settlement. On June 2, 2026, and in response to the order filed in Docket No. DE-25-025, Unitil filed an application for approval of its Revenue Decoupling Adjustment Factor (RDAF). Unitil proposes reducing its RDAF charge from $0.00216 to $0.00108 per kWh for residential customers.	Docket No. DE 25-025	Settlement Agreement (Feb. 2026)	Order (May 2026)	Docket No. DE 26-033	
NJ	Customer Cost Allocation	Bill Assistance, Disconnection Policies	A.B. 5798, as enacted in January 2026, requires the New Jersey Department of Human Services to enter into a memorandum of understanding with the Department of Community Affairs, the Board of Public Utilities, and any other state agency that administers a utility bill payment assistance program that provides ongoing assistance. Ongoing assistance is defined as assistance provided to recipients of a needs-based public assistance program that does not expire upon reaching a pre-determined total amount of assistance received or pre-determined total time period during which assistance was received, including utility shutoff prevention pursuant to the Winter Termination Program and Summer Termination Program. The memorandum of understanding will require the Department of Community Affairs to provide information to the state agencies administering utility assistance programs that provide ongoing assistance to recipients concerning recipients of or households eligible for Temporary Assistance for Needy Families, Work First New Jersey, SNAP, the supplemental security income program, and any other state or federal needs-based public assistance program. The information provided by the Department will be information necessary to enroll the recipients or eligible households into any utility bill assistance program that provides ongoing assistance to recipients and that is administered by state agencies. The state agencies administering such programs will review the eligibility criteria and recipient data to identify the information necessary to enroll those recipients of the needs-based programs and to automatically enroll eligible households into the Universal Service Fund, the Winter Termination Program, the Summer Termination Program, or any other utility bill payment assistance program that provides ongoing assistance, except for programs that provide a one-time grant or other limited-use assistance. The provisions take effect six months after enactment, though agencies may take action beforehand.	A.B. 5798 (E)				
NJ	Customer Cost Allocation	Cost Shift Prevention	A.B. 796, as passed by the Assembly in March 2026, requires each electric public utility to file an application (within 180 days of the effective date of the bill) with the New Jersey Board of Public Utilities for the provision of electricity to data centers and to implement the tariffs within a year of the effective date contingent on Board approval. The tariffs must contain protections necessary to mitigate cross-subsidization and risk of stranded costs to other customers. The Board will require each electric public utility to provide for deposits or financial security to protect ratepayers against a material increase in rates should the data center cease operations or take less service than anticipated over the initial 10-year service period and implement other relevant agreements for ratepayer protection, including those addressing transmission cost allocation. The requirements may be relaxed if data center customers provide operational flexibility or bring their own capacity sufficient to defray the need for the above requirements to protect ratepayers.	A.B. 796 (P1)				
NJ	Customer Cost Allocation	Cost Shift Prevention	A.B. 5462, as passed by the Assembly in June 2025, requires each utility to develop and submit a tariff for large load data centers (at least 100 MW of monthly peak demand) to the New Jersey Board of Public Utilities. The tariff must ensure that non-data center ratepayers are protected from costs associated with serving data center loads. Data center developers must provide deposits or other financial surety to protect against a material increase in rates if the data center ceases operation or take less power than anticipated over the first 10 years of service. The Senate passed the bill in January 2026 before a it faced a pocket veto.	A.B. 5462 (V)				
NJ	Customer Cost Allocation, Customer Cost-Saving Programs	Bill Assistance, LMI Incentives	A.B. 5435, as enacted in January 2026, requires the Division of Housing and Community Resources in the Department of Community Affairs to enter into a memorandum of understanding with each state agency and statewide non-profit energy assistance organization that is not currently on the Department's consolidated application portal and that administers its own utility assistance program to be included in the Department's website. Each relevant organization and agency must enter into the memorandum of understanding, assist the Department in updating the consolidated application, and alert the Department to temporary programs that provide financial assistance for utility bill payments and energy efficiency measures to be incorporated into the form.	A.B. 5435 (E)				
NJ	Customer Cost Allocation, Customer Cost-Saving Programs	Bill Assistance, LMI Incentives	A.B. 5733, as enacted in January 2026, requires any state agency that administers a utility bill payment assistance program or energy efficiency program to review the income threshold for the program and raise the threshold if deemed appropriate. A review will consider factors such as the alignment of LMI thresholds used across programs and agencies, the use of alternate income thresholds, and the aggregate costs and impacts of increased income thresholds. If state an increase in the state's low-income energy efficiency programs is ordered, the New Jersey Board of Public Utilities will assess if further guidance is necessary to change the income thresholds for the triennium energy efficiency and peak demand reduction programs for moderate-income programs to ensure that LMI customers are only eligible for one energy efficiency assistance program and to expand access to moderate-income programs, if appropriate.	A.B. 5733 (E)				

State	Category	Sub-Topic(s)	Description	Source				
NJ	Customer Cost Allocation, Customer Cost-Saving Programs	Bill Assistance, LMI Incentives	S.B. 4373 requires the Division of Housing and Community Resources in the Department of Community Affairs to enter into a memorandum of understanding with each state agency and statewide non-profit energy assistance organization that is not currently on the Department's consolidated application portal and that administers a utility assistance program to be included in the Department's website. Each relevant organization and agency must enter into the memorandum of understanding, assist the Department in updating the consolidated application, and alert the Department to temporary programs that provide financial assistance for utility bill payments and energy efficiency measures to be incorporated into the form. Current law only requires a memorandum of understanding to be between the Department and a statewide non-profit agency that administers its own program. The Senate passed the bill in June 2026.	S.B. 4373 (P1)				
NJ	Customer Cost Allocation, Studies and Investigations, Utility Oversight	Bill Assistance, Program Reviews, Rate Freezes, Utility Business Model	Executive Order 1, signed on January 20, 2026, directs the New Jersey Board of Public Utilities (BPU) to issue Residential Universal Bill Credits (RUBCs), or an initial set of RUBCs, to offset increases in the cost of electricity, relying on the same or similar sources of funding that provided for RUBCs in the BPU's August 13, 2025 order, by July 1, 2026. The August 2025 order adopted BPU Staff's recommendation to provide two $50 bill credits to residential customers using $385 million in available funds from the Solar Alternative Compliance Payment account associated with the state's renewable portfolio standard and the BPU's allocation of Regional Greenhouse Gas Initiative (RGGI) auction proceeds. The order also directs the BPU, the Department of Environmental Protection, and the Economic Development Authority to issue a public statement on how they will address ratepayer relief in the 2026-2026 RGGI Strategic Funding Plan, of whether any amendment or addendum of that plan is needed, and an explanation of the most efficient and effective means of providing timely cost relief to LMI ratepayers. The BPU is directed to review all components of, and rationales for, the Societal Benefits Charges (SBCs) included on electric bills, as well as the Clean Energy Program administered by the BPU and in part funded by SBCs. The BPU must also issue a true-up budget for the Clean Energy Program budget for Fiscal Year 2026, which must prioritize funding for direct ratepayer relief and identify opportunities to increase support for, or investment in, energy efficiency programs for income-qualifying ratepayers to help lower those ratepayers' bills. Further, the BPU must consider reducing the SBCs for each electric utility without compromising funding for direct energy assistance programs, including by directing RGGI funds to the programs. The BPU must also consider pursuing a pause, abeyance, or modification of the schedule governing proceedings for electric distribution utility rate increases and cost recoveries. Finally, within 180 days, the BPU will conduct a study regarding the modernization of the traditional utility business model. The study must address the relationship between the traditional business model and recent electricity affordability trends. Additionally, it must consider opportunities for achieving electricity bill reductions including making utility revenue less dependent on capital spending, expansion of performance-based ratemaking including metrics for interconnection of new generating facilities, multi-year rate plans, reductions in return on equity, state review of supplemental transmission projects, use of least-cost resource testing, greater use of asset securitization, and amendments to regulations around infrastructure investment programs.	Executive Order 1				
NJ	Customer Cost Allocation, Utility Oversight	Audits, Bill Assistance	On June 10, 2026, the New Jersey Board of Public Utilities (BPU) filed an order approving BPU Staff's recommended changes to the state's Universal Service Fund (USF) program, citing the need to address energy affordability for LMI customers. The BPU approved Staff's recommendations to authorize and direct the utilities to approve payments resulting from USF applications for the remainder of the program year and to move the program administration from the Department of Community Affairs to the BPU for the following program year. Staff also recommended that utility performance targets be amended to scale up rather than scale down to address increased workload. The USF enrollment targets would be a 2% increase over program year one (October 2025-September 2026) compared to the base year, 3% in year two compared to the prior program year, and 5% in year three compared to the prior program year. The BPU approved the recommendations, reasoning that they would improve application times and increase enrollment access due to sufficient utility resources; the BPU also noted that the utilities' costs would remain subject to audit. The Board further found that employing the utilities' resources would ultimately benefit customers and utilities by reducing utility uncollectibles, reducing disconnections, and subsequently increasing energy affordability.	Docket No. QO24110853	Order (June 2026)			
NJ	Customer Cost Allocation, Utility Oversight	Bill Assistance, Program Reviews	On April 22, 2026, the New Jersey Board of Public Utilities filed an order addressing the New Jersey Clean Energy Program Fiscal Year 2026 true-up budget and reallocation of funds. The reallocations include $102,723,388 allocated to provide a universal bill credit in accordance with Executive Order 1.	Docket No. QO25040206				
NJ	Customer Cost-Saving Programs	LMI Community Solar	On March 4, 2026, the New Jersey Board of Public Utilities filed an order in response to the Governor's Executive Order 2 from January 20, 2026. The executive order directed the Board to open 3,000 MW of capacity in the Community Solar Energy Program (CSEP) within 45 days. The Board ordered its Staff and the SuSI administrator to increase the CSEP EY 2026 block allocations by 3,000 MW. Regarding community solar credits, the Board waived the existing structure of the credit being used as a bid tiebreaker and instead mandated that newly registered projects must offer at least a 20% bill credit discount to all subscribers and at least a 25% discount to all LMI subscribers. The guaranteed bill credit discount will continue to be calculated as a percentage of the bill credits received by the customer based on their subscription size, and project owners may still offer a greater discount to increase their project competitiveness. The incentive level for the community solar market segment will decrease from $80/MWh to $60/MWh for all registrations after March 6, 2026; Board Staff must reevaluate CSEP and Administratively Determined Incentive (ADI) incentive levels and eligibility parameters in light of recent federal tax credit phase-outs and other market changes. The order also waived a rule allowing utilities to register community solar projects in the CSEP up to the amount of rolled over capacity in its service territory, citing concerns about competition and ratepayer impacts, given the potentially high amount of remaining capacity under these new circumstances.	Docket No. QO22030153	Executive Order 2			
NJ	Studies and Investigations	Cost Shift Prevention	A.B. 5466, as enacted in July 2025, directs the New Jersey Board of Public Utilities to study the effects of data center electricity usage on electricity costs in the state. The Board must (1) determine if the current cost allocation between customer classes would cause non-data center customers to subsidize data center customers; (2) determine whether ratepayers would incur unreasonable new rate increases for electrical infrastructure (e.g. transmission, distribution, generation) to support data centers; (3) estimate the portion of residential electricity rates attributable to data center-related demand (4) estimate the potential impacts to residential electricity rates attributable to data center-related demands over the next 20 years, based on a range of likely scenarios; and (5) assess policy alternatives, including requirement of special data center tariff(s), to mitigate or avoid rate increases to other customers related to data centers. The study is due 15 months after enactment of the bill. There is no publicly available information available as of June 2026.	A.B. 5466 (2025)				
NJ	Studies and Investigations	Utility Business Model	On February 4, 2026, the New Jersey Board of Public Utilities (BPU) opened a proceeding regarding a request for quotation (RFQ) regarding implementation of Executive Order 1. Executive Order 1, signed in mid-January 2026, directs the BPU within 180 days to conduct a study regarding the modernization of the traditional utility business model. On February 18, 2026, the BPU approved procurement of a consultant to study alternative utility business models to reduce electricity costs. As outlined above, the consultant will evaluate potential reforms and aim to identify how the way utilities are currently regulated has influenced increasing electric delivery charges.	Docket No. EO26020023	New Jersey BPU Press Release (Feb. 2026)			
NJ	Studies and Investigations	Utility Business Model	On April 9, 2026, the New Jersey Board of Public Utilities (BPU) initiated a proceeding on the electric utility business model study being conducted pursuant to Executive Order 1. On April 16, 2026, the BPU filed a notice of a public stakeholder meeting to address issues in the executive order pertaining to the study. The stakeholder meeting will cover the relationship between the traditional business model and recent trends affecting electricity affordability and opportunities including making utility revenue models less dependent on capital spending on infrastructure, expansion of performance based ratemaking, multi-year rate plans, lowering return on equity, least cost resource testing requirements, greater use of asset securitization, and amendments to regulations governing infrastructure investment programs.	Docket No. EO26040117				

State	Category	Sub-Topic(s)	Description	Source				
NJ	Utility Oversight	Program Reviews	On March 13, 2026, the New Jersey Board of Public Utilities (BPU) scheduled an informational session and invited comments on a BPU Staff straw proposal for a one-year extension of New Jersey's second energy efficiency and peak demand reduction program, known as "Triennium 2.5," which would extend Triennium 2 through the period of July 1, 2027 to June 30, 2028. The straw proposal focuses on promoting affordability and cites Executive Orders No. 1 and No. 2 as part of the motivation. The proposal would use gross savings (total reduction in energy consumption directly resulting from measures installed through the program), rather than net savings (gross savings adjusted to account for what would have occurred without the programs) to comply with Clean Energy Act requirements at a lower cost. BPU Staff also proposed setting the upcoming Program Year 7 (PY7)/FY2028 targets equal to that of PY6. The same total electric target of 2% savings would be adjusted for compliance based on gross savings. The document further directs each utility to apply its approved weighted average net-to-gross at the Triennium 2 portfolio level to their PY6 budget to determine its maximum Triennium 2.5 budget.	Docket No. QO25050300	Triennium 2.5 Straw Proposal (Mar. 2026)			
NJ	Utility Oversight	Program Reviews	On May 21, 2026, the New Jersey Board of Public Utilities (BPU) filed an order approving BPU Staff recommendations pertaining to the cost cap and incentive levels for the Administratively Determine Incentive (ADI) program for solar and reducing RPS compliance targets. Pertaining to updated incentive levels, the BPU approved Staff's recommendation to reduce the incentive modestly from $85/MWh to $77/MWh for the residential market segment, citing a balance between the need to accelerate solar deployment and keep costs manageable for ratepayers. The BPU certified that the cost cap was not exceeded in Energy Year (EY) 2025 and was not forecast to be exceeded in EY 2026 or EY 2027; accordingly, the BPU found that the cost cap does not serve as a constraint for the EY 2027 ADI program incentive allocations. Finally, the BPU approved Staff's recommendation to decrease the statutory RPS targets to 35% (as opposed to the statutory 41%) for EY 2027 and 40% for EY 2028 (as opposed to the statutory 44%). Staff cited concerns about renewable energy supply being significantly constrained in the PJM interconnection and there relatively few new generation facilities creating energy eligible for Class I RPS compliance, which could have potentially resulted in significant compliance costs for ratepayers if the targets were not reduced.	Docket No. QO26030096	Order (May 2026)			
NM	Customer Cost Allocation	Cost Shift Prevention, Low-Income Discount Rates	As part of a general rate case filed on March 27, 2026, El Paso Electric (EPE) proposed a new Low Income Rider to waive the monthly fixed charge for low-income residential customers enrolled in the Supplemental Nutrition Assistance Program or LIHEAP. The utility already offers a Low Income Rider in its Texas jurisdiction, and this proposal mirrors the Texas offering. EPE will identify customers using the New Mexico Human Services Department Health Care Authority Client Database, and customers would receive the discount for 12 months or the length of their enrollment in the identified program, whichever is less. The current fixed charge is $7, and EPE has a proposed an increase to $14.36 in Phase 1 and $18.89 in Phase 2. EPE also proposed two new large load tariffs. The new High Load Factor Power Service rate would apply to facilities 30 MW or higher with average monthly load factors 85% or higher. The tariff includes a minimum bill, minimum 20-year contract term, financial security requirements, exit fees, and a facility charge. The new Large Load Power Service rate would apply to facilities 10 MW or higher with monthly load factors that can vary from month to month. This tariff also includes a minimum bill, minimum 20-year contract term, and financial security requirements. EPE also proposed changes to its line extension policy to address large load requests. First, any customer requesting an alternate primary voltage line must either make a customer contribution equal to the estimated cost of the extension or pay a monthly facilities charge equal to the utility's fixed charges on the extension. Second, if the alternate extension requires a reservation of distribution capacity, then the customer must pay a Reserved Distribution Capacity Charge. Third, if a customer requires a transformer over 750 kVA, EPE will request verification from the customer's electrician. If the customer does not verify its planned connected load, then EPE will provide a transformer sized to the verified load and reserve distribution capacity for up to one year after transformer installation; if the customer still does not verify, then it will bill the Distribution Capacity Reservation Charge to any customer that requests to hold the reservation past the one-year period. Fourth, any customer interconnection 30 MW or more at the distribution level would be responsible for the costs of any unplanned substation and transmission line upgrades. If EPE installs and operates the facilities, then the customer must pay an Infrastructure Capacity Charge to recover the costs.	Docket No. 25-00082-UT				
NM	Customer Cost-Saving Programs	LMI Community Solar	On March 16, 2026, the New Mexico Public Regulation Commission opened a docket to investigate El Paso Electric's and Xcel Energy's treatment of community solar credits for budget-billed customers. Under statute, utilities must apply community solar credits "to subscriber bills within one billing cycle following the cycle during which the energy was generated" for all subscribers, but RFI responses from both utilities implied that the crediting process for budget-billed customers is different than the crediting process for non-budget-billed customers; the RFI response from Public Service Company of New Mexico explicitly stated that the process is the same for budget-billed and non-budget billed. Commission Staff held an educational session regarding the issue on April 1, 2026.	Docket No. 26-0000057				
NM	Customer Cost-Saving Programs	LMI DER Programs	On April 20, 2026, El Paso Electric (EPE) filed an application to implement a demand response and DER pilot, originally proposed in its 2025 IRP. The pilot would, at each home, install a 20 kW / 57.6 kWh front-of-the-meter solar-plus-storage system, a smart panel for full home automation and control (including HVAC, hot water heaters, electric vehicle charging, and all switched loads), and an inverter that can correct power factor and provide overall DER control. By aggregating solar, storage, demand response, and energy efficiency, the systems could be controlled to support phase balance correction for the distribution feeder for the benefit of all customers. Systems would be installed at up to 250 new homes, plus up to 10 existing low-income homes. The systems would be installed, owned, and operated by a third party; EPE would communicate dispatch and scheduling needs to the program administrator, who would then implement the dispatch instructions. The pilot has a proposed budget of $1.64 in the first year, increasing by 2% per year thereafter, and an expected nominal budget of $66.5 million over 30 years, in addition to $350,000 for a demonstration site and $47,000 for a value stream analysis. Cost recovery would be deferred to a future ratemaking proceeding.	Docket No. 26-0000079				
NM	Studies and Investigations	Energy Access	H.B. 54, as adopted in February 2026, is a memorial requesting that the New Mexico Public Regulation Commission convene a working group to develop recommendations for a regulatory and statutory framework to promote reliable and consistent utility access for mobile home parks. The working group must submit its findings by November, 1, 2026.	H.M. 54 (Adopted)				
NM	Studies and Investigations	Energy Affordability, Infrastructure Planning	Executive Order 2026-023, signed in April 2026, creates the New Mexico Energy Affordability and Reliability Council. The Council must: (1) recommend strategies that ensure residential, rural, tribal, and small business customers are not disproportionately burdened by the cost of capital investments to meet growing electricity demand; (2) recommend affordable utility rate designs that protect consumers while ensuring investment in grid modernization, reliability, and resilience; (3) assess financing strategies, alternative project delivery methods, and rate design approaches that minimize long-term rate escalation, avoided stranded costs, and prevent regressive cost impacts on frontline communities and vulnerable populations; (4) recommend strategies that advance progress to net-zero emissions by supporting affordable access to zero-carbon electricity; (5) balance cost containment with other issues when assessing strategies that preserve environmental, tribal, transparency, and quality assurance safeguards; (6) recommend measures that enhance transparency in infrastructure planning, including providing stakeholders with visibility into projected investments and associated cost impacts; (7) recommend streamlining for state and local permitting review timelines; (8) design a framework to appropriately adjust permitting to accelerate low-carbon impact projects and prioritize state resources on projects that require deeper review or coordination; and (9) ensure alignment with applicable innovation, infrastructure, and economic development funding. The Council must submit its final report, including recommendations, by November 1, 2026.	Executive Order 2026-023				
NM	Utility Business Model	Shared Savings Mechanisms	On April 16, 2026, Public Service Company of New Mexico (PNM) filed its 2027-2029 Energy Efficiency and Load Management Program Plan, continuing its sliding scale profit incentive, allowing PNM to earn 7.10% of annual program costs if it achieves 81 GWh in annual savings. For each GWh above 81 GWh, it would earn an additional 0.125% up to 86 GWh. For each GWh above 86 GWh, it would earn an additional 0.175% up to 91 GWh. For each GWh above 91 GWh, it would earn an additional 0.225% up to 100 GWh, for a maximum incentive of 10.54% of annual program costs.	Docket No. 26-0000074				

State	Category	Sub-Topic(s)	Description	Source				
NV	Customer Cost Allocation	Cost Shift Prevention	On April 20, 2026, in an ongoing proceeding to investigate resource adequacy and planning to ensure that electric utilities' supply of energy is sufficient to satisfy demands and maintain reliable, continuous service, the Public Utilities Commission of Nevada filed a procedural order. This order directs comments to be submitted on the topic of specific challenges or concerns presented by large load self-generation. On May 21, 2026, Microsoft Corporation filed comments requesting that the Commission consider a proposed Ratepayer Protection Tariff (RPT). The RPT is a rate design model that prioritizes ratepayer protections above all else by holding large load customers accountable for paying both the costs they cause and their share of existing costs associated with the provision of safe and reliable service. Under this tariff, large load customers would pay all of the new costs caused by the large load customer and otherwise applicable rates that recover the new customer's fair share of existing system costs. Ratepayers are protected from cost shifts from large customers because these costs are separated and directly allocated to the cost-causing customer.	Docket No. 20-08014				
NV	Customer Cost-Saving Programs	LMI Community Solar	In December 2025, Nevada Power and Sierra Pacific Power filed applications to implement a new tariff, Net Metering Rider-Solar Powered Affordable Housing Systems (Schedule No. NMR-SPAHS) that allows for qualifying multifamily affordable housing properties to operate solar-powered affordable housing systems, as required by A.B. 458 of 2025. A.B. 458 established virtual net metering for low-income multifamily housing with renewable energy systems no larger than 1 MW. Virtual net metering will function the same as traditional net metering currently approved for the utilities, however, net metering credits associated with the system will be allocated to the individual tenants according to the allocation schedule provided by the owner of the energy system, without requiring the energy system to be physically interconnected with the meter of each tenant. The aggregate capacity limit for each utility's tariff is 50 MW until the limit expires on December 31, 2029.	Docket No. 25-12029 (Nevada Power)	Docket No. 25-12030 (Sierra Pacific Power)	A.B. 458 (2025)		
NV	Studies and Investigations	Energy Assistance Programs	On April 17, 2026, Nevada Power submitted a report evaluating the existing programs in the state that provide energy and energy-related assistance to the state's ratepayers. The report includes information on three government and customer funded programs, three NV Energy Foundation-Funded programs, and two other programs to aid customers.	Docket No. 26-04024				
NV	Utility Business Model	Multi-Year Rate Plans, Performance Incentive Mechanisms	On June 6, 2019, the Public Utilities Commission of Nevada opened a rulemaking proceeding to amend, adopt, and/or repeal regulations in accordance with S.B. 300, which was enacted in May 2019. The bill requires the Commission to adopt regulations to establish procedures for a utility to apply to the Commission for the approval of an alternative ratemaking plan. In August 2021, the Commission released proposed regulations for alternative ratemaking in Nevada. The proposed regulations authorize, but do not require, a utility to file a multi-year rate plan or other alternative ratemaking plan. The regulations specify the timing and manner in which the proposal must be filed, and the supporting materials the utility must include. The Commission issued an order on January 2, 2025 adopting the proposed regulations as temporary regulations. The Commission filed a final order in April 2026, formally adopting the regulations.	Docket No. 19-06008	Proposed Regulations (Aug. 2021)	Order (Jan. 2025)	Order (Apr. 2026)	
NV	Utility Business Model	Performance Incentive Mechanisms	On May 1, 2026, NV Energy filed a petition with the Public Utilities Commission of Nevada for adoption of alternative ratemaking goals and outcomes, in line with new regulations. NV Energy's proposed goals and outcomes focus on providing smaller but more frequent and predictable changes in rates; enhancing efficiency at the utility; and aiming to reduce administrative burdens for the Commission, stakeholders and the utility. The petition presents four goals: (1) balancing interests while ensuring an economically viable utility model, (2) enhanced customer engagement, (3) enhanced safety and reliability screening, and (4) balanced customer interests with utility predictability. Each goal has a series of outcomes associated with it. The outcomes for Goal 1 are rates that are more predictable and feature gradual changes that reflect major capital projects; rate changes are determined reasonable based on identified cost drivers over a specified period such as a multi-year rate plans; large customer load growth is reflected in rate changes, ideally benefiting households, small businesses and existing industrial customers; and administrative cost reductions are measured to determine if more regulatory efficiency is captured with alternative ratemaking. The outcomes for Goal 2 are greater customer rate awareness through better customer education and the development of new customer awareness tools. Goal 3 has one outcome, which is tracking reliability, safety, and risk reduction related to projects that are not part of the Natural Disaster Protection Plan. The outcomes for Goal 4 are rates that support utility financial stability and dampen rate impacts when compared to traditional ratemaking; and balancing regulatory lag between customer and utility.	Docket No. 26-05001				
NY	Customer Cost Allocation	Bill Assistance	A.B. 10160, as passed by the Assembly in April 2026 and Senate in June 2026, requires gas or electric corporations to accept and credit any public assistance payment tendered on behalf of a residential customer by a social services district or the office of temporary and disability assistance, including but not limited to payments made pursuant to the home energy assistance program, and emergency funding from social services programs. Upon receipt of such payment or notice that such payment has been authorized or issued, a gas or electric corporation shall treat the payment as made for all purposes under this section, including restoration of residential utility service, and satisfaction of other forms of collections activity, regardless of the status of the customer's account.	A.B. 10160 (P2)				
NY	Customer Cost Allocation	Bill Assistance	As part of an ongoing case considering energy affordability for low-income residents of New York, the New York Public Service Commission filed an order on February 12, 2026 that permanently paused customer disenrollments in utility energy affordability programs and ensures utilities will continue to provide assistance to low-income customers during Federal government shutdowns and continued uncertainty around federally-funded programs. Additionally, the Commission filed an order on February 17, 2026 allowing Central Hudson Gas & Electric, Consolidated Edison, New York State Electric & Gas, National Grid, Orange & Rockland, and Rochester Gas & Electric to carry out their cost recovery plans for implementation of the low-income energy assistance pilots in their next base rate proceedings.	Docket No. 14-M-0565				
NY	Customer Cost Allocation	Cost Shift Prevention	A.B. 11560, as passed by the Assembly and Senate in early June 2026, requires utilities to file with the New York Public Service Commission an independent classification of service for large data centers (those with a peak demand of 20 MW or more) that is distinct from other classifications of service. The service classification should assign all costs (including those associated with infrastructure upgrades, administrative expenses, operational costs, and rate of return) to serve these large data centers entirely to this classification. The classification should also mitigate risks and impacts to other service classifications from large data centers, ensuring there are no increases to surcharges, basic service, or other fixed charges not directly related to energy usage.	A.B. 11560 (P2)				
NY	Customer Cost Allocation	Cost Shift Prevention	On February 12, 2026, the New York Public Service Commission issued an order initiating a proceeding to review the planning and interconnection processes, cost allocation mechanisms, and tariff structures relating to the integration of large loads within the state's transmission and distribution systems. Interested stakeholders were directed to file comments by May 13, 2026.	Docket No. 26-E-0045				
NY	Customer Cost Allocation	Disconnection Policies	S.B. 8118, as passed by the Senate in June 2026, prohibits utility service terminations in multifamily buildings. The bill failed to advance before the end of the legislative session.	S.B. 8118 (D)				
NY	Customer Cost Allocation	Disconnection Policies, Payment Plans	S.B. 1327, as passed by the Senate in May 2026 and the Assembly in June 2026, requires the New York Public Service Commission to establish standard payment plans for eligible customers' utility bills. Those standards include consideration of household income, ability to pay, payment history, bill size, and other factors; a grace period of 21 days to pay the bill; prorating a rate increase across a payment plan; and prohibiting disconnections while on a payment plan. Eligible customers include those households enrolled in income-based assistance programs.	S.B. 1327 (P2)				
NY	Customer Cost Allocation	Rebate Payments	A.B. 10009 and S.B. 9009, enacted in May 2026, created the Protecting Our Wallets Energy Rebate (POWER) program. The POWER program total $1 billion in rebate checks sent out to New York residents. Joint filers with incomes below $150,000 will receive a check of $200; joint filers with incomes between $150,000 and $300,000 will receive a check of $150; and Single filers with incomes below $150k will receive a check of $100.	A.B. 10009 (E)	S.B. 9009 (E)			

State	Category	Sub-Topic(s)	Description	Source	
NY	Planning and Procurement, Utility Business Model	Advanced Transmission Technologies, Performance Incentive Mechanisms	S.B. 2708, as passed by the Senate in March 2026, requires electric corporations and combination electric and gas corporations to conduct cost-effectiveness and timetable analyses of advanced transmission technologies (ATTs) in base rate proceedings, transmission planning proceedings, and capital improvement proposals. Utilities must submit strategic implementation plans within 90 days when cost-effectiveness analyses identify ATTs as cost-effective strategies. NYSERDA must conduct a study within 12 months evaluating the use and benefits of ATTs nationally and in New York state. The bill also allows the New York Department of Public Service to approve requests from distribution companies to develop grid enhancement technologies. Distribution companies may propose a performance incentive mechanism that provides a financial incentive for the cost-effective deployment of these technologies. In May 2026, the Senate recalled the bill and offered further minor amendments; it re-passed the bill in June 2026, but the bill failed to advance further before the end of the legislative session.	S.B. 2708 (D)	
NY	Planning and Procurement, Utility Oversight	Cost Recovery, Executive Compensation, Monitoring, Non-Wires Alternatives, Return on Equity Rules, Transparency	A.B. 10008 and S.B. 9008, enacted in May 2026, contain a number of provisions pertaining to utility oversight. The bill directs the New York Public Service Commission to develop performance-based targets for investor-owned utilities that tie compensation for the chief executive officer and other senior management positions of those utilities and ratepayer-funded incentive compensation programs to an energy affordability index. The Commission also must consider adjustments to the utility return on equity based on the affordability metric. The affordability metric will be based on the energy burden of each utility's residential customers, and the Commission must promulgate rules and regulations adopting a methodology utilities to calculate the affordability index, including the consideration of a variety of factors such as differentiated income tiers, sources of energy burden, and energy cost drivers in the relevant service territory. Each utility must submit its affordability index to the Commission when applying for a change in rates and must demonstrate how an increase in rates will be used to promote affordability or expand energy efficiency or cost-effective electrification efforts. Each utility must submit an annual affordability index to the Commission beginning January 1, 2027, showing the energy burden of the utility's residential customers. The Commission must also issue an annual affordability report beginning July 1, 2027 that compares New York's residential energy burden by utility to that in other states. The Commission may refer to this report when reviewing major rate change filings from utilities and is required to explain how this information impacted its decision. The Commission may also install an affordability monitor at each utility following any decision that establishes a change in rates that results in an energy burden greater than 3% for residential electric service or residential gas service, or 6% for combined residential electric and gas service. The affordability monitor will have the power to examine utility financial records and have full access to management meetings. The affordability monitor will be a third party, not affiliated with the Commission or the utility, and will report on the utility's affordability index and efforts every six months. Upon reviewing the report, the Commission is to make a determination on whether the opportunities for savings identified by the affordability monitor merit implementation; if so, the Commission is to issue an order within 180 days to implement these opportunities. If the affordability monitor identifies widespread errors, the Commission is to determine whether the utility was at fault and take corrective actions. Furthermore, the bill directs the Commission to establish rules to limit a utility's ability to recover its direct or indirect costs associated with its attendance in, participation in, preparation for, or appeal of any rate proceeding. The bill also prohibits costs associated with lobbying, political contributions, chamber of commerce or charity contributions, and public relations campaigns and advertising from being recovered in rates. Travel costs that exceed federal per diems will also be prohibited from inclusion in rates. Utilities will also be required to disclose executive compensation (chief executive officer and senior management positions) as part of filings for major changes in rates. The bill also requires electric utilities to return all revenues in excess of their authorized rate of return on equity to ratepayers in the form of bill credits, minus the amount of revenue that would be derived from a rate of return on equity equal to 0.25% if the Commission determines that this revenue provides benefits to ratepayers through cost savings or efficiency gains that exceed the benefits of refunds. In no case will utilities be allowed to retain more in excess revenues than ratepayers receive. Additionally, in any utility application for a major change in rates, the utility must include a description of any consideration of non-wire or non-pipe alternatives prior to inclusion of traditional capital investments in distribution infrastructure. The bill also directs utilities to track and disclose actual costs of all distribution upgrades performed, and the Commission is to open a proceeding to consider proposals that create greater cost certainty for distribution upgrades in order to limit the risk of cost overruns.	A.B. 10008 (E)	S.B. 9008 (E)
NY	Utility Business Model, Utility Oversight	Return on Equity Rules	S.B. 1896, as passed by the Senate in February 2026, requires the New York Public Service Commission to annually set, through a transparent public process: (1) a standardized common equity ratio for each regulated utility (electric, gas, steam, and water companies), determining how much of their capital structure counts as equity; and (2) a single authorized rate of return on equity (ROE) that applies across all regulated utilities, based on publicly available data wherever possible. If a utility actually earned more than the authorized ROE in the prior year, it must return that excess to customers as a bill credit. If it earned less, it can recover the shortfall through a surcharge. Utilities may challenge the ROE, but they must demonstrate in a public hearing that the authorized figures would threaten their finances or operations. The Commission must publish annual reports to the Governor and Legislature explaining its methodology, using publicly available data. The bill did not continue to advance before the end of the legislative session.	S.B. 1896 (D)	
NY	Utility Oversight	Cost Recovery	S.B. 3734, as passed by the Senate in April 2026, directs the New York Public Service Commission to establish rules by January 1, 2027 to limit a utility's ability to recover direct or indirect costs associated with rate proceedings. The Commission may consider setting an overall percentage of non-recoverable expenses, establishing a baseline for reasonable participation costs, and establishing discovery parameters. Utilities would be subject to limitations on recovering costs including attorneys' fees, expert witness fees, employee salaries, and related expenses associated with rate proceedings. The bill did not continue to advance before the end of the legislative session.	S.B. 3734 (D)	
NY	Utility Oversight	Monitoring	At a recent utility collections conference attended by multiple New York utilities, an employee from one of the utilities allegedly joked that “people think much better in the dark” when discussing service shutoffs. The New York Public Service Commission opened an investigation into these comments requesting a range of information from New York utilities, including: (1) identification of any programs or incentive structures utilized with third-party revenue or arrears collection vendors; (2) providing all documents, including but not limited to any policy, standard operation procedure, manual(s), or employee training materials, and a detailed description of all existing practices and policies related to arrears and revenue collection; (3) providing all documents including but not limited to any policy, standard operation procedure, manual(s), or employee training materials, and a detailed description for the qualification and termination of service for Life Saving Equipment (LSE) customers, senior citizens, and medically impaired individuals; (4) providing a detailed breakdown of the process and timeline for customer notifications issued in pursuit of termination for arrears; and (5) confirming the use of Deferred Payment Agreements (DPAs) as a mechanism to help customers avoid service shut-offs and provide all documents including but not limited to any policy, standard operation procedure, manual(s), or employee training materials, and a detailed description of the utility’s process to implement DPAs.	Docket No. 26-00971	
NY	Utility Oversight	Regulatory Decision-Making	A.B. 11021, as passed by the Assembly in May 2026, requires the New York Public Service Commission to consider ratepayer affordability, cumulative rate impacts, interests of LMI customers, and minimizing residential energy burden when examining major rate change filings. The Commission shall include and make public written summaries of specific actions taken to promote ratepayer affordability in approving orders. For multi-year rate plans, the required information shall be provided for each rate year individually and as an overview for the entire plan.	A.B. 11021 (D)	
NY	Utility Oversight	Return on Equity Rules	S.B. 7693, as passed by the Senate in February 2026, directs the New York Public Service Commission to require a gas or electric utility to return excess revenue to customers as a bill credit if it earns more than its authorized return on equity (ROE) in any 12-month period. The credit must appear on customer bills no later than 30 days after the end of each billing year, and must be clearly labeled so customers can see it. The Commission is explicitly prohibited from approving any rate plan that lets a utility keep earnings above its authorized ROE. Utilities must report to the state each year on how much excess revenue they earned and how much they returned. The bill did not continue to advance before the end of the legislative session.	S.B. 7693 (D)	

State	Category	Sub-Topic(s)	Description	Source				
NY	Utility Oversight	Transparency	A.B. 10534, as passed by the Assembly in May 2026, requires the New York Public Services Commission to establish a standardized rate application template that all utilities must use when making rate filings, with specific information requirements including executive summaries, bill impact projections, and detailed breakdowns of expenses and rate components. Utilities must provide clear and comprehensive explanations of all calculations and assumptions used in rate filings, including revenue requirements, cost of capital, and forecasting methodologies, with supporting schedules in a format allowing verification. All rate filings must be made publicly available on the New York Department of Public Service's website, subject to confidentiality provisions for proprietary information. The bill did not continue to advance before the end of the legislative session in June 2026.	A.B. 10534 (D)				
NY	Utility Oversight	Transparency	S.B. 5553, as passed by the Senate in February 2026, directs the New York Public Service Commission to require utilities to send text message notices to customers within one business day of publishing rate increase information, provided customers have opt-out options. Utilities must send email notices with identical information to the Commission's website within the same timeframe to customers who receive email communications. Utilities shall include rate increase notices on a separate page in customers' next monthly billing statements with information identical to what appears on the Commission's website. The bill did not continue to advance before the end of the legislative session in June 2026.	S.B. 5553 (D)				
OH	Customer Cost Allocation	Bill Assistance	On May 22, 2026, FirstEnergy's three Ohio electric companies - Ohio Edison, Cleveland Electric Illuminating, and Toledo Edison - filed application for a three-year electric distribution rates. The companies proposed a new Energy Assistance Fund program for customers at or below 300% of the Federal Poverty Level, which would provide grants to restore customer service up to $500 per customer per year, with a total program cost of $ 4 million; the companies do not plan to recover the costs of this program from ratepayers. The companies also proposed a new Emergency Energy Support Fund for customers at or below 200% of the Federal Poverty Level, which would provide grants up to $250 per customer per year to help customers avoid disconnection or restore service, with a forecasted cost of $1 million. The programs are proposed to run from June 1, 2029 to June 30, 2030.	Docket No. 26-0347-EL-AIR				
OH	Customer Cost Allocation	Cost Shift Prevention	In Docket No. 24-0508-EL-ATA, AEP Ohio filed an application on May 13, 2024 to create a new customer class for data centers exceeding 25 MW. The Public Utilities Commission of Ohio (PUCO) adopted a settlement agreement on July 9, 2025, establishing the utility's Data Center Tariff (Schedule DCT), which includes a 12-year term (4-year ramp plus 8 years), a minimum billing demand of at least 85% of contract capacity or peak demand over the prior 11 months, and allowing AEP Ohio to suspend service if usage exceeds the contracted level by more than 1 MW. AEP Ohio filed a revised tariff on July 11, 2025, which includes a new definition of "customer" that encompasses a financial sponsor co-signing the agreement. Consistent with a stipulation PUCO adopted, the tariff also specifies that loads over 25 MW that already signed agreements prior to the effective date of the new tariff are "grandfathered" so long as their load does not expand by more than 25 MW. PUCO issued a final order approving the revised tariff on July 23, 2025. On January 7, 2026, parties filed a stipulation in an AEP Ohio general rate case with revisions to Schedule DCT to clarify requirements for existing customers, outlining that existing load that does not increase its contract capacity by more than 25 MW is subject to the terms of its existing contract and collateral requirements (see Docket No. 25-0392-EL-AIR). Existing load that signs a new electric service agreement to expand its contract capacity by more than 25 MW is considered new load. If the new load expansion is separately metered, the separately metered original load can continue to be considered existing load. The stipulation also includes a $20,000 per month customer charge for new load. On April 1, 2026, the Commission filed an order finding that the data center provisions in the stipulation were reasonable and approving the stipulations and tariffs as modified in the order.	Docket No. 25-0392-EL-AIR	Order (Apr. 2026)			
OH	Customer Cost Allocation	Cost Shift Prevention	On January 15, 2026, FirstEnergy filed an application and compliance tariffs in the matter of the review of the non-market-based services rider (Rider NMB). On March 11, 2026, Public Utilities Commission of Ohio (PUCO) Staff filed its review, recommending approval of the application for rates effective April 1, 2026, subject to a recommendation that due to the large projected growth of data centers in Ohio, the utility will be required to provide updated data center load growth information semi-annually to PUCO Staff and that any data center not participating in the Rider NMB Pilot Program is not be eligible to the added to the Rider NMB Pilot Program after April 1, 2026. On April 17, 2026, the Ohio Consumer's Council filed a request for rehearing. On May 13, 2026, PUCO denied the request for rehearing and directed FirstEnergy to file an application within 30 days for approval of a tariff creating a separate class for data centers to assure that future costs are properly allocated to these customers. On June 12, 2026, the FirstEnergy Ohio companies proposed a new Schedule Data Center Tariff (DCT) after PUCO directed the utility to file for a separate customer class for data centers. The tariff applies to any customer operating a data center or mobile data center, with no minimum load threshold, and requires a minimum monthly billing demand equal to the higher of 85% of contracted capacity or actual usage. New data center loads must sign contracts with an initial term equal to the load ramp period (up to 4 years) plus 10 years, though customers may exit after the seventh year following the ramp period by paying an exit fee equal to 36 months of minimum charges. New customers must also post collateral covering dedicated transmission and distribution infrastructure costs, scaled to creditworthiness. Customers must procure generation from a competitive retail supplier rather than standard service.	Docket No. 26-35-EL-RDR	Docket No. 26-0697-EL-ATA			
OH	Customer Cost Allocation	Cost Shift Prevention	On March 30, 2026, as a part of its general rate case pre-filing, Duke Energy Ohio modified its electric service regulations and Rider X line extension policy to include provisions applicable to individual or aggregate customers with large service demands. For both the regulations and Rider X, customers seeking service of 40 MW or greater at one or more aggregated premises, or whose demand is reasonably expected to grow to this level, or require significant transmission and/or distribution investments by the utility for the provision of service may be required to provide the utility appropriate financial and/or performance and credit assurance at the utility's discretion.	Docket No. 26-133-EL-ATA				
OH	Customer Cost Allocation, Utility Oversight	Bill Assistance, Cost Recovery, Education	On May 30, 2025, AEP Ohio filed an application to increase its rates for electric distribution service. The full initial application requested a $405.2 million base distribution revenue increase. On January 7, 2026, AEP Ohio filed a joint stipulation and recommendation supported by a majority of parties. The revenue increase in the stipulation would be $320.1 million, compared to the initially requested $405.2 million. The stipulation also includes a cap on recovery for the distribution investment rider and enhanced service reliability rider, requires annual notice to customers whose demand has decreased and may be able to pay lower rates if they switch to a different rate schedule, eliminates a $5 competitive retail electric service provider (CRES) switching fee, and requires the utility to propose a low-income program in its next rate case. On April 1, 2026, the Public Utilities Commission of Ohio filed an order considering the stipulation filed January 7, 2026. The order included Commission Staff comment, which highlights the affordability-related provisions of the stipulation. However, other intervenors noted that consumers' total distribution rates would still increase under the stipulation. In the order, the Commission approved the stipulation, finding that the rates allowed under the stipulation benefit ratepayers and are in the public interest.	Docket No. 25-0392-EL-AIR	Stipulation (Jan. 2026)	Order (Apr. 2026)		

State	Category	Sub-Topic(s)	Description	Source				
OH	Customer Cost Allocation, Utility Oversight	Bill Assistance, Cost Shift Prevention, Disconnection Policies, Payment Plans, Transparency	H.B. 173, as substituted by the Senate in June 2026, requires each electric utility to maintain up-to-date reference tools on its website or in another publicly accessible location that allows automatic calculation of what the utility would charge its residential customers with a specific kWh usage during the last 12 months. Each submetered utility service provider that resells electricity to a tenant based on metered consumption at the tenant's dwelling will provide the tenant a discount resulting in the tenant's bill being 3% less than the bill for the standard service offer and all tariffed charges and riders that the relevant electric utility would charge a residential customer. Additionally, the bill prohibits any submetered utility service provider from billing or otherwise recovering from customers any amounts that were previously undercharged for unmetered electricity and stipulates that electricity for electric vehicle charging must be billed directly to the tenant who used the charger. A submetered utility service provider will be solely responsible for calculating, billing, and collecting any common area electricity charge; no landlord may collect a bill where a submetered utility service provider operates. The charge will not exceed the cost of electricity billed to the submetered service provider by the electric utility for common area consumption and include no markup, administrative fee, or service charge. Further, such service providers must, at a minimum, comply with the requirements for the disconnection of electric service in Ohio statute and regulations. The service providers must also report historic monthly usage and corresponding billing amounts for metered electricity to each tenant's dwelling unit for the last 12 months to enable compliance with the provision requiring a 3% discount. The provider must also disclose its process and procedures for disconnection of service, offer an alternative payment plan option to a tenant that receives submetered utility service from the provider, accept a payment from the home energy assistance program when the customer qualifies for the program, and ensure that the bill lists each charge and complies with the common area charge provisions. In March 2026, the House passed the bill. In June 2026, the Senate substituted and passed the bill, and the House concurred with the Senate amendments. The Governor vetoed the bill in late June 2026.	H.B. 173 (V)				
OH	Planning and Procurement	Advanced Transmission Technologies	On April 24, 2026, the Public Utilities Commission of Ohio opened a docket to review the implementation and cost-effectiveness of advanced transmission technologies (ATTs). H.B. 15 (enacted in 2025) requires electric transmission owners to include an evaluation report of the potential use, or investment in, ATTs to enable the electric utility to meet electric system demand through its major utility facilities. Further, it requires the report to identify locations on the transmission system where congestion has reached certain thresholds or is predicted to in the next five years; to the extent such congestion points exist, it requires the report to evaluate the cost-effectiveness of installing ATTs to address the congestion points using a payback period methodology developed by the Commission. Further, the entity must propose an implementation plan to install ATTs at each congestion point at which the payback period is less than or equal to a value determined by the Commission. On April 27, 2026, the ALJ filed an entry requiring initial and reply comments on the matter. Specifically, commenters were directed to provide feedback on ATT regulations required by H.B. 15 and Commission Staff proposals for a methodology to calculate the payback period for potential ATT installations, as well as the proposed payback period threshold value to trigger the implementation plan requirements in the new regulations.	Docket No. 26-0537-EL-UNC				
OH	Studies and Investigations	Advanced Transmission Technologies	On August 15, 2025, the Public Utilities Commission of Ohio (PUCO) opened a proceeding to implement H.B. 15 (enacted in 2025), which requires the Commission to evaluate the potential use or deployment of advanced transmission technologies (ATTs). On February 27, 2026, PUCO filed its study, which defines ATTs in alignment with H.B. 15 to include advanced conductors and grid-enhancing technologies like dynamic line ratings (DLR), advanced power flow controllers (APFCs), and topology optimization. For each technology, the report provides an overview of attributes, functions, costs, and benefits; the potential to be used and deployed; and potential reductions in project costs, timelines, permitting, and maintenance. DLR is an appropriate solution where capacity variability is acceptable and effective implementation is highly location-dependent; Ohio utilities are testing DLR and only one fully operational DLR project in PJM was available for costs and benefit metrics. In that project, DLR was estimated to save $1 million and have a 10-30% capacity benefit. APFCs are most effective in highly interconnected, meshed networks and areas with congestion or reliability needs; these appropriate conditions may not exist yet in Ohio. The report notes a lack of utility understanding of the technology as a barrier and states that no projects have been deployed in Ohio. It cites one 30% savings estimate for relevant technologies. Regarding topology optimization, the report notes that implementation is in the early stages, that such technologies are more commonly used to mitigate congestion for economic reasons than reliability reasons, and sites existing implementation through market participants submitting reconfiguration proposals for transmission operators to implement. This reconfiguration request system delivered an estimated $24 million in congestion savings in MISO. For advanced conductors, the report finds that experience with advanced conductors appears to be high, though many utilities only have limited deployment. Transmission-owning utilities in Ohio see applications and opportunities for savings, but specialized handling and training is necessary. Compared to a similar capacity increase, these technologies are cited to be 50-75% cheaper. The report further outlines PUCO's support for deploying ATTs and how H.B. 15 will facilitate additional information to aid in the consideration of ATTs and the evaluation of opportunities where they can be beneficially deployed. PUCO noted support for leveraging ATTs to expedite the interconnection of new loads and meet short-term needs; PUCO does not favor using ATTs as a substitute for traditional network upgrades deemed necessary in a specific case.	Docket No. 25-0814-EL-UNC	Advanced Transmission Technologies Study (Feb. 2026)			
OH	Studies and Investigations	Large Load Cost Shift Prevention	H.B. 646, as passed by the House in March 2026, creates a Data Center Commission, which is directed to hold two public meetings for public testimony and two public meetings for expert testimony regarding topics outlined in the bill, including consumer utility rates.	H.B. 646 (P1)				
OK	Customer Cost Allocation	Bill Assistance, Cost Shift Prevention	On June 17, 2026, Oklahoma Gas and Electric (OG&E) proposed a new tariff for extra large power and light customers. The tariff includes a Customer Affordability Charge, with proceeds credited to residential customers to help offset rising rates. It also includes a Customer Class Protection Charge, which participants must pay if their service causes adverse rate impacts on other customer classes.	Docket No. PUD2026-000046				
OK	Customer Cost Allocation	Cost Shift Prevention	H.B. 2992, as enacted in May 2026, is titled the Data Center Customer Ratepayer Protection Act of 2026. The bill requires any authority responsible for reviewing utility rates to ensure that residential, commercial, and industrial customers are protected from paying unjust rates resulting directly from electric service to large load customers; this requirement applies to all electric utilities, including investor-owned, cooperative, municipal, and public power, and retail electric suppliers must also comply with this act as a condition of providing service to large customers. Costs and revenues must be assigned and allocated in accordance with cost causation principles. The bill also requires utilities to maintain separate terms, conditions, and tariffs applicable to large load customers to ensure proper cost allocation, including cost incurred that may be unrecovered if the customer exits service or materially decreases their load. The Oklahoma Corporation Commission must promulgate rules implementing this bill, and the Commission would have exclusive jurisdiction to enforce these provisions upon any utilities it regulates.	H.B. 2992 (E)				
OK	Customer Cost Allocation	Cost Shift Prevention	Existing law provides an exemption from exclusive utility service rights for connected loads over 1 MW in unincorporated areas. H.B. 3989, as passed by the House in March 2026, revises eligibility from "connected" loads to "actual total metered" loads. It also requires utilities to notify the Oklahoma Corporation Commission that it plans to service a facility under this exemption. If the load does not reach the 1 MW minimum within the first 24 months of commercial operation, then the utility must pay a penalty to the incumbent utility in the area equaling 1% of sales to that facility per year, until the facility reaches the 1 MW threshold. The penalty could be waived if the Commission find the utility was not at fault. These notification and penalty provisions would only apply to new facilities served starting August 26, 2026. The bill did not pass the Senate by the end of the session in May 2026.	H.B. 3989 (D)				

State	Category	Sub-Topic(s)	Description	Source				
OK	Customer Cost Allocation	Cost Shift Prevention	As part of a general rate case application filed on January 2, 2026, Public Service Company of Oklahoma proposed new special terms and conditions (T&C) for new large load customers under its Large Power and Light tariff. The T&C would apply to contracted loads at least 10 MW (single site or in the aggregate) starting in 2026, covering new loads or expansions to existing loads. Customers 75 MW or more must contract for at least ten years, while customers up to 75 MW must contract for at least two years. There would also be an optional load ramp period of five years; before the customer begins taking electric service but after executing the contract, the customer must pay a monthly $4.88/kW system contribution charge, with billing demand based on the average demand for the first year of future service. Monthly billing demand must be at least 80% of the contracted capacity, or 90% of the highest previously established monthly billing demand over the past 11 months. Customers must provide collateral 24 times their previous maximum monthly non-fuel bill plus additional outstanding direct interconnection investments once the initial contract has begun (i.e. after the load ramp period). Collateral would be recomputed annually, and updated if the recomputation is 10% greater than the current amount. Customers 75 MW or greater must provide 60 months notice to terminate their contract while customers 10-75 MW must provide 24 months notice, along with an exit fee for all customers equaling the remaining minimum bill for the rest of the contract.	Docket No. PUD2025-000075				
OK	Planning and Procurement	Advanced Transmission Technologies	H.B. 3183, as passed by the House in March 2026, requires utilities to analyze advanced transmission technologies (ATTs) and grid-enhancing technologies, including dynamic line rating, advanced power flow controllers, topology optimization, high-performance conductors, and other relevant technologies. The analysis must include (1) the cost-effectiveness and timetable for deployment and (2) whether the technologies would increase transmission capacity or efficiency, reduce congestion, reduce generation curtailment, increase reliability, reduce wildfire risks, increase resiliency, or increase hosting capacity. Utilities may consult with large load customers to identify opportunities for collaboration, cost-sharing, or customer-funded deployment. The Oklahoma Corporation Commission must encourage utilities to include ATTs within their IRPs. Utilities must analyze congestion hotspots to maximize energy delivery in the near-term and provide a summary of existing and planned ATTs. If the Commission determines that deploying ATTs is cost-effective, then it must approve the utility's cost recovery. The House passed the amended version of the bill in late March 2026. The bill's title was stricken in late April 2026.	H.B. 3183 (D)				
OR	Customer Cost Allocation	Bill Assistance	On January 23, 2026, Idaho Power filed a request to modify its existing Bill Discount Program for Qualified Customers (Schedule 63). The modifications include updating the tariff's language to inform participants considered to be high-usage customers that they may be referred to Community Action Partnership (CAP) agencies or participating Community-based Organizations (CBOs) for possible energy efficiency interventions, pursuant to regulatory requirements, including the sharing of their name and contact information to facilitate the referral. High-usage customers are defined by the state as a residential customer participating in a utility-administered bill discount program whose energy consumption places them in the 90th percentile or above of all other bill discount program participants within the utility's service area. This request stems from a settlement agreement as part of the utility's 2024 general rate case. On March 3, 2026, the Oregon Public Utility Commission approved Idaho Power's request.	Docket No. ADV 1834	Order (Mar. 2026)			
OR	Customer Cost Allocation	Bill Assistance	In June 2026, the Oregon Public Utility Commission approved the creation of Portland General Electric's (PGE) Schedule 96 for large load customers. According to the order, projects larger than 100 MW will be subject to a surcharge of $0.01/kWh, with the surcharge revenue intended to fund programs that lower residential customer costs and address low-income energy burden.	Docket No. UM 2377				
OR	Customer Cost Allocation	Bill Assistance, Cost Shift Prevention	On March 11, 2025 the Oregon Public Utility Commission opened an investigation into marginal cost study treatment of costs for large customers and further modifications to Portland General Electric's (PGE) Rule C (Conditions Governing Customer Attachment to Facilities) and Rule I (New Connections, Line Extensions, and System Upgrades). This investigation was prompted through a previous docket (UE 430) filed by PGE, in which the utility requested to revise its tariff Rule C. On May 20, 2025, the Commission adopted an issues list to be addressed in this investigation, which includes: alignment with H.B. 3546; need for data center rate class; load following credit; transmission cost allocation; distribution marginal cost study; customer marginal cost study; ratemaking implementation options; direct access impact/green tariff ratemaking options; contributions in aid of construction (CIAC); and whether additional charges will result in double recovery from large loads. On August 11, 2025, PGE filed testimony proposing Schedule 96, a new data center rate class for customers engaging or who will engage in data center business with a demand of 20 MW and greater and that will align will the elements of H.B. 3546. Schedule 96 enables the appropriate allocation of the cost of serving these customers and addresses concerns about undue and unreasonable cost shifting. To address cost shifting, PGE proposes updating the marginal cost of service studies, introducing generation demand charges to all industrial schedule that will allow the utility to enable the addition of a minimum demand charge, optional contributions in aid of construction (CIAC) on distribution assets, and an option for special contracting directly with Schedule 96 customers for the cost of service, including for generating resources. On February 4, 2026, PGE, Commission Staff, and other stakeholders submitted a first partial stipulation. The stipulation adopts a majority of PGE's initial proposal with several modifications. These modifications include lowering the minimum threshold for customers that require a Large Load Customer Agreement (LLCA) from 30 MW to 20 MW and allowing customers with an LLCA to contribute up to 100% CIAC for non-shared distributed assets, among other smaller changes. In June 2026, the Commission approved the creation of Portland General Electric's (PGE) Schedule 96 for large load customers. According to the order, projects larger than 100 MW will be subject to a surcharge of $0.01/kWh, with the surcharge revenue intended to fund programs that lower residential customer costs and address low-income energy burden.	Docket No. UM 2377	Stipulation (Feb. 2026)	Order (June 2026)		
OR	Customer Cost Allocation	Cost Shift Prevention	On October 2, 2025, Pacific Power filed a request for approval of a new rate schedule, Service to New Large Energy Use Facilities (Schedule 401). The rate would be applicable to a new customer class of New Large Energy Use Facilities, which (1) require load or have reserved capacity of 20 MW or greater and (2) primarily provide computing infrastructure, data processing, and web services, as described under code 518210 of the 2022 North American Industry Classification System. These definitions follow from Oregon H.B. 3546, which took effect on June 16, 2025. The bill mandates that a new large load tariff allocate costs in a manner that is fair and proportional to the cost of serving the customer and mitigates cost-shifting. Pacific Power proposes to make the tariff mandatory for new customers, and existing customers that require significant additional utility investment or cost after June 16, 2026. Customers taking service under this rate would have a written Large Energy Use Facility Agreement with the utility, specifying the terms, conditions, and rates for service. The agreement would specific a term of at least 10 years and would be subject to Commission approval. Pacific Power proposes to address implementation of H.B. 3546 for Large Energy Use Facilities that do not require significant new costs or investments in its next general rate case.	Docket No. ADV 1790	Docket No. UE 463			
OR	Customer Cost Allocation	Cost Shift Prevention	On August 1, 2025, Pacific Power filed an application for approval of the 2026 Inter-Jurisdictional Allocation Protocol. The 2026 Protocol is intended to supersede the 2020 Protocol for California, Idaho, Oregon, Utah, and Wyoming and align with changes proposed in the Washington 2026 Protocol to ensure all resources are 100% allocated. The 2026 Protocol includes a proposal for allocating costs associated with new large loads over 50 MW.	Docket No. UM 2401				

State	Category	Sub-Topic(s)	Description	Source				
OR	Customer Cost Allocation	Disconnection Policies	On March 25, 2026, Pacific Power filed a request to modify several of its tariff rules and rate schedules in order to comply with a previous Oregon Public Utility Commission order (Order No. 25-543) regarding customer protections. These changes would apply to the following utility rules: Rule 1 General Rules and Regulations - Definitions; Rule 4 Application for Electric Service; Rule 9 Deposit; Rule 10 Billing; Rule 11A Discontinuance of Service for Nonpayment; and Rule 11B Charges for Collection Activity. Accordingly, the modifications would include: (1) removing the definition of "low-income" and replacing it with a definition for "income-qualified;" (2) adding language that allows a customer to provide, in lieu of a valid social security number or Oregon driver's license, a passport or consular identification card without regard for expiration date; (3) removing the expiration date requirement for other forms of state or federal ID; and (4) updating the terms on which the utility will assess a reconnection charge to a customer. Additionally, Pacific Power proposed several modifications specifically for the Discontinuance of Service for Non-Payment Rule (Rule 11A), including: (1) updating the time a customer can submit a written confirmation of a medical condition from 30 days to 60 days; (2) extending the length of time a chronic medical certificate is valid from 12 to 24 months; (3) limiting collection of outstanding overdue balances for income-qualified and medical certificate customers to $200; (4) updating the time a customer can pay the remaining outstanding balance from two to six months; and (5) updating severe weather and wildfire displacement moratoriums to be consistent with those resulting from Order No. 25-543. On April 14, 2026, the Commission approved the utility's proposed modifications.	Docket No. ADV 1862	Order (Apr. 2026)			
OR	Planning and Procurement	Advanced Transmission Technologies	On October 25, 2025, the Oregon Public Utility Commission Staff opened this docket to implement H.B. 3336 (enacted in 2025), which directed the Commission to establish cost-effectiveness criteria for evaluating transmission alternatives and grid-enhancing technologies (GETs). Under the bill, utilities, as part of their clean energy plan and IRP, must include a separate section that provides a strategic plan for using GETs where doing so is cost-effective. The plan must be updated concurrently with the development of, or update to, each IRP, and must: (1) include a timeline for deploying GETs; (2) provide a report on the utility's continual progress towards implementing the plan; and (3) be designed to increase transmission capacity and reliability, reduce transmission congestion and curtailment of renewable energy resources, and increase capacity to connect new renewable resources. The first plan must be carried out no later than January 1, 2030. On January 12, 2026, the Commission Staff submitted recommendations on draft review criteria for utilities' compliance with H.B. 3336. The Staff expects that utilities will report on components for each proposed addition, improvement, or modification to transmission systems with costs exceeding $10 million. These components include project description, project need, a list of each GET that was considered, a narrative description of rationale behind selection and rejection of alternatives, and identification and description of action item for deploying any identified cost-effective GET before January 1, 2030 as part of the IRP Action Plan. Staff proposes using a least cost/best fit with visibility into applicable benefits for evaluating cost-effectiveness of a GET alternative.	Docket No. UM 2409	H.B. 3336 (2025)			
OR	Studies and Investigations	Large Load Cost Shift Prevention	On January 20, 2026, the Governor of Oregon convened the Data Center Advisory Committee to develop recommendations for a comprehensive regulatory framework to strategically pursue economic development opportunities, while ensuring utility cost, infrastructure investments, and environmental impacts remain sustainable and equitable for all residents. The Committee is in charge of conducting an open and public process to understand the challenges and opportunities in key policy areas related to data centers. The Committee's report is due to the Governor by October 2026. The Committee met throughout the first half of 2026, with additional meetings planned through September. One of the Committee's meetings focused specifically on data centers, energy affordability, revenue, and incentives.	Oregon Data Center Advisory Committee				
OR	Utility Business Model	Multi-Year Rate Plans	On October 27, 2025, the Oregon Public Utility Commission Staff opened a rulemaking to establish general rate revision filing schedules and an exemption process to H.B. 3179 (enacted in 2025) implementation. On March 2, 2026, the Commission Staff filed a straw proposal on draft concepts for the transition period between now and each utility's first multi-year rate plan (MYRP). The proposal includes: (1) limiting utilities' general rate case filings to one within two years of the first MYRP and limiting the number of concurrent rate cases to two; (2) targeting total rate increase requests to track at or below inflation; (3) prioritizing the use of general rate cases where operations and maintenance reductions are possible; (4) focusing on bringing new capital projects into rates that are focused on cost-effective reliability, safety, and long-term affordability; (5) focusing on projects that can be supported through an NWA analysis; and (6) phasing increases for rate increases above 5%. On May 19, 2026, the Staff published recommendations for the Commission to issue a notice of proposed rulemaking to consider an addition to administrative rules, establishing an initial filing schedule for electric MYRPs based on the March straw proposal. On May 26, 2026, the Commission adopted the Staff's recommendations.	Docket No. AR 677	Straw Proposal (Mar. 2026)	Staff Recommendation (May 2026)	Order (May 2026)	
OR	Utility Business Model	Multi-Year Rate Plans, Performance Incentive Mechanisms	On October 27, 2025, the Oregon Public Utility Commission Staff opened a rulemaking to establish a multi-year rate plan (MYRP) framework, as required in H.B. 3179 and S.B. 688 (enacted in 2025). H.B. 3179 requires the Commission to establish rules requiring an electric company to establish an MYRP for a rate revision that is subject to the utility's return on equity. S.B. 688 allows the Commission to investigate, develop, and adopt a performance based ratemaking (PBR) framework. On December 11, 2025, Current Energy Group published a report for the Commission presenting MYRP options. These options include: (1) index-based cap MYRPs, in which a target revenue, or cap, is set for the first year of the MYRP period, then annual adjustments are permitted based on predefined factors; (2) forecasted MYRPs, which typically rely on forecasted costs, basing its revenue determination more directly on costs that are in the utility's control; and (3) formula rates, which use actual costs to determine collected revenue. Workshops on the report, the differences between PBR and MYRPs, the state's current ratemaking framework, and the Commission Staff's upcoming ratemaking framework proposal were held between December 2025 and April 2026. On May 20, 2026, Commission Staff published a straw proposal, outlining initial thoughts on the structure and design elements of an MYRP framework. The proposal includes: (1) utilizing an index-based revenue cap; (2) utilizing decoupling to effectuate the revenue cap and promote efficiency; (3) using a five-year term plan duration; (4) seeking a comprehensive scope of utility revenues with limited exceptions, including power costs, wildfire mitigation automatic adjustment clause, and Energy Trust of Oregon funding; (5) utilizing indexing to inform the revenue cap; and (6) using several performance incentive mechanisms (PIMs), including backstop PIMs (penalty-only), a limited set of additional PIMs to be considered, and exploring concepts such as equity and resilience for PIM metrics.	Docket No. AR 676	H.B. 3179 (2025)	S.B. 688 (2025)	Multi-Year Rate Plans Purpose and Design Considerations (Dec. 2025)	Straw Proposal (May 2026)
OR	Utility Oversight	Compliance Costs	In 2021, Oregon legislators enacted H.B. 2021, requiring electric companies to reduce greenhouse gas emissions associated with electricity sold. To help mitigate rate increases resulting from compliance with this bill, the legislature included a "cost cap" provision that allows electric utilities to be temporarily exempt from further compliance if the cumulative impact of their compliance costs on customer rates exceeds 6% in a given year. The components of the cost cap calculations include: (1) gross compliance cost impact on rates in the evaluation year; (2) impact on rates in the evaluation year of any costs or investments displaced by compliance costs or investments; (3) impact on rates in the evaluation year of any expected revenues from compliance costs or investments; and (4) projected annual revenue requirement for the evaluation year. This provision also established a process for the Oregon Public Utility Commission to determine the actual or anticipated cumulative rate impact of actions taken by an electric company to comply with H.B. 2021. On March 19, 2026, the Commission opened a rulemaking docket to define key elements of the cost cap evaluation and simplify assumptions to be made in such evaluations. The Commission Staff requested input on several topics, including: (1) how each of the four components of the cost cap calculation should be calculated; (2) what inputs to each component can be drawn from or based on Commission determinations in other proceedings; (3) how power costs should be accounted for; (4) how should any rules anticipate the impact of multi-year rate plans (Docket No. AR 676) on projections of annual revenue requirements; and (5) recognizing the imprecision of forecast, how should these components incorporate forecast uncertainty or ranges.	Docket No. AR 685				
OR	Utility Oversight	Rate Freezes	H.B. 4025, as enacted in March 2026, prevents any increase in the residential rates of a public utility that provides electricity from taking effect from November 1 to March 31, annually.	H.B. 4025 (E)				

State	Category	Sub-Topic(s)	Description	Source				
OR	Utility Oversight	Rate Freezes, Transparency	On September 29, 2025, the Oregon Public Utility Commission opened two concurrent dockets for the implementation of sections of H.B. 3179 (enacted in 2025) - AR 678 (rulemaking) and UM 2405 (investigation). The goal of these dockets is to adopt near-term guidance for utilities filing rate changes based on the changes required by H.B. 3179. These dockets will focus on the following provisions of H.B. 3179: (1) the prohibition on residential rate increases from November 1 - March 31; (2) general rate case impact analysis requirements; (3) the newly required annual visual representation of cost drivers; and (4) the requirement for utilities to submit reports on expected rate increases over the next 18 months at least annually. On October 9 and November 6, 2025, the Commission Staff published draft versions of these rules with minimal changes between the two filings. The draft rules address the residential rate cumulative economic impact analysis, the moratorium on residential rate increases, residential rate cost category disclosure, and annual rate adjustment forecast reporting. On November 25, 2025, the Commission approved the Staff's request to initiate a formal rulemaking on the winter rate moratorium, annual reporting schedule, and rate filing requirements in H.B. 3179. On March 17, 2026, the Commission issued an order adopting the new rules.	Docket No. AR 678	Draft Rules V2 (Nov. 2025)	Order (Nov. 2025)	Order (Mar. 2026)	
OR	Utility Oversight	Rate Freezes, Transparency	On September 29, 2025, the Oregon Public Utility Commission opened two concurrent dockets for the implementation of sections of H.B. 3179 (2025) - AR 678 (rulemaking) and UM 2405 (investigation). The goal of these dockets is to adopt near-term guidance for utilities filing rate changes based on the changes required by H.B. 3179. These dockets will focus on the following provisions of H.B. 3179, including: (1) the prohibition on residential rate increases from November 1 - March 31; (2) general rate case impact analysis requirements; (3) the newly required annual visual representation of cost drivers; and (4) the requirement for utilities to submit reports on expected rate increases over the next 18 months at least annually. On December 1, 2025, the Commission Staff published its Policy Investigation Work Plan. The plan will consist of three phases: Phase 1 will address the winter rate moratorium and will take place from March 2026 - May 2026; Phase 2 will address annual reporting and cumulative economic impact analysis and will take place from June 2026 - November 2026; and Phase 3 will be an evaluation of the effectiveness of the implementation process that will take place from January 2027 - March 2027. On May 21, 2026, the Commission Staff filed its Winter (November 1 - March 31) Moratorium Implementation (WMI) proposal. In this proposal, Commission Staff recommends: (1) using April 1 and October 31 as default effective dates for changes that affect residential bills; (2) permitting winter changes on a case-by-case basis where net residential bills decrease, where the proposed change otherwise results in less harm to customers, and in other circumstances where the facts support the conclusion that the proposed rate change does not constitute a rate increase; (3) limiting the use of deferrals and specifying interest treatment, move filing effective dates to avoid accruals between November and March; and (4) requiring predictable and transparent customer communications.	Docket No. UM 2405	Winter Moratorium Implementation Proposal (May 2026)			
PA	Customer Cost Allocation	Arrearage Management	On February 19, 2026, the Pennsylvania Public Utility Commission filed an instant rulemaking order incorporating arrearage provisions from Chapter 14, Title 66 of the Pennsylvania Public Utility Code, into the Commission's regulations, since the chapter sunset at the end of 2024. The order stated that the instant rulemaking did not serve as a general review of the regulations. Also on February 19, 2026, Vice Chair Kimberly Barrow filed a statement expressing dissatisfaction with the "copying and pasting" given the current landscape of affordability, and stating that seeking comments on several payment arrangement, termination, and fee-related topics for potential incorporation into the regulations would have been appreciated.	Docket No. L-2025-3058767				
PA	Customer Cost Allocation	Bill Assistance	H.B. 2150, as passed by the House in March 2026, creates data center reporting requirements, as well as a penalty of $10,000 per day until the data is reported. Penalties collected must be deposited into the low-income electric customer program of the electric distribution company for the service territory in which the data center in violation is located.	H.B. 2150 (P1)				
PA	Customer Cost Allocation	Bill Assistance	H.R. 350, as adopted in May 2026, notes uncertainty at the federal level regarding continued funding of LIHEAP and resolves that the Pennsylvania House of Representatives urges the President and Congress of the U.S. to continue to fund LIHEAP.	H.R. 350 (Adopted)				
PA	Customer Cost Allocation	Bill Assistance	In its 2024 rate case, Duquesne Light Company (DLC) entered into a settlement where the company agreed to hold at least one meeting to obtain feedback about the use of data from the Department of Human Services (DHS) for auto-enrollment into the Customer Assistance Program (CAP) and file a petition with a proposed process and time frame, as well as any amendments to its Universal Service and Energy Conservation Plan (USCEP) necessary to facilitate auto-enrollments within a year. On March 31, 2026, DLC filed a petition for approval of its plan to obtain data files from DHS LIHEAP grant recipients who have consented to share data and identify customers who are not currently enrolled in CAP. Eligible customers with a balance equal or greater to $250 will be automatically enrolled in CAP, while those with a balance less than $250 will be offered enrollment through a streamlined, consent-based process. Those on the auto-enrollment path will be given the opportunity to opt out, and those in the expedited enrollment path will receive information on how to provide consent to enroll. The petition also includes a process to use LIHEAP data to automatically recertify income for customers already enrolled in CAP and identify and contact customers who have defaulted from CAP and may be eligible for reinstatement. The petition outlines the proposed budget, timeline, and states that the proposal is in alignment with the auto-enrollment outlined in DLC's 2024 rate case. The Pennsylvania Public Utility Commission issued an order on June 18, 2026, approving expedited CAP enrollment and automatic CAP recertification for LIHEAP data sharing participants. However, the Commission did not approve DLC's petition to automatically enroll LIHEAP data sharing participants with an arrearage balance of $250 or more into the CAP; intead, the Commission will review this request after additional information and stakeholder comments are provided.	Docket No. R-2024-3046523	Order (June 2026)			
PA	Customer Cost Allocation	Bill Assistance, Cost Shift Prevention	H.B. 1834, as passed by the House in March 2026, establishes the data center LIHEAP enhancement account and directs the Pennsylvania Department of Human Services to use money appropriated from the account for a supplemental LIHEAP enhancement program, including a summer cooling component. By June 1 of each year, each commercial data center with an annual peak load of at least 25 MW will pay into the account, for the duration of the load, $40,000 per MW of annual peak load, up to and including 25 MW, and an additional $40,000 for each MW of annual peak load above 25 MW. The bill also requires the Pennsylvania Public Utility Commission to promulgate temporary regulations within 90 days of the effective date, and to promulgate permanent regulations within two years, pertaining to large load customers. The regulations must include retail tariff terms and conditions between a commercial data center and utilities related to financial security, contributions in aid of construction, minimum contract terms and minimum load, load ramping schedules, exit or early termination fees, threshold enforcement, utility cost tracking, curtailment through an interruptible rate, measures to limit the percentage that electric generation providers serve to large load customers, an end-of-contract process, requirements that large load customers contribute to the utility's service and energy conservation program, adoption of a rebuttable presumption for cost recovery, and minimum contract terms.	H.B. 1834 (P1)				
PA	Customer Cost Allocation	Bill Assistance, Cost Shift Prevention	On March 27, 2025, the Pennsylvania Public Utility Commission scheduled a hearing for late April 2025 to examine how data centers and other large-scale electric customers will impact the state's electric grid. Topics of interest include requirements of deposit or financial security for new large load customers, contract terms (e.g. exit fees, durations, phased-in usage schedules), interconnection matters (e.g. cost sharing, studies, agreements, and expedited process options), and best practices from other states and regions to develop a model tariff. The model tariff would be available to all electric distribution companies and would represent a preferred set of best practices based on the perspectives shared with the Commission. On April 30, 2026, the Commission filed a final order adopting the terms of a model tariff. The proposed tariff defines Large Load Customers as 50 MW individually or 100 MW in the aggregate. The tariff outlines a minimum contract length of five years and a load ramp up to five years. It includes a minimum demand charge of 80% of contracted demand and minimum load as outlined. Collateral requirements must be provided to cover network improvement costs and interconnection facilities costs, and may be provided in the form of a guarantee from the ultimate parent company, a letter of credit, or cash. The tariff further outlines an exit fee, which customers may avoid if they reduce demand by up to 20% of the initial contract term over at least five years. Customers must pay for full planning studies and interconnection studies. Customers must make an annual contribution to the company's universal service fund and are subject to a fee for interconnection facilities costs and network improvement costs through CIAC.	Docket No. M-2025-3054271	Pennsylvania PUC Press Release (Mar. 2025)	Order (Apr. 2026)		

State	Category	Sub-Topic(s)	Description	Source				
PA	Customer Cost Allocation	Bill Assistance, Disconnection Policies, Payment Plans	H.B. 2333, as passed by the House in April 2026, outlines provisions allowing for collection of security deposits from certain customers who have not established payment history, but also outlines payment arrangement and bill assistance provisions to support affordability. The bill outlines maximum lengths of payment arrangements for customers to resolve an unpaid balance: six years if the customer has a gross monthly household income level up to 150% of the federal poverty level, four years if the customer has a gross monthly household income level 150%-250% of the federal poverty level, two years if the customer has a gross monthly household income level 250-300% of the federal poverty level, and one year if the gross monthly household income level exceeds 300% of the federal poverty level. If a customer has an income level up to 300% of the federal poverty level and the customer's monthly payment would exceed 20% of the customer's average monthly bill based on the length of the payment arrangement, the Pennsylvania Public Utility Commission will extend the length of the payment so that the monthly payment does not exceed 20% of the customer's average monthly bill, not to exceed two times the length of the payment arrangement for the customer as outlined above. Pertaining to customer assistance programs, the bill provides that rates are not subject to Commission-issued payment arrangements; the Commission may issue a payment arrangement if a customer is not enrolled in the customer assistance program, even if the customer has arrears incurred while in the customer assistance program. Further, the bill directs public utilities to enter into a subsequent payment arrangement with a customer whose gross monthly income is less than 300% of the Federal Poverty Level, although the Commission may not otherwise order such a utility to enter into a subsequent payment with a customer who has defaulted on a previous payment arrangement established by a Commission order or decision. The bill further outlines protocols for service termination. Pertaining to extreme weather termination, after November 30 and before April 1, as well as after June 30 and before September 1, a public utility may not terminate service to customers with household incomes at or below 250% of the federal poverty level except where there is grounds for immediate termination as outlined in the bill; the Commission may not prohibit service termination for customers with household incomes over 250%. Further, a public utility may not terminate service on a day when the national weather service has issued a temperature-based warning for the country. Additionally, a public utility may not terminate service to a customer who is otherwise eligible for LIHEAP during a federal government shutdown that delays the disbursement of LIHEAP funding. A public utility also may not terminate service to a premises where a customer has submitted a medical certificate to the public utility. The bill also stipulates that a notice of termination will be sufficient proof of a crisis for a customer with the requisite income level to receive a LIHEAP crisis grant or utility assistance from the Department of Human Services. Pertaining to reconnection, utilities may not require a payment of reconnection fees as a condition of reconnection if the customer's income level is above 250% of the federal poverty level; if the customer's income level is between 250-400% of the federal poverty level, the reconnection fee will be included in the customer's rearreages. The bill outlines that a public utility may require payment on certain timelines for reconnection fees, with a full payment expected for customers with income exceeding 300% of the federal poverty level (or 3 additional months given a significant change in circumstances), payment over 12 months for those with incomes between 150-300% of the federal poverty level, and payment over 24 months for those with incomes up to 150% of the federal poverty level; a customer who is eligible for the utility's customer assistance program will be permitted to reconnect to services through enrollment in said program without any upfront payment of arrears. Additionally, the Commission may order a waiver of late payment charges levied by a utility as a result of a delinquent account for customers with a gross monthly income up to 150% of the federal poverty level. Finally, the bill outlines public utility responsibilities of providing information about the utility's universal service programs, referring the customer or applicant to the universal service program administrator to navigate eligibility and enrollment, attempt to collect payment on an overdue account, and report the number of medical certificates. The utility will take such actions if a customer contacts the public utility to make a payment agreement, the public utility has information that indicates the customer is or was payment troubled, or receives information that a customer's or applicant's household may qualify the customer for a universal service and energy conservation program. The provisions will terminate on December 31, 2026.	H.B. 2333 (P1)				
PA	Customer Cost Allocation, Utility Oversight	Arrearage Management, Bill Assistance, Cost Recovery, Cost Shift Prevention, Payment Plans, Transparency	On September 30, 2025, PPL Electric filed a request to increase its rates. In its application, PPL also proposed making revisions to Rate Schedule LP-5 to mirror what the utility claims it is currently requiring in its electric service agreement (ESA) process with large customers. These provisions include security instruments for line extension costs in the form of a credit, surety bond, parent guarantee, or other acceptable instrument. Throughout the proposed rate increase investigation, public input at hearings strongly reflected electricity affordability concerns. On March 13, 2026, a non-unanimous settlement agreement was filed on behalf of several active parties. In the non-unanimous settlement, PPL agreed to define a confirmed low-income customer to also include any customer who has received a LIHEAP grant within the current or immediately preceding two LIHEAP years, as well as any customer who has participated in its Customer Assistance Program (CAP) within the last year. Beginning January 1, 2027, before entering into a deferred payment arrangement (DPA) with a customer, PPL will provide customers that are either (1) a confirmed low-income customer or (2) has generated information through the DPA process documenting that the customer is in the Tier 1 income range (up to 150% of the federal poverty level (FPL)), with plain language information on CAP and its arrearage forgiveness benefits. Before January 1, 2027, PPL will increase its maximum CAP credits based on FPL tier and heating account classification. PPL also agreed to propose an adjustment to the maximum CAP credit thresholds in its next filed rate case or default service petition to account for proposed adjustments in rates. Further, by January 1, 2027, PPL will increase its Low Income Usage Reduction Program (LIURP) annual budget by $1.5 million and agreed to rollover any unspent budget. By July 1, 2027, PPL agreed to develop and implement a new process to screen new and moving customers, as well as existing customers that have not been screened in the last six months, to be referred to the CAP application process and any other universal service programs. The CAP participation threshold for determining when to start applying the $100 credit will be increased fro 44,000 to 75,000. PPL also agreed to streamline CAP enrollment, including temporary holds to allow for CAP enrollment, allowing for reconnection without upfront payment of arrears or reconnection fees upon successful enrollment into CAP within a certain window, and using LIHEAP data for CAP enrollment. PPL will also revise its CAP bill review process to ensure customers are receiving the most advantageous rates, waive reconnection fees for all customers at or below 150% FPL by July 1, 2027, and revise cash and security deposit procedures for low-income customers. Outside of the CAP program, PPL agreed not to raise distribution base rates for two years after the effective date, also referred to as a two year "stay-out" period. The utility also agreed to provide updates on actual capital expenditures, plant additions, and retirements for future test years and present in its next rate case a comparison of actual figures compared to projections from this case. PPL further agreed to maintain rather than phase out Rate RTS, which is no longer open to new customers, which will sustain lower rates for 1,300 confirmed low-income customers. Further, the utility's distribution service improvement charge may not include new plant additions until the end of June 30, 2027 or when net electric plant in service exceeds the projection for the date of June 30, 2027. PPL did not include any of the above provisions in its proposed modifications to LP-5, instead incorporating such provisions into a proposed new LP-6 rate class for customers with a peak demand of 50 MW for a single facility or 75 MW in aggregate, where ESAs require security equal to the cost of upgrades that are needed to serve the customer, placed into rate base, and recovered through transmission rates (known as the "Rate Base Security Obligation"). Once the Rate Base Obligation has been satisfied, customers pay a rate based on a minimum bill based on 80% of the load provided in the load ramp schedule for the first five years and 50% in the second five years. Contribution in aid of construction (CIAC) is required for directly assignable transmission and distribution upgrades. Finally, there is an exit fee equal to the lesser of equal to the greater of the remaining minimum load guarantee obligation or the remaining Rate Base Security Obligation. The utility proposed to only modify LP-5 to allow companies with under 50 MW of peak demand or those subject to certain exemptions under the settlement to request that the utility construct, own, operate, and/or maintain the customer's transformation equipment. Further, the settlement added language that the relevant terms and rates will include provisions ensuring that no costs associated with owning, operating, and maintaining the customer transformation equipment will be recovered from other customers. On April 17, 2026, the ALJs recommended that the Pennsylvania Public Utility Commission adopt the non-unanimous settlement without modification. On June 11, 2026, the Commission filed an order adopting the ALJ's recommendation without modification to the above provisions.	Docket No. R-2025-3057164	Order (June 2026)			

State	Category	Sub-Topic(s)	Description	Source				
PA	Customer Cost Allocation, Utility Oversight	Bill Assistance, Monitoring	On March 26, 2026, at a Pennsylvania Public Utility Commission public meeting, Commissioners voted to approve, as modified, a settlement to resolve a formal complaint that the Commission's Bureau of Investigation & Enforcement filed against FirstEnergy Pennsylvania - West Penn Power surrounding service termination and a resident passing away at the service address in the days following. The complaint alleged that West Penn violated Commission regulations by terminating service at a residence during a winter moratorium without first determining if the resident fell under 250% of the federal poverty level, failing to fully provide the resident with information about the utility's universal service programming and enrollment eligibility, and failing to fully explain the medical emergency procedures to the resident. Through the initial settlement, West Penn agreed to pay a $30,000 civil penalty, contribute $15,000 to the hardship fund contribution to Dollar Energy Fund, and commit to enhance training and improve customer income review. On January 27, 2026, the ALJ found the settlement to be reasonable. In its March 26, 2026 vote and tentative order, the Commission disagreed with the ALJ's determination and found that West Penn should pay a $60,000 civil penalty and make a $30,000 contribution to the hardship fund. Since no adverse comments were filed following the tentative order, the order became final.	Docket Number C-2024-3052650	Order (Mar. 2026)			
PA	Customer Cost Allocation, Utility Oversight	Disconnection Policies, Rate Increase Withdrawal	On March 31, 2026, PECO filed an application to increase its electric rates, including a revision to its tariffs stipulating that beginning in April 2028, the utility will waive the $20 Electric Remote Reconnect fee for all customers who were disconnected due to nonpayment and who have demonstrated household gross income at or below 150% of the Federal Poverty Level. In April 2026, several parties, including the Tenant Union Representative Network and the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania (TURN/CAUSE-PA), filed formal complaints and statements in opposition to the PECO electric rate filing. Further, the Southeast Delegation of the Pennsylvania House Democratic Caucus submitted a letter to the Commission Chairman opposing the application and a Pennsylvania state Senator submitted a letter to the Commission Chairman requesting that the application be suspended and investigated. Additionally, Governor Shapiro's office reported directly engaging with PECO and directing the utility to withdraw the rate case filing. On April 16, 2026, PECO filed a petition to withdraw its applications and to maintain electric distribution rates at the current level, stating that the company recognizes the importance of affordability for its stakeholders. On April 30, 2026, the Pennsylvania Public Utility Commission approved the petition to withdraw, stating that granting the petition will avoid unnecessary litigation costs and administrative burden.	Docket No. R-2026-3060859	Order (Apr. 2026)	Governor's Press Release (Apr. 2026)		
PA	Customer Cost-Saving Programs	Education, LMI Incentives	On December 1, 2025, Duquesne Light Company (DLC) filed its Phase V Energy Efficiency & Conservation Plan. The plan includes a Low-Income Energy Efficiency Program (LIEEP), which will provide energy assessments, customer education, and direct install and comprehensive energy saving measures. The plan also includes a Low-Income Behavioral Energy Efficiency Program (LI-BEEP), which will provide education about potential energy efficiency bill savings and work to change household energy behavior to deliver energy savings. On February 13, 2026, the joint petitioners filed a joint settlement. DLC agreed to work with implementers to include low-income program and enrollment information in all Residential Behavioral Energy Efficiency Program communications. DLC also agreed to add a $600,000 health and safety remediation program to its plan, funded through the existing LIEEP budget, as well as enhanced LIEEP outcome reporting. In the Commission's March 26, 2026 order, it found that the low-income portion of DLC's plan, as modified by the settlement, should be adopted.	Docket Number M-2025-3057325	Order (Mar. 2026)			
PA	Customer Cost-Saving Programs	Education, LMI Incentives	On November 9, 2025, FirstEnergy Pennsylvania filed its Phase V Energy Efficiency & Conservation Plan. To meet a requirement that savings counted towards a low-income savings carve-out come from specific low-income programs or low-income verified participants in multifamily housing programs, the Phase V Plan includes both a low-income program and a multifamily housing offering that will also serve low-income customers.The low-income sub-sector of the residential sector includes customized home energy reports, online energy audits, and education and outreach. The utility also plans to achieve new and incremental savings through its existing Low-Income Usage Reduction Program (LIURP). The program includes promoting the purchase and installation of certain efficient products, incentivizing certain energy efficient space and water heating equipment, braided funding audits, a behavioral education component, multifamily offerings, new home offerings for income-qualified housing, and weatherization. On February 20, 2026, the joint petitioners filed a settlement agreement. Pertaining to the residential low-income program, the utility agrees to target decreases from its low-income behavioral component and its low-income products component by 2,500 MWh in the aggregate and a 2,500 MWh increase from its low-income weatherization component and/or low-income multifamily program. It also agrees to pursue health and safety remediation with other available programs or to provide a portion of its program budget to such efforts if other program funds are not available. Further, it agrees to target spending of at least $600,000 per year on health and safety remediations for low-income households, subject to available program funding. Finally, it agrees to continue implementing and operating its low-income programs throughout the full duration of Phase V even if it meets its low-income carveout before the end of the phase. Pertaining to the multifamily sector, the utility agrees that within 150 days of plan approval, it will disseminate program materials to multifamily property managers and review its landlord consent protocols. It also agrees to clarify the incentive structure for eligible measures; for master-metered and individually-metered multifamily buildings, the utility will provide an enhanced incentive of up to 80% in common areas and 100% in low-income tenant spaces, and the utility will cover up to 80% of the cost of an ASHRAE Level 2 Audit. In its March 12, 2026 order, the Commission found that the low-income portion of the plan meets the program requirements and that the low-income portion of the plan, as modified by the settlement, should be adopted.	Docket Number M-2025-3057327	Order (Mar. 2026)			
PA	Customer Cost-Saving Programs	Education, LMI Incentives	On December 1, 2025, PECO filed its Phase V Energy Efficiency & Conservation Plan. The residential low-income subprogram provides in-home audits and education, as well as direct installation of energy efficiency measures at no charge to the participant and appliance recycling services. On February 24, 2026, the joint petitioners filed a settlement agreement, including a comparison of the original and revised plan design for comprehensive low-income measure spending. The utility agreed to adjust the plan design to increase the low-income comprehensive measure spending by $2 million by reallocating funds from non-comprehensive measures. The low-income section settlement provisions call for increased outreach to low-income customers, including through the Customer Assistance Program (CAP). In its March 26, 2026 order, the Commission found that the low-income portion of the plan meets the program requirements and that the low-income portion of the plan, as modified by the settlement, should be adopted.	Docket Number M-2025-3057328	Order (Mar. 2026)			
PA	Customer Cost-Saving Programs	Education, LMI Incentives	On December 1, 2025, PPL Electric filed its Phase V Energy Efficiency & Conservation Plan. The Resource Constrained (Low-Income) Program includes energy efficient homes, appliance recycling, and student energy education components. Resource-constrained customers will be offered similar measure offerings as the residential energy efficiency program, but at no cost. Further, the program includes $1.5 million for health and safety upgrades to enable comprehensive measures. On February 13, 2026, the joint petitioners filed a settlement agreement, including Resource Constrained Energy Efficiency Program modifications. PPL agreed to increase the budget for long-term savings measures from $7.5 million to $9.0 million, modify outreach and education for coordination between the energy efficiency and appliance recycling components, remove the student energy education component and reallocate funds to the energy efficient home component, and allocate $2 million or additional funding as needed for health and safety repairs. On March 26, 2026, the Commission filed an order finding that the low-income program components, as modified by the settlement comply with low-income program requirements.	Docket Number M-2025-3057329	Order (Mar. 2026)			
PA	Customer Cost-Saving Programs	Financing	H.B. 2347, as passed by the House in May 2026, redesignates the Energy Development Authority to the Energy Financing Authority and adds to the Authority's annual report considering assistance to LMI individuals and disadvantaged communities.	H.B. 2347 (P1)				

State	Category	Sub-Topic(s)	Description	Source				
PA	Planning and Procurement	Advanced Transmission Technologies	H.B. 2223, as passed by the House in May 2026, adds a requirement to consider advanced transmission technologies (ATTs) in certain applications relating to Pennsylvania Public Utility Commission review of siting and construction of electric transmission lines. Applicants must provide a report showing that they evaluated and assessed the use of ATTs for existing transmission infrastructure and proposed transmission infrastructure in the application, including infrastructure for which the proposed voltage would be increased above the existing levels and infrastructure that would be reconductored or reconstructed. The Commission may order the applicant to integrate ATTs to help partially or fully resolve the need identified in the application as a condition of approval. Within a year of the effective date, the Commission will adopt policies specifying the ATT assessment requirements and methods that must be used. ATTs are defined as grid-enhancing technologies such as dynamic line rating, advanced power flow controllers and topology optimization software, high-performance conductors, and any other technology identified by the Commission that increases the capacity, efficiency, reliability, or safety of a transmission system.	H.B. 2223 (P1)				
PA	Planning and Procurement, Utility Business Model, Utility Oversight	Innovative Financing, Return on Equity Rules, Transparency	On April 29, 2026, Governor Josh Shapiro filed a letter to utility leaders regarding utility bill affordability and laying out three recommended practices. First, utilities should seek to raise the most cost-effective forms of capital and favoring lower-cost debt over expensive equity; the Governor recommended applying to the U.S. Department of Energy for favorable loans. Additionally, the Governor stated that any equity share proposed in a rate case above the amount of equity employed by the utility's holding company would require extraordinary justification. Second, whenever new revenue is sought, a utility should explain in plan language why its proposed investments are necessary, using transparent data or cost-benefit analysis to demonstrate safety, reliability, or cost savings. Further, utilities should describe what amount of requested rate increase will be remitted to shareholders through corporate dividends or other means compared to what would be used directly to advance customer needs. Third, utilities should provide transparent, justifiable equity returns. To do this, utilities can prove their need for a requested return on equity by providing a benchmark, representing at least 10% of the incremental requested equity, that derived through a public competitive bidding process with multiple participants. Alternatively, the utility can request a return on equity that does not exceed the rate of the current 10-year U.S. Treasury yield plus the five-year median of the equity risk premium as published in the Federal Reserve 's Financial Stability Reports. The Governor's recommendations are non-binding, but utilities are encouraged to submit a demonstration of their compliance with the practices in future rate request to gain support from the Shapiro administration.	Governor of Pennsylvania Letter (Apr. 2026)				
PA	Utility Business Model, Utility Oversight	Return on Equity Rules	H.B. 2224, as passed by the House in June 2026, outlines new return on equity requirements for investor-owned utilities regulated by the Pennsylvania Public Utility Commission ("covered utilities"), set either by a competitive auction or at the authorized return on a covered utility's common equity equal to the sum of the 10-year treasury and 2%. The default authorized rate of return on equity will apply to each regulated service of a covered utility immediately on the effective date, regardless of whether a rate proceeding related to voluntary changes in rates is pending and when a rate proceeding was last concluded. A rate component reflecting or permitting an authorized return may no longer be considered just and reasonable, except to the extent established through a competitive equity auction. Within 60 days of the effective date, the Commission must issue an order for each covered utility setting the authorized return on equity. Within 120 days, the Commission must implement corresponding adjustments to customer rates through the Commission's most expedient mechanism, including a surcharge or credit. The Commission must also implement a true-up adjustment for the period between the effective date of the bill and the date that the adjusted rates take effect. A covered utility that believes the default authorized return is insufficient to attract capital may petition the Commission for a competitive equity auction. The return on equity provisions do not preclude performance-based ratemaking, but the performance-based ratemaking plan may not permit the aggregate effect of performance-based adjustments to increase the utility's realized return on equity by more than 2% above the authorized return on equity. The bill also requires annual report outlining each utility's requested return on equity, rate of return, and capitalization mix in the most recent rate case, the approved return on equity, the results of any competitive return on equity auctions, an analysis of the impact on average customer rates resulting from implementation, and a description of how returns on equity have changed.	H.B. 2224 (P1)				
PR	Utility Business Model	Performance Incentive Mechanisms	On March 2, 2026, PREPA filed its Energy Efficiency and Demand Response Three Year Plan, covering FY2027 and FY2028. On March 24, 2026, the Puerto Rico Energy Bureau (NEPR) ordered PREPA to file proposed performance incentive mechanisms (PIMs) and associated targets for its plan. On April 20, 2026, PREPA filed its PIMs proposal, recommending using the same performance metrics originally established for its T&D System Operation and Maintenance Agreement with LUMA in 2022: energy savings as a percentage of total energy sales and peak demand savings as a percentage of total peak demand.	Docket No. NEPR-MI-2026-0002				
PR	Utility Business Model	Revenue Decoupling	On February 27, 2025, the Puerto Rico Energy Bureau (NEPR), as part of a general rate case, ordered PREPA to file a temporary revenue-decoupling mechanism to accompany its permanent rates. The mechanism should reconcile at least semiannually. PREPA filed its formal application on July 3, 2025. PREPA proposed a revenue decoupling mechanism to apply in FY2028, to reconcile revenues from FY2027. NEPR filed an order on April 15, 2026, adopting the mechanism with minor changes.	Docket No. NEPR-AP-2023-0003	Order (Apr. 2026)			
PR	Utility Oversight	Audits, Rate Freezes	R.C.C. 243, as passed by the House in November 2025, is a joint resolution imposing a 24-month moratorium during which the Puerto Rico Energy Bureau (NEPR) cannot consider increases to PREPA's rates. During the moratorium, all ongoing tariff proceedings will be suspended. NEPR can still evaluate or authorize tariff revisions that result in adjustments or reductions that favor consumers, along with adjustments to fuel or energy costs in response to market prices. After the moratorium ends, NEPR will perform a public and independent audit of the electric tariff system that must include: (1) revisions to PREPA's reports on operational and administrative costs, (2) an evaluation of the reasonability of automatic adjustments for fuel and energy costs, (3) a verification of operator compliance with performance metrics, and (4) the identification of corrective or structural measures that reduce tariff impact on consumers. NEPR must provide an interim report to the legislature after the first 12 months of the moratorium and a final report after the second 12 months with their discoveries, conclusions, and recommendations for public policy.	R.C.C. 243 (P1)				
RI	Customer Cost Allocation	Low-Income Discount Rates	As part of a general rate case filed on November 26, 2025, RI Energy proposed lexical changes to its Low Income Rate A-60. The changes add clarifying information and reorganize the tariff for ease of understanding. During the proceeding, the utility and other participants agreed to review the structure of the rate and make revisions to improve its impact. Rate A-60 is currently two-tiered, with customers enrolled in Supplemental Security Income, LIHEAP, or SNAP receiving a 25% bill discount, and customers enrolled in Medicaid, General Public Assistance, or the Rhode Island Works Program receiving a 30% bill discount. On June 3, 2026, RI Energy filed a settlement agreement specifically for Rate A-60. Rate A-60 would shift from two tiers to five tiers: a 75% bill discount for households at 0-50% of the federal poverty limit, a 66% bill discount for households at 50-75% of the federal poverty limit, a 56% bill discount for households at 75-100% of the federal poverty limit, a 38% bill discount for households at 100-150% of the federal poverty limit, and a 10% bill discount for households at 150-250% of the federal poverty limit. There would be no changes to the eligibility criteria or participation requirements, but all budget-billing eligible customers must be offered budget billing when (re-)enrolling in Rate A-60.	Docket No. 25-45-GE	Settlement Agreement (June 2026)			

State	Category	Sub-Topic(s)	Description	Source				
RI	Customer Cost Allocation, Studies & Investigations, Utility Oversight	Cost Shift Prevention, Transparency	Executive Order 1, signed by the Governor in early February 2026, is titled Reducing Energy Costs and Improving Transparency. The executive order requires the Rhode Island Office of Energy Resources to conduct a comprehensive review of the state's net metering program (behind-the-meter and virtual) and the Renewable Energy Growth Program; the goal of the review is to control costs to ratepayers and ensure the programs do not impose and undue financial burden on households and businesses while remaining aligned with the state's emission reduction policies. The review should evaluate ratepayer impacts, state fiscal implications, and energy-system effects, assessing potential program modifications when appropriate. As part of this review, the Office must submit proposed budget changes regarding virtual net metering program to the Governor and the Office of Management and Budget by April 24, 2026; the changes should maintain ratepayer savings while updating the structure of the program, avoiding adverse impacts on existing solar projects and considering approaches used by other states to maintain cost-effective solar incentives. In addition, the Office must complete a longer-term review of behind-the-meter net metering and the Renewable Energy Growth Program, providing key findings and potential policy and legislative options to the Governor and the Office of Management and Budget by October 2026. The executive order also directs the Rhode Island Department of Public Utilities and Carriers to evaluate and communicate the anticipated ratepayer impacts of all significant energy legislation under consideration by the General Assembly to ensure that policymakers, stakeholders, and the public have a clear and timely understanding of the potential effects on utility rates, customer bills, and overall energy affordability. As part of the process, the Department must determine which proposed legislation is sufficiently broad in scope, material in ratepayer impact, or sufficiently advanced in the legislative process to warrant an official Ratepayer Impact Note. The Department must: (1) develop an internal framework for Ratepayer Impact Notes, (2) establish a legislative notification and coordination process to ensure Ratepayer Impact Notes are available to legislators, and (3) establish a process to provide plain-language impact summaries of relevant legislative proposals on its website.	Executive Order 1				
RI	Utility Oversight	Monitoring	**Background:** In October 2025, RI Energy filed an application to issue bill credits to hold customers harmless from an acquisition-related increase in rates; specifically, the credits will ensure customers are held harmless from any changes to accumulated deferred income taxes as a result of PPL Corporation's acquisition of RI Energy from National Grid in 2022. The utility withdrew its application in November 2025 due to concerns that arose during the pre-hearing process. **Recent Action:** On April 16, 2026, RI Energy re-filed its application with a revised tariff. All customers - gas and electric - would receive credits in January, February, and March of 2027 and 2028. The total amount of credits RI Energy issues would be based on the net present value of the hold harmless commitment; within that total amount, each customer would receive the same bill credit value within a month. RI Energy would reconcile any leftover total credit in the March 2028 bill. On the same day, the Rhode Island Public Utilities Commission consolidated this docket into RI Energy's ongoing general rate case.	Docket No. 25-33-GE	Docket No. 25-45-GE			
RI	Utility Oversight	Return on Equity Rules	H.B. 7127, an appropriations bill enacted in June 2026, requires utilities to participate in ISO-New England in order to own, operate, or control transmission facilities in the state. Because current utility participation is voluntary, utilities are eligible for a 0.5% adder on their return on equity for transmission assets. By mandating participation, utilities are no longer eligible for the adder.	H.B. 7127 (E)				
SC	Customer Cost Allocation	Cost Shift Prevention	On May 27, 2026, Duke Energy Progress and Duke Energy Carolinas filed a petition with the South Carolina Public Service Commission to open a docket allowing comment and investigation into the creation of a large load tariff. This petition comes in response to stipulations in Docket No. 2025-154-E providing that the parties to the stipulation (the utilities and intervenors) would work together to file a "Petition with the Commission requesting that the Commission open a generic docket for the purpose of evaluating issues associated with new large load (50 MW or greater) additions including existing rate schedules, service regulations, line extension policies, and interconnection rules," and requesting "that the Commission allow interested parties to file or otherwise present comments on topics related to new large load customers." The topics to be covered in this docket include: (1) minimum contract period and contract demand for billing purposes; (2) collateral requirements; (3) exit policies and restrictions on customer capacity reduction; (4) treatment of generation, transmission, and administrative costs; (5) interconnection costs, including opportunities to support grid-enhancing technologies to manage such costs; (6) optional tariff provisions for flexible interconnections; and (7) optional tariff provisions for the management of clean behind-the-meter resources, and optional clean transition tariffs to enable direct selection of new clean energy resources.	Docket No. 2026-138-E				
SD	Customer Cost Allocation	Cost Shift Prevention	H.B. 1038, as signed by the Governor in March 2026, allows the South Dakota Public Utilities Commission to assess the actual costs associated with processing a request for approval of contract with deviations, or other electric service agreement with a public utility, related to the provision of electric service to a customer that is a data center with a peak demand of at least 10 MW.	H.B. 1038 (E)				
SD	Customer Cost Allocation	Cost Shift Prevention	S.B. 135, as signed by the Governor in March 2026, requires a provider of electricity to establish and maintain separate terms and conditions for electric service applicable to a data center. These terms must require the data center reimburse any electricity provider for all costs fairly attributed to the center for service demand and utility consumption, including costs incurred to serve the center if the center departs the system or materially reduces its load.	S.B. 135 (E)				
TN	Customer Cost Allocation	Cost Shift Prevention	H.B. 1847, as enacted in May 2026, reshapes how large data centers pay for the infrastructure that supports them. The bill requires owners and operators of data centers with a peak demand of at least 50 MW during their first three years, including new builds and expansions, to cover the full cost of the infrastructure that serves them, such as transmission lines, substations, transformers, and related power supply resources. The bill also preserves some flexibility for utilities by allowing them to allocate a portion of infrastructure costs to broader system improvements, but only when those upgrades go beyond what the data center alone requires, can benefit other customers without reducing existing service levels, involve infrastructure not originally funded by the utility, and are allocated in line with established contribution-in-aid-of-construction policies or similar practices.	H.B. 1847 (E)				
TX	Customer Cost Allocation	Cost Shift Prevention	On April 7, 2026, El Paso Electric (EPE) filed an application for a new High Load Factor Large Power Service Rate for very large data center or advanced manufacturing customers with an annual peak demand of 75 MW or larger and an annual load factor of at least 85%. The rate is based on EPE's existing Economic Development Service Rates (Schedules 33A and 33B), approved last year; if this new rate is approved, then EPE requests Schedule 33A for larger customers be terminated. The tariff includes a provision for cost recovery associated with "dedicated" facilities via a facility charge, which would likely be transmission facilities only used by the participating customer; the value of the facility charge would be determined in the service agreement. Customers can also participate in the Green Energy Plus Tariff, which allows them to enter procurement agreements with EPE or a third party for renewable resources, with all costs associated with the resources borne by the customer. Energy from these systems would either offset the customer's load requirements (using a 15-minute netting interval) or be supplied to other customers at EPE's avoided cost. The customer would retain any RECs or environmental attributes.	Docket No. 59611				
UT	Customer Cost Allocation	Cost Shift Prevention	On May 9, 2025, the Utah Public Service Commission initiated a rulemaking proceeding as ordered by S.B. 132 (enacted in 2025), which created requirements for providing electrical service to large-scale electrical loads. The Commission filed proposed rules in October 2025. The rules describe the allocation of transmission costs between large load customers and retail customers for large load contracts, the Commission's review process for large load contracts, and a large-scale generation provider's registration and registration status with the Commission. In December 2025, numerous stakeholders filed additional comments either supporting implementation of the rules or recommending certain revisions to the rules. While S.B. 132 required the Commission to make the rules effective January 1, 2026, the Commission believes the comments it received warrant additional consideration. Therefore, the Commission will continue the rulemaking to consider potential amendments. The Commission consolidated this proceeding with Docket No. 24-035-43 and held a technical conference on April 2, 2026.	Docket No. 25-R318-01	S.B. 132 (2025)	Proposed Rules (Oct. 2025)		

State	Category	Sub-Topic(s)	Description	Source				
VA	Customer Cost Allocation	Cost Shift Prevention	On March 24, 2025, Appalachian Power Company filed a petition to update its Rate Schedule Large Power Service (L.P.S.), a large load tariff. The utility is proposing to add additional requirements to Schedule L.P.S. that will be applicable to new large load additions greater than or equal to 150 MW on an aggregated basis or 100 MW at an individual site ("large load customers"). Specifically, Appalachian seeks to add the following additional terms and conditions applicable to these customers: (1) a contract term for an initial period of 12 years; (2) a minimum five-year notice to discontinue or modify service; (3) an 80% monthly minimum billing demand; and (4) an increased minimum amount of collateral to be provided by the customer. On November 10, 2025, the parties in the case proposed the following stipulation terms: (1) the new terms of Schedule L.P.S. will not apply to existing large loads and only new loads or newly expanded loads of at least 100 MW or 150 MW in aggregate will be subject to the new terms; (2) the initial contract term will be 14 years, inclusive of the load ramp period; (3) the monthly billing demand is the highest 30-minute peak; (4) customers are subject to a monthly minimum charge; (5) the collateral requirement is as proposed in the petition; and (6) the customers have increased contractual flexibility, such as no fee for reducing load in the first five years and a minimum of 42 months notice for ending the contract. On June 1, 2026, the Virginia State Corporation Commission filed an order approving the changes to Schedule L.P.S. outlined in the stipulation.	Docket No. PUR-2025-00057	Stipulation (Nov. 2025)	Order (June 2026)		
VA	Customer Cost Allocation	Cost Shift Prevention	As part of its rate case filed on February 27, 2026, Old Dominion Power Company proposed a number of changes to its rates. Significantly, these changes include a proposed Extremely High Load Factor rate schedule (a large load tariff). Rate EHLF has the following characteristics: (1) customers with a contract capacity greater than 50 MVA and an average monthly load factor above 85% would take service under Rate EHLF. Because extremely high load factor customers' demands would not change appreciably across various times of day or seasons by definition, Rate EHLF has a single, non-time-differentiated demand charge to recover all demand-related costs of service; (2) rate EHLF requires the monthly billing demand to be the greater of (a) the maximum measured load in the billing period, (b) the highest measured load in the preceding eleven billing periods, or (c) 80% of the maximum contract capacity; (3) rate EHLF requires a minimum initial contract term of 15 years; (4) each Rate EHLF customer or its guarantor must provide collateral in the form of cash or a letter of credit equal to 24 months of the minimum billed amounts at the largest contract capacity value. Rate EHLF will not apply to existing customers.	Docket No. PUR-2026-00051				
VA	Customer Cost Allocation	Disconnection Policies	H.B. 898, signed into law in April 2026, directs the State Corporation Commission to determine, in the next relevant cost recovery proceeding, the maximum allowable amount of fees for disconnection and reconnection such utilities may charge to residential customers disconnected from service due to non-payment of bills or fees.	H.B. 898 (E)				
VA	Customer Cost Allocation	Disconnection Policies	H.B. 1002, signed into law in April 2026, requires utilities to provide notices of disconnection for nonpayment in an additional language for customers residing in a locality that also requires official communications in an additional language. The bill also prohibits certain utilities from disconnecting a residential customer without making reasonable efforts to offer bill payment assistance, arrange a payment plan, or provide information to the customer for other bill payment assistance or energy savings programs.	H.B. 1002 (E)				
VA	Customer Cost Allocation	Payment Plans	H.B. 884, signed into law in April 2026, amends the goals of the Percentage of Income Payment Program (PIPP) by reducing the percentage of eligible customers' bills that they must pay. For customers whose heating source is other than electricity, their electric bill payments are reduced from 10% to 5% of their annual household income. For customers whose heating source is electricity, their electric bill payments are reduced from 6% to 3% of their annual household income. The bill also amends the eligibility criteria of the program, beginning January 1, 2027, to include any retail electric customer of Dominion Energy or Appalachian Power with a household income at or below 200% of the federal poverty level.	H.B. 884 (E)				
VA	Customer Cost Allocation, Utility Oversight	Bill Assistance, Cost Recovery, Cost Shift Prevention, Securitization	H.B. 1393 and S.B. 253, signed into law in May 2026, amend annual funding commitments for the annual pilot program for energy assistance and weatherization for low-income, elderly, and disabled individuals conducted by Dominion Energy Virginia and Appalachian Power Company. Appalachian Power is required to continue its pilot program at no less than $1 million and no greater than $1.5 million annually. Dominion Energy is required to continue its pilot program at no less than $156 million and no greater than $204 million for the time period beginning July 1, 2026, and ending July 1, 2038. The bill extends the sunset date of such pilot programs from July 1, 2028, to July 1, 2038. The bills also allow Dominion Energy to recover costs associated with certain electrical facilities that have been approved by the State Corporation Commission as of December 1, 2033, provided that certain requirements are met and notwithstanding any limitations on such cost recovery in current law. The bills direct Dominion Energy to propose to the Commission, in any proceeding to determine rates for generation and distribution services commencing after January 1, 2027, and before July 1, 2033, that certain costs related to capacity procurement requirements and distribution infrastructure investments are allocated to the utility's customer class approved to serve customers with a contracted or measured electric demand of 25 MW or greater and an anticipated or measured average annual electric load factor of 75% or greater. The bill provides that certain customers in manufacturing, industrial, or consumer goods warehousing and distribution activities other than data storage may elect to remain on their existing rate schedule. The bills require the Commission to only approve such proposal if it determines that such tariff will not adversely affect other retail customers or the utility in a manner contrary to the public interest, and any revised tariff terms shall include protections against stranded cost risks to the utility customer base. Additionally, the bill authorizes Dominion Energy to file a petition for the securitization of certain deferred fuel costs.	H.B. 1393 (E)	S.B. 253 (E)			
VA	Customer Cost-Saving Programs	LMI Community Solar	H.B. 807 and S.B. 254, signed into law in April 2026, increase the program capacity limit for part two of Dominion Energy's community solar program from 150 MW to 525 MW. Of this total, 450 MW must serve no more than 51% low-income customers and 75 MW may serve more than 51% low-income customers. On or before the date when 268 MW of capacity under part two is substantially complete, Dominion Energy must petition the State Corporation Commission to initiate a proceeding to further expand community solar program capacity in a part three of the program. In considering part three, the Commission must evaluate the costs and benefits of the shared solar program, including the aggregate impact of the community solar program on Dominion's long-term marginal costs for generation, distribution, and transmission services. The Governor signed the bills in April 2026.	H.B. 807 (E)	S.B. 254 (E)			
VA	Customer Cost-Saving Programs	LMI DER Programs	H.B. 1062 and S.B. 327, signed into law in April 2026, require American Electric Power and Dominion Energy Virginia to petition the State Corporation Commission by December 31, 2026, to conduct a pilot program for electric energy conservation, solar energy generation, and energy storage resources for low-income, elderly, and disabled individuals. The bills direct the Commission to convene a technical conference to evaluate the creation of an energy efficiency program meeting certain requirements by November 1, 2026. Under the bills, if the Commission determines that such a program is feasible for implementation by American Electric Power and Dominion Energy Virginia, the Commission shall require such utilities to petition for approval by May 1, 2027, to implement such programs. The bill expires July 1, 2034.	H.B. 1062 (E)	S.B. 327 (E)			
VA	Customer Cost-Saving Programs	LMI Incentives	On December 1, 2025, Dominion Energy filed an application for approval of updates to its Demand Side Management (DSM) programs. As a result, the utility is requesting additional program funds for a three-year extension period for its residential and non-residential Income and Age Qualifying (IAQ) DSM programs. The proposed Residential Home Energy Services (EE) Program offers a comprehensive and unified residential home energy evaluation program offering, consisting of a no-cost introductory in-home energy audit, no-cost virtual audit, no-cost welcome kits, and an optional comprehensive Building Performance Institute audit. The proposed program will also be available for qualifying residential customers residing in manufactured housing and multifamily dwellings. The Residential Home Energy Services Program also consolidates five previously standalone program offerings, including Welcome Kits, Virtual Audit, Retrofit, Multifamily, and Manufactured Housing. Beyond these two extensions, the filing also proposes several new pilot programs specifically targeting IAQ customers: Residential IAQ Battery Storage Pilot, which incentivizes IAQ customers to discharge home battery systems during peak demand events to support grid reliability; and the Residential IAQ Battery Purchase Pilot, which provides IAQ customers with a no-cost battery storage system installation. It specifically targets IAQ customers who previously had solar panels installed through the utility's DSM IX H.B. 2789 Solar Pilot.	Docket No. PUR-2025-00210				

State	Category	Sub-Topic(s)	Description	Source				
VA	Planning and Procurement	Advanced Transmission Technologies, Planning Rules, Surplus Interconnection	H.B. 429, signed into law in April 2026, makes changes to how electric utilities develop IRPs and load forecasts. In particular, the bill changes the frequency with which a utility is required to file an IRP from biennially to triennially; requires utilities to consider the use of grid-enhancing technologies (GETs) as alternatives to new transmission infrastructure, and when new transmission lines are envisioned, to provide the reasons GETs are not sufficient to defer or eliminate the need for new transmission infrastructure; and requires utilities to consider the use of surplus interconnection service, as defined in the bill, to add new electric generation projects and energy storage resources to the grid. The bill also requires IRPs to include at least one modeling scenario that exceeds the utility's energy savings targets through maximized energy efficiency upgrades to homes and businesses; dynamic pricing to shift energy use to off-peak; battery storage; transmission line upgrades; grid-enhancing technology; virtual power plants that utilize aggregated demand response or storage; managed electric vehicle charging and vehicle-to-grid power; home and business electrification for enhanced grid utilization and associated revenue; known data center efficiency efforts and innovative data center tariffs approved by the State Corporation Commission or offsetting investments in offsite energy efficiency upgrades; and optimized use of the interstate electric grid through long-term transmission planning. The State Corporation Commission will establish guidelines that ensure that utilities develop comprehensive IRPs, and provide meaningful public engagement and maximum transparency during the planning process. By July 1, 2027, and at least once every five years thereafter, the State Corporation Commission will conduct a proceeding to identify and review each of its existing orders relevant to IRPs to determine if such orders remain necessary and effective and are not overly burdensome.	H.B. 429 (E)				
VA	Planning and Procurement	Grid Utilization, Non-Wires Alternatives	H.B. 434 and S.B. 621, signed into law in April 2026, require Dominion Energy and Appalachian Power to petition the Virginia State Corporation Commission for approval of grid utilization metrics by October 15, 2026. The petition must include assessments comparing current electric grid system performance with optimal utilization of existing electric grid assets. The bill also requires the Commission to include in an existing annual report its findings on each applicable utility's assessment of relevant grid utilization metrics, which must include an analysis of the potential for each applicable utility to increase electric grid utilization through the deployment of NWAs.	H.B. 434 (E)	S.B. 621 (E)			
VA	Studies and Investigations	Cost Reduction Policies	Executive Order 1, signed by the Governor in January 2026, establishes procedures for the Governor's Secretaries to propose cost-reducing policies. All Secretaries, including the Secretary of Energy, must provide a report to the Governor (1) reviewing the activities of their respective Secretariats to identify any actions, policies, or other changes that may readily reduce costs for Virginians; reports, guidance, recommendations, or other documentation published by commissions, strike forces, working groups, task forces, or other similar advisors over the past four years; and the impact and cost of cross-agency collaboration efforts; and (2) identifying any pending legislative proposals that if enacted would readily reduce costs for Virginians. Additionally, all executive branch agencies must provide reports identifying the agency's recommendations for changes that it may readily implement that will reduce costs for Virginians, including: (1) a review of all regulations, guidance, policies, procedures, and any other formal or informal agency action that has been taken by the agency and identification of any such action that, if modified, would readily reduce costs for Virginians without hindering access to or delivery of services; and (2) identification of new regulations, guidance, policies, procedures, and any other formal or informal agency action that could be taken.	Executive Order 1				
VA	Studies and Investigations	Cost-Saving Opportunities	S.B. 267, signed into law in April 2026, directs the Virginia Department of Energy, in consultation with the State Corporation Commission, Appalachian Power, and Dominion Energy Virginia, to conduct a comprehensive analysis of existing electric utility infrastructure to identify cost-saving opportunities that improve or preserve electric system reliability as an alternative or supplement to greenfield infrastructure projects. Provided that the Department receives sufficient voluntary financial contributions to engage independent consulting services, the Department and the Commission shall complete the analysis and submit a report to the General Assembly no later than December 1, 2026.	S.B. 267 (E)				
VA	Studies and Investigations	Large Load Cost Shift Prevention	In October 2024, the Virginia State Corporation Commission opened a new proceeding to explore the state's projected load growth from new data centers in a comprehensive manner. The proceeding will explore one or more potential frameworks that could be utilized by electric cooperatives and investor-owned utilities to serve potential new large use customer load in a manner that reasonably addresses the risks and issues attendant to this new load type, is just and reasonable to both current and future customers, and is permissible under current Virginia statutory law. It will also explore a tariff framework specific for these customers, and whether certain generation and transmission costs should be directly assigned to them. Commissioner-led technical conferences were held on December 16, 2024 and December 12, 2025.	Docket No. PUR-2024-00144				
VA	Studies and Investigations	Performance-Based Regulation	H.B. 903 and S.B. 251, signed into law in April 2026, direct the State Corporation Commission to consider whether a performance-based regulatory framework, which would evaluate electric utility performance and cost control incentives, is in the public interest of the Commonwealth. The bills also direct the Commission to develop related legislative recommendations and include its findings and recommendations in a report due July 1, 2027.	H.B. 903 (E)	S.B. 251 (E)			
VA	Utility Oversight	Cost Trackers	H.B. 1075, passed by the House in March 2026, directs the State Corporation Commission to consider certain requirements in the 2026 review of the rates, terms, and conditions for the provision of generation and distribution services by Appalachian Power. Those requirements include a review of Appalachian Power's efforts to improve system efficiency, resilience, and reliability to address rising costs of responding to severe weather events. The bill requires the Commission to submit a report summarizing its review and providing recommendations by September 1, 2027, or to include such report as part of an existing annual report.	H.B. 1075 (P1)				
VA	Utility Oversight	Disconnection Reporting	H.B. 828 and S.B. 516, enacted in April 2026, require each electric utility operating in the Commonwealth to provide a monthly report on residential customer disconnections to the Virginia State Corporation Commission. The report will include the following information: (1) The total number of residential customers served by the electric utility; (2) The total number of residential customers involuntarily disconnected due to nonpayment; (3) The number of residential customers involuntarily disconnected due to nonpayment within each 5-digit ZIP code, unless the utility is exempted by the Commission from providing such information in the report to protect customer privacy; (4) The number of residential customers involuntarily disconnected due to nonpayment that were reconnected to service (i) within less than 24 hours, (ii) in 24 hours or more but less than 48 hours, (iii) in 48 hours or more but less than 72 hours, or (iv) in 72 hours or more from the time of disconnection; (5) The average and total amounts of arrearages owed by residential customers involuntarily disconnected due to nonpayment; (6) The number of residential customers involuntarily disconnected due to nonpayment that have arrearage amounts of (i) less than $100, (ii) $100 or more but less than $500, (iii) $500 or more but less than $1000, and (iv) $1,000 or more; (7) The number of residential customers involuntarily disconnected due to nonpayment that participate in a payment assistance program, including utility-funded programs, LIHEAP, or the Percentage of Income Payment Program; (8) The number of residential customers involuntarily disconnected due to nonpayment that have a serious medical condition certification form on file with the electric utility; (9) The total number of residential customers that have arrearage amounts but are not disconnected; and (10) The average and total amounts of arrearages owed by residential customers that have arrearage amounts but are not disconnected.	H.B. 828 (E)	S.B. 516 (E)			
VT	Customer Cost Allocation	Cost Shift Prevention	H.B. 727, as passed by the House in March 2026, creates the "Vermont Sustainable Data Centers Act" for data centers that are 20 MW or larger. A data center shall be served by a large load service equity contract, which must include measures to prevent the shifting of costs to other ratepayers, payments from the data center customer for infrastructure necessary to serve the load, and implementation of demand-side management operational measures to maintain grid stability and efficiency. These include demand response and flexible load management practices such as load shifting, peak shaving, and the use of DERs. In May 2026, the bill passed the Senate with amendments unrelated to the ratepayer protection stipulations, and the House concurred on the bill with these amendments. The Governor vetoed the bill in late May 2026, and the veto was sustained.	H.B. 727 (V)				
VT	Customer Cost Allocation	Disconnection Policies	H.B. 753, as passed by the House in March 2026, requires the Commissioner of Public Service to conduct annual assessments of involuntary residential service disconnections and report findings to legislative committees by January 15, 2027, and annually thereafter. The Vermont Public Utility Commission shall adopt rules by January 1, 2028, to curtail electric utility disconnections during extreme heat periods. The bill died at the end of the legislative session in May 2026.	H.B. 753 (D)				

State	Category	Sub-Topic(s)	Description	Source				
VT	Customer Cost-Saving Programs	LMI Incentives	On July 25, 2025, the Vermont Public Utility Commission opened a docket to evaluate Vermont's three energy efficiency utilities' Demand Resources Plans (DRP) for the 2027-2029 triennium. The three energy efficiency utilities, Efficiency Vermont (EVT), Vermont Gas Systems (VGS), and Burlington Electric Department (BED) submitted proposed plans for consideration by the Commission. EVT's plan makes five major changes from the previous triennium, four of which impact customer affordability: discontinuation of Energy Efficiency Modernization Act (EEMA) programs, recognition of savings attributable to new construction, enhancements to the Weatherization Assistance Program (WAP), and flat flexible load management spending. The changes to WAP are significant in that, beginning in 2027, they will be paid for out of EVT's thermal energy budgets rather than its electric efficiency budgets, while still maintaining the size and level of service for customers. One of EVT's discontinued EEMA programs is $1 million for low-income fuel switching; EVT is proposing to continue this program with a focus on heat pumps as part of its ongoing electric resource acquisition programming in order to improve cost-effectiveness. EVT proposes to spend around $1.7 million each year on residential energy efficiency programs. According to EVT's analysis, while residential rates are expected to increase by 2% due to energy efficiency programs, bills will decrease by around 3.8%. VGS' plan includes expanded incentives and tailored offerings for LMI households, renters, and small businesses; stronger geographic equity considerations; and improved engagement with historically underserved communities. The plan introduces higher weatherization incentives for income-qualified households, streamlined intake and income-verification processes, and direct-to-contractor rebates to remove upfront cost barriers. VGS proposes to spend around $1.6-1.8 million each year on residential energy efficiency programs. BED is proposing possible reductions in services in its DRP, due to potential statutory changes in Vermont that will make natural gas more readily available. As a result, BED expects to have a surplus in its thermal energy budgets, which should be reinvested to continue delivering energy efficiency services to customers, such as a newly proposed electric panel retrofit for income-qualified customers. Overall, BED is proposing around $1 million in residential incentives over the triennium, and predicts rate increases of 2.6% and bill decreases of 0.31% for residential customers.	Case No. 25-1203	Vermont Gas Systems Demand Resources Plan (Dec. 2025)			
WA	Customer Cost Allocation	Bill Assistance	H.B. 1903, as enacted in March 2026, establishes a statewide low-income energy assistance program within the Washington Department of Commerce. The goal of this program is to reduce energy burden for low-income households and is supplemental to low-income energy assistance provided by utilities. Participating utilities may not supplant funding from this program to meet the state required energy assistance for low-income households. The Department must begin providing energy assistance no later than 14 months after funding is appropriated.	H.B. 1903 (E)				
WA	Customer Cost Allocation	Bill Assistance	Currently, the state requires each (1) locally regulated utility with more than 25,000 retail electric customers in the state; (2) town or city that operates as an electric utility with more than 25,000 retail electric customer; (3) district with more than 25,000 retail electric customers; (4) utility; and (5) irrigation district with more than 25,000 retail electric customers to annually report the total number of electric disconnections that occurred on each day for which the national weather service issued, or announced that it intended to issue, a heat-related alert. H.B. 2575, enacted in March 2026, eliminates this reporting requirement and encourages any resulting monetary savings from not reporting to be used for low-income energy assistance.	H.B. 2575 (E)				
WA	Customer Cost Allocation	Bill Assistance Programs, Low-Income Discount Rates	On March 20, 2026, as part of a general rate case, Puget Sound Energy (PSE) filed testimony that included proposals to address affordability for low-income high energy-burdened customers and named communities. The proposals are based on key insights and takeaways from PSE's 2024 Energy Burden Analysis findings. The Energy Burden Analysis allows PSE to estimate the number of low-income customers, respective energy burdens, and the energy assistance need. PSE proposes two recommendations to reduce energy burden for customers: (1) reduce energy burden on low-income customers through reduced customer charges; and (2) prioritize low-income customers who are energy-burdened customers for energy assistance. PSE is proposing that low-income residential electric service (Schedule 7) customers pay 60% of the standard monthly customer charge, before any application of bill discount rates, reducing the impact of the utility's proposed increase of this charge. Additionally, the utility's proposed time-of-use rate expansion was designed to remain compatible with affordability programs. PSE also proposes to prioritize energy assistance for low-income, energy-burdened customers to the maximum extent possible as offering significant energy assistance to all low-income customers, regardless of energy burden, appears unsustainable. Through the Energy Burden Analysis, PSE determined the reach of energy assistance for low-income, highly energy-burdened customers, and its effectiveness in reducing energy assistance need, can be improved as there are a significant number of low-income, highly energy-burdened customers who are either not receiving sufficient levels of energy assistance or are not receiving assistance at all. The utility plans on consulting with interested parties and advisory groups to help identify feasible ways to redesign some of its energy assistance programs to increase the efficacy of energy assistance funds such that they better assist low-income, highly energy-burdened households.	Docket No. UE-260005				
WA	Customer Cost Allocation	Cost Shift Prevention	H.B. 2515, which passed the House but failed to pass both chambers before the end of the legislative session, would have directed each investor-owned utility, by October 1, 2026, with an emerging large energy use facility in its service territory to submit a tariff or use policy for such facilities. Emerging large energy use facilities are defined as facilities that have a maximum aggregate contract demand of 20 MW or more and is primarily engaged in providing data processing, hosting, and related services. The tariffs or policies must be designed to avoid immediate and long-term risks to customers, including shifts in costs, stranded utility assets, and other increases costs resulting from an emerging large energy use facility. The tariffs or policies must also include: (1) a minimum contract length of 10 years; (2) collateral requirements; charges designed to, at minimum, recover infrastructure costs incurred, regardless of the facility's actual usage; (3) exit fees; (4) other provisions to hold the utility and ratepayers harmless if the facility with to substantially change its operations; (5) charges that, at minimum, cover the full costs of serving the facility, including interconnection, providing electricity service, and compliance costs; (6) a requirement that the facility, upon request, provide information related to power supply arrangements; (7) pricing structures that reflect cost causation and system conditions; and (8) provisions demonstrate that the facility's marginal load is served under a contract between the facility and the utility, where the marginal load participates in demand response or interruptible load programs and the facility funds the costs of providing peak demand reduction.	H.B. 2515 (D)				
WA	Customer Cost Allocation, Customer Cost-Saving Programs	Bill Assistance, LMI Community Solar, LMI Incentives	H.B. 2251, as enacted in March 2026, establishes the Climate Commitment Act operating account in the state treasury. Expenditures from this account may be used for projects that improve energy affordability and reduce energy burden for people with lower incomes. These projects may include bill assistance, energy efficiency and weatherization programs, and community renewable energy projects that allow qualifying participants to own or receive the benefits of those projects at reduced or no cost.	H.B. 2251 (E)				
WA	Customer Cost-Saving Programs	Tariffed On-Bill Financing	H.B. 2296, as enacted in March 2026, directs the Washington Utilities and Transportation Commission to allow an electrical company to invest in programs that achieve energy conservation and improve the efficiency of energy end use of single-family and multifamily rental housing in lieu of requiring a contribution from the premises owner to finance measures that would be cost effective in the aggregate. The Commission may allow the company to earn a return on such cost-effective investments over a duration of time that reduces the customer's energy burden and minimizes the investment's impact on the customer's bill while still providing a return on equity that incentivizes the company to make such an investment. The electrical company must prioritize investments made to reduce the energy burden of low-income customers, vulnerable populations, and customers in highly impacted communities while meeting the customer's comfort and productivity needs. These investments must be secured through the meter and recovered through the regular billing paid by the tenant, including any successor tenant, or owner of the premises. If the bill is paid by the premises' owner, the investment must be recovered according to a site-specific agreement.	H.B. 2296 (E)				

State	Category	Sub-Topic(s)	Description	Source				
WA	Planning and Procurement	Advanced Transmission Technologies, Non-Wires Alternatives	S.B. 6355, enacted in March 2026, creates an Electric Transmission Authority as a public body. The priority of this authority is to maintain or improve the reliability of electric service to state customers by: (1) supporting expeditious and efficient expansion of new capacity; (2) prioritizing partnerships for new transmission projects that increase access to grid connections for renewable resources, provides access to regional wholesale markets, are located in more than one utility service territory, or would not otherwise be built; pursuing cost-effective NWAs to increase capacity of existing infrastructure; (3) being a statewide resource for assisting with the development and coordination of upgrades including reconductoring with advanced conductors; (4) collaborating with stakeholders; (5) evaluating opportunities for coordination with regional wholesale markets; (6) supporting opportunities for community microgrids, DERs, and energy conservation; and (7) supporting community and economic development.	S.B. 6355 (E)				
WA	Studies and Investigations	Large Load Cost Shift Prevention	On March 16, 2026, the Washington Utilities and Transportation Commission opened a new proceeding for the facilitation of a Commission-led workshop series on large load interconnections and tariffs. The first conference was held on April 27, 2026 and discussed topics such as cost tracking, load forecasting and resource adequacy, and ratepayer protections.	Docket No. UE-260162				
WA	Utility Business Model	Performance Incentive Mechanisms	The Washington Utilities and Transportation Commission opened a new proceeding in October 2021 to implement S.B. 5295, enacted in May 2021. The bill directed the Commission to develop a policy statement addressing alternatives to traditional cost-of-service ratemaking, including performance measures or goals, targets, performance incentives, and penalty mechanisms. The bill further directed the Commission to consider a number of factors in the proceeding, including lowest reasonable cost planning, affordability, increases in energy burden, cost of service, customer satisfaction and engagement, service reliability, clean energy or renewable procurement, conservation acquisition, demand side management expansion, rate stability, timely execution of competitive procurement practices, attainment of state energy and emissions reduction policies, rapid integration of renewable energy resources, and fair compensation of utility employees. In Phase 1 of the proceeding, the Commission intended to gather stakeholder input on the development of utility performance metrics. Phase 2A would cover reporting and review, and Phase 2B would examine multi-year rate plan revenue adjustment mechanisms. Phase 3 would establish performance incentive mechanisms, Phase 4 would explore other alternative forms of regulation, and Phase 5 would be an ongoing process for re-evaluating and improving the policy. In April 2024, the Commission issued a Policy Statement containing interim guidance related to performance-based measures or goals, targets, performance incentives, and penalty mechanisms. This Policy Statement is not an enforceable rule. The policy statement focused on performance measures metrics and stated the Commission's preferred metrics under four goals. These goals include metrics (1) to demonstrate resilient, reliable, and customer-focused utility distribution systems; (2) related to customer affordability; (3) to evaluate equity in utility operations; and (4) related to environmental improvements. In August 2024, the Commission issued a policy statement to finalize the initial reported metrics for regulated energy companies to file with the Commission on an annual basis as published in April 2024. At this time, the Commission declined to include additional metrics, stating a comprehensive performance-based regulation (PBR) framework cannot be established with finality at this juncture. On June 17, 2025, the Commission held a workshop to discuss the docket's current status, the needs and priorities for Phases 3-5, and best practices for developing the performance incentive mechanisms (PIMs). On January 26, 2026, the Commission issued a Policy Statement clarifying reported performance metrics and addressing PIM principles. It should be noted that this statement only addressed performance metrics with requested clarification. Additionally, the statement included guiding principles for PIMs which the Commission will apply on a case-by-case basis. These principles included: (1) alignment with policy goals and outcomes; (2) clarity, measurability, and verifiability; (3) utility control and achievability; (4) balance of risk, reward, and customer benefits; (5) integration with the broader regulatory framework; (6) incentive structure and calibration; and (7) adaptability, review, and safeguards.	Docket No. U-210590	S.B. 5295 (2021)	Interim Policy Statement (Apr. 2024)	Policy Statement Addressing Initial Reported Performance Metrics (Aug. 2024)	Policy Statement Clarifying Reported Performance Metrics and Addressing PIM Principles (Jan. 2026)
WI	Customer Cost Allocation	Cost Shift Prevention	A.B. 840, which passed the Assembly but failed to pass both chambers before the end of the legislative session, requires the Wisconsin Public Service Commission to ensure in its ratemaking orders that no utility costs used for serving large data centers are allocated to or recovered from any other customer.	A.B. 840 (D)				
WI	Customer Cost Allocation	Cost Shift Prevention	On March 31, 2025, Wisconsin Electric Power (We Energies) filed an application for approval of two new tariffs: a Very Large Customer (VLC) Tariff and a Bespoke Resources Tariff. The VLC tariff would be available to customers with 500 MW or more of new load. The Bespoke Resources tariff would allow VLC customers to subscribe to specific generation resources and pay for their proportional share of those resources, preventing generation costs from being shifted to general ratepayers. VLC customers must pay for any remaining balance on bespoke resources in the event of early termination of their contracts. The VLC Tariff contains a monthly minimum bill. On May 21, 2026, the Wisconsin Public Service Commission approved the two tariffs with several modifications, including lowering the demand threshold from 500 MW to 100 MW, and requiring the VLC to be mandatory for all customers that meet said threshold.	Docket No. 6630-TE-113	Order (May 2026)			