Prepared for the New Jersey Board of Public Utilities

Modernizing New Jersey's Electric Utility Business Model

July 2026

Energy+Environmental Economics

Authors & Acknowledgements

Project Team

Energy and Environmental Economics, Inc. is a leading economic consultancy focused on the North American electric sector. For over 30 years, E3's data-driven analysis and unbiased recommendations have been used by regulators, government agencies, utilities, project developers, investors, and non-profit entities. E3 has offices in San Francisco (headquarters), Boston, New York, Chicago, Denver, and Calgary.

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Purpose of Study and this Phase 1 Report

In January 2026, Governor Sherrill's Executive Order No. 1 (EO-1) directed the New Jersey Board of Public Utilities (NJBPU) to conduct a study to evaluate pathways to modernize and potentially reform the state's electric distribution utility business model. EO-1 calls attention to the significant increase in electricity bills for New Jersey residents and businesses, driven by factors including the escalating cost of transmission and distribution infrastructure, volatility in natural gas prices, and rising wholesale generation costs in the regional PJM market.

The NJBPU engaged Energy and Environmental Economics, Inc. (E3) to conduct the EO-1 study across two phases. This report is the deliverable for Phase 1, which focuses on understanding how electricity bills in New Jersey are determined today, examining the implications of the existing utility business model for customer costs, and assessing the potential of utility business model reforms. Phase 2 will build on these findings to develop a regulatory and policy evaluation framework, including quantitative analyses for candidate reforms, and explore their opportunities and challenges for advancing customer affordability alongside the state's other policy priorities.

This Phase 1 report is intended to support stakeholder review and inform the next stage of the study. It provides a qualitative assessment of potential utility business model modernization and reform options focused on the distribution component of the customer bill that the NJBPU can directly influence, including how each option could affect utility incentives, investment decisions, cost recovery, transparency, customer outcomes, implementation complexity, and risk allocation. Most importantly, the Phase 1 report establishes a common framework for comparing options and packages of options so that the potential benefits, costs, trade-offs, barriers, and data needs are clear before Phase 2. Phase 2 will build on this foundation through more detailed quantitative analysis of options and reform packages, with the goal of supporting a more informed roadmap for long-term bill reduction, bill stabilization, transparency, accountability, and customer value.

Key points for policymakers

- Electricity bills in New Jersey have risen faster than most household essentials, which makes affordability the central concern of this study.
- Most of a typical bill (supply and transmission) is set in federal and regional markets with limited ability at the state level to influence those costs. Utility business-model reform that is regulated at the state level can act mainly on the distribution and programmatic portion of the bill, roughly a quarter of the bill, though some reforms may indirectly lower exposure to supply and transmission costs.
- The jurisdictional review and evidence show that no single reform or modernization option is a silver bullet. The most reliable near-term gains could come from "cost-discipline" measures available under existing state authority.
- More ambitious financing, incentive, and performance-based reforms could follow as data, baselines, and customer protections mature.

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Acronym Definitions

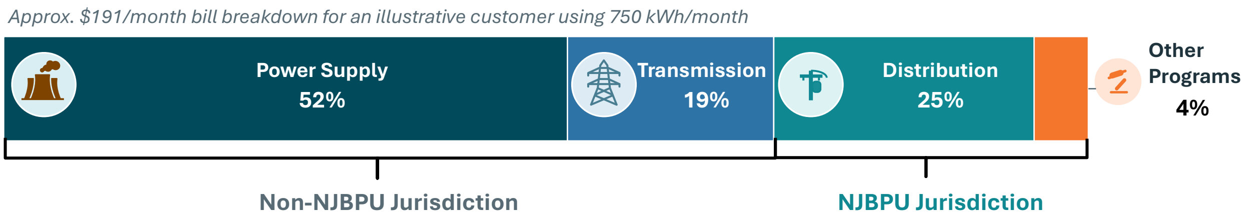
Acronym	Definition
ACE	Atlantic City Electric Company
AMI	Advanced Metering Infrastructure
BCA	Benefit-Cost Analysis
BGS	Basic Generation Service
BRA	Base Residual Auction (PJM capacity auction)
CAIDI	Customer Average Interruption Duration Index
CAGR	Compound annual growth rate
CapEx	Capital expenditures
CIP	Conservation Incentive Program
CPI	Consumer price index
CWIP	Construction Work in Progress
DER	Distributed energy resource
DOE	Department of Energy
DR	Demand response
EDC	Electric distribution company
EO-1	Executive Order No. 1 (Governor Sherrill)
ESM	Earnings sharing mechanism
EV	Electric vehicle
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse gas
GW	Gigawatt
HECO	Hawaiian Electric Company
JCP&L	Jersey Central Power & Light Company
LMI	Low- and moderate-income
LMP	Locational marginal price
LRAM	Lost Revenue Adjustment Mechanism
MRP	Multi-year rate plan
NJBPU	New Jersey Board of Public Utilities
NPV	Net present value
NWA	Non-wires alternative
Ofgem	Office of Gas and Electricity Markets (Great Britain)
OpEx	Operating expenses
PBR	Performance-based ratemaking
PIM	Performance incentive mechanism
PIPP	Percentage-of-income payment plan
PJM	PJM Interconnection LLC
PSE&G	Public Service Electric and Gas Company
PURA	Public Utilities Regulatory Authority (Connecticut)

RECO	Rockland Electric Company
RGGI	Regional Greenhouse Gas Initiative
RIIO	Revenue = Incentives + Innovation + Outputs (Ofgem framework)
ROE	Return on equity
SAIFI	System Average Interruption Frequency Index
SBC	Societal Benefits Charge
SSM	Shared Savings Mechanism
TotEx	Total expenditure
TOU	Time-of-use
UI	United Illuminating
VPP	Virtual power plant
WACC	Weighted average cost of capital

Executive Summary

Affordability has long been a core consideration in utility regulation, and recent electricity bill increases have heightened its importance in New Jersey. Electric bills have risen meaningfully over the last five years, reflecting rising costs across supply, transmission, and distribution. Distribution, the portion of the bill most directly shaped by the state's utility business model, accounts for about a quarter of a typical residential bill, with the remainder set by supply, transmission, and program charges (Figure ES-1). In response, Governor Sherrill's Executive Order No. 1 directed the New Jersey Board of Public Utilities (NJBPU) to evaluate pathways to modernize the traditional electric distribution utility business model. The NJBPU subsequently launched the **Modernizing New Jersey's Electric Utility Business Model Study** to assess whether changes to the regulatory framework could help reduce or stabilize customer bills while maintaining safe, reliable, and resilient electric service.

Figure ES-1. Average Residential Electricity Bill, 2026



The distribution and program bill components are the most direct ways for the state to influence, modernize and/or reform the utility business model, but customer affordability is also shaped by regional and federal markets that dictate power supply and transmission costs.

Notes: Weighted average of summer and winter bills across NJ EDCs, using latest approved rates (July 2026); assumes 750 kWh/month. "Other Programs" includes SBC, RGGI, CIP, and similar program and policy charges.

Accordingly, this study focuses on the areas where NJBPU has the clearest regulatory levers to influence customer affordability over time, including utility distribution spending, cost recovery, rate design, and certain program charges. Other major bill components, particularly supply and transmission, may be influenced by some NJBPU decisions but are driven largely by PJM Interconnection (PJM) market outcomes, Federal Energy Regulatory Commission (FERC) regulated transmission rates, wholesale fuel prices, capacity market dynamics, and New Jersey's Basic Generation Service (BGS) procurement structure.

Key Questions

This Phase 1 report is organized around three key questions:

1. **Electric Bills and the Utility Business Model:** What is driving New Jersey electric bills? What is the relationship between the traditional EDC (electric distribution company) business model and recent trends affecting electricity affordability?

2. **Reform Options:** What are the utility business model reform options and pathways that could potentially improve affordability? What are the key challenges to implementing these reforms in New Jersey?

3. **Evaluation and Roadmap Development:** How should New Jersey evaluate and consider sequencing potential reform options? What are the key utility business model reform options and policy pathways to evaluate quantitatively in Phase 2?

Key findings and recommendations based on this assessment are provided below.

Key Findings

Finding 1.

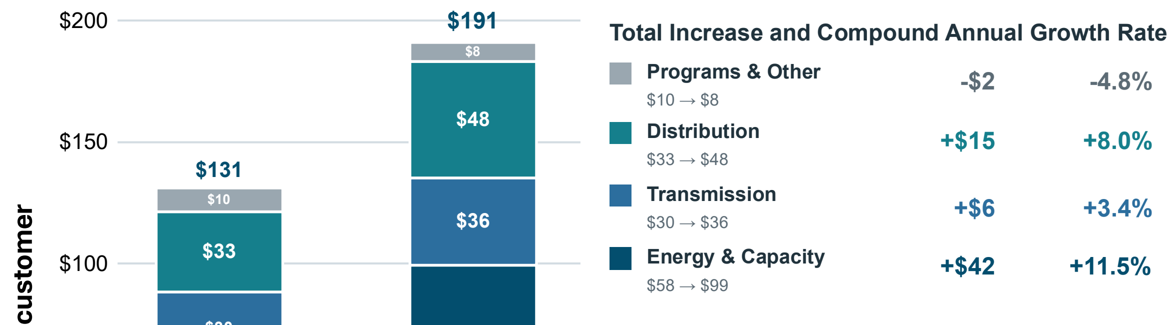
All major components of electric bills have increased over the last five years, including distribution costs, which are the focus of this study.

Residential rates rose 7.4% annually over the last five years, with growth across all major components of electric bills (Figure ES-2). Commercial and industrial customers experienced similar pressure, with rates rising 6.4% and 8.9% annually over the same period.[1] Distribution costs, which are the focus of this study, grew primarily as a result of inflation, aging asset replacement, supply-chain challenges, and load growth.

This finding has two implications for business model reform. First, distribution utility reform is important because distribution costs are material and within NJBPU's direct regulatory authority. Second, distribution reform cannot address the full affordability challenge on its own, because the largest share of recent bill growth has come from cost categories driven in whole or in part by PJM markets, FERC-regulated transmission, fuel prices, and the BGS procurement structure. Phase 2 should therefore evaluate distribution business model reforms while also coordinating with parallel workstreams on supply, transmission, load management, and customer affordability protections.

[1] Compound annual growth rates presented, derived from U.S. Energy Information Administration (EIA), "Average retail price of electricity New Jersey monthly", April 2021 through April 2026. Available at: https://www.eia.gov/electricity/data/browser/#/topic/7?agg=0.

Figure ES-2. Average Monthly Residential Bill by Cost Component, 2021 and 2026



FOCUS OF THIS STUDY

Study focuses primarily on BPU -regulated distribution and program charges, which are roughly a quarter of total bills and rose at about twice the rate of inflation over the past five years

Residential customer weighted average across NJ EDCs. Nominal $, assumes 750 kWh per month, using summer and winter rates approved as of July 2021 and July 2026. 8 winter months and 4 summer months assumed for average monthly bill shown. “Programs & Other” includes SBC, RGGI, CIP, and similar program and policy charges.

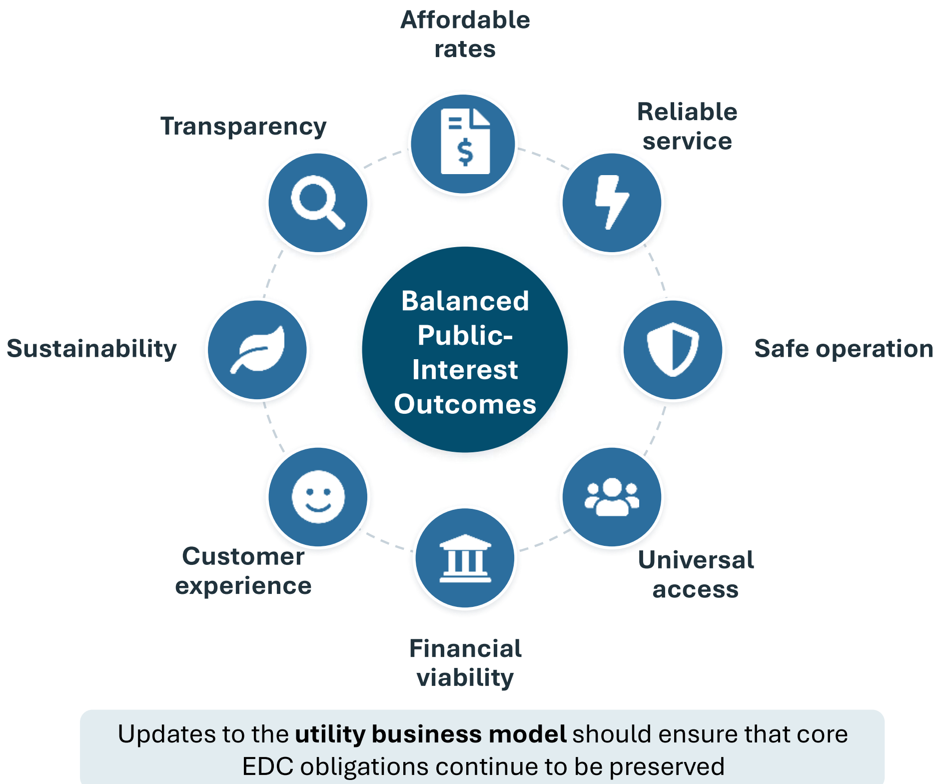
Finding 2.

Utility business models have been designed to balance multiple public-interest objectives, including affordability, but the current model has known limitations as a cost-minimization framework.

New Jersey’s EDCs are regulated monopolies. Because it would be inefficient to build competing sets of poles, wires, and substations to serve the same customers, electricity distribution is a natural monopoly. In New Jersey, 98% of customers take service from one of four investor-owned EDCs: Public Service Electric and Gas (PSE&G), Jersey Central Power and Light (JCP&L), Atlantic City Electric (ACE), and Rockland Electric Company (RECO). In exchange for an exclusive service territory, each EDC accepts an obligation to provide safe, adequate, and nondiscriminatory service at just and reasonable rates, with oversight from NJBPU. The utility business model is the regulatory framework that governs this arrangement, determining how EDCs recover costs, earn returns, and are incentivized to invest in and operate the distribution system.

With that backdrop, New Jersey’s EDC utility business model has been designed to support a broad set of public-interest outcomes: safe and reliable service, universal access, reasonable rates, sustainability, utility financial integrity, customer protections, and the ability to make long-lived infrastructure investments (Figure ES-3). While affordability is the primary focus of this study and a core objective, these other objectives remain essential. As the state pursues business model modernization and reform, it will be important to ensure that all of the core obligations of the EDCs are preserved.

Figure ES-3. New Jersey's Utility Business Model is Designed to Meet Core EDC Obligations



New Jersey's current EDC business model is grounded in cost-of-service regulation. This model has historically supported reliable service and enabled utilities to attract capital for long-lived infrastructure, but it is not designed primarily to minimize costs. Under cost-of-service regulation, utilities recover operating expenses and taxes, depreciate approved capital investments over time, and earn an authorized return on the rate base. Rate base is the remaining, unrecovered value of utility investments that have been approved for recovery from customers, such as poles, wires, substations, transformers, and other distribution system assets.

Because utilities earn returns on capital investments, this business model does not incentivize utilities to reduce capital spending. In addition, utilities do not earn returns on operating and maintenance solutions, such as demand-side resources, third-party distributed energy resources (DERs), or non-wires alternatives (NWAs), that could replace capital solutions at lower cost. This potential preference toward capital investment does not mean that these investments are unnecessary; many may be essential for safe, reliable, and resilient service. Rather, it means the regulatory framework must provide sufficient oversight and incentives to ensure that capital investments are prudent, cost-effective, and compared against viable alternatives.

This model, as implemented in New Jersey, also includes a throughput incentive: utilities collect more revenue by selling more electricity, creating potential misalignment with energy-efficiency and load-management goals. New Jersey currently addresses this to some extent through revenue adjustment for mandated efficiency and peak-reduction programs.

The principal check on potential bias in capital spending is close regulatory review. The NJBPU, the New Jersey Division of the Rate Counsel (Rate Counsel), and stakeholders review utility spending to ensure rates are just and reasonable, and that utility spending is prudent. However, the effectiveness of regulatory review can be limited by the information asymmetry between regulators and utilities and by the time and resources required to appropriately scrutinize utility spending in detail. General rate cases usually only occur every few years, creating a regulatory lag that places cost risk on utilities between cases and provides some efficiency discipline, but that same lag can discourage timely investment, especially in advance of need. Capital trackers, such as PSE&G's Infrastructure Advancement Program, can reduce regulatory lag for selected investment categories and support the timely recovery of costs. However, they also involve a tradeoff: accelerated recovery can weaken the cost-discipline function of general rate cases if not paired with clear eligibility criteria, spending caps, benefit-cost review, and ongoing performance reporting.

Finding 3

Reforms that support affordability can better align utility incentives with affordability goals, enhance scrutiny of utility spending, or modify financing and cost recovery.

Across North America and internationally, regulators have adopted a wide range of reforms to the utility business model. This report assesses several possible options across numerous dimensions. This report groups the options into four broad regulatory approaches:

1. Modifying financing and cost recovery;
2. Aligning utility incentives with cost minimization;
3. Enhancing regulatory scrutiny of spending; and
4. Improving system utilization and targeted bill impacts.

This report also distinguishes among the financing and cost recovery impacts that each reform may have, including whether it avoids costs, shifts cost recovery over time or across customers, or transfers risk among parties (Figure ES-4). This distinction is essential to avoid overstating reform benefits. For example, depreciation changes may reduce near-term bills, but shift cost recovery to future customers. Rate design changes may lower bills for targeted customers while increasing bills for others. Securitization may lower financing costs for eligible costs, but it does not eliminate the underlying cost. Stronger capital accountability can reduce total costs, but only if it changes project selection, scope, timing, or risk allocation.

Figure ES-4. Financing and Cost Recovery Impacts

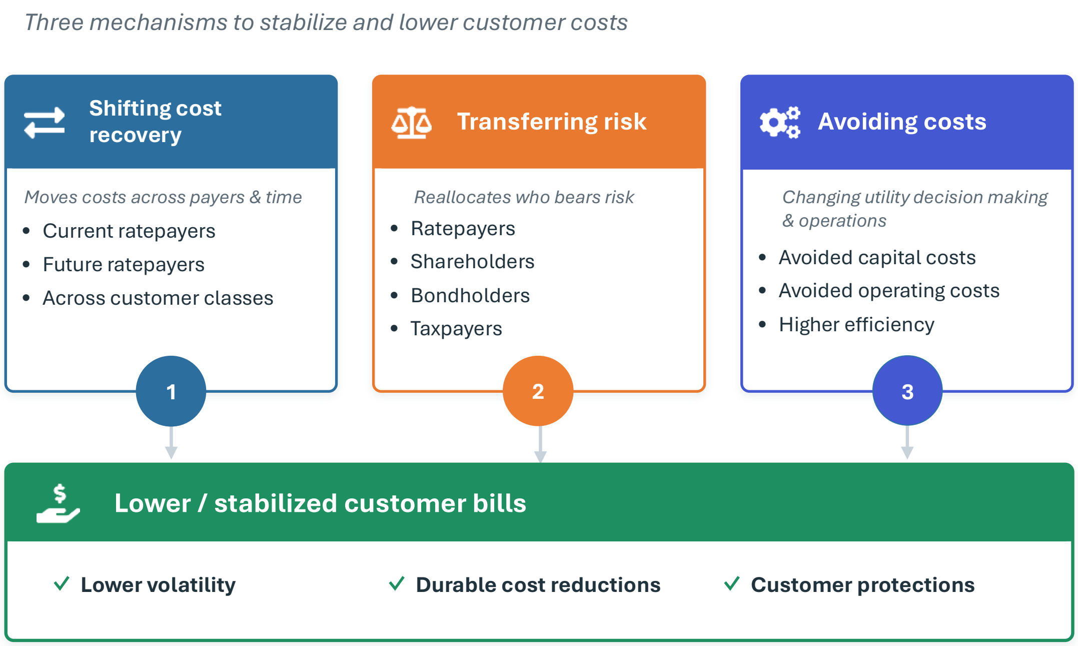


Table ES-1 below summarizes the specific reform and modernization options that are explicitly examined in this report. The Reform Category reflects the regulatory approach and how reform options are organized throughout the report. The Financing and Cost Recovery Impact indicates whether each reform shifts cost recovery, transfers risk, or avoids costs, as described above.

Table ES-1. Overview of Reform Options Assessed in this Phase 1 Report

Reform Category	Reform Option	Financing and Cost Recovery Impact*	Description
Modify Financing and Cost Recovery	**Return on equity and capital structure reforms**	Transfer, Avoid	Adjust the allowed shareholder return or debt/equity mix used to set rates.
	Criteria-based lower-cost project pathways	Transfer, Shift, Avoid	Allow qualifying projects to use lower-cost financing or partnerships if customer-value tests are met.
	Securitization	Transfer, Avoid	Use ratepayer-backed bonds to refinance eligible costs at lower financing cost.
	Modified capital recovery rules	Transfer, Shift, Avoid	Change rules related to capital cost recovery including depreciation periods and construction work in progress rules.
	Performance-based ratemaking (PBR)	Transfer, Avoid	Use an integrated framework tying utility financial outcomes to performance, cost control or policy objectives.

Align Utility Incentives with Cost Minimization	**Multi-year rate plans (MRPs)**	Transfer, Avoid	Set rates or revenues for several years using formulas and guardrails to strengthen cost-control incentives.
	Earnings sharing mechanisms (ESMs)	Transfer, Avoid	Share above- or below-target earnings between customers and shareholders.
	Performance incentive mechanisms (PIMs)	Transfer, Avoid	Reward or penalize measurable performance outcomes.
	Revenue regulation and decoupling	Shift, Avoid	Reduce the link between sales volume and allowed revenue to limit throughput incentives.
	TotEx-based regulation	Avoid	Treat capital and operating spending more symmetrically to reduce potential capital bias.
	Shared savings mechanisms (SSMs)	Avoid	Reduce potential utility bias toward capital spending by sharing verified cost savings of operating solutions.
Enhance Regulatory Scrutiny of Utility Spending	**Strengthening accountability for capital spending outcomes**	Avoid	Require clearer need statements, alternatives review, cost controls, and benefit tracking.
	Reduce automatic cost recovery	Transfer, Avoid	Add guardrails, caps, sunsets, and review requirements for riders and trackers.
Improve System Utilization and Targeted Bill Impacts	**Enhancing grid utilization and load management**	Shift, Avoid	Use demand flexibility and load management to reduce peaks and defer investments.
	Rate design	Shift, Avoid	Update rate structures to better reflect costs, peak demand, and customer protections.
	Customer programs to enable cost-effective DERs	Avoid	Use customer-sited resources when they can deliver verified system or customer benefits.

* Financing and cost recovery impact mapping is screening-level and not a quantitative ranking. Shift = shifting cost recovery across customers or time; Transfer = transferring risk among ratepayers, shareholders, bondholders, or taxpayers; Avoid = avoiding costs through changed decisions, operations, utilization, or efficiency.

Finding 4.

Utility business model reforms can support affordability, but they should be evaluated across key decision-making criteria, including bill reduction potential, transparency, implementation barriers and timelines, and risk.

Utility business model reforms can support affordability but will also have other impacts on the regulator, utilities, customers, and other stakeholders. Reforms should therefore be assessed against a consistent set of decision-making criteria. These criteria include how each reform impacts transparency and regulatory complexity, its implementation needs, its bill reduction potential, the risk it could raise bills, and realistic implementation timelines. The table below summarizes the screening-level assessment of these criteria across utility business model reform options, as discussed in detail in this report. The scorecard presented here is *directional*, to inform priorities and scenario design in Phase 2, and will be updated in Phase 2 based on feedback and more detailed modeling.

The criteria should also be interpreted together. In particular, the bill reduction evaluates the relative magnitude of achievable savings of the reform option while the remaining criteria describe whether the reform can be implemented prudently in New Jersey. A reform with high bill-reduction potential may still be a poor near-term candidate if it requires new authority or other legislative changes, reduces transparency, or creates material bill-increase risk. Conversely, reforms that could yield more modest bill reductions may be high-value near-term steps if they improve transparency, strengthen regulatory oversight, and establish baselines for later reforms.

Table ES-2. Screening-Level Scorecard for Utility Business Model Reform Options

Reform option	Transparency	Regulatory complexity	Implementation needs	Bill reduction potential *	Bill increase risk	Timeline
Modify Financing and Cost Recovery						
Return on equity & capital structure reforms	Neutral	Neutral	Low	Mid	Low	Near
Criteria-based lower-cost project pathways	Increase	Increase	Mid	Low	Low	Mid
Securitization	Neutral	Increase	Mid	Mid	Low	Mid
Modified capital recovery rules	Neutral	Neutral	Low	Mid	Mid	Near
Align Utility Incentives with Cost Minimization						
Performance Based Ratemaking (PBR)	Decrease/ Increase	Increase	Mid	Mid	Mid	Mid–Long
Multi-year rate plans (MRPs)	Decrease	Decrease	Mid	Mid	Mid to High	Mid–Long
Earnings sharing mechanisms (ESMs)	Neutral	Neutral	Low	Low	Low	Mid–Long
Performance incentive mechanisms (PIMs)	Increase	Increase	Low	Low	Mid	Near
Revenue regulation / decoupling	Neutral	Neutral	Low	Low	Low	Near
TotEx-based regulation	Neutral	Increase	High	Mid	Mid	Long
Shared savings mechanisms (SSMs)	Increase	Increase	Low	Mid	Low	Near
Enhance Regulatory Scrutiny of Utility Spending						
Strengthening accountability for capital spending outcomes	Increase	Increase	Mid	High	Low	Near
Reduce automatic cost recovery	Increase	Decrease	Mid	Mid	Mid	Near

Screening-level qualitative assessment (Phase 1).
** Relative magnitude of achievable savings. Will be updated based on quantitative analysis in Phase 2.*

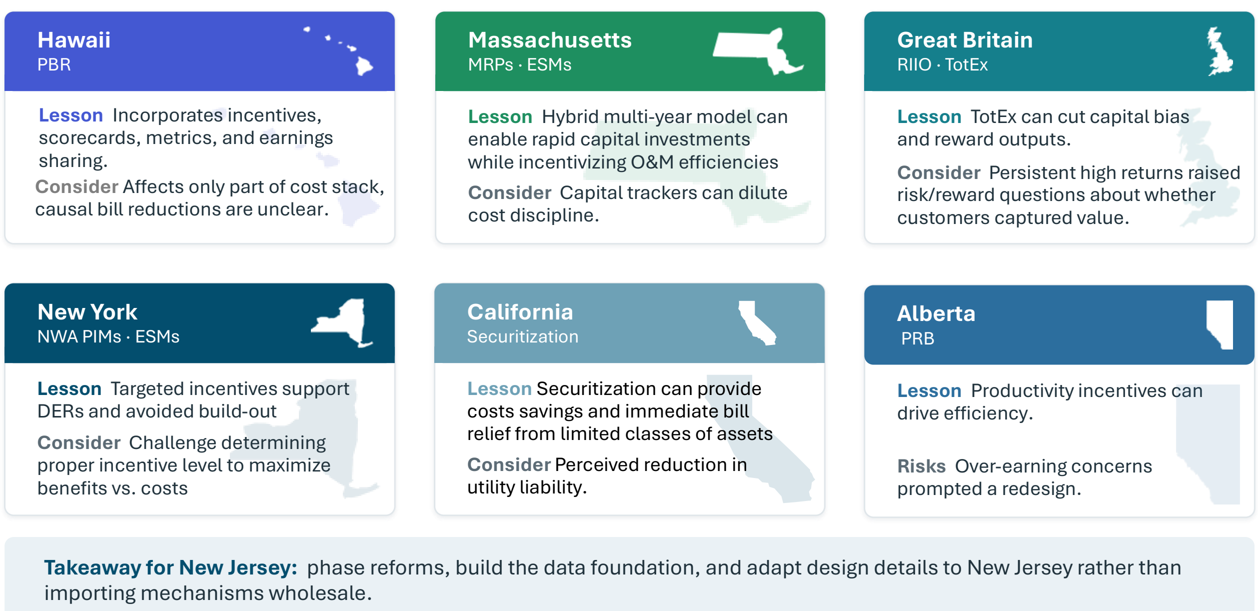
Finding 5.

Jurisdictional experience is instructive, and reforms can deliver targeted benefits, but outcomes are design-dependent.

New Jersey can learn from the other jurisdictions that have implemented various utility business model reform options, including successes, challenges, and risks (highlighted in Figure ES-5). Performance-based ratemaking in Hawaii links incentives, scorecards, multi-year rate plans, and earnings sharing, though quantifying bill impacts due to an unknowable baseline is challenging. Great Britain, under total expenditure (TotEx)-based regulation, showed that productivity incentives and total-expenditure regulation can curb potential capital bias, yet raised concerns about over-earning and risk-and-reward issues that prompted modifications. More targeted tools, such as New York's non-wires alternatives and California's securitization of key asset types, can potentially deliver benefits more quickly, but have historically been difficult to isolate the impact of due to countervailing impacts and a lack of a strong baseline to quantify benefits against.

The recurring lesson across jurisdictions is that success is highly design-dependent, and measuring that success depends on setting clear objectives and tracking measurable metrics. Reforms cannot be imported directly from other states or countries without careful adaptation; the same mechanism can perform differently depending on baseline utility incentives, market structure, customer needs, capital investment requirements, data availability, and regulatory capacity.

Figure ES-5. Selected Examples of Jurisdictional Reforms for Consideration in New Jersey



Finding 6.

No single business model reform is likely to be a standalone affordability solution. Complementary packages of reforms, sequenced appropriately, may better support affordability outcomes.

New Jersey's affordability challenge is the result of multiple cost drivers and will likely require a portfolio of reforms and supporting policies rather than a single regulatory mechanism. In addition, many of the most comprehensive business model reforms, such as performance-based ratemaking (PBR), multi-year rate plans (MRPs), and TotEx-based regulation, require significant regulatory design, data development, stakeholder engagement, and implementation capacity. These reforms may have value over time, but they are unlikely to provide immediate or standalone affordability relief without careful design and supporting guardrails.

Phase 2 may evaluate utility business model reforms and pathways to quantitatively assess their ability to address different affordability cost drivers in New Jersey. Evaluating different policy tools as packages rather than as isolated options can help identify the right policy portfolios and risk guardrails for New Jersey. For example, Figure ES-6 highlights illustrative reform packages that could be further evaluated in the quantitative analysis of Phase 2. These are not presented as recommendations for implementation, but rather to demonstrate the types of scenarios that could be developed.

Assessing the timing of any potential business model reform pathway will be important. While some reforms may appear attractive at first, they can create unintended consequences if implemented before the necessary foundation is in place. A reform that lowers near-term bills may shift costs to future customers. A reform that increases utility incentives may raise bills if the metrics are poorly calibrated. A reform that accelerates cost recovery may support timely investment but weaken the cost-discipline function of general rate cases. Phase 2 should therefore focus not only on whether individual reforms can support affordability, but also on how they should be combined, sequenced, and bounded.

Figure ES-6. <u>Illustrative</u> Examples of Potential Reform Packages to Assess in Phase 2

Cost Discipline Foundation

Near-term · under existing BPU authority

Improve transparency, accountability, and the quality of spending decisions

- Capital-plan templates & benefit-cost analysis
- NWA screening, cost caps & ex post review
- Earned-vs-authorized ROE reporting

Financing Modernization

Near- to mid-term

Adjust the financing and capital-recovery parts of the revenue requirement

- ROE & capital-structure sensitivities
- Depreciation & CWIP treatment
- Securitization & lower-cost pathways

Targeted Incentives & Shared Savings

Mid-term · test and refine

Align utility earnings with measurable customer value

- Performance scorecards & targeted PIMs
- Shared savings for non-wires alternatives
- ESM guardrails; limited MRP elements

Staged Performance-Based Ratemaking

Longer-term

Move to broader performance-based regulation once baselines are ready and if early staged implementation demonstrates customer value

- Multi-year rate plans / full PBR
- Decoupling & outcome-based models
- ESM guardrails

Note: These should <u>not</u> be considered final recommendations of what New Jersey should implement. They are illustrative examples of candidate reform pathways to evaluate in the Phase 2 modeling and broader Roadmap development.

Finding 7.

A roadmap for reform should define clear objectives, a long-term strategy, and metrics that directly measure outcomes. Implementation requires strong regulatory capacity and flexibility to iterate over time.

Business model reform is most useful when it is organized around specific objectives and measurable outcomes. For New Jersey, affordability should ideally be measured through multiple lenses, including, for example, total bills, rates, distribution revenue requirement growth, energy burden, arrearages, disconnections, bill volatility, and distributional impacts across customer classes and income groups. Average bills alone do not show which customers are most affected, and energy burden metrics alone do not identify which cost drivers are within NJBPU's control.

Phase 2 should therefore include the development of both a common analytical foundation and an overall roadmap. This includes a baseline for total bills, distribution revenue requirements, rate base growth, major bill drivers, customer class impacts, and affordability metrics across EDCs. It should also distinguish among reforms that reduce total system costs, shift costs across customers or time, transfer risk among parties, stabilize bills, or provide targeted customer protections. This distinction is essential for avoiding overstatement of reform benefits and for ensuring that stakeholders understand what each reform is expected to achieve.

A staged reform roadmap could begin with the data and reporting foundation needed to consistently measure affordability and utility performance. It could then move to targeted reforms that can be implemented, tested, and refined, such as capital accountability measures, targeted PIMs, shared savings, financing sensitivities, and rider/tracker guardrails. The roadmap can prioritize the lower regret items first, layer on more complex reforms with experience, and iterate over time. Broadly, more comprehensive reforms could be considered if early reforms demonstrate customer value, and the NJBPU, utilities, Rate Counsel, and stakeholders have developed sufficient experience with the relevant data, metrics, and governance processes.

Finding 8.

Cost drivers beyond the distribution system are also important to address in parallel.

Distribution business model reform is important because distribution costs are material and are the portion of the bill most directly shaped by NJBPU-regulated utility ratemaking. However, distribution reform alone cannot resolve New Jersey's affordability challenge. Power supply and transmission make up most of the typical electric bill and drive a substantial share of recent bill growth. These costs are shaped by factors including PJM market outcomes, FERC-regulated transmission rates, wholesale fuel prices, regional capacity market dynamics, and the structure of New Jersey's Basic Generation Service procurement.

Supply-side questions, including whether the BGS procurement structure provides sufficient hedging and how longer-term or state procurement would interact with PJM markets and transmission costs, which are set by FERC through PJM's tariff, raise different jurisdictional, market, and legal considerations. These are best pursued alongside, but analytically separate from, distribution business model reform, so that the distinct levers and the limits of NJBPU authority over each remain clear.

At the same time, some distribution-level reforms may indirectly affect supply and transmission costs. Load management, demand response, managed electric vehicle (EV) charging, virtual power plants (VPPs), DER programs, and rate design can reduce peak demand, improve system utilization, and potentially reduce exposure to capacity, transmission, or local distribution upgrades. These strategies should be evaluated as potential affordability tools. This would likely involve parallel efforts: business model reforms focused on NJBPU-regulated distribution costs; broader analysis of supply and transmission cost drivers; and customer-focused strategies that address energy burden, bill volatility, arrearages, and protections for vulnerable customers. Keeping these tracks coordinated but analytically distinct can help clarify which levers are available, which institutions control them, and what outcomes each reform can realistically deliver.

Next Steps

Taken together, the Phase 1 findings suggest that Phase 2 should focus on developing an evidence-based roadmap rather than selecting a final reform package at the outset. Phase 2 should use quantitative analysis and stakeholder input to test candidate reform packages, estimate bill and customer impacts, evaluate utility financial and implementation risks, and identify the guardrails needed to protect customers. The roadmap can then distinguish reforms that may be advanced in the near term under existing NJBPU authority; reforms that should be implemented in part or in phases; reforms that should be studied further; reforms that require legislative or separate procedural action; and reforms that should be deferred unless a clearer New Jersey-specific use case emerges.

1. Introduction and Study Context

1.1 Study Context

In January 2026, Governor Sherrill's Executive Order No. 1 (EO-1) directed the New Jersey Board of Public Utilities (NJBPU) to evaluate pathways to modernize the state's electric distribution utility business model. The Executive Order responds to rising electricity bills for New Jersey residents and businesses, driven by a combination of higher transmission and distribution infrastructure costs, natural gas price volatility, and increasing wholesale capacity costs in the PJM market.

The NJBPU engaged Energy and Environmental Economics, Inc. (E3) to support this study in two phases. This Phase 1 report establishes the factual and policy foundation for that work. It explains how electricity bills are determined in New Jersey today, identifies the cost drivers most relevant to customer affordability, assesses the current electric distribution company (EDC) business model, and evaluates a range of potential reform options based on experience in New Jersey and other jurisdictions. Phase 2 will build on these findings through quantitative analysis, stakeholder engagement, and development of a roadmap for potential utility business model reforms.

For purposes of this study, the **utility business model** refers to the regulatory framework that determines how EDCs recover costs, earn returns, and are incentivized to make decisions about distribution system investments and operations. This includes traditional cost-of-service ratemaking, capital recovery rules, authorized return on investment, treatment of capital versus operating expenditures, cost-recovery riders, and any performance-based or incentive mechanisms layered on top of the existing framework. "Business model reform," therefore, refers to changes in how utilities are paid and incentivized, not changes to their core obligation to provide safe, adequate, proper, reliable, and reasonably priced service.

Governor Sherrill's Executive Order No. 1 *(pg. 7)*

... NJBPU shall **complete and issue a study regarding modernization of the traditional electric distribution utility business model.** The study shall:

i. address the relationship between the traditional business model and recent trends affecting electricity affordability;

ii. identify potential policy pathways and opportunities for achieving long-term reductions to, and stabilization of, electric bills; and

iii. consider opportunities including, but not limited to, making utility revenue models less dependent on capital spending on infrastructure; expansion of performance-based ratemaking, whereby performance would include, among other things, the rate at which utilities approve the interconnection of new electricity generating facilities to the grid; multi-year rate plans; reductions in utilities' return on equity; state review of supplemental transmission projects; least-cost resource testing requirements; greater use of asset securitization; and amendments to the regulations governing infrastructure investment programs.

Affordability is the primary focus of this study, but it is not the only objective that utility regulation must balance. NJBPU must also ensure safe and reliable service, nondiscriminatory access, utility financial integrity, environmental quality, customer protection, and progress toward New Jersey's broader energy policy goals. Accordingly, this study evaluates business model reform options for their potential to improve affordability, and for the trade-offs they may introduce with respect to other regulatory and policy objectives.

In New Jersey, the NJBPU seeks to "ensure that safe, adequate, and proper utility services are provided at reasonable, non-discriminatory rates to all members of the public who desire such services... [and] to develop and regulate a competitive, economically cost-effective energy policy that promotes responsible growth and clean renewable energy sources while maintaining a high quality of life in New Jersey."[2] Affordability is thus a critical policy objective for regulators like the NJBPU to consider alongside the other objectives they are mandated to balance. Accordingly, this study evaluates business model reform options not only for their potential to improve affordability, but also for the trade-offs they may introduce with respect to other regulatory and policy objectives.

1.2 Stakeholder Engagement

The NJBPU staff, with support from the Regulatory Assistance Project (RAP), held two stakeholder sessions, each followed by a public comment period, to gather input that informed the development of this report. The first session, held in a hybrid format on May 7, included an overview of Governor Sherrill's EO-1, a panel of former public utility commissioners from states that have undertaken relevant utility business model reforms, and an interactive discussion to collect feedback on what goals and customer outcomes should be prioritized for the NJBPU's approach to this effort.

The second session, held virtually on June 15, featured a presentation from the E3 project team outlining the goals of the utility business model reform study, New Jersey's current business model, potential reform options, and an open comment section for anyone who registered to provide comments.

Participants in both sessions included regulated electric distribution companies, New Jersey's Rate Counsel, citizen groups, individual ratepayers, and various energy sector organizations. In total, Board staff received and reviewed 56 public comments.

1.3 Key Questions

This Phase 1 report is organized around key questions that NJBPU and E3 identified at the outset of the study:

1. **Electric Bills and the Utility Business Model:** What is driving New Jersey electric bills? What is the relationship between the traditional EDC business model and recent trends affecting electricity affordability?

[2] New Jersey Board of Public Utilities, "Mission," accessed July 2026, https://www.nj.gov/NJBPU/NJBPU/about/mission/.

2. **Reform Options:** What are the utility business model reform options and policy pathways that could potentially support affordability? What are the key challenges to implementing reforms in New Jersey?

3. **Evaluation and Roadmap Development:** How should New Jersey evaluate and potentially sequence possible reform options? What are the key policy pathways and options to evaluate quantitatively in Phase 2?

1.4 Report Organization

The remainder of this report is organized into four sections and three appendices:

+ **Section 2, Understanding Electricity Bills in New Jersey Today,** contextualizes electricity affordability in New Jersey relative to other household costs, introduces the metrics used to measure affordability, and explains how New Jersey electricity bills are constructed across supply, transmission, distribution, and program and policy charges. The section also describes the state's current cost-of-service business model and the challenges it presents for controlling customer costs.
+ **Section 3, Assessment of Potential Utility Business Model Reforms and Policy Levers,** surveys the reform options available to NJBPU and evaluates their applicability to improving affordability in New Jersey.
+ **Section 4, Recommendations for Advancing Utility Business Model Reforms and Priorities for Phase 2,** translates the Phase 1 findings into guiding principles for a New Jersey reform roadmap. It identifies candidate reform pathways, explains how those pathways can be translated into modeling scenarios for quantitative analysis, and outlines priorities for Phase 2 analytical work, roadmap development, and stakeholder engagement.
+ **Section 5, Conclusion,** summarizes the study's overall conclusions.
+ **Appendix A** provides overviews of key jurisdictions that have worked to modernize and reform utility business models.
+ **Appendix B** compiles detailed summaries of jurisdictional examples for reform options referenced throughout the report.
+ **Appendix C** provides a directional, screening-level assessment of the reform options discussed in Section 3.

2. Understanding Electricity Bills in New Jersey Today

2.1 Contextualizing Electricity Affordability in New Jersey

EO-1 directs NJBPU to examine **energy affordability** as it relates to the current utility business model in New Jersey. This section establishes the initial fact base to support this inquiry, including synthesizing recent electricity bill increases in the broader context of household costs, explaining how New Jersey bills are built, and identifying which cost components are most directly affected by distribution utility regulation.[3] For this assessment, E3 relies on a broad definition: **energy can be considered affordable when households across socio-economic statuses are able to access essential energy services without facing undue financial strain.**[4,5,6] This definition may be refined based on stakeholder feedback in Phase 2.

Electricity affordability is shaped by both the amount customers are asked to pay and their ability to pay it. Monthly bills are a function of usage, rates, rate design, weather, housing characteristics, customer-sited technologies, and participation in federal or state assistance programs. At the same time, non-energy expenses such as housing, food, health care, transportation, and childcare affect the household budget available for utility bills. Because of this, affordability cannot be assessed from rates alone; it requires a view of total bills, household income, and the distribution of impacts across customers.

Electricity rates, in turn, are shaped by several drivers of their own, including electric and gas supply costs, delivery infrastructure costs, and the utility business model itself. This study focuses primarily on utility business model reforms to support energy affordability in New Jersey, while acknowledging that other factors also influence energy bills and burden for households and businesses. Prior research conducted on behalf of the NJBPU explores in greater detail the role of other factors, such as targeted policies and rate options, in reducing energy burden for low- and middle-income customers.[7]

Like much of the country, New Jersey has seen the cost of living climb over the past five years. The prices of everyday essentials, such as household energy, food, and housing, have outpaced overall

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[3] We note that the current Phase 1 report relies on publicly available information and represents a preliminary review of energy bills today. A more thorough review of cost drivers may be compiled as part of the Phase 2 assessment.

[4] Synapse Energy Economics, "New Jersey Affordability Report," November 13, 2025, https://www.synapse-energy.com/sites/default/files/New%20Jersey%20Affordability%20Report_11.13.25%2025-082.pdf.

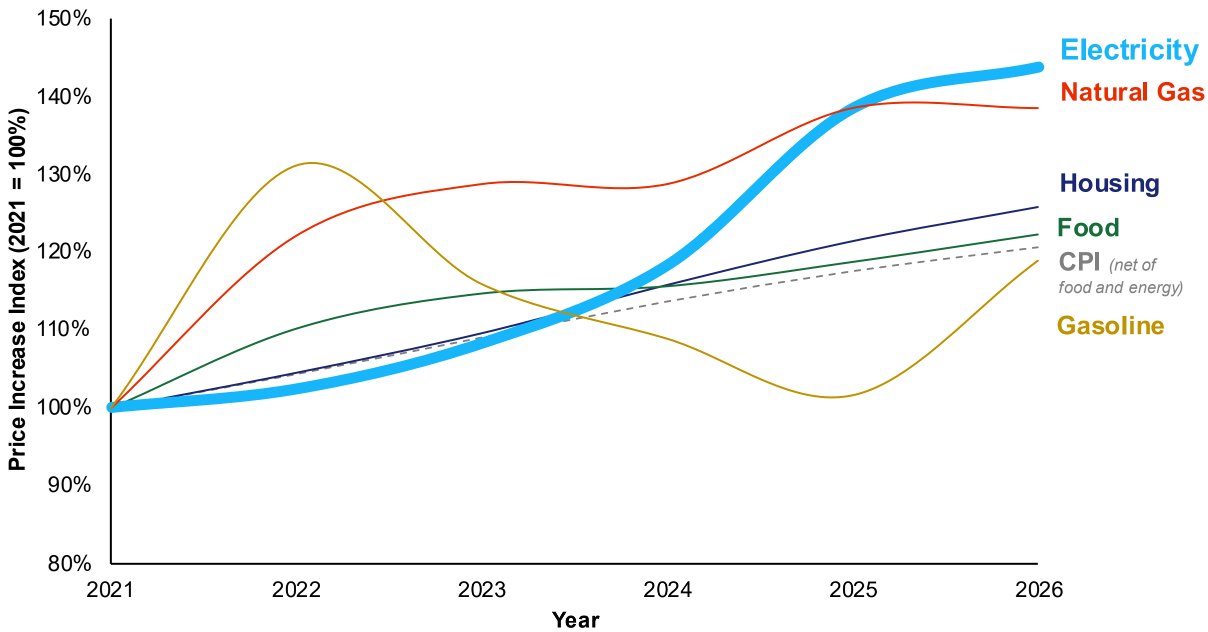
[5] Destenie Nock, "Defining Energy Affordability," Peoples Energy Analytics, 2025, https://www.mass.gov/doc/defining-energy-affordability/download.

[6] California Public Utilities Commission, "Affordability," accessed July 2026, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/affordability.

[7] The Brattle Group, "Assessment of Energy Affordability in New Jersey," December 9, 2024, prepared for the New Jersey Board of Public Utilities, https://www.nj.gov/NJBPU/pdf/reports/Brattle%20Report%20-%20Assessment%20of%20Energy%20Affordability%20in%20New%20Jersey_FINAL.pdf.

inflation across the economy. Electricity costs have seen the highest 5-year compound annual growth rate (CAGR) relative to other household essentials, as shown in Figure 1. The increase in the cost of living has been felt across the state, but most acutely by low- and moderate-income households, for whom rising expenses force difficult trade-offs among essential goods and services.

Figure 1. New Jersey Household Costs from 2021 to 2026, Across Key Expense Categories (Nominal $)[8]



Bureau of Labor Statistics (BLS) for New York-Newark-Jersey City, NY-NJ-PA, all urban consumers, not seasonally adjusted, annual averages presented (Jan-May for 2026): Housing, Food-At-Home, Consumer Price Index (CPI) excluding food and energy, gasoline
Energy Information Administration (EIA): residential electricity and natural gas delivered rates

2.2 Energy Affordability Metrics

Regulators in states such as California, Ohio, and Massachusetts increasingly use various affordability metrics to evaluate the impact of energy costs on customers. These metrics are used in rate cases and other regulatory proceedings when regulators require utilities to consider how ratemaking, investment, or cost recovery decisions affect customer bills. These metrics generally fall into four broad categories:

[8] Electricity: EIA, “Average Residential Retail Price of Electricity”, https://www.eia.gov/electricity/data/eia861/;
Natural gas: EIA, "New Jersey Price of Natural Gas Delivered to Residential Consumers," https://www.eia.gov/dnav/ng/hist/n3010nj3m.htm;
Housing, Food, CPI, Gasoline: U.S. Bureau of Labor Statistics, "Housing in New York-Newark-Jersey City, NY-NJ-PA, Accessed July 2026. https://www.bls.gov/regions/northeast/news-release/consumerpriceindex_newyork.htm

1. **Direct energy expense metrics**: typically, the utility bill itself, reported on an annual or monthly basis, with the latter helping communicate seasonal variation in energy bills due to high-demand end-uses (e.g., heat pumps, air conditioning).

2. **Income-based energy expense metrics**: energy costs against a household's ability to pay. The most common, **energy burden**, is determined by energy utility bills as a percentage of gross income, with 6% often treated as a high burden and 10% as severe.[9] This definition usually does not consider personal vehicle use costs, but adapting it to do so can enable a more holistic understanding of energy expenses, especially when comparisons include customers who use electric vehicles. Some states operationalize it through **percentage-of-income payment plans** (PIPPs), which set bills (or caps on bills) for low-income customers as a function of monthly income.[10] California's "**affordability-ratio**" approach goes even further, dividing essential utility costs by income after housing costs, recognizing that housing is typically paid before utilities, which limits the budget left for energy.

3. **Contextual spend metrics**: reference points that put a bill in perspective. For example, California uses the Hours at Minimum Wage (HM) metric to quantify the "hours of earned employment at the city minimum wage necessary for a household to pay for essential utility service charges."[11] Similarly, cost of living metrics contextualize rate and bill increases relative to economy-wide inflation. For example, the Bureau of Labor Statistics (BLS) identifies increases in consumer costs across different expenditure categories, including energy. Though rarely used as planning metrics in regulatory proceedings, they shed light on the total cost pressure on customers and can inform strategies to limit rate shocks.

4. **Arrears and disconnections metrics:** counts of customers unable to pay their utility bill, reported annually or seasonally. For example, Pennsylvania requires this reporting from investor-owned utilities, feeding into Universal Service Programs and Collections Performance Reports.[12] These trends reveal the scale and distribution of customers left inadequately protected by energy affordability programs.

Whichever metrics are used, holistic energy affordability analysis considers distributional impacts, i.e., how these metrics vary across different customer types. While utilities and regulators typically still opt for "average" customer metrics, this can obscure the affordability challenges faced by specific customers. Tracking metrics across household income, geography, household technologies, size, occupancy status, and building type can support more targeted strategies.

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[9] Ariel Drehobl, Lauren Ross, and Roxana Ayala, "How High Are Household Energy Burdens?" American Council for an Energy-Efficient Economy, September 2020, https://www.aceee.org/sites/default/files/energy-affordability.pdf.

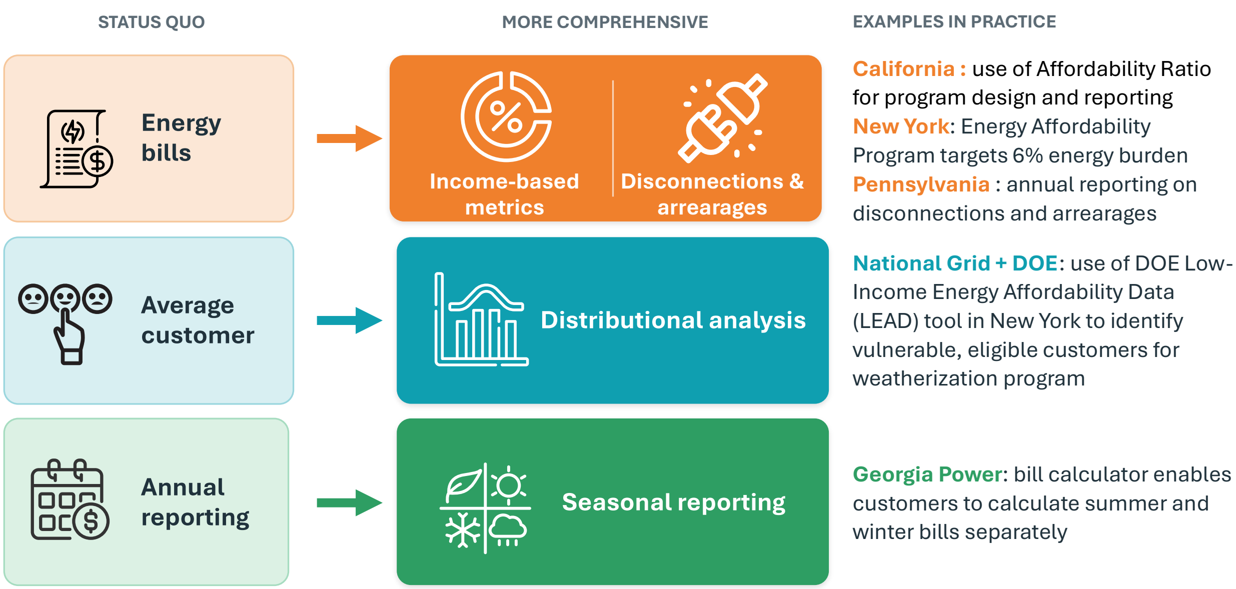
[10] Ohio Department of Development, "Percentage of Income Payment Plan Plus," accessed July 2026, https://development.ohio.gov/individual/energy-assistance/2-percentage-of-income-payment-plan-plus.

[11] California Public Utilities Commission, "Affordability," accessed July 2026, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/affordability.

[12] Pennsylvania Public Utility Commission, "Universal Service Programs and Collections Performance Reports," accessed July 2026, https://www.puc.pa.gov/filing-resources/reports/universal-service-programs-and-collections-performance-reports/.

However, regulators have begun to act on this distinction (see Figure 2). When the California Public Utilities Commission (CPUC) directed its utilities to roll out time-of-use rates for residential customers, it specified the need to ensure that "any time-of-use rate schedule does not cause unreasonable hardship for senior citizens or economically vulnerable customers in hot climate zones,"[13] with the understanding that these specific subgroups had high cooling loads and less access to demand flexibility technologies. Similarly, in Massachusetts, the Department of Public Utilities (DPU) approved the use of tiered discount rates for National Grid, "to assist the spectrum of income-eligible customers in managing their electric energy burden,"[14] reflecting that identical monthly energy bills impose different energy burdens across income groups.

Figure 2. Example Energy Affordability Metrics and Reporting Framework



While the qualitative assessment in this Phase 1 report does not evaluate a range of affordability metrics given the scope, Phase 2 of this study will build on input from stakeholders to recommend appropriate metrics for the NJBPU to use in quantifying affordability impacts.

2.3 Understanding Electricity Supply and Delivery in New Jersey

This subsection explains the components of an electricity bill and the main parties that set prices at each stage of supply and delivery, and it presents example bills across New Jersey's utilities.

[13] California Public Utilities Code, Section 745(c)(2). ; https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?lawCode=PUC&sectionNum=745.&article=2.&highlight=true&keyword=time-of-use%20rate%20schedule%20does%20not%20cause

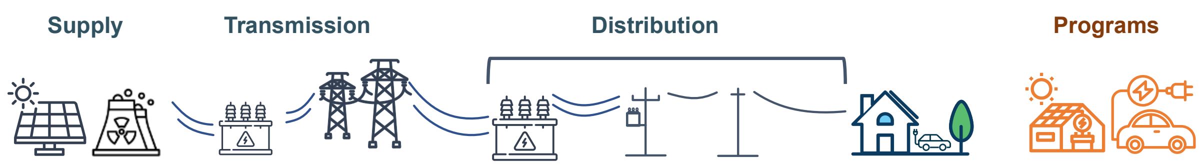
[14] Massachusetts Department of Public Utilities, D.P.U. 23-150, Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, Final Order, September 30, 2024, https://media.wbur.org/wp/2024/10/D.P.U.-23-150-National-Grid-Rate-Case-Final-Order-9.30.24.pdf

More than 98% of New Jersey customers receive delivery service from one of four regulated, investor-owned EDCs: Public Service Electric & Gas (PSE&G), Jersey Central Power & Light (JCP&L), Atlantic City Electric (ACE), and Rockland Electric (RECO).[15] The remainder are served by municipally-owned utilities, which generally fall outside the NJBPU's jurisdiction and are not a focus of this study.

2.3.1 Electricity Rate Components

Customer energy bills reflect the total cost needed to deliver safe and reliable electricity service and cover related utility programs. For purposes of this study, E3 groups the typical residential electric bill into four components: energy and capacity, transmission, distribution, and other program or policy charges. This framing is useful because each component is driven by different cost factors and governed by different institutions. These categories are shown visually in Figure 3 and described below.

Figure 3. Electric System Cost Components



- **Energy and Capacity (supply):** The cost of producing electricity and ensuring enough generation to meet peak demand (capacity). New Jersey is part of PJM Interconnection, LLC (PJM), the regional transmission organization that operates wholesale energy and capacity markets. In New Jersey, most residential customers (about 94%) rely on "default" supply service, where supply is provided through Basic Generation Service (BGS), which the EDCs procure through an annual auction, with results certified by the NJBPU.[16] Residential customers who choose a third-party supplier pay that supplier's contract price instead of BGS.[17] Supply costs are driven primarily by wholesale market prices, PJM market rules, BGS procurement outcomes, and customer usage patterns. EDCs pass supply costs directly to customers, while third-party suppliers may earn a profit on those costs but structure their offerings to remain competitive.

- **Transmission:** The cost of the high-voltage transmission system, which moves electricity from generators to local distribution systems. In NJ, these facilities are planned and operated

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[15] American Public Power Association, "2026 Public Power Statistical Report," 2026, https://www.publicpower.org/system/files/documents/2026_Public-Power-Statistical-Report.pdf; U.S. Energy Information Administration, "Electric Power Annual, Table 2.11," https://www.eia.gov/electricity/annual/table.php?t=epa_02_11.html.

[16] New Jersey Board of Public Utilities (NJBPU), 'NJ Switching Data April 2026': https://www.nj.gov/NJBPU/pdf/energy/April%202026%20Electric.pdf

[17] New Jersey Board of Public Utilities, "About NJBPU - Basic Generation Service," accessed July 2026, https://nj.gov/NJBPU/NJBPU/about/divisions/energy/bgs.html.

through PJM and regulated by the Federal Energy Regulatory Commission (FERC) through PJM's transmission tariff, including a FERC-approved return on equity on investments.[18] EDCs pass the FERC-set transmission charge through to customers without a retail markup, with the opportunity to make a profit on the transmission assets that they own through these FERC-regulated investments.

- **Distribution:** The cost of building, operating, and maintaining the local low-voltage network of substations, transformers, poles, and wires that delivers power to homes and businesses. This system is built and operated by the EDCs, who recover costs from customers through distribution rates. EDCs earn authorized returns on their capital investments in distribution infrastructure. This is the EDC's core business that is regulated by the NJBPU.
- **Other (programs & policy):** Other charges that fund state energy-efficiency, clean-energy, nuclear, and low-income programs, recovered through "riders," which are additional charges on bills. EDCs earn authorized returns on some of these charges.

This structure highlights an important jurisdictional point for this study. Authority over New Jersey electric rates is split across state and federal jurisdictions. The NJBPU regulates retail distribution rates and certifies the BGS supply auction, though supply and transmission costs can at times be influenced by state decisions. In contrast, FERC has jurisdiction over transmission rates, and wholesale energy and capacity markets are operated by PJM and are also subject to FERC authority.

2.3.2 Electric Distribution Company Breakdown

Electric distribution service is regulated as a natural monopoly because duplicative poles, wires, and substations would generally be inefficient. In practice, this means that customers must take distribution service from the distribution provider assigned to their location, and the NJBPU regulates the rates and terms of that monopoly service. Table 1 summarizes New Jersey's EDCs and the approximate number of electric customers served by each. PSE&G is the largest by customer count, followed by JCP&L, ACE, and RECO.

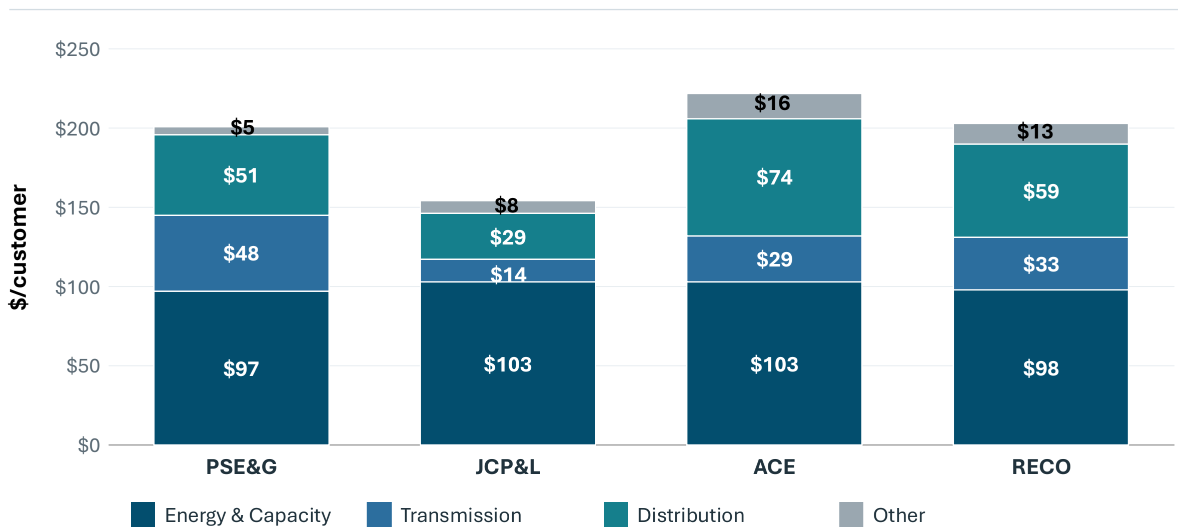
[18] Federal Power Act, Section 201, 16 U.S.C. Section 824(b); PJM Interconnection, "Open Access Transmission Tariff," https://www.pjm.com/pjmfiles/directory/merged-tariffs/oatt.pdf.

Table 1. New Jersey's Four Regulated EDCs and Approximate Electric Customers Served[19]

Electric Distribution Company	Service Territory	Approximate Electric Customers
PSE&G	2,600 square mile corridor extending across the state	2,100,000
JCP&L	13 counties across Northern, Western, and East Central NJ	1,100,000
ACE	2,700 square mile area, 8 counties across southern NJ	547,000
RECO	Parts of Bergen, Passaic & Sussex counties	72,000

The composition of a residential bill varies materially by EDC. In New Jersey in 2026, the share of the residential bill that reflects distribution costs ranges from 19% to 33%, depending on the EDC. The average bill across EDCs is 25% distribution costs. Figure 4 shows the breakdown of customer bills across electric system components. The bills shown reflect tiered residential service rates. EDCs also offer time-of-use rates for residential customers, which are not included in this analysis, but reflect similar shares of cost components across bills. Similarly, while the analysis presented focuses on residential customer bills, similar trends persist for commercial and industrial customers in New Jersey as well.

Figure 4. 2026 Average Monthly Residential Electricity Bill, assuming 750 kWh/month usage



Nominal $, assumes 750 kWh per month, using summer and winter rates approved as of July 2026. 8 winter months and 4 summer months assumed for average monthly bill shown. "Other" includes SBC, RGGI, CIP, and similar program and policy charges.

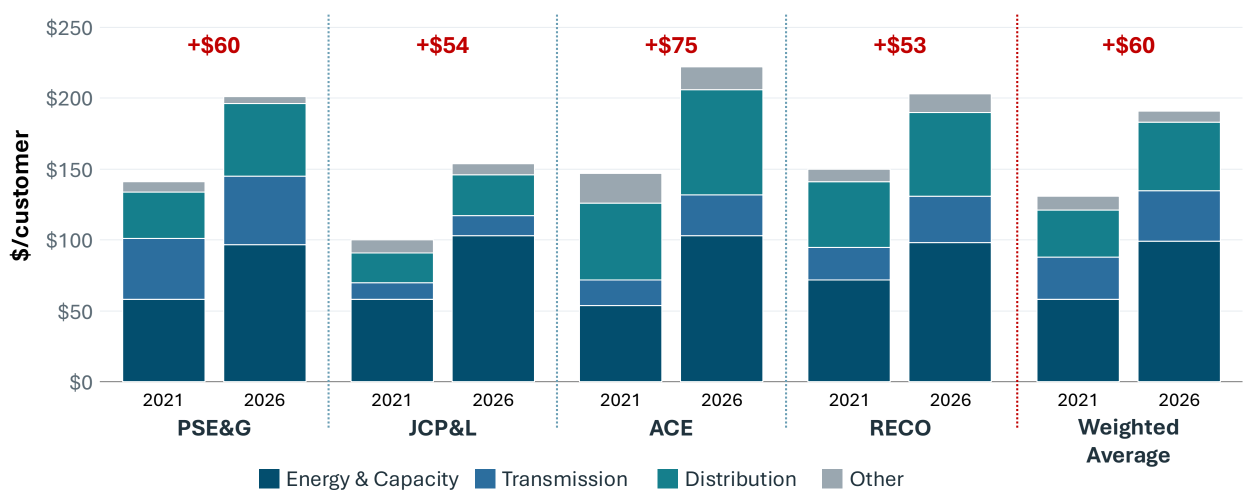
[19] Customer counts and service territory descriptions are drawn from the New Jersey Division of the Rate Counsel website.

2.4 Cost Drivers across System Components

Electricity bills have increased materially in New Jersey over the past five years. Those increases are not attributable to a single source; they reflect cost growth across supply, transmission, distribution, and other program or policy charges. This section summarizes the main drivers by bill component to clarify which pressures are most directly addressable through distribution utility business model reform. As noted above, given the qualitative scope, this assessment is preliminary based on public data and will be updated at a more disaggregated level in Phase 2.

Figure 5 compares illustrative 2021 and 2026 residential electricity bills for single-family homes in New Jersey. These bills are based on 750 kWh/month consumption and represent an average monthly bill across the full year. The energy and capacity portion of the bill saw the greatest growth from 2021 to 2026, accounting for almost 70% of the increase in the electricity bill ($42/mo). Distribution accounted for about 25% of the total increase ($15/mo). The proportion of bill increases across components was similar across EDCs. This pattern underscores that distribution reform is important and within the NJBPU's most direct authority, but it cannot address the entire affordability challenge on its own.

Figure 5. 2021 and 2026 Average Monthly Residential Electricity Bill (assuming 750 kWh/month usage)



Nominal $, assumes 750 kWh per month, using summer and winter rates approved as of July 2021 and July 2026. 8 winter months and 4 summer months assumed for average monthly bill shown. "Other" includes SBC, RGGI, CIP, and similar program and policy charges.

Table 2 summarizes selected cost drivers across the major bill components. Many factors shown here have contributed to cost increases across jurisdictions nationwide. The significant increases in capacity market costs reflect tight market conditions, where load growth across the economy, especially driven by large loads such as data centers, has coincided with the retirement of thermal generation and the slow deployment of new resources to meet increased demand. This challenge has been exacerbated by slow rates of transmission interconnection in PJM, which has led to transmission price increases and slow deployment of new generators that can serve peak demand.

Increases in distribution system spending nationwide have been driven primarily by the need to replace aging infrastructure and by equipment cost increases that outpace inflation.[20]

Table 2. Selected Cost Drivers across Electricity Cost Components

Driver	Energy and Capacity	Transmission	Distribution
Inflation	Inflation increased capital, equipment, labor, and operating costs across the system. **Distribution equipment cost increases have outpaced economy-wide inflation** in particular: unit costs for wire and cables have increased by over 300% from 2020 to 2025, while transformer unit costs have increased by over 150% over the same timeframe.[21]		
Supply chain constraints	**Gas turbine shortages** have affected the development of new firm generation capacity resources, with long lead times leading to tight capacity market conditions, increased development costs due to limited equipment availability, and ultimately, significantly increased capacity costs in PJM.	**Lead times for large power transformers and high-voltage circuit breakers** have increased significantly in the last five years nation-wide, to roughly double pre-pandemic levels. This has exacerbated delays in reliability and interconnection project timelines.[22,23]	**Nation-wide distribution transformer shortages** and other equipment constraints have driven up the cost of key distribution system equipment and challenged replacement and upgrade schedules.[24]
Load growth and reliability needs	**Increasing load growth across the economy, driven especially by large users like data centers, has led to higher capacity market prices in PJM**. The 2025 PJM Long-Term Load Forecast Report estimates a PJM winter peak 10-year growth of 62 GW, at an average annual growth rate of 3.8%, with data centers contributing heavily to the increase in expected demand.[25] This load growth has driven demand for incremental generation and transmission capacity, driving up energy and capacity costs.		After asset replacement, **capacity expansion to meet anticipated load growth was the next most important driver of increased distribution spending nation-wide.**[26]

[20] Lawrence Berkeley National Laboratory, "Utility Distribution Costs," April 2026, https://eta-publications.lbl.gov/sites/default/files/2026-04/utility_distribution_costs_final.pdf.

[21] Lawrence Berkeley National Laboratory, "Utility Distribution Costs," April 2026, https://eta-publications.lbl.gov/sites/default/files/2026-04/utility_distribution_costs_final.pdf.

[22] Wood Mackenzie, "Mind the Gap: Tackling Supply Chain Challenges in the Electric T&D Sector," accessed July 2026, https://www.woodmac.com/news/opinion/mind-the-gap-tackling-supply-chain-challenges-in-the-electric-td-sector/.

[23] Wood Mackenzie, "Power Transformers and Distribution Transformers Will Face Supply Deficits of 30% and 10% in 2025," press release, accessed July 2026, https://www.woodmac.com/press-releases/power-transformers-and-distribution-transformers-will-face-supply-deficits-of-30-and-10-in-2025/.

[24] Wood Mackenzie, "Power Transformers and Distribution Transformers Will Face Supply Deficits of 30% and 10% in 2025," press release, accessed July 2026, https://www.woodmac.com/press-releases/power-transformers-and-distribution-transformers-will-face-supply-deficits-of-30-and-10-in-2025/.

[25] PJM Long-Term Load Forecast Report 2025, accessed July 2026, https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.pdf

[26] Lawrence Berkeley National Laboratory, "Utility Distribution Costs," April 2026, https://eta-publications.lbl.gov/sites/default/files/2026-04/utility_distribution_costs_final.pdf.

Replacement of aging infrastructure and/or retirement of existing infrastructure	**Coal and natural gas combustion turbine plants retiring in PJM have lowered available firm capacity supply**, leading to higher capacity auction clearing prices. With over 3 GW of nameplate coal capacity retired in 2024 and 2025[27] and approximately 11 GW of thermal resources at risk of retirement by 2030,[28] tight capacity market conditions have driven high supply costs.	**Aging transmission infrastructure,** including conductors and substation equipment, have necessitated significant utility investments in transmission system improvements in PJM.[29]	**Aging distribution system infrastructure across the country has led to increased capital costs** to replace and upgrade infrastructure to continue reliable service, accommodate increased loads, and enable distributed energy resources (DERs). A 2024 National Laboratory of the Rockies Study identified that roughly 55% of in-service transformers are more than 33 years old and approaching the end of life.[30]
Slow deployment of new resources	**Slow development of generation projects in PJM's interconnection queue** has exacerbated tight generation capacity supply conditions. At the time of the 2026/27 Base Residual Auction (BRA), 106 GW of nameplate capacity was waiting for interconnection agreements and 23 GW was at the "engineering and procurement" stage of project development.[31]	**Slow buildout of new transmission** in PJM has limited the rate of interconnection of new generation capacity resources and increased transmission congestion costs. Congestion costs are reflected in supply costs through locational marginal prices (LMP).	

[27] Office of the People's Counsel for the District of Columbia and Synapse Energy Economics, "PJM Capacity Market Report," May 2025, https://opc-dc.gov/wp-content/uploads/2025/05/PJM-Capacity-Market-Report-FINAL-OPC-Synapse.pdf.

[28] PJM State of the Market – 2026, Section 5 – Capacity Market, accessed July 2026, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2026/2026q1-som-pjm-sec5.pdf

[29] PJM Interconnection, "2025 Regional Transmission Expansion Plan Report," 2025, https://www.pjm.com/-/media/DotCom/library/reports-notices/2025-rtep/2025-rtep-report.pdf.

[30] National Laboratory of the Rockies, "Transformer Study," 2025, https://docs.nlr.gov/docs/fy25osti/92076.pdf.

[31] GridLab, "Price Impact of Additional Renewable and BESS Supply," accessed July 2026, https://gridlab.org/portfolio-item/price-impact-of-additional-renewable-bess-supply/.

2.5 Current EDC Business Model

New Jersey's EDCs are regulated monopolies. An electric distribution network is understood to be a natural monopoly, as it would generally be inefficient to build multiple overlapping sets of poles, wires, substations, and related infrastructure to serve the same customers. However, in the absence of competition, a monopoly may have the ability and incentive to charge prices above competitive levels. For this reason, while EDCs have obligations to provide safe, adequate, and proper service, they cannot set rates without NJBPU's approval.

The U.S. utility regulation model is grounded in a longstanding legal framework for regulating monopoly and public-service industries. The modern public utility regulatory model was developed primarily in the late 19th and early 20th centuries. This framework can be understood as a hierarchy of requirements and practices. The model is designed to balance utility financial integrity with customer protection.

At a high level, legal precedent requires that utility regulation not be so restrictive that it becomes confiscatory. In utility ratemaking, courts have interpreted this standard to mean that a utility must have a reasonable opportunity, but not a guarantee, to earn a fair return on its investments.

The next level is the applicable "just and reasonable" standard. For wholesale electricity sales and transmission service regulated by FERC, this standard comes from the U.S. Federal Power Act. For retail distribution service, this standard is defined in New Jersey statutes; NJBPU is responsible for ensuring that utility investments are prudently incurred and subsequently charged to customers through "just and reasonable" rates.[32]

Within those legal boundaries, regulators have flexibility in how they set rates. The U.S. Supreme Court has held that utility ratemaking law does not require regulators to use any specific methodology for setting rates as long as the "end result" satisfies the applicable standards. EDCs in New Jersey are currently regulated through a cost-of-service model, as described below. Regulation under alternative business models and changes to parts of the cost-of-service model that could stabilize or reduce distribution bills are discussed in depth below.

2.5.1 Cost-of-Service Model

The existing cost-of-service model employed for EDCs in New Jersey is the dominant ratemaking model in the United States. Under this model, regulators establish a utility revenue requirement, which defines the costs the utility is allowed to recover through rates. The revenue requirement typically includes operating and maintenance expenses, depreciation of capital assets, taxes, an authorized return on investment, and other approved costs.

A central feature of cost-of-service ratemaking is the treatment of capital investments. EDC capital investments are subject to prudency review by the NJBPU. Once approved, these costs are added to

[32] New Jersey Revised Statutes, Section 48:2-21 (2025), https://law.justia.com/codes/new-jersey/title-48/section-48-2-21/.

the utility's **rate base**, on which the utility earns an approved **rate of return**. The regulated capital structure and return on equity (ROE) are intended to provide investors with a fair return commensurate with the utility's risk profile, enabling the utility to attract the capital required to build and maintain the electric grid. Utilities finance capital projects (plant, grid infrastructure, etc.) using a blend of debt and equity, since neither pure debt nor pure equity is cost-efficient at scale.

Regulators approve the target capital structure, typically in a rate case, setting the debt-equity ratio and the allowed ROE used to calculate revenue requirements. The utility earns its profit through the authorized ROE applied to the equity-financed rate base (equity ratio multiplied by total rate base), while debt costs are recovered without profit margins for the utility. Regulators weigh factors like credit rating impact, financial risk, comparable utility structures, and the cost of capital when setting the appropriate ratio to appropriately balance ratepayer interests with high enough ROE to attract sufficient capital for grid investments. Utilities are unable to rely too strongly on debt financing as excessive leverage raises default risk, potentially triggering credit rating downgrades, higher borrowing costs, and a reduced cushion to absorb losses, which would increase ratepayer costs in the long run and could threaten reliable service.

The total revenue requirement can be categorized into the following components:

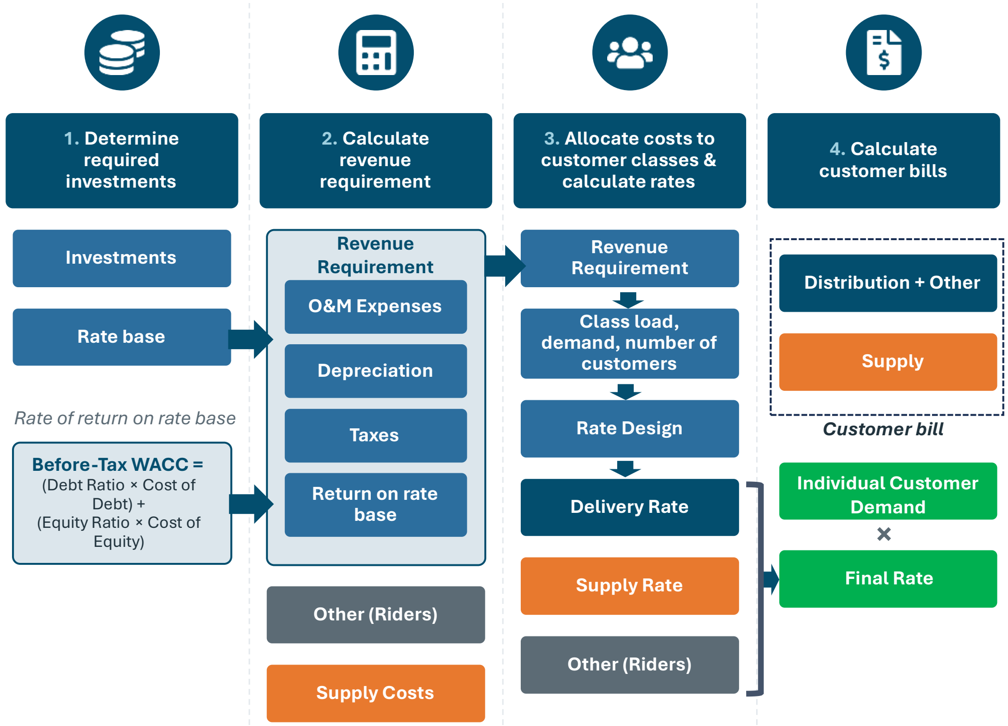
- operating and maintenance expenses,
- depreciation of capital assets,
- taxes,
- authorized return on investment, and
- other approved costs.

After the total revenue requirement is calculated, it is allocated to customer classes (e.g., residential, commercial, and industrial) using cost allocation factors tied to various usage metrics such as annual sales, peak demand, and number of customers.

Class revenue allocations are then translated into volumetric $/kWh charges, fixed monthly charges ($/customer), and, in some cases, peak-demand $/kW charges. These rates are charged to customers based on their usage and determine the final customer electricity bill.

A schematic showing the cost-of-service ratemaking process, from utility investments to customer bills, is shown in Figure 6.

Figure 6. Customer Electricity Bills under Cost-of-Service Ratemaking



2.6 Challenges Associated with Existing Utility Business Model

Cost-of-service regulation is intended to balance affordable, predictable, and fair customer rates with sufficient utility financial incentives to support investment and public policy objectives. This section summarizes the challenges in cost-of-service ratemaking and the strategies employed by other jurisdictions to mitigate these concerns. This section focuses on drivers linked to the cost-of-service ratemaking paradigm. For example, these include inadequate incentives to control costs and sales, and the use of accelerated cost recovery approaches for approved investments that trade cost control incentives and controls for rapid deployment.

Under cost-of-service ratemaking, **utilities have a financial incentive to make investments** and add to the rate base on which they earn returns. This incentive can be in tension with affordability goals because shareholders earn a greater return when utilities spend more, and capital-intensive investments may be prioritized over lower-cost alternatives. The most important solution to managing utility costs under cost-of-service ratemaking is close regulatory review of utility cost recovery to ensure that rates charged to customers are just and reasonable.[33] Many states also have ratepayer advocacy offices to further ensure that ratepayers' costs and needs are protected in regulatory decisions regarding utilities, including cost recovery. However, the effectiveness of this counterbalance is limited by the regulatory burden of closely examining utility expenses, as well as the information asymmetry between regulators and utilities regarding how to most cost-effectively

[33] New Jersey Statutes Annotated, Section 48:2-21.

build, maintain, and operate the electric distribution system while maintaining reliable service and meeting other policy goals.

Cost-of-service ratemaking, as currently implemented in New Jersey, also presents a **throughput incentive** challenge: utilities receive greater revenues from selling more electricity. This is especially noteworthy and concerning to certain stakeholders, given the imperative for utilities to decarbonize and modernize the electric grid without endangering customer energy affordability, through investments in energy efficiency, load management, and other strategies to mitigate drivers of electricity demand. To mitigate this challenge, other states have implemented revenue decoupling, separating utility revenues from electric sales.

New Jersey has limited revenue decoupling mechanisms, which compensate utilities for revenue losses specifically attributable to NJBPU-mandated energy efficiency and peak demand reduction programs, a small fraction of total volumetric charges on customer bills. Other states, such as Massachusetts, have employed full revenue decoupling, i.e., guaranteed recovery of the total revenues, regardless of electricity sales, to address this misaligned incentive. However, as electrification becomes the preferred end-use decarbonization strategy, revenue recoupling is being explored in some jurisdictions to promote load growth and unlock additional utility revenue for capital-intensive investments, such as grid modernization.[34]

An additional challenge posed by the scale of electric grid investments required to modernize and meet policy-driven load growth is the risk utilities face of disallowances for these extraordinary costs, as well as the financial implications of delayed rate-base treatment of these costs. In New Jersey, EDC delivery rate changes are approved through each rate case, which occurs every few years. This creates a “regulatory lag”, or a gap between when a utility incurs costs and when it can recover those costs through rates. This lag places the risk of cost increases between rate cases on utilities, temporarily protecting customers from cost increases prior to investments being approved in rate cases. This creates an efficiency incentive for utilities to control costs, as cost recovery “lags” investments. However, this also disincentivizes the rapid deployment of capital for policy-aligned imperatives such as the buildout of electric vehicle charging infrastructure and grid modernization, as utilities are not guaranteed cost recovery on these investments. Regulators allow EDCs to mitigate this risk through capital trackers and cost recovery mechanisms that allow accelerated cost recovery outside of full rate cases (e.g., PSE&G’s Infrastructure Advancement Program supporting grid modernization investments). These capital trackers reflect a tradeoff between the cost control incentives created by regulatory lag, and the regulatory oversight that accompanies traditional rate base investments, with the desire to accelerate investments in certain policy-aligned infrastructure categories.

These challenges set the stage for the next chapter, which examines alternative business model reforms and policy levers to address the incentive for utilities to over-rely on capital spending and increase sales, as well as the disincentive to quickly deploy capital to meet policy-driven needs.

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[34] Rocky Mountain Institute, "Revenue Decoupling," RMI Electricity Affordability Toolkit, accessed July 2026, https://affordability-toolkit.rmi.org/policies/revenue-decoupling.

3. Assessment of Potential Utility Business Model Reforms and Policy Levers

New Jersey's electricity affordability challenge is driven by cost pressures across supply, transmission, distribution, and other policy-related program charges. This assessment focuses on areas where NJBPU has direct authority, including over EDC delivery rates and the regulatory framework that determines how distribution costs are reviewed, approved, and recovered from customers.

This section evaluates the landscape of potential policy levers and utility business model reform options that could help to stabilize or reduce distribution-related electric bills. The goal of this section is not to identify a single reform as a standalone solution, but rather to assess a broad set of tools that may be available to New Jersey to help stabilize and reduce distribution-related electric bills for New Jersey customers. These tools take a range of approaches to support both affordability and other key state objectives, such as increasing transparency, building customer confidence, and ensuring that traditional utility business model objectives are met.

While some tools directly lower financing costs or other components of the revenue requirement, others operate by changing utility incentives, increasing scrutiny of capital spending, or improving utilization of existing infrastructure. In discussing potential approaches, this section draws on existing examples and lessons learned to date from strategies and policy levers utilized in other jurisdictions across North America and the United Kingdom, with more detailed jurisdictional case studies in the appendix.

3.1 Overview of Potential Reform Options and Mechanisms for Influencing Affordability

As required by EO-1, this study focuses on affordability as the primary objective of utility business model reforms. The reform options evaluated in this study affect affordability and customer bills through distinct mechanisms that vary in how directly they influence customer bills.

This report uses two complementary ways to characterize cost impacts. First, this section organizes reforms by the **regulatory approach** through which they may influence affordability. Second, the report distinguishes among the **financing and cost recovery impacts** that each reform may have, including whether it has the potential to avoid costs, shift cost recovery over time or across customers, or transfer risk among parties. As described in specific cases below, these impacts are not *necessarily* exclusive and can depend on the implementation details.

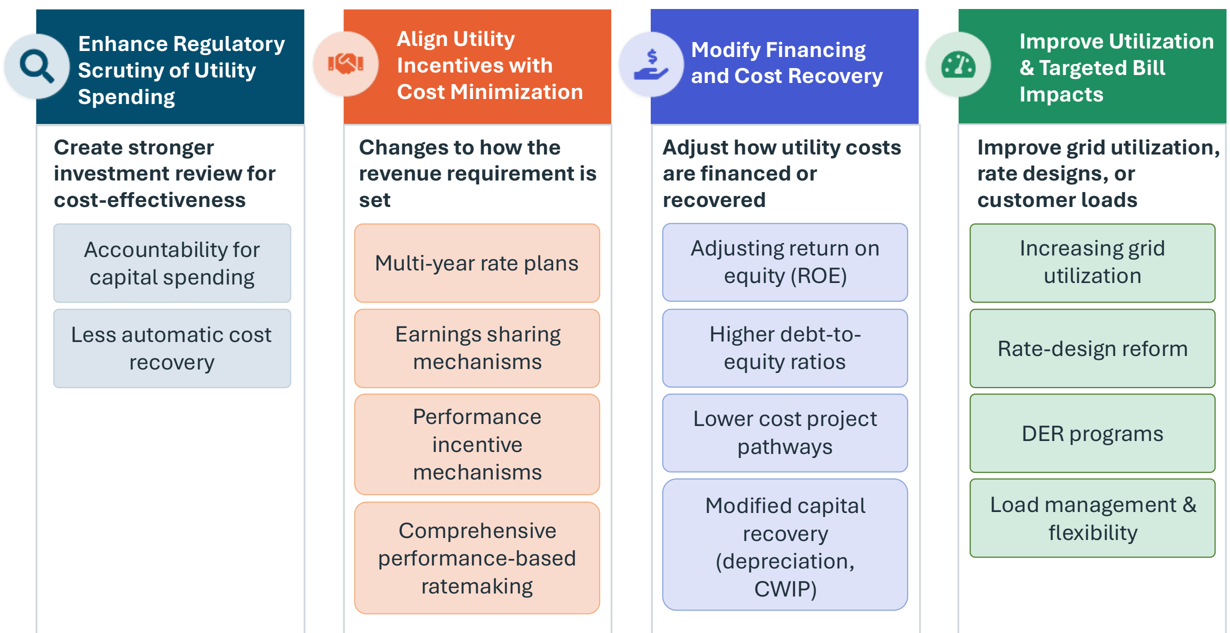
The first characterization is used to organize the reform options reviewed in this section. As shown in Figure 7, reform options are grouped into four general types of regulatory approaches:

- **Modifying financing and cost recovery treatment:** Adjusting the financing, depreciation, or cost-recovery component of the revenue requirement. These tools can lower near-term bills or financing costs, but some may shift costs across time or alter risk allocation rather than reduce underlying system costs. These distinct impacts are also shown in Figure 8 below.

- **Aligning utility incentives with cost minimization:** Changing how utilities earn or retain revenues so they have stronger incentives to contain costs or pursue lower-cost alternatives.
- **Enhancing regulatory scrutiny of utility spending:** Improving the quality of information, planning, and review before capital costs are recovered from customers.
- **Improving system utilization and targeted bill impacts:** Reducing average costs or targeted bills by shifting load, deferring upgrades, or changing how costs are allocated.

Figure 7. Potential Reform Levers to Support Customer Affordability

*Key **business model reform options** affect affordability through the following four regulatory approaches:*

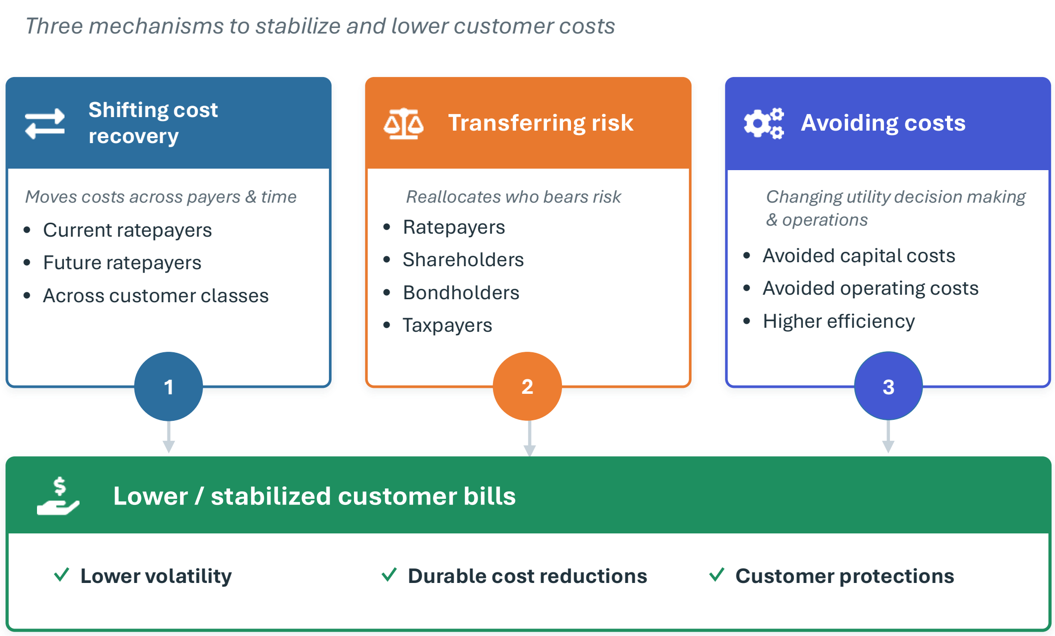


These approaches have different implications and create different trade-offs. For example, financing and cost-recovery tools can produce rate relief, but may entail trade-offs related to utility financial integrity, intergenerational cost recovery, or risk allocation. Similarly, utility incentive reforms can produce savings, but experience to date shows that they can also lead to conflicting regulatory changes that undermine long-term customer affordability outcomes. Thus, utility incentive reforms must be carefully designed to achieve the intended result, including well-established baselines, performance metrics, and guardrails. Iterative changes may be required to address unforeseen outcomes and to ensure cost savings. In contrast, regulatory scrutiny reforms may not look as transformative as other reforms, but they are often a practical near-term step because they improve transparency, accountability, and decision quality under existing regulatory authority. Utilization and rate-design tools can reduce system costs, impact targeted customer bills, and provide customers with more control over their energy expenditures, but they must be designed carefully to manage cost shifting and localized impacts.

The second characterization, shown below in Figure 8, is used throughout the report to interpret the cost recovery impact of each reform. This distinction is important because not every reform that lowers or stabilizes customer bills reduces total system costs. In particular, reforms may affect affordability through three broad impacts:

+ **Shifting cost recovery:** Moving costs across payors, customer classes, or time periods. Examples may include changes to depreciation, rate design, or funding certain programs through taxes rather than rates.
+ **Transferring risk:** Changing which party bears performance, financing, construction, market, or cost-recovery risk. Risk may be transferred among ratepayers, shareholders, bondholders, taxpayers, or participating customers.
+ **Avoiding costs:** Reducing the underlying cost of providing service, such as through avoided capital investment, reduced cost overruns, lower financing costs, improved system utilization, avoided operating costs, or higher efficiency.

Figure 8. Financing and Cost Recovery Impacts



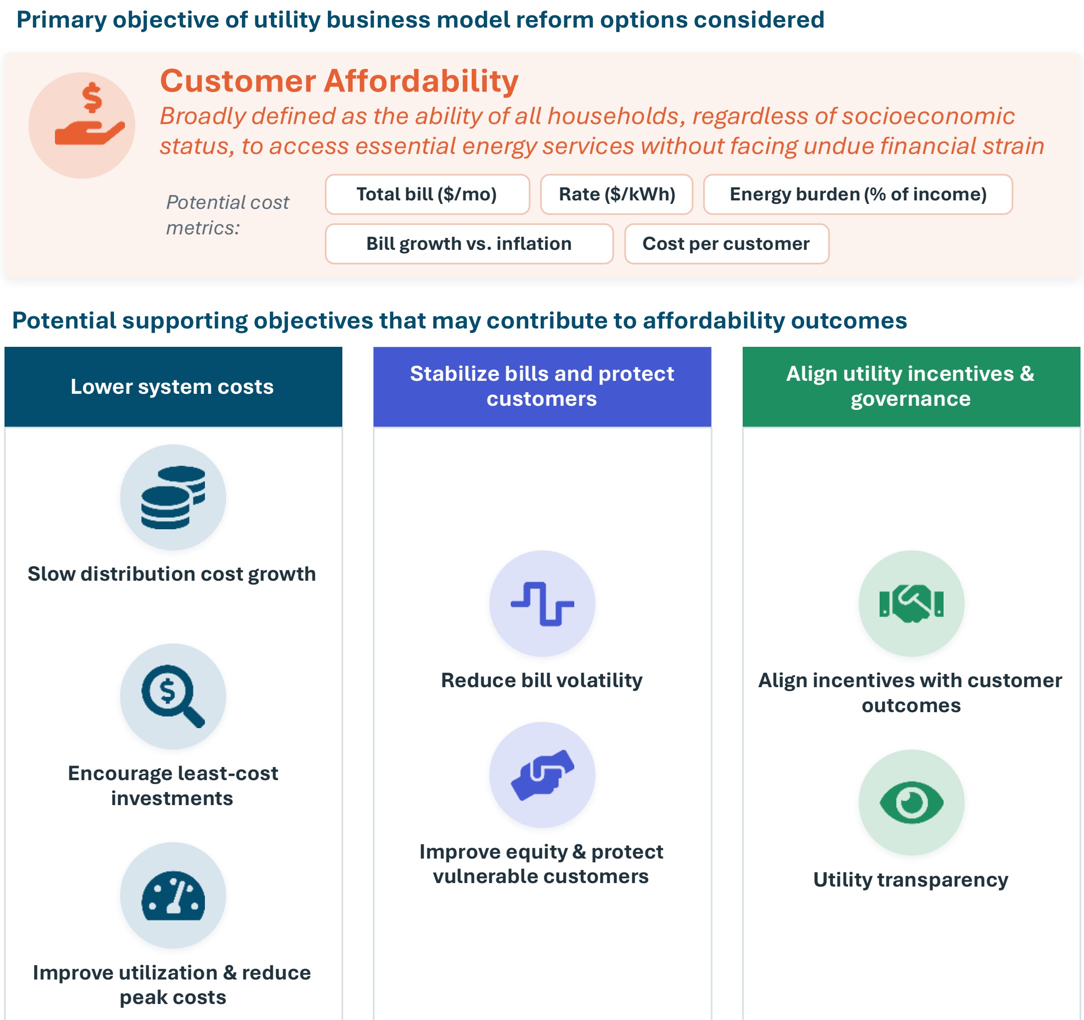
This distinction helps clarify a key difference across reforms. For example, a lower authorized return on equity may reduce the financing component of the revenue requirement. In contrast, a longer depreciation schedule may reduce near-term bills, but shift recovery to future customers, or a rate design change may improve affordability for targeted customers but reallocate costs to others. Thus, this characterization helps identify which reforms are most likely to reduce total costs, which primarily manage or reallocate bill impacts, and which require additional safeguards to protect customers.

3.2 Other Potential Objectives of Utility Business Model Reform

Utility business model reforms are tools for advancing specific regulatory objectives, and it will be important to align on the specific regulatory objective for each reform and to assess trade-offs. While this study is focused primarily on affordability, it is only one of several objectives that utility regulation must balance. New Jersey's utility business model must also support safe and reliable service, reasonable utility access to capital, customer service, equity, resilience, efficient DER integration and optimization, and state clean energy, decarbonization, and other policy goals. These objectives can be complementary, but they can also be in tension. For example, reforms that reduce financing costs may lower near-term customer bills but could raise concerns about utility financial integrity. In contrast, reforms that encourage reliability, resilience, or grid modernization investments may produce long-term customer benefits but increase bills in the near term.

In addition, utility business model reforms implemented to date also target other key objectives, including everything from building consumer confidence through greater cost transparency to supporting the achievement of state policy goals like greater clean energy deployment. This report identifies potential reforms and policy levers that can support these other regulatory objectives, though it is not the focus of Phase 1. As the study proceeds to Phase 2, potential reforms will be evaluated based on the specific objectives they are intended to advance, the strategy through which they are expected to affect said objectives, and the metrics that would be used to assess whether they are working. For reforms that are not primarily affordability-focused but may indirectly influence affordability, their affordability implications will still be evaluated.

Figure 9. Potential Objectives of Utility Business Model Reform



To support this distinction, the evaluation in the following sections identifies each reform's primary cost-reduction impact but should be interpreted alongside any broader regulatory objective the reform is designed to advance. This distinction is important because reforms will typically only achieve the objectives they are designed to address. A reform that scores well on affordability may not be the best tool for other objectives, and a reform that advances reliability, resilience, or decarbonization may not reduce customer bills.

3.3 Criteria for Assessing Utility Business Model Reform Options

The study evaluated potential utility business model reform options and policy levers using a set of high-level criteria. These evaluation criteria are summarized below in Table 3. Detailed explanations of the scoring of each reform option are provided in the following sections. The goal of this assessment was not to "pick winners" or to select a single preferred option, but to support a practical screening of options for their potential to support stabilizing, lowering, or deferring costs for customers in New Jersey. This qualitative screening can help identify which reforms are appropriate for near-term “low regrets” consideration, and which should be prioritized for analytical assessment in Phase 2 of this study.

Table 3. Summary of Evaluation Considerations

Criteria	Description and Scoring
Financing and Cost Recovery Impact	Impact on financing and cost recovery; may involve multiple types (see Figure 8) • **Transferring risk**: Reallocates who bears risk (ratepayers, shareholders, bondholders, taxpayers) • **Shifting costs**: Moves costs between current and future ratepayers, and/or across classes or customer types • **Avoiding costs**: Reduces the underlying utility cost of service through avoided investments, avoided operating costs, and/or higher efficiency
Transparency	Impact on regulatory visibility into utility costs and decisions: • **Increase:** Requires new standardized reporting, public performance disclosure, or benefit-cost documentation that improves regulatory visibility • **Neutral:** Has no inherent change to reporting or oversight obligations • **Decrease:** Reduces the frequency or level of detail of reporting and/or regulatory review.
Regulatory complexity	Impact on administrative burden for the utility and regulator; for example, increasing transparency may require additional action and effort. • **Increase:** Adds new filings, monitoring, or review requirements • **Neutral:** Has no meaningful change to administrative obligations • **Decrease:** Consolidates or reduces the frequency of filings, monitoring, or review requirements
Implementation needs	Likely difficulty of implementing the reform in New Jersey given legal authority, required processes, and/or stakeholder complexity. • **Low:** Implementable through existing NJBPU rate case or rulemaking authority without new legislation • **Mid:** Requires new dedicated proceedings, significant rulemaking, or stakeholder process beyond normal rate cases • **High:** Requires legislative action, major structural changes to the regulatory framework, or resolution of significant legal uncertainty
Bill reduction potential	The relative magnitude of achievable savings of the reform option. All reforms have a range of potential impacts; this scores an approximate average implementation. Quantitative modelling in Phase 2 will revise these impact estimates. • **Low:** Reform targets a narrow cost category or impacts bills indirectly • **Mid:** Reform has meaningful but partial bill impact, either because it affects only a portion of the revenue requirement or because savings depend on design • **High:** Reform has the potential to materially reduce total distribution bills across all customers
Bill increase risk	The potential risk that implementing the reform produces unintended bill increases or adverse customer outcomes, assuming an average reform implementation. • **Low:** Customer protections are well-established, adverse outcomes unlikely • **Mid:** Bill increases are possible under poor design or unfavorable conditions • **High:** There is material risk of bill increases regardless of design or conditions
Timeline	Timeframe over which New Jersey could realistically implement reform. Year ranges are illustrative. • **Near-term:** 1-2 years, typically within existing proceedings • **Mid-term:** 2-5 years, typically requires new proceedings or other enabling steps • **Long-term:** 5+ years, typically requires legislation or significant new frameworks

These criteria should be interpreted together. In particular, the financing and cost-recovery impact describes how a reform may affect bills, while the remaining criteria describe whether the reform can be implemented effectively in New Jersey. A reform with high bill-reduction potential may still be a poor near-term candidate if it requires new authority, reduces transparency, or creates material bill-increase or financing risk. Conversely, reforms with more modest bill reductions may be high-value near-term steps if they improve transparency, strengthen regulatory oversight, and establish baselines for later reforms.

These criteria identify likely or potential outcomes of the utility business model reforms. Whether a specific reform would increase transparency or risk increasing utility bills, for example, is ultimately a product of how the reform is designed and implemented. Many of the reforms in this study can mitigate or avoid their potential downsides with careful design. The criteria scoring in this report is not intended to provide definitive answers to the efficacy or the merits of specific reforms, but rather to provide insights into the potential upsides and drawbacks of each reform.

The specific reform option scoring assigned in this report reflects a directional, screening-level judgment informed by the jurisdictional review (see Appendices A and B for full details) and New Jersey's specific regulatory, institutional, and market context. The illustrative screening-level scores are designed to support prioritization and scenario design and are neither definitive nor a substitute for the quantitative analysis that Phase 2 will provide. Additional directional assessments are discussed in Appendix C.

3.4 Modifying Financing and Cost Recovery

Financing and cost-recovery tools affect the revenue requirement without necessarily changing how utilities plan, operate, or invest. These options are important because their bill impacts can often be quantified more directly than those of broader incentive reforms. Their limitation is that some tools primarily change the timing, financing cost, or risk allocation of recovery rather than the underlying drivers of capital spending. They should therefore be evaluated alongside planning, accountability, and utilization reforms that can reduce the need for future costs.

3.4.1 Return on Equity and Capital Structure Reforms

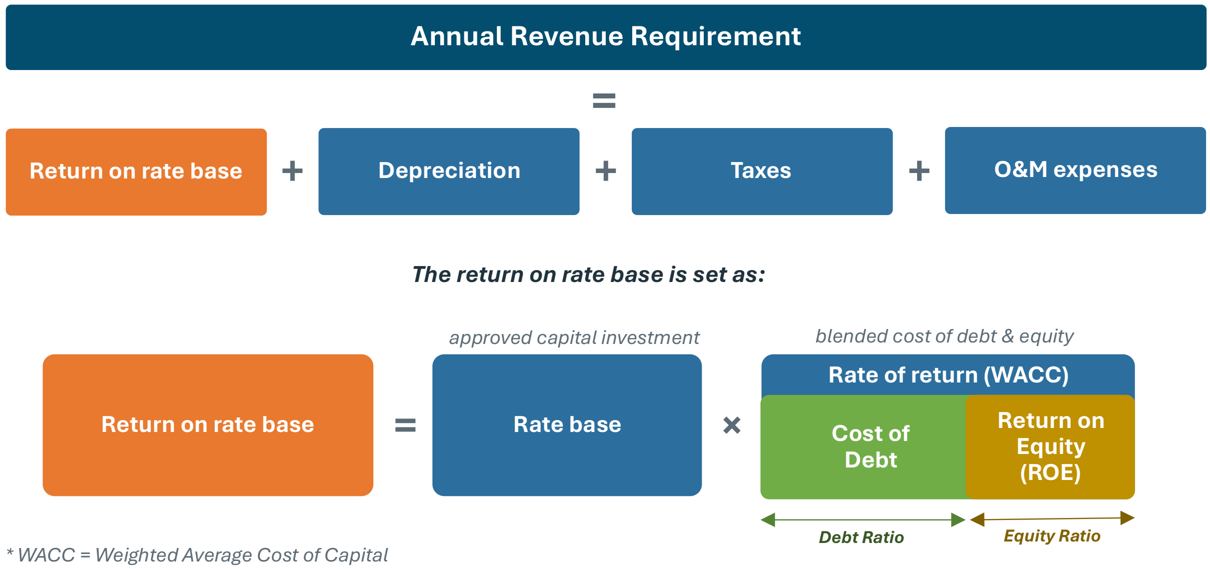
Reducing authorized ROE or adjusting the approved debt/equity ratio is one of the most direct ways to reduce the financing component of distribution rates. Under cost-of-service regulation, customers pay depreciation, operating expenses, taxes, and a return on the rate base, which reflects the utility's net capital investment, on which it earns a return. This relationship is illustrated in Figure 10. Because equity is more expensive than debt, both the authorized ROE and equity ratio affect the weighted average cost of capital (WACC) embedded in

> *Lowering the allowed **return on equity** or **shifting toward debt** directly cuts the financing part of bills and can be done within a rate case. Incremental and well-supported changes over time support sustainable, long-term reform.*

customer rates. There is also evidence that higher ROE can further incentivize capital spending.[35]

Figure 10. Illustration of Capital Structure and ROE Impact on Revenue Requirement

Capital structure and approved ROE determine the return on rate base that the utility collects through rates

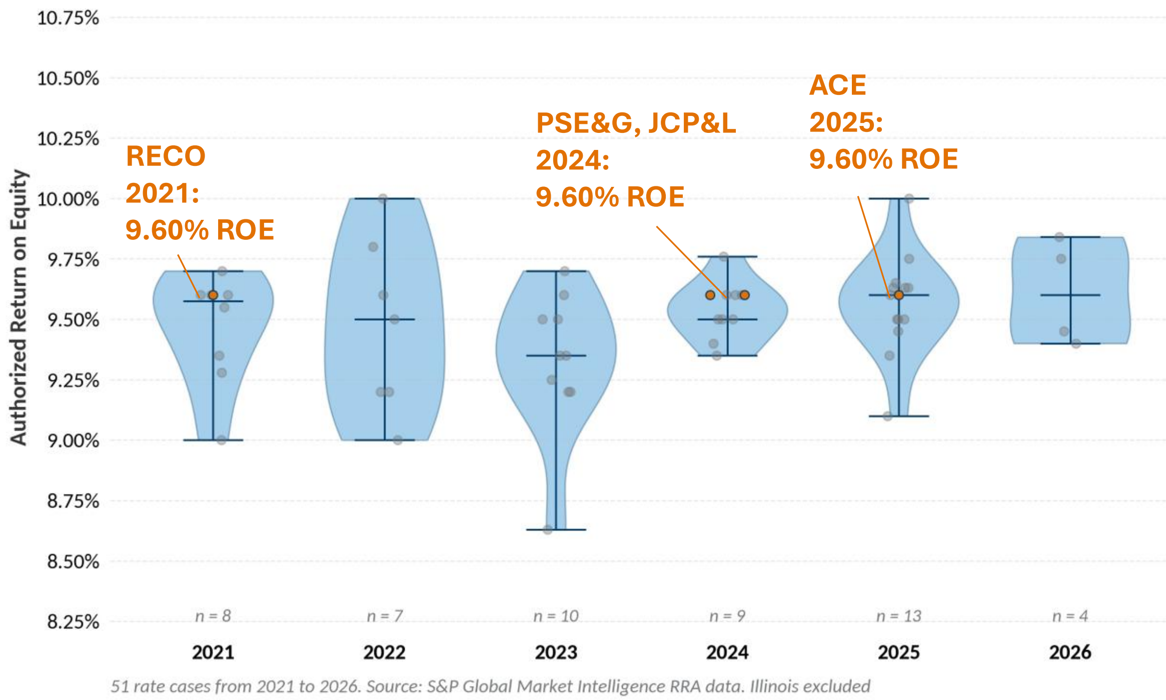


As shown in Figure 11, authorized distribution-only ROE for electric utilities across the United States from 2016 through March of 2026 ranged from 8.25% to 10%, with a median value of 9.50%.[36] New Jersey's EDCs currently have authorized ROEs of 9.60%.

[35] Karl Dunkle Werner and Stephen Jarvis, "Rate of Return Regulation Revisited," *Journal of Public Economics* 259 (2026): 105654, https://doi.org/10.1016/j.jpubeco.2026.105654

[36] E3 analysis of authorized utility ROE from 2016 through 2026, using S&P Global Market Intelligence Regulatory Research Associates Rate Case History database, accessed on July 9, 2026. The range presented excludes Illinois utility ROE due to the use of formula rate mechanisms,

Figure 11. Authorized Electric Utility Distribution-Only ROE, 2016 to 2026



Capital structure reforms that adjust capital structure more heavily toward debt (higher leverage) lower a utility's WACC and, in turn, lower revenues that the utility collects from customers. Capital structure reforms may also consider the ability of a utility's parent company to access debt and subsequently contribute it to the utility as equity (referred to as double-leveraging).

Proponents of a higher debt-to-equity ratio argue that, because utilities are low-risk investments, they should attract low-interest debt. However, this relationship does not hold without limit. As a utility takes on more leverage, the layer of equity that protects debt lenders – and ultimately ratepayers – shrinks and may reduce cash flows available to cover interest payments. Higher leverage can impact key credit rating metrics and, in some instances, prompt credit rating agencies to downgrade the utility's credit rating. A credit rating downgrade generally raises the utility's cost of debt and influences the ability to raise the needed amount of capital. A downgrade can potentially lead to higher return on equity levels as well as higher interest rates that the utility pays on new, refinanced, and/or variable rate debt due to a higher perceived risk premium, which potentially requires a higher return to attract capital. Because those higher borrowing costs are themselves passed through to ratepayers, this puts upward pressure on rates. This upward pressure on rates may be offset by the downward pressure applied by the lower ROE, depending on the circumstances.

Recently discussed options across the U.S. for **reforming ROE** include the following:

- Standardizing financial models used in rate cases to exclude methods that recycle previously awarded ROEs. These standards could be codified in legislation to remove case-by-case regulatory discretion.

- Calculating the authorized ROE through a default formula tied to Treasury yields. This approach standardizes the ROE calculation process at the risk of ignoring company or region-specific differences in risk.[37]
- Holding a competitive equity auction in which investors bid the minimum return they require. Competitive equity auctions are an emerging ROE reform option that has yet to be implemented by any state, though it is actively being explored in Pennsylvania.

In New Jersey, NJBPU has the authority to review ROE and capital structure through general rate cases. The policy question is thus whether and how to use that authority, how to appropriately and transparently evaluate recent discussions on best practices for calculating ROE benefits, and what risks or benefits may result. Modest changes may reduce customer costs with a limited implementation burden. More comprehensive changes, particularly if implemented without careful consideration of the risks and benefits and input from key stakeholders, could reduce financial headroom, heighten perceived regulatory risk, and increase future debt and/or equity costs. Therefore, the balance regulators must strike in any ROE and capital structure reform is achieving reasonable, near-term bill relief, modernizing financial models and ROE calculation approaches, as appropriate, and maintaining utility access to capital on reasonable terms.

Jurisdictional experience supports a balanced, incremental, and iterative approach. The Connecticut Public Utilities Regulatory Authority (PURA) approved an effective ROE of 8.63% for United Illuminating (UI) in 2023, substantially below the requested amount and UI's prior ROE values. To determine the base authorized ROE of 9.10% and additional penalties, the regulator cited both comparable distribution utility returns and performance concerns. Utilities and credit rating agencies later asserted that methodological changes to the calculation of base ROE and the specific application of ROE penalties were a significant departure from precedent and created regulatory uncertainty. However, notably, UI's credit rating remained investment grade. PURA subsequently raised UI's ROE in 2025.

Colorado's Black Hills decision similarly illustrates that commissions can reject proposed capital structures and authorized returns when supported by a record, but utilities may challenge reductions as departures from precedent that risk negative reactions from the financing community. Regulatory investigations prior to adopting new ROE practices in rate cases are an approach to addressing the claim that these reforms create regulatory uncertainty. Additionally, Pennsylvania's proposed ROE legislation and competitive auction concept show growing interest in market-based ROE reform, but these approaches remain untested.

[37] American Economic Liberties Project, "New Economic Liberties Paper Exposes How Investor-Owned Utilities Exploit Rate-of-Return Policies to Overcharge Americans," January 17, 2025, https://www.economicliberties.us/press-release/new-economic-liberties-paper-exposes-how-investor-owned-utilities-exploit-rate-of-return-policies-to-overcharge-americans/.

Table 4. Evaluation of Return on Equity and Capital Structure Reforms

Metric	Score	Explanation
Financing and Cost Recovery Impact	**Transferring risk, avoiding costs**	• Directly reduces the return component of the revenue requirement • Effect is immediate once reflected in rates and applies to the full rate base • Deeper reforms may be possible over time, with additional rate reductions, depending on the efficacy of emerging approaches • May result in medium to longer-term increases in costs that may or may not be offset by the reduced financing costs, if the utility risk profile is negatively perceived by the financing community, increasing the cost of debt
Transparency	**Neutral**	• ROE and capital structure adjustments do not inherently improve or reduce visibility into utility costs or performance
Regulatory complexity	**Neutral**	• ROE and capital structure adjustments do not inherently increase or reduce administrative burden for the utility and regulators
Implementation needs	**Low**	• NJBPU already has full authority to set ROE and capital structure in rate cases; no statutory change required. • Experience shows that setting an ROE below that of other jurisdictions is achievable but must be grounded in rigorous analysis. • Does not require changes to utility operations or capital programs
Bill reduction potential	**Mid**	• Directly reduces the financing portion of the revenue requirement, although the total impact may be limited because the financing component is only a share of total distribution costs and practically defensible ROE reductions tend to be modest in scale
Bill increase risk	**Low**	• ROE reduction reduces financial headroom and could increase the cost of future debt. This risk may be manageable for small changes of ROE, but could be more significant for larger reductions. Quantifying the risk for more material capital structure changes can be evaluated in Phase 2.
Timeline	**Near-term**	• NJBPU can launch a proceeding to investigate changes to capital structure and ROE. Any changes would be implemented in the next general rate case for each EDC. No changes to legislation are required. • Particularly actionable for utilities with rate cases already pending or scheduled.
Preliminary Takeaway for New Jersey	**Implication:** Commissions can directly reduce financing costs when supported by a rigorous record, but reductions should be calibrated to avoid unnecessary financing risk, litigation, and/or unintended consequences. **Recommendations**: ROE and capital structure review are worth near-term quantitative review as part of Phase 2 quantitative assessment and/or in the context of upcoming rate case.	

3.4.2 Criteria-based Lower-cost Project Pathways

Ratepayer costs can also be reduced by creating an optional, **criteria-based lower-cost pathway** through which certain projects can qualify for financing structures that reduce the cost of capital below the utility's standard WACC. Examples include access to higher shares of debt (which have lower rates than equity), lower debt expenses (e.g., tax-exempt debt or governmental loan programs), or lower authorized equity returns. The concept is project-specific rather than utility-wide, allowing regulators to apply differentiated financing treatment on a case-by-case basis without altering the overall authorized return. By reducing the cost of capital for qualifying projects, criteria-based pathways can lower the revenue requirement for large discrete investments.

Well-defined approval pathways for lower-cost financing can speed-up and discipline spending on well-justified project types, but the savings hinge on strict eligibility and customer-benefit tests.

The primary advantage is that this option can reduce customer costs while preserving the traditional rate case framework for the broader utility. It also increases transparency because qualifying projects must meet explicit eligibility and customer-value criteria. The main tradeoff is increased administrative complexity: the NJBPU would need standards for eligibility, risk transfer, cost caps, prudence review, and the sharing of benefits among customers, utilities, and any financing partner.

New Jersey's existing Infrastructure Bank (I-Bank) provides an in-state example, providing lower-cost financing to local governments and authorities making qualifying public infrastructure investments. This financing is funded by bonds that the I-Bank issues, whose strong credit rating attracts lower interest rates than utilities would otherwise pay on their own. Current statutes limit the I-Bank to environmental infrastructure (e.g., wastewater and water supply), transportation, aviation, marine, and hazard mitigation/resilience projects,[38] but the model could potentially be extended to electric system investments. Other examples include the Department of Energy (DOE) loan programs for capital-intensive energy projects and the Pacific Gas and Electric (PG&E)/Citizens Energy partnership, under which Citizens finances certain transmission assets at a lower cost and directs a portion of returns toward community benefits. These examples are described in more detail in the jurisdictional summary in the appendix.

Lower-cost project pathways might be especially attractive for project categories that are understood to carry lower risk to the utility. Utility ROEs are intended in part to provide a risk premium to the utility for funding capital investments for a potentially extended period before they can recover costs. It follows that capital programs that allow for rapid cost recovery through riders might reasonably warrant a lower ROE, thereby reducing financing costs that flow through to customers. New Jersey's Infrastructure Investment Program (IIP), which funds grid modernization and resiliency efforts, is an example of a program where this could be implemented.

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[38] New Jersey Infrastructure Bank, "New Jersey Infrastructure Trust Act / Enabling Act," February 2025, https://cdn.njib.gov/njib/statutes/Updated%20enabling%20act%20Feb%202025.pdf.

Table 5. Evaluation of Criteria-based Lower-cost Project Pathways

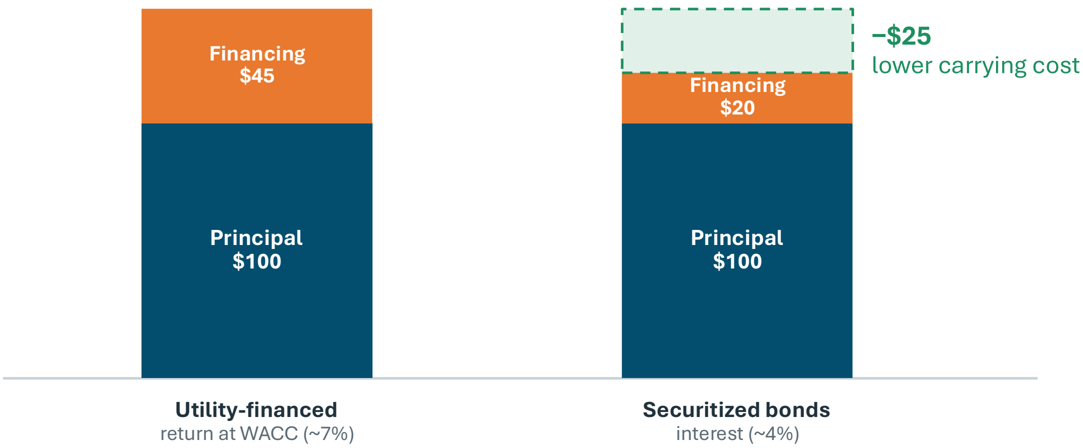
Metric	Score	Explanation
Financing and Cost Recovery Impact	**Transferring risk; shifting costs; avoiding costs**	• Reduces the cost of capital for qualifying projects by directly lowering the revenue requirement for targeted investments • Some risk is transferred from customers to the applicable financing institution
Transparency	**Increase**	• Criteria-based pathways require documentation for each qualifying project. • Improves transparency of project-level cost recovery relative to standard rate-base treatment.
Regulatory complexity	**Increase**	• Additional documentation and evaluation requirements for each project increase administrative burden
Implementation needs	**Mid**	• No statutory change is strictly required • Federal loan programs such as DOE LPO require separate application processes. • U.S. experience has been largely case-by-case rather than standardized
Bill reduction potential	**Low**	• Directly reduces the financing portion of the revenue requirement, although the total impact may be limited, as the reform only targets select projects
Bill increase risk	**Low**	• Safeguards can mitigate the risk of cost overruns being passed to customers.
Timeline	**Mid-term**	• Initial case-by-case applications could proceed in the near term. • A systematic and replicable program would likely require longer to develop and implement.
Preliminary Takeaway for New Jersey	**Implication:** Valuable for specific investments, such as large grid modernization, resilience, or interconnection-related investments where customer benefits can be clearly documented and strict customer-value tests can be applied. **Recommendations**: Review recent investment categories as part of Phase 2 quantitative assessment to assess whether certain investment categories or specific projects could be targeted (e.g., substation rebuild or expansion) for near- to mid-term lower-cost financing.	

3.4.3 Securitization

Securitization allows a utility to refinance a defined category of costs by issuing lower-cost bonds backed by revenues from ratepayers. Because the bonds carry lower interest rates than conventional utility debt, they reduce the total financing cost associated with eligible cost streams and lower the annual revenue requirement. The technique is well established in the United States, such as for coal plant retirements and more recently wildfire-related costs, but its application in New Jersey may require legislation for new eligible categories.

Figure 12. Illustration of Securitization Impact on Utility Costs

Securitization could replace utility financing of certain costs with low-cost, ratepayer-backed bonds — lowering the carrying cost, though it would not reduce the underlying cost itself.



Refinancing large, typically one-time costs at lower rates can deliver clear up-front savings, but it works best for well-defined cost categories and needs guardrails to ensure prudent use.

New Jersey's past experience with utility asset securitization is limited, but there is precedent from the State's deregulation of the electricity market in the early 2000s. The transition to a deregulated market presented a stranded cost problem for utilities divesting of their generation assets, due to potential differences between their market and book values. By statute and with NJBPU approval, utilities were allowed to issue transition bonds to recoup their stranded costs, backed by a non-bypassable ratepayer charge over a term of up to 15 years. Utilities that divested a majority of their generation assets could securitize the full amount of those costs.[39]

A key question for implementing securitization going forward is which specific investments would be securitized. Securitization is most effective when applied to narrow, well-defined cost categories where customers benefit from replacing higher-cost financing with lower-cost bonds. It is less compelling when used to socialize risks that should remain with utility shareholders or when it shifts costs to future customers without reducing total costs. Given this, securitization is a targeted mid-term tool that can be explored. If applied, it should also be coupled with clear consumer protections, savings tests, and limits on future cost shifting.

[39] New Jersey Revised Statutes, Section 48:3-62, https://law.justia.com/codes/new-jersey/title-48/section-48-3-62/.

Table 6. Evaluation of Securitization

Metric	Score	Explanation
Financing and Cost Recovery Impact	**Transferring risk; avoiding costs**	• Securitization bonds carry lower interest rates than conventional utility debt, directly reducing financing costs for eligible costs. • Repayment risk is transferred to customers
Transparency	**Neutral**	• Securitization does not change visibility into utility operations or capital decisions.
Regulatory complexity	**Increase**	• Implementing securitization would require dedicated proceedings and potentially new statutory authority, adding near-term regulatory workload.
Implementation needs	**Mid**	• Well-established legal and financial precedent in other U.S. states, but may require New Jersey-specific legislative or other adaptations to implement.
Bill reduction potential	**Mid**	• Directly reduces the financing portion of the revenue requirement, although the total impact may be limited due to only impacting a portion of the revenue requirement and only targeting eligible costs
Bill increase risk	**Low**	• Limited risk. Securitization decreases financing costs.
Timeline	**Mid-term**	• Requires enabling legislation before most New Jersey applications are viable.
Preliminary Takeaway for New Jersey	**Implication**: This can be valuable for specific types of costs, such as emergency response, large grid modernization, resilience, or interconnection-related investments where customer benefits can be clearly documented and strict customer-value tests can be applied. **Recommendation:** Unlikely to be primary affordability solution for New Jersey but may have targeted applications. Consider securitization for large, well-defined cost categories where up-front customer savings are clear, paired with strict eligibility criteria so it does not become a routine financing path.	

3.4.4 Modified Capital Recovery Rules

Capital cost recovery rules determine what assets a utility can include in its rate base and how quickly it recoups the cost of its infrastructure investments through customer rates. Reforming capital recovery rules related to depreciation schedules and Construction Work in Progress (CWIP) is particularly relevant to affordability objectives. These rules directly affect the annual revenue requirement without requiring changes to the capital spending itself. Longer depreciation periods reduce near-term annual revenue requirements by spreading costs over more years. Limiting or modifying CWIP delays recovery until projects are used and useful, reducing customer exposure to construction risk, but may come at the cost of higher financing costs.

> *Adjusting **depreciation and construction-in-progress rules** can lower near-term bills and reduce customers' exposure to project risk, but it can shift costs onto future ratepayers if not bounded.*

Depreciation schedules determine how quickly utilities recover the cost of their capital assets through customer rates. Under traditional straight-line depreciation, the annual cost is the total asset cost divided by the assumed useful life. Extending the useful life assumption reduces the annual depreciation component of the revenue requirement. Over this longer depreciation period, the utility collects additional returns (on an undiscounted, simple sum basis over years) because assets remain in the rate base longer; however, the utility still recovers the same net present value (NPV) over the extended period that is equal to the total cost of the project. Longer depreciation periods shift obligations to future ratepayers; depending on the perceived customer discount rate, this may garner perceived affordability benefits in the near term, particularly if discount rates are relatively high, because customers would strongly value nearer-term bill reductions. However, for assets facing potential early retirement, extending depreciation creates stranded cost risk. Typical best practice is to align the depreciation schedule with the likely useful life of an asset.

In typical ratemaking, capital investments enter the rate base only after they are placed in service, meaning customers begin paying a return on an investment only once it is operational and delivering benefits. In contrast, **Construction Work in Progress (CWIP)** allows utilities to include capital costs in rate base before assets are in service, enabling cost recovery to begin during construction. CWIP shifts construction risk from utilities to customers. If a project is delayed, canceled, or underperforms, customers may have already borne costs disproportionate to the benefits they receive.

Modified CWIP rules strengthen cost controls and reduce risk to customers. Possible reforms include:

1. Setting budget caps and prohibiting change orders.
2. Approving a lower authorized ROE for CWIP investments.
3. Prohibiting the use of CWIP and requiring that projects be completed before they are entered into rate base.

While CWIP restrictions can protect customers from paying for incomplete or delayed projects, they may increase utility financing needs during construction. For large projects, a lower ROE on CWIP, budget caps, milestone-based approvals, and limits on change orders may provide a better balance than a categorical prohibition.

Table 7. Evaluation of Modified Capital Recovery Rules

Metric	Score	Explanation
Financing and Cost Recovery Impact	**Transferring risk; shifting costs; avoiding costs**	• Longer depreciation periods directly reduce the annual depreciation component of the revenue requirement in the near-term; however, they do not change the total net present value costs of a project. • Limiting CWIP reduces near-term revenue requirements (delaying capital inclusion in the rate base) and limits customer exposure to risk of construction spending overages.

		• Both mechanisms shift costs to future ratepayers.
Transparency	**Neutral**	• No inherent improvement or reduction in regulatory transparency.
Regulatory complexity	**Neutral**	• No inherent improvement or reduction in regulatory burden.
Implementation needs	**Low**	• Fully within NJBPU's existing rate case authority. • No statutory change, enabling legislation, or new proceeding type required. • Can be addressed in the next general rate case
Bill reduction potential	**Mid**	• Reduces the rate base and the depreciation component of the revenue requirement in the near-term; both may have targeted applications but are not a scalable standalone affordability solution.
Bill increase risk	**Mid**	• Longer depreciation has near-term rate reduction, but it creates extended obligations for future ratepayers. • Limiting the use of CWIP shifts costs into the future over a shorter period, which may cause higher annual costs once the asset is active. Limiting CWIP can also increase utility borrowing costs. • For assets at risk of early retirement, extending depreciation creates stranded cost risk.
Timeline	**Near-term**	• Can be addressed in the next general rate case for each EDC.
Preliminary Takeaway for New Jersey	**Implication**: Both may have targeted applications, but are not standalone affordability solutions. Longer depreciation periods reduce near-term annual revenue requirements by spreading costs over more years. Limiting or modifying CWIP delays recovery until projects are used and useful, reducing customer exposure to construction risk, but should be bounded. **Recommendation**: Evaluate this as a project-specific option rather than a full-scale affordability solution.	

3.5 Aligning Utility Incentives with Cost Minimization

Reforms that align utility incentives with cost minimization change how utilities earn revenues over time. Their potential value lies in reducing the structural incentive or bias toward capital spending and creating incentives for cost containment, performance, and lower-cost alternatives. Their risk is that poor design can increase bills, reduce transparency, or reward utilities for outcomes that would have occurred anyway.

3.5.1 Performance-Based Ratemaking (PBR)

Performance-based ratemaking (PBR) is a framework that connects utility financial outcomes to specified objectives. For purposes of this assessment, we consider PBR to include the following three mechanisms: multi-year rate plans (MRPs), earnings sharing mechanisms (ESMs), and targeted performance incentive mechanisms (PIMs). We recognize that other variants of PBR exist. In the following sections, we evaluate each of these components of PBR individually.

> ***PBR** is not a standalone affordability solution to date. The reforms typically included in a PBR framework should be evaluated as part of a "staged" pathway that focuses first on building capacity and implementing early reforms (e.g., scorecards, PIMs), which can be evaluated for savings and durability.*

The jurisdictional evidence on PBR is mixed. Hawaii adopted a PBR framework for Hawaiian Electric Company (HECO) that includes a five-year MRP, PIMs, an ESM, and exceptional project recovery. Hawaii illustrates both the promise and the challenge of PBR: several targeted metrics improved, but expected residential bill savings have not clearly materialized, and the rebasing process has generated disputes over inflation treatment and whether the framework is drifting back toward cost-of-service ratemaking. These benefits and challenges in Hawaii highlight practical implementation considerations and are detailed further in Appendix B.

Before considering any comprehensive reform framework, such as PBR, New Jersey would benefit from a deeper quantitative assessment of how selected PBR components could be introduced gradually over time. In Phase 2, the NJBPU may evaluate a staged pathway that begins with foundational data, reporting, and capital-planning improvements before testing targeted incentives, shared savings mechanisms, earnings-sharing guardrails, or limited multi-year rate plan elements. A potential staged pathway is described in Section 4.2.4. Any future PBR framework would require careful planning and design, including credible baselines, capital planning data, productivity factors, stakeholder confidence, and customer protections.

3.5.2 Multi-year Rate Plans

Multi-year Rate Plans (MRPs) replace frequent cost-of-service rate cases with a multi-year framework for adjusting rates or revenues in a formulaic manner. A typical MRP begins with a cost-based revenue requirement in the initial year, then updates allowed revenues using an inflation factor, and, as appropriate, a productivity offset, exogenous cost provisions, and defined reopeners or off-ramps, as discussed in more detail below and illustrated in Figure 13.[40]

> *A **multi-year rate plan** can reward cost control between rate cases, but it carries high implementation and bill-increase risk and is best pursued with a strong understanding of baselines and carefully designed guardrails.*

[40] The term "multi-year rate plan" has also been applied to any rate plan that authorizes revenues for more than one year, such as for three forward-looking test years, while still calculating the cost-of-service in each test year. Applied in this way, MRPs have limited cost-containment incentives. In this report, we define MRPs such that allowed rates or revenues for multiple years are set independently of the utility's own costs, without reconciling to match actual spending.

The affordability theory is straightforward: if allowed revenues are set in advance and are not automatically reconciled to actual spending, the utility has an incentive to control costs and retain part of the savings. However, realizing these theoretical savings depends on strong design. If the initial revenue requirement is too high, productivity factors are too weak, or cost trackers proliferate, customers may not benefit. Less frequent rate cases also reduce scrutiny between rebasing periods and can create rate shock when the plan resets.

Well-designed MRPs strengthen the utility's incentives to increase productivity within a given revenue or rate cap. Most forms of MRPs include some or all of the following five steps:

1. **Rebasing:** Begin with a form of cost-based rates that the regulator believes provides a reasonable opportunity for the utility to earn on and recover its prudently incurred costs. Rebasing is performed at pre-defined intervals (often five years).
2. **Inflation (I):** Develop a transparent index that has demonstrated a positive correlation with the utility's historical costs of service. This step is most often based on an economy-wide inflation factor that includes both labor and other goods.
3. **Productivity (X):** Develop an estimate of expected changes in productivity (outputs divided by inputs) of the distribution utility industry to adjust the inflation index. Where I is an economy-wide inflation measure, X is often also designed to capture differences between the economy-wide and utility-specific productivity growth estimates.
4. **Facilitate Material Unfunded Capital Applications:** Incremental funding provisions allow utilities to collect costs outside of the base revenue requirement (as defined by the formula rate). These may include distinct funding mechanisms such as:
    - Pass-through mechanisms that account for fluctuations in costs that utilities have limited control over. These mechanisms range from fuel costs to grid modernization and wildfire mitigation investments.
    - Exogenous provisions (Z-factor) for recovery of costs related to uncontrollable events.
    - Supplemental Recovery Mechanism (K-factor) for recovery of capital and O&M for projects not included in the base revenue requirement.
5. **Re-open rate plan if needed:** Allow for adjustment of the rate plan in the middle of a given MRP cycle if unexpected conditions arise that necessitate it. This can include drastic changes in utility costs, returns falling below authorized levels, and changes in tax laws or interest rates.[41]

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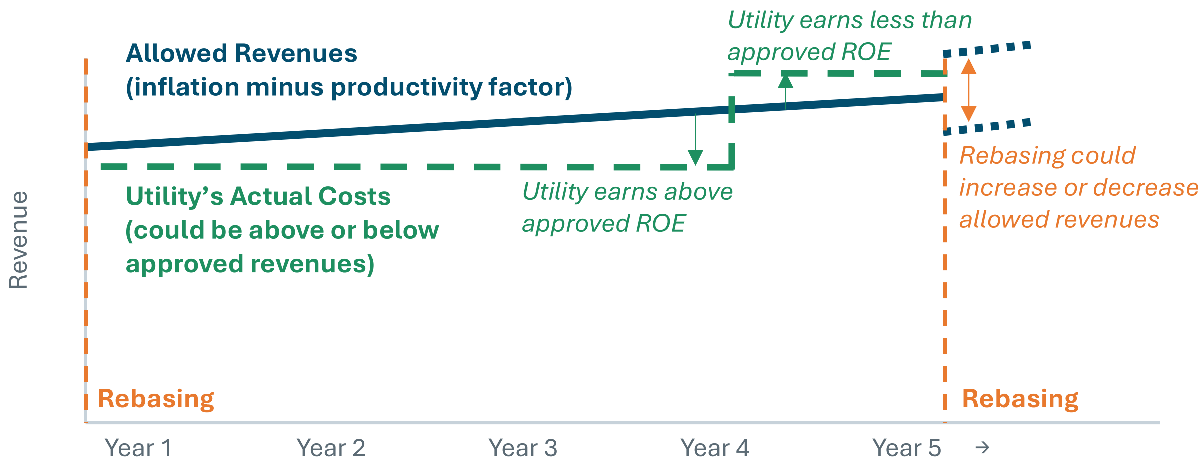
[41] William Zarakas, et al.,"Performance Based Regulation Plans: Goals, Incentives, and Alignment," The Brattle Group, December 6, 2017, https://www.brattle.com/wp-content/uploads/2021/05/14487_2017_12_06_-_brown_et_al_-_pbr_plans_goals_incentives_and_alignment_-_for_dte.pdf.

Figure 13. Illustration of Multi-year Rate Plans

*An MRP sets allowed revenues for several years based on inflation and a productivity factor. If a utility spends less, they earn above their approved ROE. If they spend more, they earn less than their approved ROE.**



**Not considering an Earnings Sharing Mechanism (ESM)*

MRPs can be implemented with either a rate-cap or revenue-cap formula. A rate-cap formula authorizes approved rates. In contrast, a revenue-cap formula authorizes approved revenues, with updated actual or forecast sales values used to set rates each year. A revenue-cap formula is similar to a revenue decoupling mechanism, as discussed below in Section 3.5.5.

Jurisdictional experience with MRPs is mixed. In recent history, National Grid in Massachusetts used revenue-cap adjustments for a mix of capital and O&M costs, with additional riders for specific capital programs. Due to rapidly accelerating infrastructure needs, the regulator now allows capital cost recovery through a mix of riders and traditional cost-of-service mechanisms. In practice, the balance that an MRP strikes between the base revenue cap and the categories of costs collected separately is a central design choice: the more spending recovered through trackers outside the cap, the weaker the plan's cost-discipline incentive.

As described above, the preliminary recommendation suggests an MRP may be appropriate as a mid- to long-term pathway, but only after the NJBPU has developed a strong understanding of baselines, capital planning data, and productivity factors, further built stakeholder confidence, and carefully designed guardrails for trackers, reopeners, and earnings sharing. Phase 2 should evaluate a staged pathway.

Table 8. Evaluation of Multi-Year Rate Plans

Metric	Score	Explanation
Financing and Cost Recovery Impact	**Transferring risk; avoiding costs**	• Incentivizes utilities to manage costs within the price or revenue cap in order to increase earnings. • Productivity offsets (X-factors) directly reduce revenue requirement growth over the planning period relative to inflation.
Transparency	**Decrease**	• Reduces regulatory scrutiny of specific utility costs, instead relying upon formula-based calculations of allowed rates or revenues. • Reduction in transparency may be offset by separate utility investment planning requirements or proceedings.
Regulatory complexity	**Decrease**	• MRPs typically reduce the frequency of rate cases and consolidate multiple, existing cost recovery pathways, which can reduce regulatory burden. • However, the regulatory burden associated with rebasing and determining appropriate inflation factors, productivity factors, and other MRP components is significant. • Overall, the impact on MRPs depends on the relative changes in burden across those factors.
Implementation needs	**Mid**	• Implementing MRPs would require legislative changes • Requires significant analytical and stakeholder process work — designing attrition formula, productivity factor, and capital tracker rules.
Bill reduction potential	**Mid**	• Can directly reduce revenue requirement and incentivizes lower costs through productivity offsets, but only if rebasing, inflation, and productivity factors are well-designed; poorly designed MRPs can raise bills rather than lower them.
Bill increase risk	**Mid to High**	• MRPs could result in higher rates, rather than lower, if rebasing, inflation, or productivity factors are not set appropriately. • MRPs frequently accumulate cost trackers over time, which can circumvent the core cost-discipline function if not controlled. • Less frequent rate cases can produce rate shock if attrition relief mechanisms are not well-calibrated.
Timeline	**Mid to long-term**	• Time is needed for legislation and establishing MRP framework.
Preliminary Takeaway for New Jersey	**Implication:** A well-designed MRP can strengthen cost-control incentives, but only with robust rebasing, a credible productivity factor, and tracker guardrails; if poorly designed it can raise bills and reduce transparency. **Recommendation**: MRPs should be evaluated as part of the quantitative assessment in Phase 2 with scenarios evaluating the appropriate approach to phasing in over time.	

3.5.3 Earnings Sharing Mechanisms

Earnings Sharing Mechanisms (ESMs) are often used with MRPs to limit windfall gains or losses and allocate risks between utilities and customers. An ESM puts a cap on the earned utility ROE, above which a portion of earnings is shared with ratepayers, as illustrated in Figure 14. Some designs also put a floor on the earned utility ROE, below which additional revenues are collected from ratepayers.

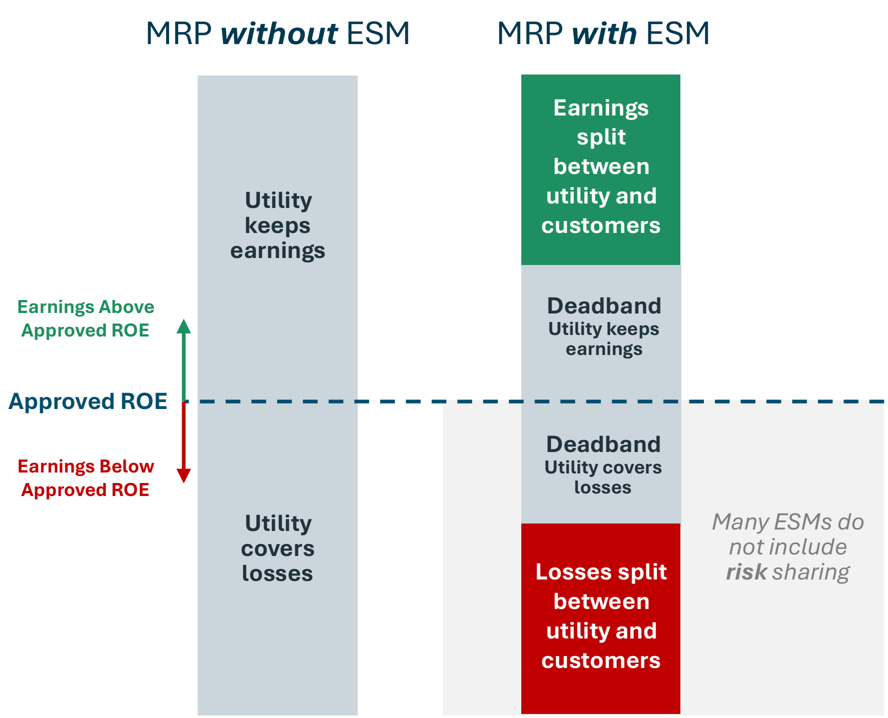
> *An **earnings-sharing mechanism** is a guardrail, not a standalone affordability measure, and is most useful paired with an MRP. It protects customers from windfall gains and shares risk, but mutes utility cost-containment incentives.*

There are several variations of ESMs, with the following key design parameters:

- Risk sharing direction: ESMs can define a cap on earned ROE, and no floor ("upside" risk sharing), or can be implemented with a cap and floor ("symmetric" risk sharing).
- Deadband: A deadband around the approved ROE is often defined, within which the utility retains any excess earnings.
- Customer/utility sharing split: Outside of the deadband, the split of excess earnings (or deficits) can be split between customers and the utility with different ratios (e.g., 50/50 or 80/20). Some ESMs include multiple "tiers" of utility over- or under-earnings (defined as an ROE basis point range), with different sharing splits defined for each tier.

Figure 14. Illustration of Earnings Sharing Mechanisms (ESM)

An ESM is used with an MRP to allocate risk and rewards between utilities and customers when utility spends above or below approved revenues.



ESMs are useful guardrails, but they are not cost-reduction mechanisms on their own. An upside-only ESM can protect customers if the utility over-earns. A symmetric ESM can reduce utility risk, but it can also expose customers to under-earning recovery and weaken the cost-containment incentives that make MRPs attractive in the first place. Design details also matter because deadband width, sharing ratios, tiers, and whether downside sharing is allowed will determine how much risk customers bear.

ESMs are widely implemented in jurisdictions with MRPs, although the design of ESMs varies. The ESM design parameters for key jurisdictions are summarized below in Table 9.

Table 9. Summary of ESMs in Key Jurisdictions

Jurisdiction/ Company	Risk Sharing	Dead Band (Basis Pts)	Tier 1		Tier 2	
			Basis Point Range	Customer/ Utility Sharing (%)	Basis Point Range	Customer/ Utility Sharing (%)
WI – We Energy[42]	Upside	15	15-40	50/50	40	100/0
NY – ConEd[43,44]	Upside	50	50 – 100	50/50	100 – 150	75/25
GA – Georgia Power[45]	Symmetric	100	>100	80/20		
ON – Enbridge and Union Gas[46]	Upside	100	100-300	50/50	>300	90/10
MA - National Grid (Gas): (Boston Gas / Colonial Gas)[47]	Upside	200	> 200	75/25	–	–
MA – National Grid (Electric): (Massachusetts Electric / Nantucket Electric)[48]	Upside	100	>100	75/25	–	–
Vermont – Green Mountain Power[49]	Asymmetric	50	50-125 Upside 50-150 Downside	75/25 50/50	>125 Upside >150 Downside	100/0 0/100
BC – FortisBC and Fortis Energy Inc[50]	Symmetric	N/A	>0	50/50	–	–
HI – HECO[51]	Symmetric	300	300 – 450	50/50	> 450	90/10
AB – Alberta (AUC distribution utilities: ATCO, FortisAlberta, ENMAX, EPCOR, Apex)[52]	Upside	200	200-400	40/60	>400	80/20

[42] WEC Energy Group, "April 2026 Investor Presentation," U.S. Securities and Exchange Commission, 2026, https://www.sec.gov/Archives/edgar/data/783325/000078332526000040/a042026aprilfinal.htm.

[43] New York Public Service Commission, "Order Adopting Terms of a Joint Proposal and Establishing Electric and Gas Rate Plans," pp. 51-53, https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B800DE79B-0000-C74C-9247-B3A408818830%7D&DocTitle=Order%20Adopting%20Terms%20of%20a%20Joint%20Proposal%20and%20Establishing%20Electric%20and%20Gas%20Rate%20Plans.

[44] NY also has a Tier 3: >150 basis point the customer/utility share is 90/10

[45] Southern Company, Current Report Form 8-K, Item 8.01, U.S. Securities and Exchange Commission, May 19, 2025, https://www.sec.gov/Archives/edgar/data/41091/000009212225000048/so-20250519.htm.

Table 10. Evaluation of Earnings Sharing Mechanisms

Metric	Score	Explanation
Financing and Cost Recovery Impact	**Transferring risk; avoiding costs**	• By splitting risk between the utilities and customers, ESMs make implementation of MRPs more palatable to both groups (depending on their design). • Relative to an MRP without an ESM, an ESM cap reduces the incentive for a utility to reduce spending. However, it also directly decreases costs to ratepayers (by providing refunds) if the utility does over-earn relative to its approved ROE. • Relative to an MRP without an ESM, an ESM floor can increase costs from ratepayers, since the utility can collect a portion of under-earnings through rates. However, it also reduces the utility's risk of insolvency.
Transparency	**Neutral**	• ESMs do not impact regulatory transparency.
Regulatory complexity	**Neutral**	• ESMs do not have a significant impact on the administrative burden on utilities or regulators.
Implementation needs	**Low**	• Implementation of an ESM within an MRP is standard practice. The main implementation challenges lie within the design and management of the MRP itself.
Bill reduction potential	**Low**	• Relatively small ability to reduce total bills; ESMs are primarily a customer protection guardrail on MRP/PBR over-earnings rather than a standalone cost-reduction mechanism.
Bill increase risk	**Low**	• ESMs can mute the cost-containment incentives of an MRP, which can lead to higher utility spending relative to an MRP without an ESM, but this impact is likely small.
Timeline	**Mid to long-term**	• Dependent on timeline of MRP implementation.

[46] Ontario Energy Board, "Decision and Interim Rate Order," p. 5, https://www.oeb.ca/node/4943.
[47] National Grid, "Performance-Based Ratemaking Adjustment Provision," Section 9.0, p. 7 of 8, https://www.nationalgridus.com/media/pdfs/billing-payments/tariffs/mag/93.1-perf-based-ratemaking.pdf.
[48] Massachusetts Department of Public Utilities, D.P.U. 23-150, "National Grid Electric Base Distribution Rate Case," p. 61, Section f, https://www.mass.gov/info-details/dpu-23-150-national-grid-electric-base-distribution-rate-case.
[49] Green Mountain Power, "2023 Regulation Plan as Amended November 18, 2024," p. 21 of 27, https://greenmountainpower.com/wp-content/uploads/2025/05/2023-Regulation-Plan-as-amended-Nov-18-2024.pdf.
[50] British Columbia Utilities Commission, "FortisBC Energy Inc. and FortisBC Inc. 2025-2027 Rate-Setting Framework Decision," Table 2, https://docs.bcuc.com/documents/orders/2025/doc_80655_g-69-25-g-70-25-fei-fbc-2025-2027-rate-setting-framework-final.pdf.
[51] Hawaii Public Utilities Commission, Docket No. 2018-0088, "Decision and Order No. 37507," December 22, 2020, pp. 183-184, Table 11, https://puc.hawaii.gov/wp-content/uploads/2020/12/2018-0088.PBR_.Phase-2-DO.Final_.mk_.12-22-2020.E-FILED.pdf.
[52] Alberta Utilities Commission, Decision 27388-D01-2023, p. 78, https://ucahelps.alberta.ca/media/uxahtbes/decision-27388.pdf.

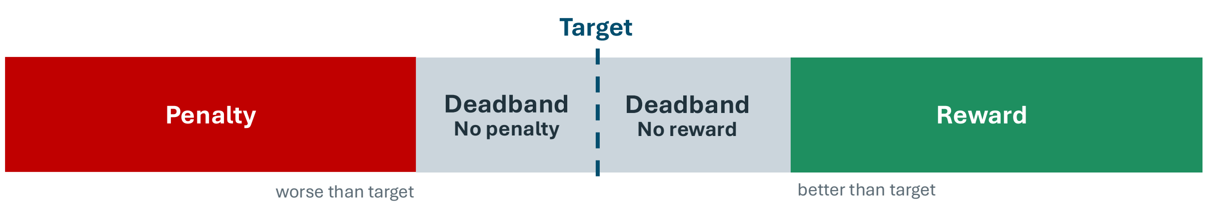
Metric	Score	Explanation
Preliminary Takeaway for New Jersey		**Implications:** An ESM should be included as a customer protection mechanism with any MRP. Symmetric earnings bands can be useful in early implementation. An upside-focused design that returns a large share of excess earnings to customers would be most aligned with affordability, while downside sharing should be limited or justified by clear offsetting benefits. **Recommendations:** In Phase 2, evaluate using an ESM as a guardrail combined with an MRP.

3.5.4 Performance Incentive Mechanisms (PIMs)

Performance incentive mechanisms (PIMs) tie utility earnings to specific outcomes, such as interconnection timelines, peak reduction, reliability, customer service, low-income participation, or DER integration. PIMs can be designed to either reward utilities for achieving outcomes or penalize them for falling short, as illustrated in Figure 15. PIMs have also been used to support policy-related objectives, such as Advanced Metering Infrastructure (AMI) deployment, peak load management, equity-related objectives, and sustainability-related objectives, such as emissions reductions or electrification goals.[53]

Figure 15. Illustration of Performance Incentive Mechanisms (PIMs)

A PIM lets a utility earn a modest reward for beating a target on a specific, measurable outcome — or face a penalty for missing it.



PIMs are most effective when they are narrow, measurable, and tied to outcomes that customers value. They are weakest when they reward broad policy objectives without a clear baseline or when they pay utilities for performance they were already required or likely to achieve (for example, CAIDI and SAIFI reliability requirements). For affordability, the most relevant PIMs are those tied to verified avoided or deferred costs, system utilization, interconnection improvements, demand reduction, or cost-effective DER deployment.

***PIMs** can steer utilities toward specific outcomes, but they pay off only when tied to clear, measurable metrics; start small and targeted.*

In successful implementations, PIMs achieve improvements across targeted goals and reduce the oversight costs by condensing areas of performance concern into unified metrics. That said, PIMs have historically achieved mixed results, and the degree to which PIMs actually incentivize the

[53] Mark N. Lowry, "Performance Incentive Mechanisms," presentation to NASUCA, October 2021, https://www.nasuca.org/wp-content/uploads/2021/10/Lowry-Presentation-for-NASUCA-Final.pdf.

desired behavior is difficult to measure.[54] For example, New York uses multiple earnings adjustment mechanisms across DER, demand response, electrification, and emissions outcomes, but stakeholders have questioned whether awards can be causally linked to utility actions. Hawaii awarded incentives for renewable portfolio standard achievement and interconnection time reductions, but again, a causal link with utility actions is hard to draw. These examples are described in Appendix B.

For New Jersey, our preliminary assessment is that targeted PIMs are near-term candidates if tied to specific, measurable cost drivers. The NJBPU should avoid broad metric proliferation and prioritize a small set of metrics linked to avoided distribution investment, peak reduction, interconnection timeliness, and verified customer savings.

[54] Mark LeBel et al., "Improving Utility Performance Incentives in the United States," Regulatory Assistance Project, October 2023, https://www.raponline.org/wp-content/uploads/2023/10/rap-improving-utility-performance-incentives-in-the-united-states-2023-october.pdf.

Table 11. Evaluation of Performance Incentive Mechanisms

Metric	Score	Explanation
Financing and Cost Recovery Impact	**Transferring risk; avoiding costs**	• PIMs align utility earnings with outcomes such as interconnection speed, peak reduction, and avoided capital investment. Many PIMs do not relate to affordability outcomes or have only secondary impacts on affordability.
Transparency	**Increase**	• PIMs require clear metric definitions, public baselines, and annual performance reporting. • Directly improves visibility into utility performance on targeted issues.
Regulatory complexity	**Increase**	• Additional monitoring of performance and metrics requires greater administrative burden
Implementation needs	**Low**	• NJBPU has full authority to establish PIMs in rate cases or by order; no statutory change required. • Targeted PIMs on specific metrics can be designed and implemented in the next round of rate cases.
Bill reduction potential	**Low**	• Relatively small ability to reduce total bills; most impactful PIMs are those tied to verified avoided or deferred costs, but many PIMs do not directly target affordability and some can increase system costs.
Bill increase risk	**Mid**	• Poorly calibrated PIMs can yield increased utility earnings without producing intended outcomes. • Metric proliferation can dilute management focus and add administrative burden without commensurate benefit. • Risk may be manageable with a small, well-defined metric set and anti-gaming provisions. • Many PIMs do not target affordability (directly or indirectly) and could result in increased system costs (for example, PIMs related to reliability).
Timeline	**Near-term**	• Targeted PIMs can be designed and implemented in the next round of rate cases.
Preliminary Takeaway for New Jersey	**Implications:** Targeted PIMs are near-term candidates if tied to specific, measurable cost drivers. **Recommendations:** Evaluate range of potential upside or downside PIMs in Phase 2 and consider targeted PIMs in next rate case.	

3.5.5 Revenue Regulation and Decoupling

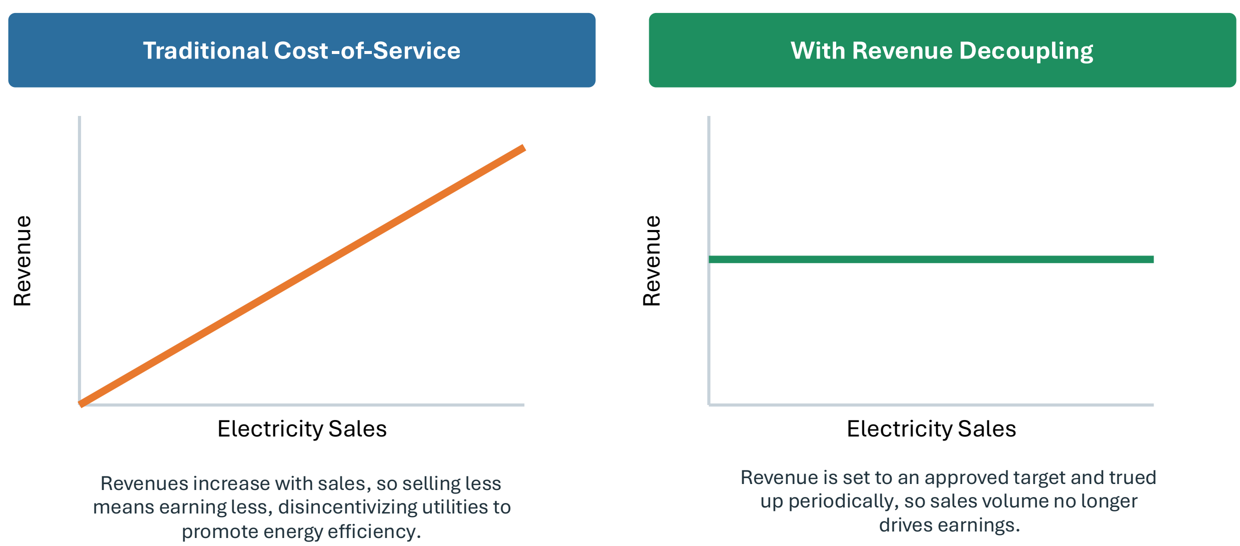
Under traditional cost-of-service ratemaking, ***rates*** are set based on a forecast of sales and costs. Because the utility is authorized to charge specific rates, its ***revenues*** are impacted if the volume of sales that materializes is different from what was forecast. This creates a financial disincentive for the utility to implement demand-side measures that reduce sales, including efficiency programs, rooftop solar, and demand response.

> ***Revenue decoupling*** *stabilizes utility revenues and removes the incentive to sell more power, but it introduces significant regulatory requirements and does not lower costs on its own.*

Revenue decoupling breaks the link between utility sales volumes and utility revenues, as illustrated in Figure 16. Instead of depending on actual kWh sales, the utility is authorized to recover an approved revenue level through periodic true-up mechanisms that reconcile actual revenues against the authorized amount. This removes the disincentive for utilities to support efficiency, rooftop solar, demand response, and other measures that reduce volumetric sales. Revenue decoupling can be implemented universally for changes between forecast and actual sales, or on a limited basis, considering only selected drivers of changes to sales (e.g., weather-related impacts or energy efficiency program impacts). Revenue regulation can also be used within an MRP, as discussed above.

Figure 16. Illustration of Revenue Decoupling

Decoupling breaks the link between a utility's revenue and how much electricity it sells, so it is financially neutral to selling less — supporting efficiency and load management.



EDCs in New Jersey do not currently have a universal revenue decoupling mechanism, but PSE&G and ACE have partial decoupling for efficiency-related revenue losses. This partial decoupling mechanism is referred to as the Conservation Incentive Programs (CIP). Other jurisdictions, including California, Connecticut, Maine, Minnesota, and Washington, use broader forms of decoupling. Evidence suggests that decoupling true-ups can move rates both up and down; therefore, it should not be presented as a rate-reduction tool by itself. See details in Appendix B.

Revenue decoupling's primary affordability value is indirect. By removing the utility's financial disincentive to support efficiency and DER adoption, it enables demand-side programs that reduce customer bills and system costs over time. By stabilizing utility revenues year-to-year irrespective of customer energy demand, decoupling can reduce perceived risk to creditors and modestly lower the utility's cost of debt, thereby reducing the revenue requirement. If not paired with performance obligations, however, guaranteed revenues insulate utilities from penalties for operational underperformance and provide no certainty of cost reductions for customers.

For New Jersey, broader decoupling could be considered as an enabling reform, especially if the state increases reliance on efficiency, demand response, virtual power plants (VPPs), and DER programs. However, it should be paired with cost-control obligations, transparent true-up reporting, and performance metrics to prevent guaranteed revenue recovery from weakening affordability incentives.

Table 12. Evaluation of Revenue Regulation and Decoupling

Metric	Score	Explanation
Financing and Cost Recovery Impact	**Shifting costs; Avoiding costs**	• Removes the utility's financial disincentive to support efficiency and DER adoption. • Does not directly reduce the total revenue requirement; primary affordability value is indirect, enabling demand-side programs that could reduce customer bills and system costs. • Most valuable as an enabling reform paired with cost-containment mechanisms rather than as a standalone affordability tool.
Transparency	**Neutral**	• No change to visibility into utility costs or spending decisions. • Decoupling mechanisms themselves are transparent but their bill effects can be opaque to customers.
Regulatory complexity	**Neutral**	• Annual true-up filings may slightly increase regulatory burden, but is unlikely to be significant.
Implementation needs	**Low**	• Within NJBPU's existing authority; no statutory change required
Bill reduction potential	**Low**	• Relatively small ability to reduce total bills; primary affordability value is indirect, for example enabling demand-side programs rather than direct cost reduction.
Bill increase risk	**Low**	• Increases to rates are typically offset by decreased usage (e.g. due to energy efficiency), mitigating most bill increase risk.
Timeline	**Near-term**	• Can be designed and implemented in the next general rate case for each EDC.
Preliminary Takeaway for New Jersey	**Implications:** Decoupling stabilizes utility revenue and removes the incentive to increase sales, which supports efficiency and DER goals, but it does not by itself lower costs and can modestly raise or lower bills depending on sales trends. **Recommendations:** Treat broader decoupling as an enabling reform rather than a standalone affordability measure. In Phase 2, evaluate whether existing Conservation Incentive Program (CIP) and Lost Revenue Adjustment Mechanism (LRAM) mechanisms should be expanded or harmonized if paired with cost-control obligations, transparent true-up reporting, performance metrics for efficiency, DERs, and load management, and bill-impact safeguards.	

3.5.6 TotEx-based Regulation

While traditional cost-of-service ratemaking provides utilities a rate of return only on capital expenditures, **TotEx-based regulation** combines capital (CapEx) and operational (OpEx) expenditures into a unified expenditure pool. That pool is then divided into “fast money", which is passed through directly to ratepayers, and “slow money,” which is treated as rate base, depreciated, and subject to a regulated return. The goal is to reduce the utility’s incentive to build capital projects rather than implement operating solutions by giving non-capital alternatives similar financial treatment.

*Removing the incentives toward capital spending can lower total costs, but **TotEx-based regulation** is data- and capacity-intensive and is untested in the United States.*

The most prominent example is Great Britain’s Revenue = Incentives + Innovation + Outputs (RIIO) framework. RIIO combines TotEx, revenue caps, output incentives, and sharing mechanisms. Its experience shows that the framework can create a more integrated view of capital and operating solutions, but also that detailed design choices can generate windfalls or disputes. For example, assumptions about inflation-linked debt and financing costs became contentious during RIIO-2, leading to changes in RIIO-3.

There is no domestic U.S. implementation of true TotEx regulation. For New Jersey, the largest barriers are accounting treatment, compatibility with ASC 980, cost allocation methods, capitalization rates, stakeholder understanding, and regulatory capacity. In addition, TotEx would not automatically reduce bills; savings would depend on whether utilities actually substitute lower-cost operating or customer-side solutions for traditional capital investment. Given these challenges, the preliminary recommendation is that TotEx should be treated as a long-term option to monitor. In general, more easily implementable reforms (e.g., shared savings, OpEx solution capitalization, capital and grid planning accountability) can address the same potential capital-bias concern with lower implementation risk.

Table 13. Evaluation of TotEx-based Regulation

Metric	Score	Explanation
Financing and Cost Recovery Impact	**Avoiding costs**	• Reduces the utility’s potential bias toward capital-heavy solutions by giving non-capital measures the same financial treatment as traditional infrastructure. However, it does not directly reduce total spend; bill savings depend on whether utilities substitute lower-cost non-capital solutions. • TotEx alone can incentivize higher total spending; must be combined with separate cost containment mechanisms such as an MRP or shared savings mechanism.
Transparency	**Neutral**	• Treating CapEx and OpEx as a unified pool simplifies comparison of capital and non-capital solutions.

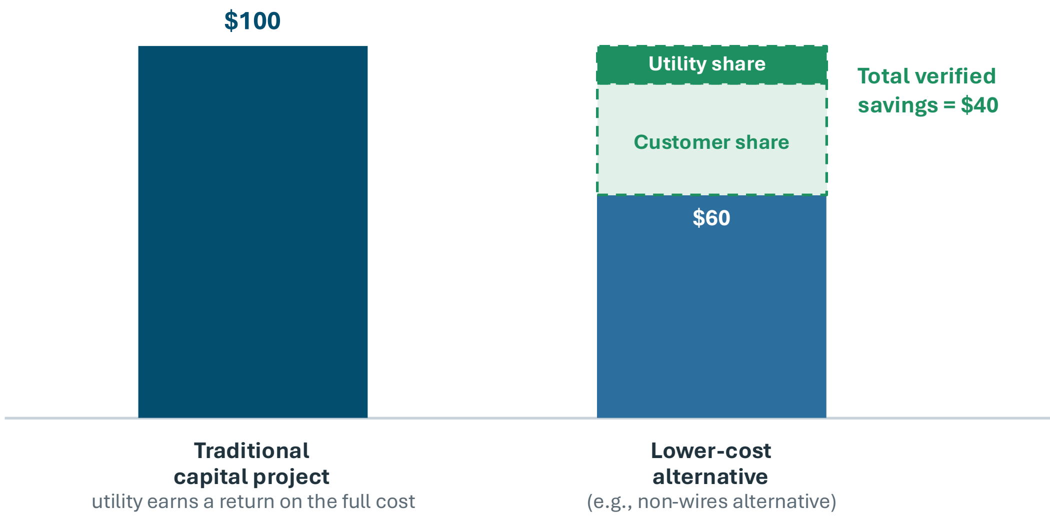
Metric	Score	Explanation
Regulatory complexity	**Increase**	• Combining CapEx and OpEx requires new regulatory processes and accounting methodologies that would significantly increase near-term regulatory complexity.
Implementation needs	**High**	• Potential incompatibility with ASC 980 accounting standards is a significant barrier in the U.S. context; no domestic precedent exists. Resolving ASC 980 compatibility requires accounting guidance, legal analysis, and potentially utility-specific rulings. • New accounting, cost-allocation, and capitalization rate methodologies add near-term regulatory and administrative complexity, particularly given this has not been done in the U.S. before
Bill reduction potential	**Mid**	• Medium ability to directly reduce bills; savings depend on whether utilities actually substitute lower-cost non-capital solutions for traditional infrastructure, and TotEx alone can incentivize higher total spending without paired cost-containment mechanisms.
Bill increase risk	**Mid**	• TotEx frameworks can produce windfall utility earnings if productivity targets and risk-sharing are poorly calibrated. • Requires reliable CapEx forecasting to set the capitalization rate properly; forecasting errors can shift costs to customers. • Risk is heightened in the U.S. context given absence of domestic precedent.
Timeline	**Long-term**	• Resolving legislative compatibility, developing regulations, and building stakeholder consensus would likely require several years • No domestic U.S. implementation examples exist; NJ would be pioneering this approach.
Preliminary Takeaway for New Jersey	**Implications**: TotEx regulation removes the potential bias toward capital over operating solutions and can lower total costs, but requires significant cost-data, classification, and regulatory-capacity changes, making it a longer-term option. **Recommendations**: While identifying opportunities to apply certain principles may be valuable, including targeted application of shared savings or OpEx capitalization, we recommend deprioritizing this for near-term analysis and re-visiting in future years.	

3.5.7 Shared Savings Mechanisms (SSMs)

Shared savings mechanisms (SSMs) offer an incentive for the utility to adopt non-traditional solutions that are less expensive than the traditional capital solution, which the utility is financially incentivized to prefer, given that utilities profit from capital investments.[55] Like TotEx-based regulation, SSMs address the utility's incentive to build capital projects rather than implement operating solutions, but to a lesser extent. As their name suggests, SSMs allow utilities to retain a portion of the verified cost savings from an operations-based solution versus a capital solution while requiring the remainder to be passed on to customers, as illustrated in Figure 17.

Figure 17. Illustration of Shared Savings Mechanisms (SSMs)

When a utility can meet a need with a cheaper non-traditional solution instead of a large capital project, the verified savings could be shared — most to customers, a slice to the utility as an incentive.



SSMs are a relatively well-established ratemaking mechanism, with early versions primarily used for sharing the net benefits of energy efficiency programs with customers.[56] More recently, SSMs have been used to incentivize utilities to implement non-wire alternative (NWA) solutions, including storage and demand response, and share the resulting cost savings with customers. Minnesota's SSM for energy conservation illustrates tying utility incentives to quantified net benefits, while also raising the familiar question of how large the incentive must be to change behavior, as described further in Appendix B. For New Jersey, SSMs are a near-term option to help correct the incentives built into the current business model toward capital solutions. SSMs can lead to lower system costs and savings for customers when lower-cost operating solutions exist.

[55] Another, less-established approach to incentivizing the adoption of non-traditional solutions to be capitalized, which equalizes the utilities' financial incentive to deploy non-traditional solutions with traditional capital solutions.

[56] Joseph H. Eto et al., "Sharing the Savings to Promote Energy Efficiency," Lawrence Berkeley National Laboratory, https://emp.lbl.gov/publications/sharing-savings-promote-energy.

Table 14. Evaluation of Shared Savings Mechanisms

Metric	Score	Explanation
Financing and Cost Recovery Impact	**Avoiding costs**	• SSMs create a direct financial incentive for utilities to pursue lower-cost, non-traditional alternatives, such as NWAs, as a substitute for capital projects.
Transparency	**Increase**	• SSMs require clear metric definitions, public baselines, and annual performance reporting.
Regulatory complexity	**Increase**	• Requires determination of counterfactual capital solutions and evaluation of specific project costs.
Implementation needs	**Low**	• NJBPU has authority to establish SSMs in rate cases or by order; no statutory change required.
Bill reduction potential	**Mid**	• Can lower bills when cheaper operating solutions exist to capital projects. Reduced capital spending reduces unnecessary rate-base growth.
Bill increase risk	**Low**	• Utility is only provided with incentive payment if material cost savings are identified.
Timeline	**Near-term**	• SSMs require development of baselines and measurement protocols. Near-term implementation is likely possible for targeted applications.
Preliminary Takeaway for New Jersey	**Implications:** SSMs and related mechanisms are near-term candidates to incentivize building lower-cost, non-traditional solutions over capital projects. **Recommendations:** Evaluate potential savings from SSMs in Phase 2 and consider developing baselines and measurement protocols for SSMs in the near-term.	

3.6 Enhancing Regulatory Scrutiny of Utility Spending

Strengthening capital accountability may be the most important near-term reform category for New Jersey. Unlike PBR, it does not require a new ratemaking framework. Instead, it applies existing regulatory tools more consistently to improve the information base for utility spending decisions. This approach can reduce the risk that customers pay for capital programs with weak benefit-cost justification, poor alternatives analysis, or insufficient performance accountability.

3.6.1 Strengthening Accountability for Capital Spending Outcomes

Capital spending accountability reforms include stronger documentation requirements before cost recovery, standardized capital program reporting, benefit-cost analysis, non-wires alternative screening, cost caps, milestone-based approvals, variance reporting, and post-construction performance reviews. These tools do not directly lower financing rates. They reduce costs only if better scrutiny changes which projects are approved, how projects are scoped, or how risks are allocated.

> ***Capital spending accountability*** *is a high value near-term move: it needs no new authority, improves the information base for spending decisions, and lays the groundwork for later reforms.*

These reforms also address a core challenge in regulation: information asymmetry. Utilities have better information about system conditions, project alternatives, and operational risks than regulators or stakeholders. Standardized planning and reporting can narrow that information gap and build the record needed for future reforms. It also improves the NJBPU's ability to distinguish between necessary investments and spending that could be deferred, downsized, or replaced by lower-cost alternatives. Tools include requiring demonstration of benefits before authorizing additional spending, setting cost caps, tying funding to specific project milestones, and reducing reliance on automatic recovery mechanisms (as discussed in the next section).

Several jurisdictions provide examples. Massachusetts requires electric utilities to file Electric Sector Modernization Plans and demonstrate how proposed investments support grid modernization needs, though stakeholders have disputed whether utilities consistently evaluate core and incremental investments using the same benefit-cost standards. New York's distribution system planning process requires utilities to identify system needs, screen for NWAs, and report capital investment plans and expenditures. Illinois has gone further by requiring multi-year grid plans and rejecting initial utility plans where the commission found insufficient cost-effectiveness justification; revised plans were approved after substantial reductions in proposed spending.

Strengthening accountability for capital spending outcomes typically relies on more effectively using existing regulatory tools rather than requiring new regulatory mechanisms. It builds a stronger foundation of knowledge and expertise for commission staff members for any subsequent MRP or PIMs design. Given this, capital accountability is a high-priority, often lower-regrets reform. The NJBPU can begin requiring enhanced documentation, variance reporting, and alternatives analysis in current proceedings without waiting for legislation, laying the foundation for future reform.

Key near-term capital accountability elements for New Jersey to consider include:

- A standardized capital plan template across all EDCs, with consistent program categories, cost drivers, alternatives considered, benefit-cost assumptions, and expected customer impacts.
- Mandatory NWA screening for distribution projects above a defined cost threshold or in constrained circuits where customer-side alternatives may be viable.
- Milestone-based approvals for large programs, with cost caps, variance thresholds, and clear consequences for material overruns.
- A public dashboard or annual report tracking forecast versus actual capital spending, project status, performance outcomes, and bill impacts.
- Rider and tracker guardrails so accelerated recovery mechanisms do not erode the cost-discipline function of general rate cases.

Table 15. Evaluation of Approaches that Strengthen Accountability for Capital Spending Outcomes

Metric	Score	Explanation
Financing and Cost Recovery Impact	**Avoiding costs**	• Applies existing regulatory tools more systematically to reduce the risk that capital programs with weak benefit-cost ratios are approved and passed through to customers.
Transparency	**Increase**	• Standardized documentation requirements and variance reporting directly improve visibility into utility capital decisions. • Creates a continuous accountability record throughout the project lifecycle.
Regulatory complexity	**Increase**	• Increasing scrutiny and documentation requires additional administrative effort
Implementation needs	**Mid**	• Fully within existing NJBPU authority using existing tools; no new legal authority required. • NJBPU can begin requiring enhanced capital program documentation in current proceedings immediately. • Successful implementation requires thoughtful design of filing requirements with significant stakeholder input. If done poorly, these filings can create additional administrative and regulatory burden without adding any value.
Bill reduction potential	**High**	• Ability to lower total bills by systematically reducing capital costs, reflecting that improved capital spending scrutiny can mitigate unnecessary rate-base growth across the full distribution system. • This reduction would arise if capital scrutiny changes project selection or scope, so savings are not guaranteed. This will be evaluated in more detail in Phase 2.
Bill increase risk	**Low**	• Well-designed accountability mechanisms protect cost recovery for incurred costs.
Timeline	**Near-term**	• NJBPU can begin requiring enhanced documentation in current proceedings immediately.
Preliminary Takeaway for New Jersey	**Implication:** Capital accountability is one of the most actionable near-term reform categories for New Jersey because it can improve transparency and slow unnecessary rate-base growth while operating within existing NJBPU authority. It also creates the data foundation needed for later PIMs, shared savings, MRP, or PBR elements. **Recommendation:** Prioritize this in Phase 2 by developing standardized EDC capital plan templates, benefit-cost and alternatives-analysis requirements, NWA screening thresholds, forecast-versus-actual reporting, and rider/tracker guardrails for major capital programs.	

3.6.2 Reducing Automatic Cost Recovery

Reducing automatic cost recovery focuses on the riders, trackers, and other adjustment mechanisms that allow utility costs to be recovered outside of a full base rate case. These mechanisms can serve important purposes: they can reduce regulatory lag, support timely recovery of policy-aligned investments, and lower utility financing risk. If used too broadly, however, they can weaken the cost discipline of general rate cases by shifting spending into narrower, more frequent proceedings and shortening the periods in which utilities bear cost-management risk.

For New Jersey, the key question is whether the NJBPU should apply a more standardized and transparent framework for determining when accelerated recovery is justified, what costs are eligible, how spending is capped, how variances are reviewed, and when mechanisms sunset or are folded back into base rates. A Phase 2 review could begin with a cross-EDC inventory of infrastructure riders, trackers, and related adjustment mechanisms, including their statutory or regulatory basis, eligible cost categories, caps, earnings tests, prudence review requirements, variance reporting, customer bill impacts, and sunset provisions. This review would help identify where existing mechanisms are well targeted and where additional guardrails may be warranted.

Potential reforms include tightening eligibility criteria, requiring project-level benefit-cost and alternatives analysis, establishing spending caps and variance thresholds, requiring forecast-versus-actual reporting, applying earnings tests, limiting recovery to used-and-useful assets or milestone-based progress, and requiring periodic rebasing into general rates. These reforms can improve affordability if they slow unnecessary cost growth, reduce cost overruns, or ensure that accelerated recovery is reserved for projects with clear customer value.

Table 16. Evaluation of Reducing Automatic Cost Recovery

Metric	Score	Explanation
Financing and Cost Recovery Impact	**Transferring risk; avoiding costs;**	• Narrows the use of accelerated recovery to projects with clear customer value. • Can slow rate-base growth by restoring more cost-management risk to utilities between rate cases. • May transfer some construction, timing, or overrun risk from customers back to utilities if costs are not eligible for automatic recovery.
Transparency	**Increase**	• Requires a public inventory of riders and trackers, clear eligibility criteria, forecast-versus-actual reporting, and bill-impact reporting. • Improves visibility into how much spending is recovered outside general rate cases.
Regulatory complexity	**Decrease**	• Consolidates review processes and regulatory proceedings. • This reduction may not be realized if the reform adds new administrative needs, such as reporting, prudence reviews, and statewide guardrails.

Metric	Score	Explanation
Implementation needs	**Mid**	• Many guardrails can be added through rate cases, rider reviews, or NJBPU orders under existing authority. • A broader standardized framework across all EDCs may require a dedicated proceeding and, for some statutorily created charges, legislative coordination.
Bill reduction potential	**Mid**	• Does not automatically reduce existing costs, but can slow future cost growth by limiting automatic pass-throughs, reducing cost overruns, and improving project selection. • Savings depend on the amount of spending currently flowing through accelerated recovery mechanisms and the stringency of the guardrails.
Bill increase risk	**Mid**	• Overly restrictive rules could delay needed reliability or resilience investments or increase utility financing risk. • Risk can be mitigated through clear eligibility criteria, safety and reliability exceptions, and timely review of well-justified investments.
Timeline	**Near-term to Mid-term**	• Rider/tracker inventory, reporting requirements, and case-specific guardrails can begin in the near term. • A standardized statewide framework may require a mid-term proceeding.
Preliminary Takeaway for New Jersey	**Implication:** Reviewing accelerated recovery is a high-value complement to capital accountability because New Jersey already uses multiple riders and trackers that affect customer bills. **Recommendation:** Phase 2 should develop a cross-EDC rider/tracker inventory and propose consistent guardrails, including eligibility criteria, cost caps, sunset provisions, earnings tests, prudence review, variance reporting, bill-impact reporting, and ex post review	

3.7 Improving System Utilization and Targeted Bill Impacts

The reforms in the previous sections focus on how utility costs are reviewed and recovered. Utilization and rate-design tools focus on how the system is used and how costs are allocated. These options can support affordability by spreading fixed costs over more load, reducing peaks, deferring upgrades, and targeting bill relief to customers most exposed to energy burden. They are especially important in a period of electrification, data center growth, and increasing DER adoption.

3.7.1 Enhancing Grid Utilization and Load Management

Transmission and distribution systems are built for peak conditions. If additional load can be served without requiring new peak-driven investment, existing fixed costs can be spread across more kWh, and average rates can fall. Conversely, unmanaged load growth can increase local peaks and require new infrastructure investment. The affordability value of load growth, therefore, depends on timing, location, flexibility, and the cost of any required upgrades.

Load management, demand-side resources, and VPPs are increasingly important tools. This includes demand response, energy efficiency, managed electric vehicle (EV) charging, and load shifting. VPPs aggregate distributed resources (e.g., batteries, thermostats, solar, EV chargers, and flexible loads) so they can be dispatched as a coordinated resource. When targeted to constrained hours or specific circuits, these tools can defer upgrades and reduce supply, capacity, or distribution costs.

New Jersey already has relevant building blocks, including JCP&L's Energy Savings Rewards program with battery, EV charging, and thermostat tracks. Executive Order No. 2 also directs the NJBPU to develop a statewide VPP program and improve participation of demand-side resources in PJM markets. While this effort is separate from the Phase 2 quantitative analysis, these efforts should be coordinated with the business model reforms discussed above, because utilities may need clear incentives, cost recovery, and performance metrics to pursue customer-side resources as alternatives to traditional infrastructure.

In particular, New Jersey could evaluate load management and system utilization as potential affordability strategies, not only as clean energy or reliability measures, but it will be important to support any programs or policies with clear benefit-cost analysis and to ensure program designs do not impose unintended cost shifts. The strongest candidates are programs with clear locational value, dispatchability, verified peak impacts, and transparent benefit-cost analysis.

Data centers and other large loads also present an opportunity to spread out system costs over more load, thereby reducing costs for all customers. They can also present challenges. Bill S731/A796, recently passed by the New Jersey legislature, is intended to get ahead of some of those challenges. The bill "requires electric public utilities to develop and apply special rules for certain data centers to protect non-data center customers from increased costs."[57]

3.7.2 Rate Design

Rate design determines how the total revenue requirement is allocated across customer classes and translated into the specific charges that customers see on their bills. Even without changing total costs, rate design changes can reduce bills for targeted customer groups, improve the alignment between what customers pay and the costs their usage patterns impose on the system, and create incentives for behavior, such as off-peak consumption or load flexibility, that reduces overall system costs. Examples of rate design options include time-of-use rates, income-graduated fixed charges, demand charges for large commercial and industrial customers, and changes to the allocation of distribution costs between fixed and variable components.

Rate design changes are inherently redistributive: reducing bills for some customers typically increases them for others, and reforms perceived as choosing winners and losers can become politically contentious. These risks are manageable with careful design, customer education, and

[57] State of New Jersey Senate, *Senate No. 731*, 222nd Legislature, Third Reprint, sponsored by Senators John J. Burzichelli and John F. McKeon. https://pub.njleg.state.nj.us/Bills/2026/S1000/731_R3.PDF

bill protection provisions, but require deliberate stakeholder engagement. Rate design reforms can be implemented in existing rate case frameworks without new legislation.

For New Jersey, rate design should be included as a complementary affordability lever, but it should not be conflated with cost reduction. The NJBPU should distinguish between reforms that reduce total system costs and reforms that reallocate costs to improve targeted affordability or better align rates with cost causation.

3.7.3 Customer Programs to Enable Cost-effective DERs

Customer programs for energy efficiency, flexible load, distributed generation, storage, managed charging, and VPP aggregation can reduce bills directly for participants and indirectly for all customers if they avoid or defer utility costs. The affordability case depends on whether program benefits exceed program costs and whether savings are reflected in utility planning and ratemaking.

Customer programs that enable cost-effective DER adoption, such as utility-run efficiency programs, managed EV charging, demand response, and VPP aggregation, can serve as both an affordability tool and a clean energy and grid management tool. The effectiveness of these programs depends on cost-effectiveness screening, program design, and whether the utility has financial incentives to actively support customer adoption. In the absence of revenue decoupling, utilities may have limited financial incentive to aggressively promote DER adoption, since lower electricity sales reduce volumetric revenues; pairing DER programs with decoupling weakens this likely counterproductive dynamic. In evaluating DERs, programs should be screened for cost-effectiveness, locational value, participation equity, and verified system impacts.

3.8 Additional Emerging Reform Options

Several options may affect customer bills but are either outside the core distribution utility business model, outside direct NJBPU control, or too nascent for detailed evaluation in this section. These options are important to acknowledge, but are not evaluated in detail, given that they are outside the core scope of the Phase 1 assessment.

3.8.1 Distribution Services Procurement as a Distribution System Operator (DSO)

A broader reform pathway that merits consideration is the movement toward distribution services procurement and selected distribution system operator (DSO) functions. Under this model, the EDC would not only build and operate utility-owned distribution infrastructure but would also identify locational and temporal system needs and procure services from third-party providers, aggregators, and customer-sited resources where those resources can provide lower-cost or higher-value alternatives. These services could include demand response, distributed storage, managed EV charging, flexible building loads, solar-plus-storage, virtual power plants, or other distributed energy resources that provide capacity, reliability, resilience, voltage support, congestion relief, or peak reduction.

Traditional cost-of-service regulation generally compensates utilities more directly for utility-owned capital investment rather than for procuring third-party or customer-sited services. A DSO-like pathway would therefore require changes to planning, procurement, cost recovery, data access, operational coordination, measurement and verification, and utility compensation. In addition to impacting the utility business model, this reform overlaps with supply-side work directed by EO-2 (e.g., capacity, energy, and ancillary service value of customer-sited resources and reduced BGS exposure).

Potential benefits may include reduced capital bias, greater use of customer-sited resources, improved system utilization, more competition to meet distribution needs, and better alignment between utility earnings and customer value. Key potential risks include unclear baselines, operational performance risk, double-counting of distribution and wholesale value, cybersecurity and dispatchability requirements, customer participation uncertainty, cost shifting to non-participants, and the need for stronger data systems and regulatory capacity.

3.8.2 Differentiated Reliability Service

Differentiated reliability service refers to rate structures and service offerings that allow customers to elect different reliability tiers, at different prices, rather than receiving uniform distribution reliability service. The mechanism primarily applies to commercial and industrial customers who are more willing to accept occasional interruptions in exchange for lower rates. Customers on lower reliability tiers can be charged less because less firm capacity needs to be procured on their behalf. Reduced capacity procurement may also decrease rates for other customers, depending on how costs are allocated among customer classes.

Whether a particular customer is able and willing to take service on a lower reliability tier depends on both the physical capabilities of their equipment and the cost of power compared to their revenues. This concept has also been proposed for large data center loads, where non-firm interconnection is being explored to accelerate interconnection while limiting bill impacts on other customers. [58] In practice, this would likely require that data centers have sufficient backup generation to power their entire operation, since data centers typically require very high levels of reliability.

3.8.3 Moving Programs from Rates to Taxes

Certain New Jersey customer bill charges fund state policy-related programs, including energy efficiency, the Universal Service Fund, and Regional Greenhouse Gas Initiative (RGGI) recovery charges. Funding these programs through state tax revenues via the state budget offers a mechanism to directly remove these costs from customer bills. Proponents contend that keeping policy-related costs in rate surcharges is inappropriate because they are not a cost of supplying electricity, and regressive because they burden low-income customers disproportionately relative

[58] Utility Dive, "FERC Accepts SPP Plan for Chills Large-Load Transmission Service," June 8, 2026, https://www.utilitydive.com/news/ferc-spp-chills-large-load-transmission-service/822211/.

to income. Shifting these costs to taxes allows more progressive financing structures. Opponents note that legislative authorization for what may be perceived as a tax increase is a significant political barrier, and that budget-funded programs compete annually with other state priorities for funding, creating ongoing funding vulnerability as compared to the relative stability of ratepayer-funded riders.

3.8.4 Modifications to Supply Model

Supply costs have been a major driver of recent bill increases, but they are largely shaped by PJM wholesale markets and the BGS procurement structure. Options such as direct EDC participation in PJM markets, central state procurement, or re-regulation of generation would be major structural changes requiring separate legal, market, and FERC/PJM analysis. They should be considered in parallel with affordability workstreams and are outside the scope of this study. However, some distribution business model reforms could indirectly affect supply costs, as discussed in the previous section.

3.8.5 Regulatory Sandboxes

Innovation is necessary in order to meet growing loads and demands on the electricity grid. Numerous technologies exist today to solve challenges facing the grid, and technologies are continuing to advance at a rapid pace. However, regulatory objectives and processes can be at odds with the ability and willingness of regulated utilities to test and deploy innovative technologies. States across the country are increasingly recognizing the need to reduce regulatory barriers to encourage the adoption of advanced technologies that support grid needs, benefit utility customers, and achieve other state goals.

One approach to encouraging energy innovation that states are increasingly exploring is the use of "regulatory sandboxes", which provide a structured environment for testing new ideas, technologies, and programs to reduce risk and provide meaningful learning outcomes before rolling them out more broadly. A recent report for Lawrence Berkeley National Lab identified 15 jurisdictions that have explored sandbox-type mechanisms for electric utilities.[59] Of those jurisdictions, 12 adopted such mechanisms, which are ongoing. The Grid Flexibility Services working group is currently exploring the concept of regulatory sandboxes and their potential application in New Jersey.

3.9 Summary of Findings Across Reform Options

This section assessed a broad set of utility business model reforms against a consistent set of criteria: how each reform impacts financing and cost recovery, its effect on transparency and regulatory complexity, its implementation needs, its bill reduction potential and the risk it could raise bills, and a realistic implementation timeline. This assessment is intended to provide insights into the potential upsides and drawbacks of each reform; however, **the risks and benefits of any reform ultimately depend on specific design and implementation decisions.** The range of potential

[59] Regulatory Sandboxes and Other Processes to Expedite Utility Adoption of Advanced Grid Technologies, Relf, Grace, Matia Whiting, Lisa C Schwartz, Evan Cappers (2025), available at: regulatory_sandboxes_06.10.2025.pdf.

outcomes of each reform, depending on the design, is also highlighted by the jurisdictional evidence to date, as presented in this section and further detailed in Appendix B. In many cases, a lack of clear baselines, tracking data, or counterfactuals limits the direct conclusions that can be drawn on the affordability impacts of each reform option.

Table 17 below summarizes the evaluation criteria across all reforms. Several findings emerge from this qualitative assessment. **First, no single reform is a complete affordability solution.** The tools with the largest potential bill impact also carry the greatest implementation barriers, the longest timelines, or the highest risk of unintended bill increases. In contrast, the most actionable near-term tools tend to be incremental.

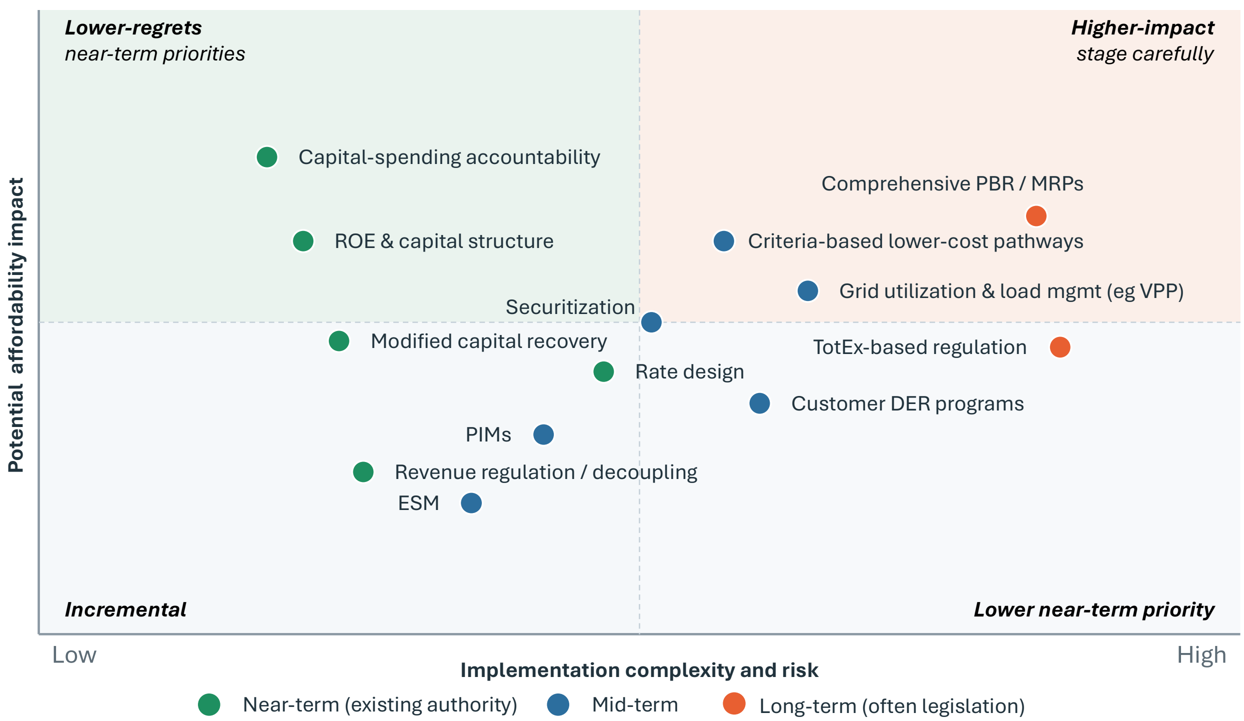
Table 17: Screening-Level Scorecard for Utility Business Model Reform Options

Reform option	Transparency	Regulatory complexity	Implementation needs	Bill reduction potential *	Bill increase risk	Timeline
Modify Financing and Cost Recovery						
Return on equity & capital structure reforms	Neutral	Neutral	Low	Mid	Low	Near
Criteria-based lower-cost project pathways	Increase	Increase	Mid	Low	Low	Mid
Securitization	Neutral	Increase	Mid	Mid	Low	Mid
Modified capital recovery rules	Neutral	Neutral	Low	Mid	Mid	Near
Align Utility Incentives with Cost Minimization						
Performance Based Ratemaking (PBR)	Decrease/ Increase	Increase	Mid	Mid	Mid	Mid–Long
Multi-year rate plans (MRPs)	Decrease	Decrease	Mid	Mid	Mid to High	Mid–Long
Earnings sharing mechanisms (ESMs)	Neutral	Neutral	Low	Low	Low	Mid–Long
Performance incentive mechanisms (PIMs)	Increase	Increase	Low	Low	Mid	Near
Revenue regulation / decoupling	Neutral	Neutral	Low	Low	Low	Near
TotEx-based regulation	Neutral	Increase	High	Mid	Mid	Long
Shared savings mechanisms (SSMs)	Increase	Increase	Low	Mid	Low	Near
Enhance Regulatory Scrutiny of Utility Spending						
Strengthening accountability for capital spending outcomes	Increase	Increase	Mid	High	Low	Near
Reduce automatic cost recovery	Increase	Decrease	Mid	Mid	Mid	Near

Screening-level qualitative assessment (Phase 1).
** Relative magnitude of achievable savings. Will be updated based on quantitative analysis in Phase 2.*

Second, **reforms can be sequenced, first building a foundation of near-term "low regrets" actions.** These likely include strengthening capital-spending accountability, tightening guardrails for automatic cost recovery mechanisms, and reviewing ROE, capital structure, and capital-recovery rules. These "low regrets" reforms can be pursued now, are within existing NJBPU authority, improve transparency, and have lower bill-increase risk. Incentive-based reforms (MRPs, ESMs, PIMs) are better positioned for near-term quantitative study and are mid- to long-term steps to be taken after New Jersey has built the baselines, data, and guardrails needed to implement them without harming customers. Utilization, rate-design, and DER programs are complementary levers that can advance in parallel, provided they are screened for benefit-cost and cost-shifting.

Figure 18. Directional/Illustrative Assessment of Options in Terms of Implementation Complexity and Affordability Impact, to be refined through Phase 2 Quantitative Study



Third, the matrix makes clear that **capital accountability is an important near-term priority**. It needs no new statutory authority, directly improves the information base for spending decisions, and lays the foundation for any later reform. Finally, the trends in the assessment and the review of empirical evidence from existing jurisdictions **pursuing utility business model reforms demonstrate that building regulatory capacity and then sequencing bigger reforms on top of a foundation once baselines, data, and guardrails are in place** can be more effective both at generating broader stakeholder buy-in and delivering durable value. Translating these findings into a near-term roadmap of actions and a Phase 2 analytical plan is described in more detail below, in Section 4.

4. Recommendations for Advancing Utility Business Model Reforms and Priorities for Phase 2

This section translates the Phase 1 qualitative assessment into a recommended starting point for Phase 2. The purpose is not to identify a final reform package at this stage. Rather, it is to describe the steps for New Jersey to evaluate, refine, and sequence utility business model reforms that could support affordability, while preserving the core obligations of EDCs to provide nondiscriminatory access to safe, adequate, reliable, and environmentally responsible service at just and reasonable rates.

This Phase 1 analysis illustrates that no single utility business model reform is likely to serve as a standalone solution to New Jersey's affordability challenge. Customer bills are driven by multiple cost components, including supply, transmission, distribution, and program charges, only some of which are directly addressed through distribution utility business model reform. The Phase 1 assessment also found that reform options affect affordability through different mechanisms: some reduce near-term costs directly, some change utility incentives, some increase scrutiny of utility spending, and some improve system utilization or target customer bill impacts.

Based on this, this section summarizes our recommendations along two categories of action, which we propose proceed in parallel but interrelated tracks in Phase 2, following the release of this report:

1. **Roadmap development:** This track should define a staged policy and implementation roadmap for potential business model reforms. The roadmap should identify which reforms can be pursued in the near term under existing NJBPU authority, which require additional analysis or stakeholder processes, which may require legislative action, and which should be deferred unless a clearer New Jersey-specific use case emerges.
2. **Supporting quantitative analysis:** This track should provide the analytical foundation for the roadmap. Quantitative work should test the bill impacts, customer impacts, utility financial impacts, implementation risks, and trade-offs associated with potential reforms. The analysis should help determine whether the preliminary roadmap should be advanced, modified, narrowed, or expanded.

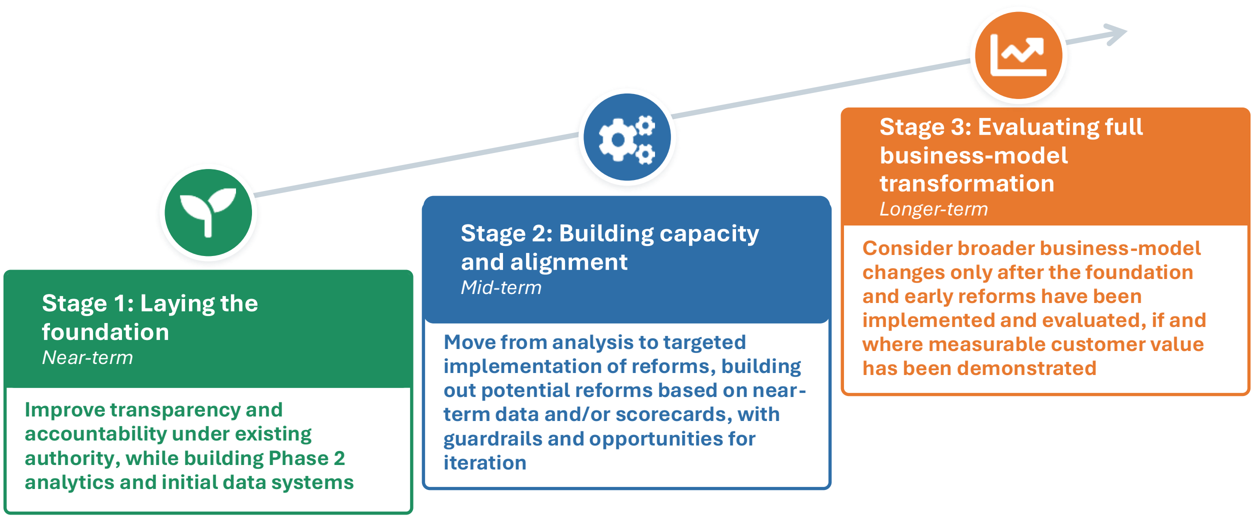
Phase 2 should help New Jersey move from a qualitative assessment of potential utility business model reforms to an evidence-based roadmap for action. This requires both policy design and quantitative testing. The policy roadmap should define the sequence of reforms, the implementation pathway, the authority or process required, and the guardrails needed to protect customers. It should also guide which quantitative questions are most important to answer. The quantitative analysis should, in turn, refine the roadmap by identifying which reforms are likely to produce measurable customer value, which primarily shift or stabilize bills, which require stronger safeguards, and which are not likely to be worth pursuing in the near term.

This distinction is important because many utility business model reforms sound similar at a high level but operate through different potential customer affordability mechanisms. Some reforms may reduce total costs by avoiding capital investment, lowering financing costs, or improving system utilization. Others may shift costs among customers, shift costs across time, reduce bill volatility, or provide targeted customer protection without reducing total system costs. Phase 2 should distinguish among these effects explicitly.

4.1 Phase 1 Findings Provide Potential Principles for a New Jersey Business Model Reform Roadmap

The goal of building a roadmap is to identify the set of policies and implementation activities that are needed to support potential business model reform. This roadmap is likely to be "staged", with the near-term path focused first on reforms that improve transparency, increase cost discipline, and strengthen the analytical foundation for future regulatory decisions. More complex incentive-based reforms could then be considered only after the NJBPU has developed the data, metrics, baselines, and guardrails needed to manage implementation risk.

Figure 19. Potential/Illustrative Stages for the Roadmap



This approach reflects several Phase 1 findings. First, affordability should be treated as the primary objective of this study, but it is not the only objective that utility regulation must balance. Reforms should also preserve safety, reliability, environmental quality, utility financial integrity, equity, customer protections, and achievement of state policy goals. Second, reforms should be evaluated based on how changes to financing and cost-recovery impact customer bills. A reform that reduces total costs should not be treated the same as a reform that shifts costs among customers, shifts costs across time, or stabilizes bills without lowering long-run costs. Third, the most visible and major potential reforms, such as PBR or TotEx-based regulation, are not necessarily the most actionable near-term affordability tools.

As a starting point to be refined through engagement with stakeholders, potential key principles for Phase 2 could include:

- **Start with least-regrets reforms that improve transparency and cost discipline.** Near-term reforms should focus on improving the information available to the NJBPU, stakeholders, and customers; strengthening review of capital spending; and ensuring that accelerated cost recovery mechanisms do not weaken cost discipline. These reforms are valuable even if New Jersey ultimately does not adopt a comprehensive utility business model reform framework.
- **Design and build out more standardized cross-EDC scorecard.** New Jersey has several program-specific performance reporting and accountability tools (e.g., reliability, energy efficiency, etc). New Jersey could build from these existing structures toward a more standardized scorecard that links potential key performance metrics. Initially, such a scorecard could be informational and support transparency, stakeholder review, and Phase 2 modeling. Over time, selected metrics could become formal reporting requirements, guardrails, shared-savings inputs, PIMs, or components of any staged MRP or PBR pathway.
- **Quantify direct cost-reduction tools before recommending implementation.** In the near-term, take a careful look at potential financing and capital recovery reforms, such as ROE changes, capital structure adjustments, depreciation changes, CWIP treatment, securitization, and lower-cost project pathways. If designed carefully, these could produce more direct and quantifiable bill impacts than broader reforms. However, they should be carefully evaluated for utility financial integrity, capital access, intergenerational equity, and long-term cost impacts.
- **Evaluate incentive reforms as staged tools, not immediate comprehensive transformation.** Moving to targeted PIMs, SSMs, earnings sharing, and MRP plan elements may have value, but they require credible baselines, clear metrics, customer protections, and anti-gaming provisions. New Jersey should evaluate a staged pathway before considering PBR. This not only limits potential risks and harms but also allows for iteration and continued learning.
- **Treat utilization, load management, and rate design as affordability strategies, but distinguish cost reduction from cost allocation.** Demand flexibility, managed EV charging, VPPs, DER programs, and rate design can improve affordability by reducing peak-driven costs, deferring investments, improving use of existing infrastructure, or targeting customer bill impacts. However, some rate design changes and customer programs reallocate costs rather than reduce them, so Phase 2 should evaluate both system-level savings and distributional impacts.

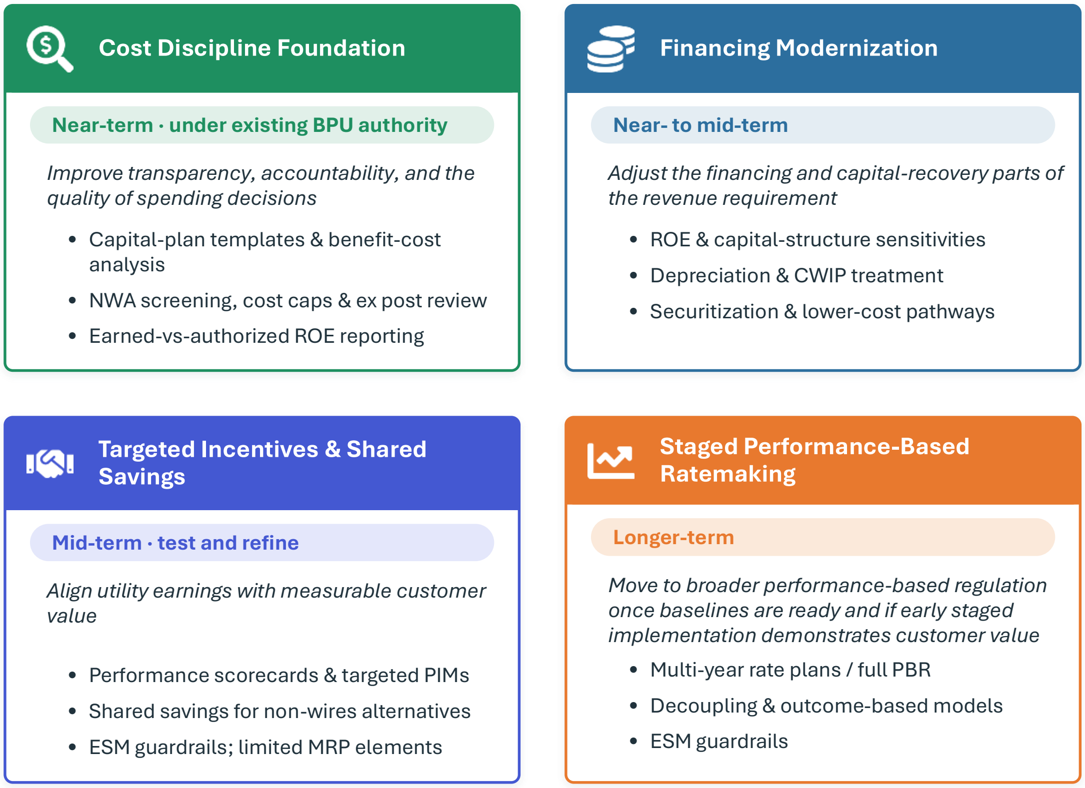
Discussions with stakeholders and NJBPU will both refine and adjust guiding principles, which can then inform the decision-making framework and Roadmap development, as described below.

4.2 Phase 2 Candidate Reform Pathways

In Phase 1, a broad set of potential utility business model reform options and policy levers was identified. For Phase 2, these options should be organized into candidate reform pathways (or reform packages) rather than evaluated only as isolated mechanisms. A pathway groups complementary reforms that address a similar affordability mechanism or that would need to be designed together to be effective. This is important because individual reforms rarely work in isolation; a pathway structure allows New Jersey to test how mutually reinforcing tools could operate together, while preserving flexibility to modify or narrow the package based on stakeholder input and quantitative results.

The candidate pathways below should be treated as “strawman” or starting points for Phase 2 evaluation. They are <u>not</u> final recommendations for implementation. These pathways are <u>not</u> mutually exclusive and could be combined or reconfigured. Rather, they provide a structured framework for organizing the quantitative analysis, stakeholder discussion, and roadmap development process.

Figure 20. Illustrative Candidate Reform Packages to Evaluate in Modeling



Note: These should not be considered final recommendations of what New Jersey should implement They are illustrative examples of candidate reform pathways to evaluate in the Phase 2 modeling and broader Roadmap development.

4.2.1 Potential Candidate Reform Pathway: Cost Discipline Foundation

The **Cost Discipline Foundation Pathway** focuses on improving transparency, regulatory accountability, and the quality of utility spending decisions. This should be the highest-priority near-term pathway because it can be advanced largely under existing NJBPU authority and would support almost any future reform direction. NJBPU already has work underway that will provide greater transparency and documentation on EDC distribution planning and investments through the proposed Proactive System Upgrade Plan.[60]

This pathway addresses a known challenge in traditional cost-of-service regulation: utilities often have better information than regulators and stakeholders about system needs, project alternatives, costs, and operational risks. Strengthening capital planning documentation, benefit-cost analysis, and ex post review can reduce this information asymmetry and improve the NJBPU's ability to

[60] NJBPU, "Straw Proposal – Proactive System Upgrade Planning Requirements," 2026, STRAW PROPOSAL - ProActive SYSTEM UPGRADE PLANNING REQUIREMENTS.

distinguish necessary investments from projects that could be deferred, downsized, or replaced by lower-cost alternatives.

This package of policies could include:

- Standardized affordability and performance metrics;
- Standardized EDC capital plan templates;
- Stronger benefit-cost analysis for major distribution investments;
- NWA screening for qualifying capital projects;
- Capital project cost caps, milestone-based approvals, variance reporting, and ex post review;
- Public reporting of forecast versus actual capital spending and customer bill impacts;
- Review of infrastructure investment riders, trackers, eligibility criteria, cost caps, and sunset provisions; and
- Reporting of utility earned ROE relative to authorized ROE (consistently across utilities, beyond rate cases).

This pathway may only produce small near-term bill stabilization or reductions on its own. Its value lies in slowing unnecessary cost growth, improving regulatory confidence, and creating the data foundation needed for more advanced incentive mechanisms, shared savings approaches, or multi-year rate plan elements.

Within the modeling, this pathway could be represented with a scenario that includes lower or deferred capital additions, reduced cost overruns, tighter rider recovery, reduced rate base growth, and/or NWA deferral assumptions.

4.2.2 Potential Candidate Reform Pathway: Financing Modernization Pathway

The **Financing Modernization Pathway** would evaluate reforms that directly affect the financing or capital recovery components of the revenue requirement. These tools may provide clearer near-term bill impacts than broader incentive reforms, but they also require careful calibration.

Potential components include:

- ROE sensitivity analysis;
- Capital structure sensitivity analysis;
- Review of depreciation schedules for selected asset classes;
- Modified CWIP treatment, including lower CWIP ROE, milestone requirements, cost caps, or used-and-useful limitations;
- Criteria-based lower-cost project pathways for qualifying investments;
- Securitization screening for narrow, well-defined eligible cost categories;
- Utility financial integrity analysis, including credit metrics, equity ratio, earned returns, and capital access.

This package should be evaluated as a targeted affordability strategy, not as a substitute for cost discipline. Lowering the cost of capital or changing cost recovery can reduce customer bills, but it does not necessarily reduce the underlying need for utility investment. For that reason, financing reforms should be paired with stronger capital review, customer-value tests, and cost caps.

Within the modeling, this pathway could be represented by multiple scenarios that include authorized ROE changes, capital structure changes, changes to depreciation schedules, changes to CWIP treatment, securitization, and/or lower-cost financing assumptions.

4.2.3 Potential Candidate Reform Pathway: Targeted Incentives and Shared Savings Pathway

The **Targeted Incentives and Shared Savings Pathway** would evaluate whether New Jersey should adopt mechanisms that align utility earnings with measurable customer value. Phase 1 suggests that New Jersey should be cautious about moving too quickly to performance-based ratemaking and instead evaluate targeted tools that can be tested, measured, and refined.

Potential components include:

- Scorecards for affordability, capital spending, reliability, customer service, and system utilization;
- Targeted performance incentive mechanisms tied to verified peak reduction, avoided distribution investment, interconnection timelines, arrearage reduction, or reliability guardrails;
- SSMs for NWAs or other verified lower-cost alternatives;
- ESMs as customer protection guardrails;
- Limited MRP elements after baselines and tracker guardrails are developed; and
- Periodic review, rebasing, and off-ramps to ensure customer protections remain effective.

Jurisdictional experience suggests that a small number of high-value metrics are most likely to yield the greatest results from performance incentives. Experience also suggests that individual performance incentives are most effective when a clear baseline, a measurable outcome, and a reasonable basis for attributing performance to utility action are established. For affordability, the most relevant incentives are those tied to avoided or deferred costs, improved utilization, verified customer savings, or customer protection outcomes.

Within the modeling, this pathway could be represented by multiple scenarios that include avoided capital assumptions, utility incentive payments, customer/utility sharing ratios, earnings sharing thresholds, and/or performance caps and penalties.

4.2.4 Potential Candidate Reform Pathway: Staged PBR Pathway

The **Staged Performance-Based Ratemaking Pathway** would evaluate whether New Jersey should move over time from targeted reforms toward a broader performance-based ratemaking framework. This pathway should be modeled as a phased scenario that allows the NJBPU to test what additional value a more comprehensive suite of reforms could provide after foundational reporting and capital accountability are in place.

Potential components of this pathway could include:

- Stage 1 foundation elements, including standardized affordability and performance metrics, capital-plan reporting, rider/tracker inventory, earned ROE reporting, and scorecards;
- Targeted PIMs tied to measurable customer value, such as verified peak reduction, avoided distribution investment, interconnection timeliness, arrearage reduction, and service quality;
- SSMs for NWAs or other verified lower-cost solutions, with clear baselines and customer/utility sharing ratios;
- ESMs to protect customers from over-earnings and to provide a guardrail if broader multi-year rate plans are later considered;
- A potential MRP or revenue-cap framework with an inflation factor, productivity offset, customer dividend or stretch factor, exogenous-cost treatment, limited reopeners, and periodic rebasing;
- Tracker and rider guardrails so that cost recovery outside the cap does not undermine the cost-discipline purpose of the framework; and
- Reliability, safety, customer service, and financial integrity off-ramps to ensure affordability reforms do not compromise core EDC obligations.

For modeling purposes, this pathway should be represented as a staged scenario rather than a single static case. An initial case could model the effect of stronger reporting and capital accountability on capital additions, cost overruns, or rider recovery. A second case could layer in targeted PIMs, shared savings, and earnings sharing. A later case could test a multi-year rate plan or revenue-cap framework using assumptions for inflation, productivity, rebasing frequency, tracker treatment, incentive payments, and customer sharing.

The purpose of this scenario is to establish an analytical benchmark for the value and risks of broader business model transformation.

4.2.5 Other Additional Candidate Reform Pathways

Other potential policy packages could create viable reform pathways and be considered in the roadmap and modeled as scenarios as part of the quantitative analysis. These pathways could include both variations on the levers above, as well as policy levers beyond the business model, including, for example:

- Grid utilization
- Demand flexibility and load management
- Rate design
- Supply-side reforms (e.g., market and legal)
- Innovation and regulatory sandboxes

4.3 Translating Reform Pathways into Modeling Scenarios and Sensitivities

In Phase 2, a set of candidate reform pathways, with feedback from stakeholders, can be translated into modeling scenarios in the quantitative tool. This is the bridge between the roadmap and the quantitative analysis: while the reform pathways are policy concepts, the modeling scenarios are analytical representations of those concepts. The scenarios are explicitly not final implementation recommendations, but rather analytical constructs that allow the NJBPU and stakeholders to test how different combinations of reforms could affect bills, revenue requirements, rate base, customer classes, low- and moderate-income customers, utility financial metrics, and reliability guardrails relative to a common baseline.

Each scenario should begin with a current-framework baseline that reflects existing rates, cost drivers, capital spending trajectories, riders, cost recovery mechanisms, rate design, and supply assumptions. Reform scenarios should then modify specific assumptions - such as authorized ROE, capital structure, depreciation treatment, capital additions, rider recovery, peak reduction, load shape, incentive payments, or customer class cost allocation - to estimate potential impacts relative to that baseline.

As the modeling scenarios proceed, it will be important to evaluate both the collective policy pathways as scenarios and the sensitivities of individual drivers to help isolate the impact of individual levers. For major scenarios, it will also be valuable to consider “bookend cases” that reflect drivers of both upside and downside uncertainty, to understand the full range of plausible impacts.

4.4 Priorities for Quantitative Analysis in Phase 2

The supporting quantitative analysis should be designed to answer the questions needed to refine the roadmap. Phase 2 should not model every reform in equal detail. Instead, it should prioritize analysis that can materially affect near-term NJBPU decisions or determine whether a reform should move forward, be redesigned, or be deferred. Key questions could include:

+ **Where is the largest achievable customer value?** The analysis should identify whether the most material affordability opportunities are likely to come from reducing capital additions, lowering financing costs, improving system utilization, reducing peak-related supply and capacity exposure, modifying rate design, or targeting customer protections.
+ **Which reforms reduce costs, and which primarily shift or stabilize bills?** Phase 2 should clearly distinguish among total cost reduction, cost shifting, cost deferral, bill stabilization, and targeted customer protection. This distinction will help ensure stakeholders are clear-eyed about the affordability benefits of reforms that mainly shift costs across customers, taxpayers, or time.
+ **Which reforms are actionable under existing NJBPU authority?** A deeper legal and regulatory review should identify reforms that can be implemented through rate cases, planning proceedings, tariff changes, rider reviews, orders, reporting requirements, or data requests without requiring new statutory authority.

- **What customer groups are affected?** Leveraging the data requests from the utilities, Phase 2 should evaluate impacts by EDC, customer class, usage profile, and income segment where feasible. Particular attention should be paid to low- and moderate-income customers, customers with high energy burden, and customers with limited ability to respond to rate design changes.
- **What guardrails are needed?** Each reform should be evaluated for necessary customer protections, including caps, off-ramps, earnings sharing, reliability guardrails, utility financial integrity checks, benefit-cost tests, cost caps, and ex post review.
- **What data and reporting are needed for implementation?** The analysis should identify data gaps that need to be addressed before implementation, including capital plan detail, cost-driver data, avoided-cost assumptions, load profiles, customer segmentation, arrearage and disconnection data, reliability metrics, and utility financial metrics.

Table 18. Preliminary Recommended Phase 2 Analytical Workstreams

Workstream	Purpose	Illustrative outputs
Affordability and bill baseline	Establish a common baseline for assessing reform impacts	Bill-driver decomposition; affordability metrics; bill impacts by EDC and class
Capital spending and rider review	Identify where stronger scrutiny could reduce unnecessary cost growth	Capital plan template; tracker/rider inventory; eligibility and sunset recommendations
Financing and recovery analysis	Quantify bill impacts and financial risks of direct cost-reduction tools	ROE/capital structure sensitivities; depreciation/CWIP scenarios; securitization screening
Utilization and load management analysis*	Estimate value of peak reduction and flexible load	PJM peak value; EDC system peak value; local distribution deferral value; VPP/DR scenarios
Rate design and customer impacts*	Evaluate targeted affordability and cost-causation options	Customer class impacts; Low- and moderate-income (LMI) impacts; time-of-use (TOU)/fixed charge/demand charge scenarios
Targeted incentive design	Assess value of PIMs, shared savings, or MRP elements	Candidate metrics; baselines; incentive levels; caps; penalties; reporting rules
Supply-side coordination track*	Separate supply volatility questions from EDC business model reform	BGS hedging assessment; supply volatility options; risk allocation analysis

* These activities will proceed through other NJBPU tracks rather than directly through the Utility Business Model reform process.

4.5 Using Scenario Results to Refine the Roadmap

The purpose of the scenario modeling is both to evaluate bill impacts, and to help determine which reforms should move forward, which require redesign, which should be implemented in part or in phases, which need stronger guardrails, and which should be deferred. Scenario results should be used to refine the roadmap based on customer value, feasibility, implementation risk, jurisdictional fit, and alignment with New Jersey's regulatory objectives.

As a strawman for consideration, modeling results could be translated into key categories for roadmap decisions:

- **Advance near-term:** The reform shows measurable customer value, low implementation risk, and a clear pathway under existing NJBPU authority.
- **Study further or implement in part or in phases:** The reform has potential value but requires better data, baselines, stakeholder design, or testing before broader implementation.
- **Defer:** The reform has high complexity, low near-term bill impact, unclear customer value, or no clear New Jersey-specific use case.
- **Coordinate separately:** The reform affects affordability but falls outside the core EDC distribution business model reform.

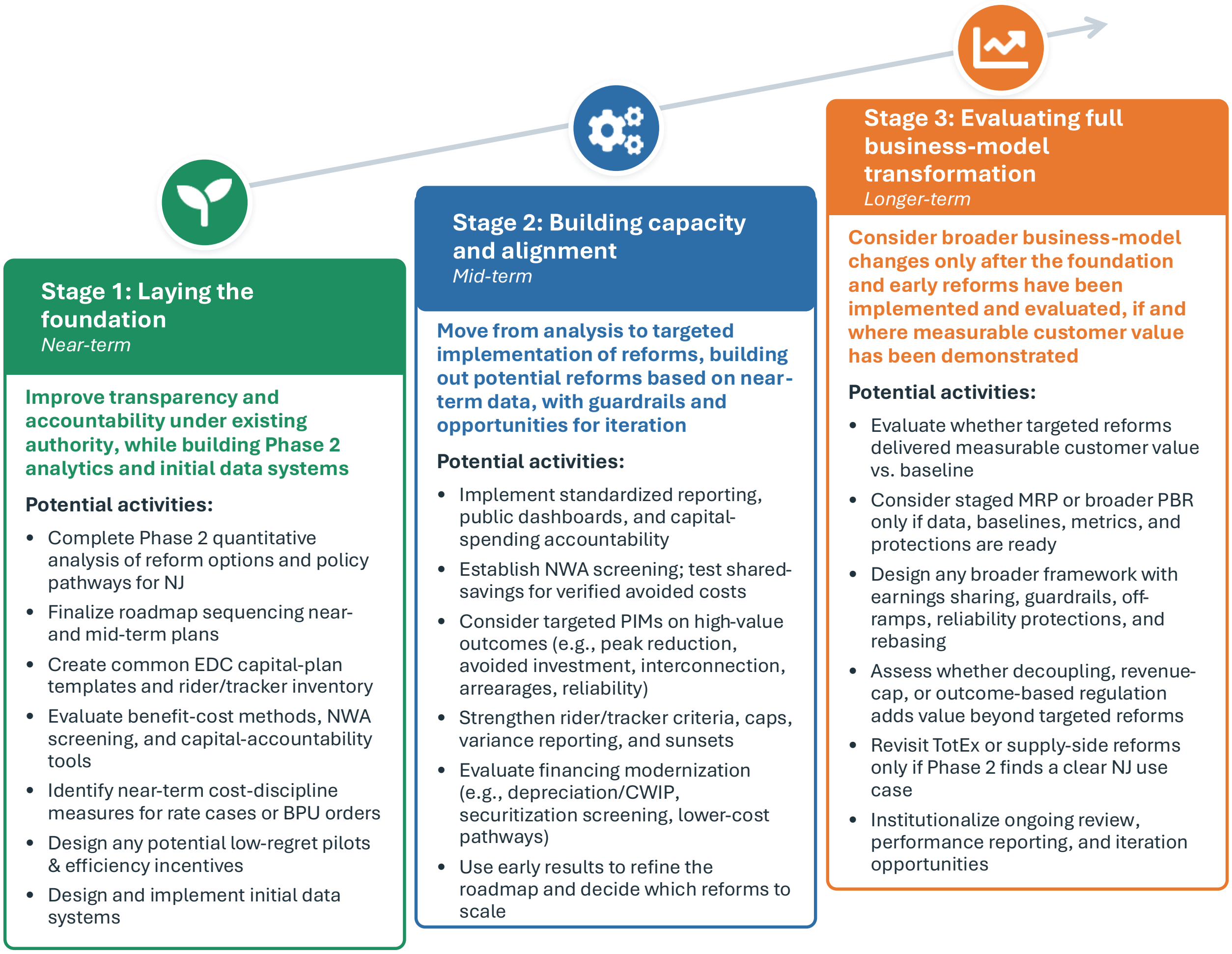
This type of decision-making framework will be especially important for distinguishing between near-term actions and longer-term structural reforms.

4.6 Phase 2 Roadmap Development Recommendations

The Phase 2 roadmap should organize potential reforms by timing, authority, implementation readiness, stakeholder acceptance, and the specific affordability mechanism each reform is intended to address. This roadmap could build off the list of potential reforms identified in this report, which could be refined through further work with stakeholders and NJBPU to prioritize and finalize a sequencing of reforms, leveraging the quantitative analysis. It should identify the sequence of actions that would allow NJBPU to move from assessment to implementation while managing risks to customers, reliability, and utility financial integrity.

Figure 21 below provides a "strawman" for the potential roadmap structure. Broadly, the first phase of the roadmap could focus on activities that build transparency and accountability, and develop the fact base needed to evaluate more comprehensive reforms. The second phase could focus on testing larger but targeted reforms, as well as potentially implementing certain reforms in part or in phases, while building the evidence base to define the pathway for broader changes. The third phase is when broader business model reforms may be pursued, building on the foundation and learnings from the prior work.

Figure 21. Potential "Strawman" of Roadmap Phases and Activities



The roadmap should also distinguish between reforms that can be advanced through existing NJBPU proceedings and those that require new processes or legislation. For example, Phase 1 indicates that ROE review, capital spending accountability, rate design, and certain targeted PIMs may be considered through existing regulatory tools, while some elements of PBR, TotEx regulation, moving program costs from rates to taxes, and some supply-side reforms would require more substantial analytical development, stakeholder engagement, and potentially legislative action.

Ultimately, we anticipate that the roadmap should include:

- A prioritized list of reform options;
- The affordability strategy for each reform;
- Expected timing and implementation pathway;
- Whether the reform can be advanced under the existing NJBPU authority;
- Data and reporting requirements;
- Estimated customer bill impacts or ranges;
- Customer class and low-income impacts;

- Utility financial integrity assessment;
- Reliability and service quality guardrails;
- Stakeholder input through working groups;
- Recommended next steps for implementation, pilot design, or deferral.

4.7 Enabling Stakeholder Engagement and Governance

To support the ultimate roadmap and the broader implementation of EO-1, E3 recommends developing a clear process for stakeholder engagement and broader discussions on business model reform priorities with an opportunity for robust dialogue and, where appropriate, stakeholder forums to discuss specific topics. Specific topics for discussion may include, but need not be limited to:

+ Further defining and establishing metrics around energy affordability;
+ Defining broader regulatory goals, priority customer outcomes, and baseline metrics tied to the identified outcomes to track utility performance and the impact of future reforms;
+ The findings of this study and the potential business model reforms detailed herein;
+ The "starting point" potential reform pathways for Phase 2 analysis identified in this chapter; and
+ Jurisdiction-specific information related to the implementation of utility business model reforms in New Jersey.

Stakeholder engagement will ultimately be vital to the long-term success of any reform explored and implemented. Therefore, key objectives of any stakeholder engagement during Phase 2 may include, but are not limited to:

+ Developing a shared vision for near-, medium-, and long-term utility business model reforms and buy-in from key stakeholders to support design and implementation of future reforms.
+ Creating a shared understanding of what drives customer bills and which levers NJBPU can influence.
+ Eliciting stakeholder views on the most important affordability, reliability, equity, clean energy, and business model concerns.
+ Identifying implementation barriers early, including statutory, tariff, data, market, financeability, and customer participation barriers.
+ Testing whether proposed metrics and reform packages are understandable, auditable, and durable.
+ Improving the quality of the roadmap by incorporating stakeholder input into the final analysis and any recommended next steps.

Figure 22 outlines some of the key stakeholder groups expected to be engaged during Phase 2 roadmap development.

Figure 22. Key Stakeholders and Topics to Address as Part of Phase 2 Roadmap Development

Customers & advocates
Affordability, equity, consumer protection

Electric distribution companies
Reliability, cost recovery, financeability

Rate Counsel & public agencies
Customer protection, prudence, public interest

PJM & market participants
Capacity, transmission, DER aggregation

DER, storage & technology providers
Interconnection, market participation, procurement

Large customers & economic development
Cost causation, reliability, competitiveness

Environmental & clean energy
Efficiency, electrification, emissions

5. Conclusion

New Jersey faces upward pressure on electricity bills, driven by rising costs across nearly all cost categories. About one-quarter of those costs are distribution system costs. While utility business model reform is not a standalone solution for affordability, it is one of the more direct levers that NJBPU can act on.

This Phase 1 assessment finds that no single reform is a standalone solution. The most reliable near-term gains come from low-regret, foundational measures that strengthen the evidence base and the scrutiny of spending under the Board's existing authority, while more ambitious incentive- and performance-based frameworks can be staged deliberately as data, baselines, metrics, and customer protections mature. This sequencing lets New Jersey capture value early while considering more comprehensive reform later.

Phase 2 should convert this qualitative assessment into an evidence-based roadmap, pairing quantitative bill-impact analysis with a staged policy design that specifies which reforms can proceed now under existing NJBPU authority, which require additional process or legislation, and which should await a clearer New Jersey-specific case supported by further analysis and empirical evidence. Consistent metrics, credible baselines, and structured stakeholder engagement will be essential to translating these findings into measurable customer benefits in both the near and longer term.

Ultimately, the goal is a utility business model that continues to deliver safe, reliable, and environmentally responsible service while giving the Board and the public better tools to hold costs accountable to results. The recommendations in this report are intended as a starting point for that work, to be tested and refined through the analysis and engagement outlined for Phase 2.

Appendix A: Jurisdictional Case Study Snapshots

Hawaii PBR

MRP example using a five-year revenue cap, I-X formula, earnings sharing, limited trackers, and reopeners.

Jurisdiction / utility	Reform type	Focus
Hawaii; Hawaiian Electric Companies	Revenue-cap MRP within broader PBR framework	Cost-control design and treatment of costs outside the cap

Mechanism map

Revenue cap	I-X formula	Customer dividend	Limited exceptions	Reopener
Five-year budget	GDP price index minus productivity	Deducted from target revenues to share savings	Fuel, purchased power, exceptional projects	PUC discretion or defined triggers

Key highlights

- Revenue cap applied broadly to CapEx and OpEx, with annual formula adjustments rather than annual cost-of-service updates
- Symmetrical ESM with a 300bps deadband seeks to preserve efficiency incentives while allowing both cost and savings sharing
- Cost trackers were limited and paired with fuel-cost risk sharing, shared savings, or case-specific review of exceptional projects
- Paired with broad suite of PIMs and ESMs

Observed experience / unresolved issues

- Reported capital and O&M efficiencies suggest the MRP created some cost-discipline effects, but total bill outcomes depended on costs beyond the revenue cap (e.g. fuel and wildfire costs)
- The Exceptional Project Recovery Mechanism raises questions about how to properly constrain supplemental capital requests
- Some advocates argue recently proposed revenue cap "true-up" process may nullify the efficiency benefits of PBR

Key trade-offs and takeaways

Reforms can improve outcomes, but cannot control all external factors

Even well-designed reforms may only mute the impact of external factors (e.g. higher fuel costs)

Deadband design is a core tradeoff

A wider deadband can preserve utility efficiency incentives, but customers receive a lower share

Reopeners provide flexibility but require discipline

Off-ramps and reopeners help manage extreme conditions, but should only be used for targeted expenses (e.g., specific types of projects or exogenous costs)

New York NWA PIM

Policy-focused incentive within broader suite of upside-only incentives.

Jurisdiction / utility	Reform type	Focus
New York; Con-Edison	Upside-only PIM	Incentivize cost-saving non-wires investments

Mechanism map

Total basis points	Estimated avoided costs	Customer dividend	Upside-only	Risk sharing
All PIMs cannot exceed 100 basis points of ROE	GDP price index minus productivity	Incentive tied to system cost savings	Incentive floor is $0	Incentive pays out 50% of NWA cost over- or underruns

Key highlights

- Incentive tied to preliminary project-specific BCA that utility must conduct, approved only if benefit/cost > 1
- Tying incentive to fixed BCA structure unifies estimation of shared savings to customers
- Overall PIMs cap reduces odds of utility gaming to maximize payout to customer disbenefit

Observed experience / unresolved issues

- Utility requests incentive levels close to the overall cap, raising questions as to whether PIM is causative of desired behavior

Key trade-offs and takeaways

Project-specific assessment is double-edged sword

Requiring a BCA for NWA solutions may increase customer benefits, but may also increase administrative overhead and reduce scalability if regulatory review is required for each project BCA

Risk sharing partially insulates utility

50% of cost overruns are covered by the incentive, blunting the signal for cost control but still giving the utility “skin in the game”

Shared incentive cap blends policy priorities

Gathering all PIMs under a pooled incentive cap gives utility flexibility to select suite of measures that meet combined policy goals, but may also enable gaming and blunts the incentive of some PIMs

Great Britain RIIO

Comprehensive TotEx implementation with revenue cap, market-based adjustments and reopeners.

Jurisdiction / utility	Reform type	Focus
Great Britain, Office of Gas and Electricity Markets (Ofgem)	Allow utility return on all "slow money" including portion of OpEx, with multiannual cap on return	Incentivize efficient operation and remove CapEx bias

Mechanism map

Five-year cap	Slow money + Fast money	Adjustment mechanisms	Savings and cost sharing	Re-openers
Price controls set for five years	Return based on CapEx and OpEx	Five types of uncertainty mechanisms for within-period true-ups	Relative to allowance are split between utility and customers	Utilities can apply for within-period adjustments under certain conditions

Key highlights

- ROE set on five-year basis following an extensive regulatory proceeding
- Authorized base allowed return is set the same for all regulated utilities, but actual returns vary based on performance and utility-specific intra-period adjustments
- Utilities may receive additional incentives for customer-benefitting activities that go beyond BAU

Observed experience / unresolved issues

- Utility requests incentive levels close to the overall cap, raising questions as to whether PIM is causative of desired behavior
- Unexpected market and inflationary conditions may result in utility windfalls
- Large swings in allowed ROE from cycle-to-cycle have been observed
- Eight-year price control period in initial phase was deemed too long and shortened

Key trade-offs and takeaways

Price control period is key design decision

Longer periods incentivize efficiency, but reduce flexibility to changing conditions

Careful design needed to avoid windfalls

Adjustment mechanisms that are too flexible can increase returns without requiring a direct increase in performance

Periodically revisiting business model design can allow for evidence-based reforms

RIIO structure is revisited in adjudicated process before each price control period, enabling significant redesign as needed, based on learned experience from prior periods

Massachusetts MRPs (National Grid)

Hybridized, O&M-focused MRP implementation with separate treatment of capital investments for National Grid in Massachusetts.

Jurisdiction / utility	Reform type	Focus
Massachusetts, National Grid)	Multi-year rate plan for O&M only with formula-driven revenue cap, ESM, and additional recovery mechanisms for capital	Incentivize productivity while enabling large expected capital build-out under electrification and other policy priorities

Mechanism map

Five-year rate plan for O&M only	I-X formula for O&M	Dedicated rider for core CapEx	Grid modernization separate	Earnings sharing (ESM)
Capital recovery is treated separately	Composite utility inflation index (I) minus partial-factor productivity (X)	Revenue requirement growth capped at 3% of total revenues	Treated under separate dockets & recovery mechanisms	Shares over/under earnings with customers

Key highlights

- Revenue requirement formula only indexes to O&M in most recent plan
- Core capital in a dedicated tracker with revenue requirement growth capped at 3% of total revenues. Remainder can be folded into next rate case for prudency review.
- Capital-intensive state-mandated Electric Sector Modernization Plans to be recovered through separate rider and docket
- Some exogenous costs are captured in a separate storm fund rather than captured through the Z-factor

Observed experience / unresolved issues

- Consumer dividend slightly reduced in more recent cycles based on claims of substantial cost savings to date
- Tracker-based and traditional cost-of-service capital recovery risks eroding cost discipline intended by MRP, but kept in place based on expected large increase in infrastructure buildout

Key trade-offs and takeaways

MRPs can come in hybrid models

Categories of costs falling under an MRP cap can be adjusted to meet current needs

Trackers offer relief valve for policy-driven capital investment needs...

...but must be balanced against cost discipline

Appendix B: Additional Details of Jurisdictional Examples

B.1. ROE and Capital Structure Reforms

Connecticut (Eversource / United Illuminating): In 2023, Connecticut's Public Utilities Regulatory Authority (PURA) approved an effective ROE for United Illuminating of 8.63%, below the requested 10.2% and the 9.69% national average across vertically-integrated electric utilities in 2022. As its rationale for the reduced ROE, PURA first used long-standing analytical approaches, the discounted cash flow and capital asset pricing models, with modified inputs to reach the 9.10% base ROE calculation. In addition, PURA also cited the average ROE for distribution-only electric utilities (like UI) of 9.11% to justify the reasonableness of the outputs of its modeling. PURA included additional reductions due to what it considered as the utility's poor performance related to: (1) submitting an incomplete cost of service study and rate design analysis, (2) failing to identify specific opportunities adopted by other utilities to reduce transmission costs passed to ratepayers, (3) poor customer service performance, and (4) inadequate remediation of a decommissioned power plant site.[61,62]

UI and credit rating agencies characterized the decision as a significant departure from regulatory precedent. Notably, however, the Connecticut Superior Court largely upheld PURA's authorized ROE on appeal and UI's credit ratings remained investment grade throughout.[63,64]

In the subsequent 2025 rate case (decided after the resignation of its chair), PURA found some of the performance-related penalties to have been resolved and raised UI's ROE to 9.25%. While a reduction in ROE inherently puts downward pressure on rates relative to the counterfactual, any downstream ratepayer impacts of the 2023 ROE reduction were relatively short-lived due to this reversal.

Pennsylvania Governor's letter to utilities and HB 2224: In the Spring of 2026, both the executive and legislative branches in the Pennsylvania state government took actions to begin pursuing ROE rate reforms, signaling increased scrutiny. The proposed legislation would peg authorized ROE to the 10-year U.S. Treasury yield + 2 percentage points for all investor-owned utilities and is framed as a "safe harbor" return fair for a low-risk monopoly. The legislation also includes a competitive equity auction fallback, which the utilities can appeal to if they consider the formula to be too low. This public utilities commission-overseen auction would allow investors to bid ROEs on their proposed

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[61] Connecticut Public Utilities Regulatory Authority, "PURA Ruling Sets Distribution Rates for United Illuminating Customers," August 25, 2023, https://portal.ct.gov/pura/press-releases/2023/pura-ruling-sets-distribution-rates-for-united-illuminating-customers.

[62] Connecticut Public Utilities Regulatory Authority, Docket No. 22-08-08, Final Decision, August 25, 2023, https://www.dpuc.state.ct.us/dockcurr.nsf/4b3c728dd1c0d642852586db0069aa70/dd7c1a0c81056b1485258a16004f1d22/$FILE/220808-082523.pdf.

[63] United Illuminating, "United Illuminating Files Appeal of PURA's Final Decision in Rate Case," press release, Sept. 18, 2023. https://www.uinet.com/w/united-illuminating-files-appeal-of-pura-s-final-decision-in-rate-case

[64] CT Office of Consumer Counsel, OCC FAQ (Dec. 2024): "United Illuminating and its parent, Avangrid, remain at A- and BBB+, respectively." https://portal.ct.gov/-/media/occ/dec-2024-credit-rating-faq.pdf

investment, mimicking competitive discovery of the true equity value in a market setting. At the time of writing, HB 2224 has passed one of two chambers in the state legislature.[65,66]

Colorado Black Hills 2024-2025 Rate Case Leverage Increase: In Black Hills Electric's 2024-2025 rate case, the investor-owned utility requested a WACC of approximately 7.72%, built on a 52.66% common equity ratio, a 10.5% return on equity, and a 4.61% cost of long-term debt. In its March 2025 decision, the Commission rejected Black Hills' proposed capital structure and instead imposed a structure of 47–49% equity (51–53% debt) and a return on equity of 9.3–9.5%, producing a weighted average cost of capital of roughly 6.9%. In its April 2025 rehearing application, Black Hills argued that this reduction was an arbitrary, legally unsupported departure from precedent and that this would erode investor confidence and undermine its ability to attract capital. By reducing both the equity ratio and the authorized return, the Commission lowered the overall cost of capital embedded in customer rates.[67,68]

B.2. Criteria-Based Lower-Cost Project Pathways

New Jersey's Infrastructure Bank provides an in-state example upon which such programs can be modeled. The Infrastructure Bank offers lower-cost financing to local governments and authorities making qualifying infrastructure investments, the project list for which is approved by the Legislature on an annual basis. This financing is funded by bonds issued by the I-Bank, whose strong credit rating (due to state backing) attracts lower interest rates than localities would otherwise pay on their own. Current statutes limit the I-Bank to environmental infrastructure (e.g., wastewater and water supply), transportation, aviation, marine, and hazard mitigation/resilience projects,[69] but the model could potentially be extended to electric system investments.

US Department of Energy Loan Programs Office: The loan programs offered by the DOE's Loan Programs Office (LPO, now operating as the Office of Energy Dominance Financing) offer one example of government-backed financing for qualifying projects. Established through the Energy Policy Act of 2005, the office furnishes low-interest direct loans and loan guarantees to projects meeting established criteria, often capital-intensive projects that are considered likely to help meet identified policy or reliability needs or promote system cost benefits. LPO's underwriting of first-of-a-kind projects has also been considered valuable for obtaining better private financing terms for the next-of-a-kind.[70] LPO has also suffered from several challenges. The office is criticized for being

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[65] Office of Pennsylvania Governor Josh Shapiro, letter to utility chief executive officers, April 29, 2026, https://s3.documentcloud.org/documents/28086151/2026429-jds-utility-ceos-letter-v2.pdf.

[66] Pennsylvania General Assembly, House Bill 2224, 2025-2026 Regular Session, https://www.palegis.us/legislation/bills/2025/hb2224.

[67] Colorado Public Utilities Commission, Proceeding No. 24AL-0275E, "Black Hills Electric Rate Case," https://puc.colorado.gov/black-hills-electric-rate-case.

[68] Colorado Public Utilities Commission, filing in Proceeding No. 24AL-0275E, https://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_session_id=&p_fil=G_825566.

[69] New Jersey Infrastructure Bank, "New Jersey Infrastructure Trust Act / Enabling Act," February 2025, https://cdn.njib.gov/njib/statutes/Updated%20enabling%20act%20Feb%202025.pdf.

[70] Nuclear Innovation Alliance, "The Role of DOE's Office of Energy Dominance Financing in U.S. Nuclear Energy Leadership," March 2026 update, https://nuclearinnovationalliance.org/sites/default/files/2026-04/The%20Role%20of%20DOE%E2%80%99s%20Office%20of%20Energy%20Dominance%20Financing%20in%20U.S.%20Nuclear%20Energy%20Leadership%20-%20March%202026%20Update.pdf.

inefficient at closing loans, with some commentators linking this to a risk-averse culture stemming from high-profile failures of past projects.[71] Recent events have also demonstrated that the office is susceptible to shifts in political forces, with the Trump administration suddenly pausing or rescinding financing for vast swathes of projects considered out of line with new priorities.

PG&E / Citizens Energy Nonprofit Public-Private Transmission Leasing Partnership: In this partnership, Citizens Energy Corporation (Citizens), a nonprofit energy company, is leasing the financing rights of several high-voltage transmission lines from PG&E, which PG&E develops and owns.

In the deal, Citizens agreed to invest up to ~$1 billion that PG&E would have otherwise financed through the typical WACC mechanism.[72] Because Citizens does not have shareholders, its financing costs are lower, as it can fund the asset with a much higher proportion of debt than equity. In addition, the debt itself can be tax-exempt and can come at a lower interest rate. Financing cost savings are therefore both a reduction in the cost-of-capital of the infrastructure and the tax components of the revenue requirements for the rate base.

Citizens has also stated that it intends to invest most of its profits from the program into clean energy investments in low-income and disadvantaged communities in PG&E's service area.[73] This is an increasingly common model in California; Other transmission projects that Citizens has participated in public-private financing for include Sunrise Powerlink, Sycamore–Peñasquitos, and the S-Line Upgrade.[74,75]

B.3. Securitization

Securitization has been employed in multiple contexts within the United States. A frequent use case is for accelerating the retirement of uneconomic coal plants, as was the case with New Mexico's San Juan Generating Station, financed via ratepayer-backed bonds as enabled under the state's Energy Transition Act.[76]

More recently, securitization has been used to finance other categories of capital-intensive investments. In **California**, the **2019 statute AB 1054** established a $21B securitized fund to cover wildfire-related costs caused by the delivery system, with the bond interest payments recovered as a non-bypassable charge on customer bills. An additional $18B of funding was supplied in the 2025

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[71] Bipartisan Policy Center, "Three Big Ideas for Modernizing DOE's Loan Program," accessed July 2026, https://bipartisanpolicy.org/issue-brief/three-big-ideas-for-modernizing-does-loan-program/.

[72] Citizens Pacific Transmission LLC, "Application for Participating Transmission Owner Status," California ISO, https://www.caiso.com/documents/citizens-pacific-transmission-llc-new-pto-application.pdf.

[73] Citizens Energy Corporation, "PG&E, Citizens Partnership on Charitable Programs," press release, https://citizensenergy.com/pressrelease/pge-citizens-partnership-on-charitable-programs/.

[74] Citizens Energy Corporation, "Citizens Transmission,", https://citizensenergy.com/businesses/citizens-transmission/.

[75] Federal Energy Regulatory Commission, filing in Docket No. EL21-15-000, April 15, 2021, https://www.ferc.gov/sites/default/files/2021-04/EL21-15-000-041521.pdf.

[76] Rocky Mountain Institute, "Securitization in Action: How U.S. States Are Shaping an Equitable Coal Transition," https://rmi.org/resources/securitization-in-action-how-us-states-are-shaping-an-equitable-coal-transition/.

passage of SB 254.[77] Access to the funding requires approval from the regulator; however, the utility benefits from the presumption of prudence if they have been certified as meeting safety requirements in an annual review.[78] Critics argue this inappropriately reduces the liability faced by utilities and shifts risk to ratepayers.[79] In a recent report, the CPUC questioned whether utilities and ratepayers are the proper entities to cover wildfire costs,[80] suggesting securitization might best be used for narrow cost categories that have a direct relation to a utility's core responsibilities.

B.4. Modified Capital Recovery Rules

Depreciation period length is an issue frequently debated in regulatory proceedings. Proposals for modifying electric depreciation periods have arisen in **California's long-term gas planning proceeding**. Staff and other stakeholders have proposed backloading electric asset depreciation as a way to offset near-term rate increases that would accompany accelerated depreciation of the gas distribution system.[81] While the proceeding is ongoing, Southern California Edison (SCE) posed several criticisms, amongst them that this would weaken the utility's near-term ability to make capital investments and could be inequitable in cases where gas and electric service are provided by two separate utilities. While the staff proposal did not necessarily require extension of electric asset lives, SCE's criticisms still apply to the broader concept of shifting or spreading cost recovery further into the future.

Georgia Power's Plant Vogtle Units 3 and 4 are an example of the significant cost risk that CWIP can put on ratepayers. CWIP costs were originally approved at $14 billion in 2009, whereas actual costs reached $37 billion before the units were put in service in 2023 and 2024.[82] While CWIP rules contributed to enabling the utility to build large new nuclear units, as was the regulator's intention, critics highlight that by enabling the utility to collect a return on capital expenditures immediately, it reduces the utility's incentive to predict and mitigate eventual cost overruns.[83,84]

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[77] S&P Global Ratings, "PG&E Corp. Ratings Affirmed On Passing Of California Senate Bill 254; Outlook Remains Positive," September 17, 2025, https://www.spglobal.com/ratings/en/regulatory/article/-/view/type/HTML/id/3442580.

[78] Utility Dive, "CPUC Safety Certification Eases PG&E Access to Wildfire Insurance Fund," January 20 2021, https://www.utilitydive.com/news/cpuc-safety-certification-eases-pge-access-to-wildfire-insurance-fund-pro/593618/.

[79] Utility Dive, "California Tees Up Wildfire Liability Bill as Utility, Consumer Groups Dive In," July 3, 2019, https://www.utilitydive.com/news/california-tees-up-wildfire-liability-bill-as-utility-consumer-groups-dive/558134/.

[80] California Wildfire Fund, "SB 254 Study: Information and Recommendations," January 30, 2026, https://www.cawildfirefund.com/sites/wildfire/files/documents/2026/cpuc-sb-254-study-information-and-recommendations_30jan2026-final.pdf.

[81] California Public Utilities Commission, "2024 Joint Agency Staff Paper: Progress Towards a Gas Transition", February 22, 2024, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M550/K500/550500746.PDF.

[82] Manhattan Institute, "The Hidden Tax on Your Power Bill: Construction Work in Progress," December 2025, https://media4.manhattan-institute.org/wp-content/uploads/the-hidden-tax-on-your-power-bill-construction-work-in-progress.pdf.

[83] Utility Dive, "CWIP: Construction Work in Progress and Ratepayers," December 5, 2025, https://www.utilitydive.com/news/cwip-construction-work-progress-ratepayers-supercycle/807132/.

[84] Federal Energy Regulatory Commission, "Chairman Christie's Dissent in Part and Concurrence in Part, Valley Link Incentives Award," May 13 2025, https://www.ferc.gov/news-events/news/chairman-christies-dissent-part-and-concurrence-part-valley-link-incentives-award.

B.5. Multi-Year Rate Plans

Hawaii offers a prominent example of multi-year ratemaking. In response to the 2018 Hawaii Ratepayer Protection Act, the Hawaii Public Utilities Commission established a multi-year rate plan for HECO starting in 2021. The MRP is the centerpiece of a broader suite of PBR measures, including an ESM and PIMs (see following sections) and a reopener provision. At the core of the MRP is HECO's annual target revenue, defined as:

$$Annual\ Revenue\ Adjustment = I - X + Z - CD$$

Where:

- *I* reflects nationwide inflation as indexed by the GDP Price Index (GDPPI).
- *X* reflects the deviation in average cost growth for the utility sector relative to the overall economy (i.e., a negative *X* means costs increased more quickly than for other sectors and the allowed revenues should be raised proportionally).
- *Z* accounts for exogenous events.
- *CD* represents a "Customer Dividend" or "stretch factor" used to ensure customers share in any efficiency savings the utility achieves and is set up front.

The framework includes an ESM that kicks in above or below a 300 bps deadband (see Table 9). HECO is allowed to recover costs of particularly large incremental investments outside of an MRP under the Exceptional Project Recovery Mechanism, provided the projects fall within certain categories and recovery is approved by the PUC. The MRP also includes a reopener mechanism to revisit base rates under certain conditions.[85]

The HECO MRP is on a five-year cycle, making 2026 a critical year for refining the ongoing approach to ratemaking after the completion of the first cycle. In March 2026, HECO applied for a rebasing of its target revenue to take effect at the start of 2027.[86] The combined filings reveal diverging stances on the role of the MRP. As part of its proposal, HECO proposed an $83.2 million inflation "true-up" to recover the gap between inflation as forecasted under the *I*-factor and actual inflation, which exceeded it. Some stakeholders argue this circumvents the MRP's core design of placing inflation forecast risk on the utility as an incentive to operate efficiently.[87] Commenters also express concern that HECO's petition effectively cherry-picks cost increases without accounting for any corresponding cost decreases over the course of the first cycle.[88] Writ large, detractors see rebasing itself as presenting a risk that the MRP reverts to something closer to traditional cost-of-service ratemaking. Some proponents of the true-up point to FERC Form 1 data that indicates capital and O&M expenditures have dropped since the implementation of PBR.[89]

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[85] Hawaii Public Utilities Commission, "Overview of the Performance-Based Regulation Framework," August 2024, https://puc.hawaii.gov/energy/pbr/overview-of-the-pbr-framework/.

[86] Hawaiian Electric Companies and Ulupono Initiative LLC, "Joint Alternative Rebasing Proposal," Hawaii Public Utilities Commission Docket No. 2018-0088.

[87] Life of the Land, reply comments, Hawaii Public Utilities Commission Docket No. 2018-0088.

[88] Division of Consumer Advocacy, reply comments, Hawaii Public Utilities Commission Docket No. 2018-0088.

[89] Ulupono Initiative, "Re-Basing Brief," December 5, 2024, https://ulupono.com/media/yiflfc0u/2024-12-05-ui-re-basing-brief-final.pdf.

National Grid in Massachusetts provides one example of an MRP that has evolved recently to meet changing policy needs. Until 2024, the MRP operated under a formula similar to Hawaii's, applying an inflation-indexed revenue cap to all of the company's distribution revenue requirement, with additional productivity, exogenous events, and customer dividend factors. In light of what are forecasted to be drastic capital investments to meet state policy needs, the state has moved to a "PBR-O" structure where only O&M expenses are treated in this way.[90] Core capital expenditures are covered separately, with an automatic cap on annual revenue requirement escalation equal to 3% of total revenues; any costs exceeding this amount are to be petitioned for recovery in the utility's next rate case.[91]

A large component of forthcoming capital expenditures is expected to come under the Electric Sector Modernization Plans (ESMPs, more detail below), which are presently captured in a rider that is adjusted annually on a backward-looking basis, with prudency reviews applied to the year's investments. As of the time of writing, long-term ESMP cost recovery mechanisms are to be the subject of future proceedings.[92] Key stakeholders (including the state Attorney General and Department of Energy Resources) have raised concerns that the new mechanism weakens incentives for capital expenditure control that were inherent to the old model.

Green Mountain Power in Vermont takes a unique approach to multi-year rate planning. Implemented on a three-year term, the plan starts with a traditional cost-of-service test year approach in the first year, followed by annual true-ups to the revenue requirement based on differentiated formulas or cost forecasts for distinct cost components. O&M costs are segmented under three categorizations, the first of which is assumed to be wholly under the utility's control and therefore locked for the plan duration, with the other two being reconciled annually based on inflation and cost forecasts. There are limited opportunities for capital cost recovery outside of the MRP, although this mechanism has been used for specific investments, including distribution system hardening.[93]

Illinois has conducted MRPs in recent years, under recent laws that allow the utilities to choose between a traditional rate case or a four-year MRP.[94] One of the novel features of the Illinois MRP is the link between the multiyear grid planning process (MYGP) and the MRP, which, along with improvements made to the forecasting methodology, has provided the Illinois Commerce Commission (ICC) and stakeholders with enhanced transparency and understanding of planned investments.

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[90] National Grid, "Performance-Based Ratemaking Provision," Massachusetts Electric Company tariff, October 1, 2025, https://www.nationalgridus.com/media/pdfs/billing-payments/tariffs/mae/2025/mdpu_1612_pbr_provision_10.01.25.pdf.

[91] National Grid, "D.P.U. 23-150, Final Order," Massachusetts Department of Public Utilities., Sept. 30, 2024, https://media.wbur.org/wp/2024/10/D.P.U.-23-150-National-Grid-Rate-Case-Final-Order-9.30.24.pdf.

[92] NSTAR Electric Company, "D.P.U. 24-10, Electric Sector Modernization Plans, Final Order," Massachusetts Department of Public Utilities, August 29, 2024, https://electricgrid.mass.gov/wp-content/uploads/2025/07/D.P.U.-24-10-11-12-ESMP-Final-Order-8.29.24.pdf.

[93] Green Mountain Power, "Green Mountain Power Launches First-in-Nation 2030 Zero Outages Initiative," October 10 2023, https://greenmountainpower.com/news/green-mountain-power-launches-first-in-nation-2030-zero-outages-initiative/.

The utilities' initial MRP proposals were rejected and slimmed down substantially by the regulator. Reconciliation mechanisms, which allow the utilities to recover up to 105% of their approved revenue requirement for unexpected changes in costs, have been targets of criticism, with some commenters arguing they circumvent the cost containment incentive inherent to MRP. Both Ameren and Con Edison have requested reconciliation mechanisms up to the cap.[95]

Alberta is a jurisdiction with one of the longest-running MRPs in North America, now on its third four-year cycle. Rather than a revenue cap, Alberta operates under a price cap, tied to an I-X formula as defined by the Alberta Utilities Commission:[96]

$$Rt = Rt - 1 * (1 + I - X) \pm K \pm Kbar \pm Y \pm Z - ESM$$

Where:

- $\boldsymbol{Rt}$ = Rates for the current year
- $\boldsymbol{Rt{-}1}$ = Rates for the previous year
- $\boldsymbol{I}$ = The I factor, tied to a mix of labor (60%) and non-labor (40%) cost indexes
- $\boldsymbol{X}$ = The productivity offset, set at 0.4%, including a 0.3% premium to ensure benefit-sharing with customers
- $\boldsymbol{K}$ = "Type 1" capital adjustments, which account for extraordinary capital projects
- $\boldsymbol{Kbar}$ = "Type 2" capital adjustments, which are ordinary and recurring
- $\boldsymbol{Y}$ = flow-through costs to the customer, including certain fees and taxes
- $\boldsymbol{Z}$ = the typical Z-factor for exogenous events
- $\boldsymbol{ESM}$ = an earnings sharing mechanism as described in Table 9.

The evolution of MRPs in Alberta has exemplified some of the core tensions of performance-based ratemaking. In the first two cycles of MRP, utilities generally earned returns above their base ROE. Despite the utilities' contention that it was no longer necessary, the Commission determined there was sufficient directional evidence to keep the stretch factor in place, citing that the gap was "nevertheless indicative of cost savings achieved through realized efficiencies," and that utilities "will still have considerable opportunity to achieve efficiencies in the upcoming term," justifying upfront benefit-sharing. The Commission further decided that the ESM and the 0.3% X-factor premium should be added to increase customers' share of MRP benefits. While these additions were considered likely to dampen the efficiency incentive, they were seen as necessary to ensure the ongoing equity of the MRP structure.[97]

[95] Illinois Commerce Commission, "Petition for Approval of a Multi-Year Rate Plan," https://icc.illinois.gov/downloads/public/edocket/597028.PDF.

[96] Alberta Utilities Commission, Decision 30274-D01-2025: FortisAlberta Inc., 2026 Annual Performance-Based Regulation Rate Adjustment, Proceeding 30274, December 17, 2025, https://media.auc.ab.ca/prd-wp-uploads/regulatory_documents/Reference/30274-D01-2025.pdf.

[97] Alberta Utilities Commission, Decision 27388-D01-2023: 2024-2028 "Performance-Based Regulation Plan for Alberta Electric and Gas Distribution Utilities," Proceeding 27388, October 4, 2023, https://prd-api-efiling20.auc.ab.ca/Anonymous/DownloadPublicDocumentAsync/794425

B.6. PIMs

New York State: New York offers one example of a jurisdiction with a variety of PIMs in effect, targeted towards DER deployment, demand response, and emissions goals. It is also a jurisdiction where the effectiveness of PIMs has been questioned by stakeholders. For example, in 2024, Con Edison was awarded the maximum incentive for both its building electrification and residential managed charging goals, but no robust counterfactual exists to confirm this was due to the PIMs.[98]

Regular evaluation of PIMs in rate cases makes their implementation in New York more transparent.[99] In addition, PIMs in New York are evaluated in combination, rather than individually. This is also manifested through a requirement that the utility's combined earnings from PIMs do not exceed a specified total (in 2016, this was 100 basis points).[100] This combined evaluation can help ensure progress towards overall policy objectives.

A unique PIM for NWA implementation has been in effect for Con Edison since 2017. The mechanism provides the utility 30% of the calculated difference between the net costs and benefits of an NWA solution and those of the associated traditional transmission and distribution project.[101] The company must run an initial benefit-cost analysis (BCA) and indicate that it is likely to have a benefit-cost ratio greater than 1 before implementing the project.[102] After true-ups, the final incentive paid out is equal to the initial calculated incentive plus 50% of the cost overruns or underruns of the NWA project, with a floor of $0.

Similar to this NWA incentive, all active PIMs in New York are structured as upside-only incentives, with no penalties for utility underperformance.[103] New York DPS staff have expressed concern that this potentially incentivizes utilities to request the maximum possible multiplier for compensation against performance metrics, i.e., that the utilities will unfoundedly claim that a higher incremental payout is what's necessary to effectuate the desired measures.[104]

Hawaii: As discussed in the MRP section above, in 2021, Hawaii adopted a PBR framework that included MRP and a portfolio of PIMs. The PIMs in Hawaii included five new mechanisms targeting

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[98] Consolidated Edison Company of New York, Inc., Cases 22-E-0064/22-G-0065, "2024 Earnings Adjustment Mechanism Achievement Report," June 30, 2025, https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BA0E7CB97-0000-CC28-A711-8AD038AF68C9%7D.

[99] Carina Rosenbach and Rachel Gold, "How PIM Evaluation Can Level Up," RMI, August 6, 2025, https://rmi.org/resources/how-pim-evaluation-can-level-up/.

[100] New York State Public Service Commission, Case 14-M-0101, "Order Adopting a Ratemaking and Utility Revenue Model Policy Framework," issued May 19, 2016, https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BD6EC8F0B-6141-4A82-A857-B79CF0A71BF0%7D.

[101] RMI, "Con Edison Non-Wires Alternatives Incentive," PIM ID 44, PIMs Database, https://pims.rmi.org/details/44.

[102] New York State Public Service Commission, Cases 25-E-0072/25-G-0073, "Order Adopting Terms of a Joint Proposal and Establishing Electric and Gas Rate Plans," issued January 22, 2026, https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B800DE79B-0000-C74C-9247-B3A408818830%7D.

[103] RMI, "PIMs Database," https://pims.rmi.org/.

[104] New York Department of Public Service Staff, direct testimony of the EAM Panel, https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BE0E1AB8F-0000-CD2D-8D65-4F9BFE5B2B5A%7D&DocTitle=Staff+EAM+Panel+Direct+Testimony.

outcomes of growing importance to the state: interconnection approval time, grid services acquired from DERs, renewable portfolio standard achievement, low-to-moderate income energy efficiency, and advanced metering infrastructure utilization.[105,106] Data on the utilities' performance shows an overperformance on their renewable portfolio standard that awarded a $1 million performance incentive, as well as an interconnection time reduction goal that awarded a $2.8 million performance incentive.[107] These awards suggest PIMs have made a positive impact, but it is not possible to determine whether there is a causal link between PIMs and performance.

Some critics argue that the promised benefits of PBR in Hawaii (including the MRP, see above, and PIMs) have not materialized. Initial PUC projections were $1.27/month in residential bill savings (~$69.9 million through 2025).[108] However, it is difficult to assess whether such savings were delivered compared to the counterfactual, as Hawaii faced a number of extraordinary factors that placed significant upward pressure on utility rates, including the September 2022 retirement of Oahu's last coal plant, global oil price spikes following Russia's invasion of Ukraine, and financial consequences of the August 2023 Maui wildfires.[109,110]

Minnesota: Minnesota maintains a shared savings mechanism that provides financial rewards for energy conservation, tied to verifiable reductions in retail sales stemming from demand-side measures. As of 2024, for retail sales savings exceeding 1.5%, the utility is awarded an increasing fraction of the resulting net benefits. The incentive applies up to a 2.2% savings cap, which would award the utility 5.5% of the net benefits.[111] The remaining 94.5% of net benefits flow to ratepayers and society.

The net benefits are calculated by the new "Minnesota test", which accounts for both the direct utility system impacts of a measure (e.g., generation and capacity avoided costs) as well as other non-utility system impacts, including avoided GHG emissions.[112] Arguments over the mechanism structure echoed classic debates of incentive design. Because the Minnesota test greatly expanded

[105] Hawaii Public Utilities Commission, "Monitoring Hawaiian Electric's Progress," accessed July 2026, https://puc.hawaii.gov/energy/pbr/monitoring-hawaiian-electrics-progress/.

[106] Hawaiian Electric, "Performance Scorecards and Metrics," accessed July 2026, https://www.hawaiianelectric.com/about-us/performance-scorecards-and-metrics.

[107] Hawaiian Electric Company, Inc., Hawai'i Electric Light Company, Inc., and Maui Electric Company, Limited, "Notice Transmittal to Update Target Revenue through the Major Project Interim Recovery Adjustment Mechanism and Calculation of 2021 Performance Incentive Mechanism and Shared Savings Mechanism Financial Incentives," Transmittal No. 22-01, filed February 25, 2022, https://www.hawaiianelectric.com/documents/about_us/pbr_metrics/additional_reports/20220225_trans_22_01_heco_cos_notice_transmittal.pdf.

[108] Hawaii Public Utilities Commission, "Hawaii PUC Approves Portfolio of Performance Mechanisms for Hawaiian Electric," press release, June 1, 2021, https://puc.hawaii.gov/wp-content/uploads/2021/06/PBR-PIM-DO-Press-Release.Final_.V2.06-01-2021.pdf.

[109] Utility Dive, "Hawaiian Electric braces for bill increases amid high oil prices, coal plant retirement": https://www.utilitydive.com/news/hawaiian-electric-coal-bills-earnings/629151/

[110] Hawai'i Public Utilities Commission, Decision and Order No. 42228, Docket No. 2025-0156 (In re Hawaiian Electric Companies' 2025–2027 Wildfire Mitigation Plan), filed Dec. 31, 2025, https://puc.hawaii.gov/news-release/puc-approves-hawaiian-electric-wildfire-mitigation-plan-and-completes-wildfire-recovery-fund-study/.

[111] Rocky Mountain Institute, "PIMs Database: Shared Savings DSM Mechanism," accessed July 2026, https://pims.rmi.org/details/147.

[112] Minnesota Department of Commerce, eDockets filing on the Minnesota test and conservation incentives, https://efiling.web.commerce.state.mn.us/documents/%7B00DF3887-0000-C719-B71B-0523B746A81D%7D/download?contentSequence=0&rowIndex=1.

the pool of net benefits relative to prior cycles, opponents of the proposal argued it necessarily resulted in a higher incentive without requiring additional conservation. They also noted that reduced incentives over previous cycles had not produced any reductions in utility performance, indicating that incentives could be further reduced, particularly because Minnesota's incentives outstripped those of comparable states.[113]

Illinois: Com Ed is one example of a utility with an affordability-focused PIM. The utility can receive an award of up to 5 ROE basis points for achieving at least 6.7% and up to 10% annual reductions in residential customer disconnections. To date, Com Ed has not been awarded any incentives for this PIM, due to failing to meet the necessary burden of proof that their actions have led to reductions in disconnections as determined by the regulator.[114]

B.7. Revenue Decoupling

Revenue decoupling has been widely implemented. Examples include California, Connecticut, Maine, Minnesota, and Washington. Some empirical evidence suggests that revenue decoupling has not uniformly resulted in rate decreases. A 2021 Berkeley Lab report surveyed annual retail rate adjustments for utilities between 2005 and 2017. It found that revenue decoupling mechanisms resulted in both rate increases and decreases across the utilities, with the majority of them being within 1 percent. The report also found that 64% of rate adjustments were upwards, with the vast majority of upwards adjustments being followed by another upward adjustment the following year (in 86% of cases).[115] Importantly, however, rate increases may not necessarily result in an increase in customer utility bills, as revenue decoupling also typically supports increased energy efficiency measures. However, an increase in utility rates that is offset by some energy efficiency measures may create inequities.

B.8. TotEx-Based Regulation

There are no existing implementations of TotEx in the United States. The most notable example of TotEx ratemaking is **Great Britain's RIIO**, administered by Ofgem, the market regulator. In Great Britain, TotEx is combined with a revenue cap and a shared savings mechanism to incentivize efficient expenditures by the utility (see also revenue regulation discussion in 3.5.5 and SSMs discussion in Section 3.5.7).[116] Similar to an MRP, RIIO's design is revisited on a multi-year cycle, with allowed revenues and adjustment mechanisms being defined before the start of the price control period.

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[113]Minnesota Department of Commerce, eDockets filing on conservation incentive mechanism comments, https://efiling.web.commerce.state.mn.us/documents/%7B90E1418D-0000-CF10-A989-6CCF85EAF967%7D/download?contentSequence=0&rowIndex=9.

[114] Illinois Commerce Commission, Docket P2025-0383 filing, https://icc.illinois.gov/docket/P2025-0383/documents/374311/files/656050.pdf.

[115] Lawrence Berkeley National Laboratory, "The Distribution of U.S. Electric Utility Revenue Decoupling Rate Impacts from 2005 to 2017," 2021, https://eta-publications.lbl.gov/sites/default/files/electricutilitydecouplingmechanismsintheunitedstates_brief_final.pdf.

[116] Rocky Mountain Institute, "Making the Clean Energy Transition Affordable," July 2022, https://rmi.org/app/uploads/dlm_uploads/2022/07/making_the_clean_energy_transition_affordable.pdf.

In general, disputes about the merits of RIIO have not hinged on the overall framework, but rather on the details of its design. Poor design of performance benchmarks can result in accidental over- or under-compensation of the utility. In the second RIIO price control period (RIIO-2, beginning 2021), RIIO's design assumed utilities would primarily use inflation-linked debt for financing and therefore indexed their debt allowance to track inflation. Because utilities primarily used fixed-rate debt, which was relatively cheaper due to high inflation during that period, this design effectively awarded utilities billions in additional revenues without any related efficiency improvement.[117] Ofgem implemented updates under RIIO-3 to close this gap. The allowed ROE is another point of conflict in RIIO and has fluctuated drastically between price control periods in response to changing market conditions and policy priorities. Additionally, between RIIO-1 and RIIO-2, the cycle length was reduced from eight years to five in response to stakeholder feedback that longer price control periods reduced flexibility under rapidly changing industry conditions. Note that none of these design issues are fundamentally unique to TotEx-based regulation; for example, many of them are shared by MRPs.

Given that TotEx has no domestic examples, several questions would need to be resolved by regulators to ensure the framework adapts well to the New Jersey context. A primary concern often raised is whether TotEx is compatible with ASC 980, an accounting rule that lets utilities defer recognizing costs they will later recover from customers, keeping reported income smooth rather than volatile. TotEx may be incompatible because the "slow money" on which the return is based is decoupled from actual capital expenditures. It remains unclear whether a true incompatibility exists, although some analyses suggest TotEx would indeed be ASC 980-compliant.[118] If it is found not to be, then credit ratings could be impacted, as utilities would have to report income and costs in the "lumpy" intervals in which they were earned or incurred, creating the perception of volatility. The precise extent to which credit ratings would be impacted in this scenario is uncertain.

B.9. Strengthening Accountability & Regulatory Scrutiny

Massachusetts Electric Sector Modernization Plan (ESMP): Required by the Massachusetts legislature, the Electric Sector Modernization Plans (ESMPs) are cyclical strategic roadmaps to modernize and upgrade the electric grid. The first ESMPs were submitted by the utilities and approved by the regulator in 2024, with follow-on filings to fill in specific gaps identified by the regulator in the initial filings (namely around proactive DER interconnection planning).

In the ESMP proceedings, recurring debates have formed over the appropriate level of regulatory scrutiny to apply to utility investment decisions. By law, the DPU can only approve a utility's ESMP if it shows that benefits exceed the costs via a net-benefits test. Conversely, non-ESMP "core" investments are reviewed through normal rate cases. Detractors, including the Attorney General, argued the utilities' classification of investments in either bucket was strategic, having to do with the

[117] Citizens Advice, "Energy Network Companies Pocket GBP 4 Billion in Excess Profits from Cost Of Living Crisis," press release, https://www.citizensadvice.org.uk/about-us/media-centre/press-releases/energy-network-companies-pocket-gbp4-billion-in-excess-profits-from-cost-of/.

[118] Rocky Mountain Institute, "Making the Clean Energy Transition Affordable: How TotEx Ratemaking Could Address Utility Capex Bias in the United States" July 2022, https://rmi.org/app/uploads/dlm_uploads/2022/07/making_the_clean_energy_transition_affordable.pdf.

desired cost recovery mechanism rather than tied to fundamental differences in investment type. Other advocates similarly objected to the utilities' bifurcation, urging for a more comprehensive forum where planned investments are collectively subject to net-benefits review. The utilities pushed back, arguing that subjecting all planned investments to a net-benefits review would create "significant regulatory uncertainty" and stall their ability to provide "safe and reliable service". The DPU largely sided with the utilities, declining to make the ESMPs each utility's central distribution planning document.[119,120]

The Healey-Driscoll administration subsequently filed proposed legislation that would require the ESMPs to reflect a complete picture of future distribution system investments, including both policy-driven investments and "core" investments, with the intention of enhancing the transparency of grid planning and ensuring co-optimized investments.[121]

New York Public Service Commission (PSC): New York's distribution system planning requirements under the Reforming the Energy Vision (REV) proceeding require that utilities prepare detailed distribution system implementation plans (DSIPs).[122] These plans must identify system needs and non-wires alternative opportunities before committing to traditional capital solutions. Utilities are also required to publicly report NWA procurement status and outcomes in recurring reports. New York also maintains continuous capital reporting between rate cases, which distinguishes its model from project pre-approval alone. Utilities file standing capital information (Capital Investment Plans) with the PSC and recurring quarterly Capital Expenditure Reports that track actuals against forecast by program.[123] DPS staff also engage with utilities regularly, leading to more transparent and informed regulatory oversight.

In practice, the framework requires utilities to screen distribution projects for non-wires alternatives and document a benefit-cost analysis before committing to traditional capital. In one case, a utility (NYSEG) used this process to defer an estimated $13.7 million substation upgrade for up to ten years by deploying a 1 MW/2.9 MWh battery energy storage system as a non-wires alternative, with project spending tracked in quarterly reports filed with the New York Department of Public Service.[124] A core tension in the program is information asymmetry between the utility and project developers, who lack the data needed to identify and compete for project opportunities. New York's experience suggests that planning-stage screening can change capital decisions, but its success depends on

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[119] Massachusetts Department of Public Utilities, "Electric Sector Modernization Plans Order Findings," accessed July 2026, https://www.mass.gov/info-details/electric-sector-modernization-plans-order-findings.

[120] Massachusetts Department of Public Utilities, "Final Electric Sector Modernization Plan Order," August 29, 2024, https://www.mass.gov/doc/final-esmp-order-82924/download.

[121] Massachusetts Executive Office of Energy and Environmental Affairs, "The Energy Affordability, Independence, and Innovation Act," accessed July 2026, https://www.mass.gov/info-details/the-energy-affordability-independence-and-innovation-act.

[122] New York Public Service Commission, Case No. 16-M-0411, https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=16-M-0411

[123] Joint Utilities of New York, "Capital Investment Plans," accessed July 2026, https://jointutilitiesofny.org/utility-specific-pages/system-data/capital-investment-plans.

[124] New York State Electric & Gas Corporation. (2026, January 29). Stillwater NWA implementation plan, benefit cost analysis, and incentive compliance filing (Cases 22-E-0317 et al.). New York Department of Public Service. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B90FF099C-0000-CA14-BDDA-017DE174AD68%7D

efficiently resolving this information asymmetry and on ensuring regulatory staff capacity to oversee the process.[125]

Illinois - ICC Multi-Year Grid Plans and Back-End Prudence Reconciliation: Since the passing of the Climate and Equitable Jobs Act (CEJA) in 2021, Illinois' largest electric utilities are required to file Multi-Year Integrated Grid Plans paired with multi-year rate plans. The stated goal of these requirements is to increase the effectiveness, accountability, and performance of these utilities by requiring them to bear the burden of demonstrating that costs were prudent and reasonable. Following the implementation of this law, the ICC has increased its oversight over ratemaking.

For instance, in December of 2023, the Illinois Commerce Commission (ICC) rejected ComEd's and Ameren's initial grid plan, finding that the utilities failed to comply with several components of CEJA (including cost-effectiveness, affordability, transparency, and equity requirements) and directed both to revise and resubmit within three months.[126] The re-filed plans were approved by the ICC in December of the following year with 25% and 75% reductions in proposed spending, respectively. Consumer and environmental advocates praised the decision as a meaningful shift toward tighter oversight. The utilities disagreed, with one stating that the initial plan "was the result of a transparent two-year regulatory process with significant input from stakeholders, including the ICC's own expert staff," and that it met the statute's requirements.[127] A dissenting commissioner also argued the ICC could have modified rather than rejected the plans.[128]

Illinois's experience suggests that a binding review of cost-effectiveness can materially change capital plans and reduce approved spending, but that doing so may result in additional processes and effort from commission and utility staff and stakeholders. Such novel processes can also result in disputes over process and standards; however, disputes are not uncommon in any regulatory proceeding.

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[125] New York Public Service Commission, Case No. 16-M-0411, https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=16-M-0411

[126] Illinois Commerce Commission, "ICC Rejects Ameren Illinois and ComEd Grid Plans," press release, December 14, 2023, https://www.illinois.gov/news/release.html?releaseid=29425.

[127] Capitol News Illinois (Andrew Adams), "State regulators once again flex muscle in rejecting utilities' grid plans, lessening rate hikes", December 15, 2023, https://capitolnewsillinois.com/news/state-regulators-once-again-flex-muscle-in-rejecting-utilities-grid-plans-lessening-rate-hikes/.

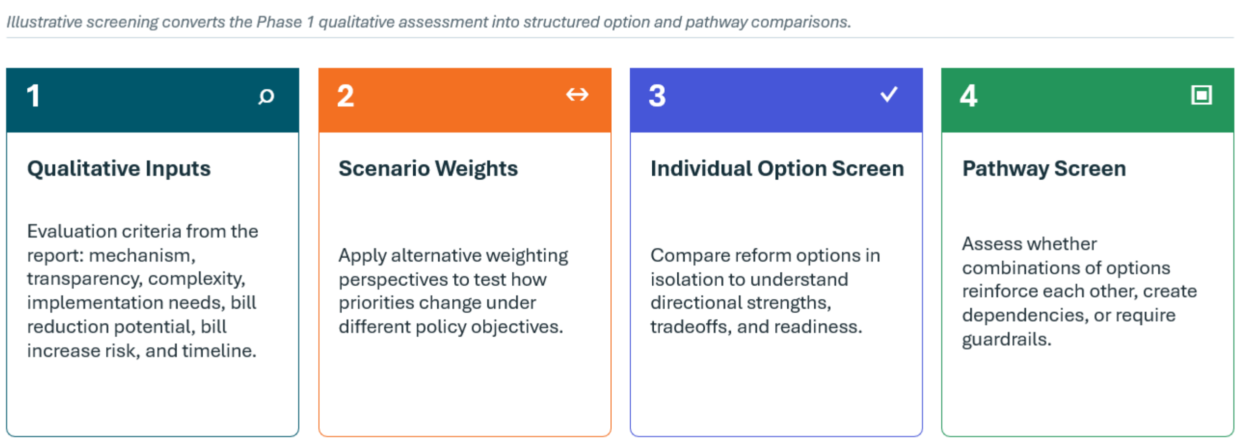
[128] Illinois Commerce Commission, Docket P2023-0055, https://icc.illinois.gov/docket/P2023-0055/documents.

Appendix C: Directional Assessment of Reforms

This appendix provides an illustrative, screening-level approach for comparing the reform options assessed in Section 3 and the candidate reform pathways described in Section 4. The purpose of this appendix is to make the qualitative tradeoffs transparent before any Phase 2 stakeholder process, quantitative analysis, and roadmap development. This appendix is illustrative only and intended to provide a conceptual framework and approach that can support the development, testing, and iteration assessments for one or more reform options.

A directional assessment can start with the evaluation criteria in this report that then converts a qualitative judgment into relative “scores”, tests how results change under different weighting assumptions, and then evaluates whether options work together as holistic packages, which we term as “candidate reform pathways”. This can be useful because different reforms serve different roles with different tradeoffs: some can be implemented under existing authority, some may provide clearer near-term bill impacts, some mainly shift cost recovery or transfer risk, and others require more data, regulatory capacity, stakeholder process, or statutory changes.

Figure C-1. Illustrative framework for directional assessment of individual options and candidate reform pathways



C.1 Screening criteria and scoring approach

The proposed illustrative framework uses the same types of evaluation criteria discussed in the body of this report (see Section 3.3). Each criterion has a directional interpretation. Criteria can be assigned “scores” (e.g., scale from 1-10, low/medium/high, better/worse/neutral, symbols such as + or -, etc.) that indicate a stronger fit for the relevant screen, but the direction of “better” varies by criterion. For example, higher transparency is favorable, as is lower bill-increase risk and lower implementation needs. The financing and cost recovery impact is descriptive and helps distinguish cost reduction from cost shifting and risk transfer.

This illustrative framework can be applied in two steps.

First, **each option is screened individually** to understand its role, likely value, readiness, and risks. The evaluation of reform options provided in Section 3 and summarized in Table 17 provides an example directional inputs used to compare the reform options. The most useful interpretation of this evaluation is comparative. Reforms that increase transparency and have low implementation needs may be valuable early, even if they do not produce large direct benefits on their own. Conversely, reforms with larger potential impact may need to be modeled, piloted, or sequenced after data, baselines, and guardrails are in place.

Second, **options are grouped into candidate reform pathways** and assessed for coherence, dependencies, and whether they create a logical sequence from foundational improvements to more complex reforms.

C.2 Illustrative sensitivity screens for individual options

Different **stakeholders may place different weights on each evaluation criteria** (e.g., affordability impact, implementation readiness, transparency, or long-term structural change). This appendix shows four illustrative sensitivity screens. These screens are not meant to choose a preferred option. They demonstrate how a common framework can reveal the options that tend to arise under different policy objectives.

Table C-1. Illustrative screens used to stress-test option rankings

Screen	Description	Illustrative weighting emphasis
Balanced	Balances affordability potential with risk, transparency, implementation needs, timeline, and mechanism fit.	Bill Reduction 25%, Bill Risk 20%, Transparency 15%, Regulatory Complexity 10%, Implementation 10%, timeline 10%, Mechanism 10%
Least-regrets	Prioritizes lower bill-increase risk, transparency, low implementation needs, and near-term feasibility.	Bill Reduction 10%, Bill Risk 25%, Transparency 20%, Regulatory Complexity 10%, Implementation 20%, Timeline 15%
Affordability	Places more weight on potential bill reduction and avoiding costs while retaining a risk screen.	Bill Reduction 40%, Bill Risk 15%, Transparency 10%, Regulatory Complexity 5%, Implementation 10%, Timeline 5%, Mechanism 15%
Structural	Tests options that may change utility decision-making or incentive structure more substantially over time.	Bill Reduction 30%, Bill Risk 10%, Transparency 10%, Regulatory Complexity 5%, Implementation 5%, Mechanism 40%

C.3 Candidate reform pathway assessment

Candidate reform pathways, i.e. a holistic package of reform options, should be assessed differently than individual options. **A package is more than the average of its parts.** A useful package has a clear objective, combines options that reinforce each other, sequences dependencies logically, and includes guardrails for reliability, financeability, equity, and customer protection. See below an illustrative table of scoring for candidate reform pathways.

Table C-2. Illustrative scoring of candidate reform pathways

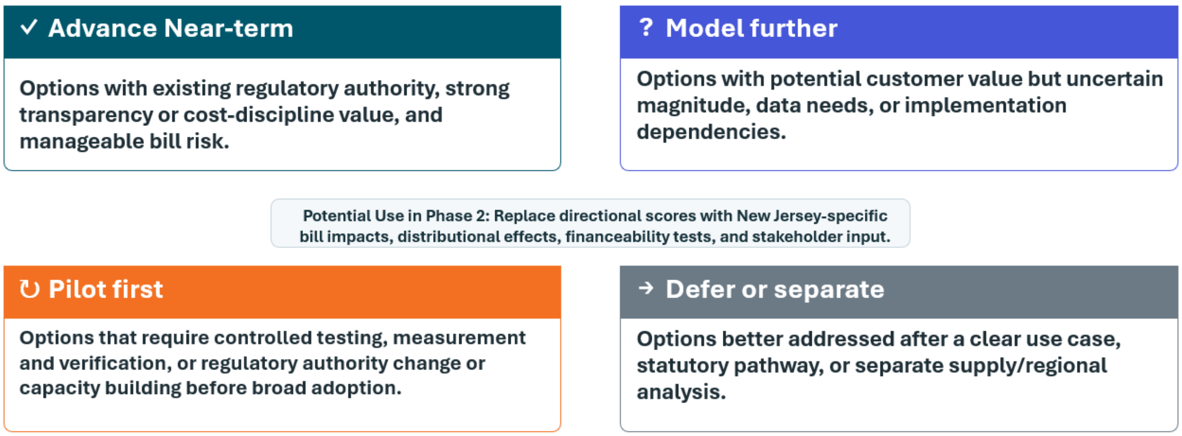
Candidate pathway	# Options	Balanced	Least regrets	Afford-ability	Structural	Primary tradeoff to test
Cost Discipline Foundation	**7**	Score	Score	Score	Score	Potentially low near-term risk, but may not fully change utility earnings incentives or cost outcomes.
Financing Modernization	**4**	Score	Score	Score	Score	May lead to direct quantifiable bill impacts but there may be issues assessing near to longer term cost-benefits.
Targeted Incentives and Shared Savings	**5**	Score	Score	Score	Score	Design choices and baseline determination are key vs. ability to track and measure outcomes.
Staged Comprehensive PBR	**6**	Score	Score	Score	Score	Could change incentives more materially over time, but requires data, productivity factors, tracker guardrails, and strong governance.
Other Additional Candidate Reforms	**6**	Score	Score	Score	Score	May address important affordability drivers, but some levers may not work well together.

C.4 How to interpret and use the directional assessment

This illustrative directional assessment can potentially be used to frame Phase 2 analytical questions. It can help identify which options are ready for near-term development, which should be modeled in more detail, which may require pilots or regulatory “sandboxes” for experimentation / testing / iteration, and which should be deferred or separated into other workstreams. The most important output of this kind of exercise is not the “score” itself, but the determination of the relative rankings and tradeoffs behind any “score”.

Figure C-2. Potential decision categories for interpreting the directional assessment

The purpose is to structure quantitative analysis and roadmap decisions, not to close off options.



As noted, this appendix is meant to provide an illustrative framework that can be further developed in Phase 2, which can support more directional assessments of reform options and/or candidate reform pathways that are further informed by New Jersey-specific quantitative analysis and stakeholder input. The framework can then be used to refine the Phase 2 roadmap that distinguishes near-term actions from options that should be modeled further, piloted, deferred, or potentially assigned to a separate process.

Glossary

This glossary provides general definitions for selected technical terms used in this report. Context specific definitions may vary by jurisdiction, tariff, or proceeding.

Term	High-level meaning in this report
Automatic cost recovery	A mechanism that allows defined costs to be recovered through rates outside of a general rate case.
Baseline / counterfactual	The reference case used to estimate what would have happened without a reform, program, or investment.
Basic Generation Service (BGS)	New Jersey's default electric supply service for customers who do not choose a third-party supplier. EDCs procure supply through an annual NJBPU-certified auction and pass these supply costs through to customers.
Benefit-cost analysis (BCA)	A structured comparison of the expected benefits and costs of an investment, program, or alternative. BCA is used to test whether a proposed action is expected to provide net customer or system value.
Bill stabilization	Reducing volatility or sudden increases in customer bills over time. Bill stabilization can improve customer outcomes even when it does not reduce total system costs.
Capital expenditure (CapEx)	Utility spending on long-lived assets, such as substations, poles, wires, transformers, meters, or grid modernization systems. CapEx is typically recovered from customers over time.
Capital bias	The incentive under traditional cost-of-service regulation for utilities to prefer capital investments over operating, customer-side, or third-party alternatives because utilities generally earn a return on capital placed in rate base.
Capital structure	The mix of debt and equity used to finance utility investments. Because equity is generally more expensive than debt, capital structure affects the financing cost recovered in rates.
Construction Work in Progress (CWIP)	Costs for assets that are still under construction. If CWIP is included in rate base, customers may begin paying a return before the asset is placed in service.
Cost allocation	The process of assigning the revenue requirement among customer classes, such as residential, commercial, and industrial customers.
Cost-of-service regulation	The traditional utility ratemaking model in which regulators set rates to recover prudently incurred costs, including depreciation and an authorized return on approved investments, O&M expenses, and taxes.
Cost recovery	The process by which a utility collects approved costs from customers through base rates, riders, trackers, or other charges.
Cost shift	A change in the recovery of costs between individual customers, customer classes, taxpayers, shareholders, bondholders, or time periods.
Customer class	A group of customers with similar service characteristics, such as residential, commercial, industrial, or street lighting customers.
Deadband	A range around a target, such as an authorized ROE, within which no reward, penalty, or earnings sharing is triggered. A wider deadband gives the utility more opportunity to retain gains or losses before sharing begins.

Term	High-level meaning in this report
Depreciation	The recovery of a capital asset's cost over its assumed useful life. Longer depreciation schedules can lower near-term bills but shift more cost recovery to future customers.
Distribution System Operator (DSO)	A regulated entity that actively manages the distribution grid to integrate distributed energy resources, flexible load, storage, and demand response, including by procuring cost-effective third-party or customer-sited solutions as alternatives to traditional utility infrastructure where appropriate.
Earnings sharing mechanism (ESM)	A ratemaking guardrail that shares utility earnings above, and sometimes below, a defined threshold between shareholders and customers.
Energy affordability	The ability of customers to access essential energy services without undue financial strain. In this report, affordability is evaluated through bills, rates, energy burden, volatility, and distributional impacts.
Multi-year rate plan (MRP)	A framework that sets rates or allowed revenues for multiple years using formulas, guardrails, and periodic review rather than tying allowed revenues directly to the utility's cost-of-service.
Non-wires alternative (NWA)	A non-traditional solution, such as energy efficiency, demand response, storage, or distributed energy resources, that can defer or avoid a traditional distribution or transmission investment.
Operating expense (OpEx)	Utility spending on day-to-day operations and maintenance, such as labor, vegetation management, billing, customer service, and repair activities. OpEx is generally recovered as incurred.
Performance-based ratemaking (PBR)	A broad regulatory framework that links utility financial outcomes to performance, cost control, or policy objectives. Typically includes elements such as MRPs, PIMs, and ESMs.
Performance incentive mechanism (PIM)	A reward or penalty tied to a specific metric or outcome, such as interconnection timelines, peak reduction, reliability, customer service, or arrearage reduction.
Prudence review	A regulatory review of whether utility spending decisions were reasonable based on the information available when the decision was made.
Rate base	Rate base is the approved net investment on which a utility is allowed to earn a return.
Rate case	A formal regulatory proceeding in which a utility requests changes to rates and the regulator evaluates the revenue requirement, cost allocation, rate design, and related issues.
Rate cap	A form of MRP or PBR in which the price charged per unit is capped or adjusted by formula. Actual utility revenues can still vary with sales volumes.
Rate design	The structure of charges customers see on their bills, such as fixed monthly charges, volumetric $/kWh charges, demand charges, or time-varying rates.
Rebasing	Resetting the revenue requirement, rates, or allowed revenues based on updated cost and performance information, often at the beginning or end of a multi-year plan.
Regulatory lag	The time between when a utility incurs costs and when those costs are reflected in rates. Regulatory lag can create cost-control incentives but may also delay cost recovery for needed investments.
Reopener / off-ramp	A provision that allows a rate plan or reform to be adjusted, paused, or terminated if specified conditions occur, such as major cost changes, reliability concerns, or financial distress.

Term	High-level meaning in this report
Revenue cap	A form of MRP in which the total revenue, as opposed to rates, that the utility may collect set. Rates may be trued up if sales differ from forecast.
Revenue decoupling	A mechanism that separates utility revenue recovery from sales volumes by truing up actual revenues to an approved target.
Revenue requirement	The total amount a utility is authorized to collect from customers to cover operating costs, depreciation, taxes, and an allowed return on rate base.
Return on equity (ROE)	The allowed return on the equity portion of rate base. ROE is a key component of the utility's authorized return and revenue requirement.
Rider / tracker	A tariff mechanism used to recover a specific category of costs, credits, or program charges, often outside base distribution rates.
Securitization	The use of ratepayer-backed bonds to refinance eligible costs at a lower financing cost.
Shared savings mechanism	An incentive structure that allows a utility to retain a portion of verified savings from a lower-cost alternative, relative to a traditional capital solution, while returning the remaining savings to customers.
Throughput incentive	The financial incentive a utility may have to increase sales when revenues are tied to volumetric electricity usage.
Total expenditure (TotEx) regulation	A framework that treats capital and operating spending more symmetrically to reduce the incentive for utilities to favor capital projects over lower-cost operating or customer-side solutions.
Used and useful	A ratemaking principle under which utilities generally begin earning a return on an asset once it is completed, in service, and providing benefit to customers.
Weighted average cost of capital (WACC)	The blended cost of debt and equity used to calculate the return component of the revenue requirement.