Costs, Benefits, and Methods of Implementing Alternative Rate Mechanisms for Utility Ratemaking

Research Memorandum No. 531

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Foreword

The nonpartisan Legislative Research Commission staff who produced this report would like to thank all of those who provided assistance in its completion. Officials from the Kentucky Public Service Commission provided data, information, and feedback. Representatives from regulated public utilities provided information and shared their experiences operating in different regulatory environments. Officials from state public utility commissions throughout the country also shared information on public utility regulation in their jurisdictions.

Jay D. Hartz
Director

Legislative Research Commission
Frankfort, Kentucky
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Summary

The Legislative Research Commission directed this study to examine the costs, mechanisms for, and benefits of implementing alternative rate mechanisms (ARMs) for public utilities regulated by the Kentucky Public Service Commission (KYPSC). The KYPSC regulates the rates and terms of service for the roughly 1,100 public utilities under its jurisdiction, which include investor-owned electric, natural gas, water, and sewer utilities, electric cooperatives, and water boards and commissions. KYPSC regulation is necessary to avoid monopoly pricing that may otherwise be in effect for the vital services that public utilities provide. Rates for regulated public utilities are determined through rate cases, which are administrative proceedings through which the KYPSC gathers information from the utilities and qualifying intervening parties to determine how much revenue the utility is allowed to collect and what rates it can charge its customers to achieve the required revenue. This method of setting rates is known as traditional cost of service ratemaking.

The goal of the ratemaking process is to establish utility rates that are fair, just, and reasonable. Among other things, this means the rates

- are not unduly burdensome to customers;
- are sufficient to support safe and reliable utility service;
- allow the utility to recover its costs for providing the service; and
- for investor-owned utilities, provide a fair rate of return to the utilities and their investors.

In order to better accomplish these and other policy goals, over the years Kentucky and other states have implemented changes to their traditional cost of service ratemaking procedures. These changes are generally referred to as alternative rate mechanisms. For this study, staff reviewed ARMs that have been adopted in Kentucky and other states. The study examines the purpose of each ARM, how long it had been in effect, and the way that it changed the traditional cost of service ratemaking procedure in the state where it was adopted.

The review showed that, to the extent that ARMs have been able to achieve their purposes in influencing traditional cost of service ratemaking, the degree of their effectiveness depended on their particular design and how tailored they were to the needs and deficiencies of the ratemaking procedures where they were adopted.

Also included in the study is a discussion of various streamlining measures that have been adopted in Kentucky for small natural gas utilities, small water boards, and electric distribution cooperatives. Some of these regulated utilities, due to their size, governance, or business organization, have historically been so reluctant to raise their customers' rates that they delay the filing of rate cases until their financial standing or utility service could be put at risk. Through the implementation of streamlining measures to remove some of the cost, time, and technical barriers to ratemaking for these eligible utilities, the KYPSC has successfully encouraged them to file more frequent rate cases. However, the KYPSC has stated that it may not be appropriate to extend these streamlining measures to other regulated utility sectors that are operating under different financial pressures and do not need to be encouraged to file more frequent rate cases.

Recent proposals to implement annual rate review mechanisms through streamlined ratemaking proceedings for other utility sectors in Kentucky, including investor-owned electric, water, and natural gas utilities, are also examined and discussed. Annual rate review mechanisms allow regulated utilities to make annual filings for streamlined rate case proceedings with the KYPSC so that their rates can be adjusted between full rate cases to account for differences between their projected costs of service and what their actual costs turned out to be, among other things. These annual rate review proposals have not been adopted in Kentucky due in part to concerns voiced by consumer advocacy groups, the Office of Attorney General, and the KYPSC that the proposals went too far in limiting intervenor and public involvement in the process and that utility filings and rate increases would not be subject to enough public scrutiny. However, proponents of annual rate review mechanisms, including representatives of regulated utilities operating in Kentucky and Tennessee, maintain that a well-designed annual rate review mechanism could effectively reduce the time, expense, and administrative burden of a rate case while providing sufficient public and intervenor involvement to ensure that rate changes approved by a public utility commission through the process were fair, just, and reasonable.

Finally, the study examined annual rate review mechanisms adopted in several other southeastern states. The states examined varied in how much their annual rate review mechanisms streamlined their ratemaking processes and how much public and intervenor involvement was allowed. The study found that annual rate review mechanisms adopted in other states necessarily involved at least some tradeoff between the benefits to be gained by streamlining the traditional ratemaking process and the consequences of limiting intervenor and public involvement in the process.

Chapter 1

Introduction

The Legislative Research Commission directed nonpartisan staff to study the costs, the mechanisms, and the benefits of implementing alternative rate mechanisms (ARMs) for public utilities regulated by the Kentucky Public Service Commission (KYPSC). The authorizing memorandum directs that the study include an examination of state public utility commissions that use ARMs, with descriptions of when the ARMs were adopted and a determination as to whether the ARMs produced "just and reasonable" rates; promoted the safety, reliability, and resiliency of energy infrastructure; and enhanced the economic development opportunities in those states.[1]

The Kentucky Public Service Commission And Regulated Public Utilities

The Kentucky Public Service Commission (KYPSC) regulates approximately 1,100 public utilities, including nonmunicipal electric, natural gas, water, and sewer utilities.

The KYPSC is a governmental administrative body, empowered by the Kentucky General Assembly to regulate the rates and terms of service for public utilities under its jurisdiction. These public utilities include investor-owned electric, natural gas, water and sewer utilities, and customer-owned electric and telephone cooperatives, water boards, and water associations. The KYPSC also regulates some aspects of natural gas pipelines. Overall, the KYPSC regulates approximately 1,100 public utilities.[2]

However, not all public utilities are regulated by the KYPSC. Municipal utilities are generally exempt from KYPSC regulation, although the KYPSC does regulate a municipal utility's rates and service for provision of wholesale utility service to a public utility. Public utilities that fall under the jurisdiction of the Tennessee Valley Authority are also not regulated by the KYPSC.

Additionally, not all of the 1,100 public utilities regulated by the KYPSC are subjected to complete regulation of their rates and service. Some public utilities, such as telephone companies or cooperatives, are under less stringent regulation, and in 2000 the KYPSC allowed natural gas unbundling, which is a partial deregulation of retail choice of the fuel supplier.[3]

Why Regulate Public Utilities?

Utility services are so essential to the health, welfare, and economic well-being of the state that their rates and terms of service are regulated.

At the core of public utility regulation is the idea that public utilities are entities "dedicated to public use" or "affected with public interest."[4] They are entities that sell goods and services to the public for compensation that are so essential for the health, welfare, and economic well-being of the state that their rates and services should be subject to state regulation and oversight.[5] Additionally, in the absence of regulation, utilities would be able to operate as natural monopolies, with no competition for the service they provide. A customer's only recourse for high rates or poor service would be to go without the service or move to the service area of a utility that provided better or cheaper service.[6]

Regulated utilities are granted exclusive franchises to provide their services within their certified service areas and are guaranteed the revenue they need to operate. In return, they must provide all of their customers with safe, adequate, and reliable utility service and must submit to KYPSC regulation.

In order to avoid these problems and accomplish effective regulation, public utilities are granted certain privileges in operating their businesses in exchange for accepting obligations relating to their rates and service. The KYPSC grants each regulated public utility a distinct certified service area in the commonwealth, in which it is the only authorized provider for its particular utility service. Additionally, the regulated utility is allowed to recover its reasonably incurred costs of service and, if it is investor-owned, it is allowed to earn a fair return on its capital investment through the rates that it charges. In exchange for these privileges, the regulated utility accepts the obligations to provide all paying customers in its service area with safe, adequate, reliable, convenient, and nondiscriminatory service and to submit to comprehensive regulatory oversight by the KYPSC. This exchange of a regulated utility's privileges for its obligations is known as the "regulatory compact," and it is the logical foundation of utility regulation in the commonwealth.[7]

Ratemaking is the process through which the KYPSC determines a regulated utility's rates.

In its regulatory capacity, the KYPSC seeks to protect the public by ensuring the fair, nondiscriminatory provision of public utility service and fair, just, and reasonable utility rates. This is accomplished through the ratemaking process, through which the regulated utility, the Office of Attorney General, and intervening stakeholders litigate what the utility's rates should be before the KYPSC. As discussed in Chapter 2, in traditional ratemaking in Kentucky and other jurisdictions, the regulator determines the regulated utility's total revenue requirement—its costs of service (COS)—plus a reasonable return on investment, then allocates a rate to each customer class the utility serves to achieve the required revenue. This traditional ratemaking process is known as "cost of service" ratemaking.[8]

What Are Alternative Rate Mechanisms?

Alternative rate mechanisms are changes to traditional cost of service (COS) ratemaking that states have adopted to accomplish specific policy goals.

For the purposes of this study, *alternative rate mechanism* is defined as any change to traditional cost of service ratemaking that has been adopted by a state to accomplish a specific policy goal. As discussed in Chapter 2, traditional COS ratemaking may have shortcomings in areas (such as incentivizing energy conservation and efficiency gains, recovering environmental compliance costs, or reducing administrative inefficiency) that may be addressed through the adoption of an ARM.

To provide the appropriate background for discussions of how ARMs may be adopted to change the ratemaking process, Chapter 2 discusses general traditional ratemaking principles and how the process is accomplished in the commonwealth. The following chapters discuss ARMs that have been adopted in Kentucky and other jurisdictions and how they have changed traditional ratemaking where they were adopted. Chapter 4 examines measures that have been proposed or adopted in Kentucky and other jurisdictions to streamline the ratemaking process for certain utility sectors, either through modifications to the general rate case procedure or through annual rate review mechanisms.

Study Objectives

This study has the following research objectives:

- Provide background information on public utility regulation and the current ratemaking process in Kentucky.
- Provide multistate, descriptive information about types of ARMs adopted by state public utility commissions (PUCs).
- Discuss streamlined ratemaking procedures proposed or adopted in Kentucky, and review measures other states have implemented to streamline the ratemaking process, with particular focus on annual rate review mechanisms.
- Provide sufficient information on ratemaking, the policy goals and effectiveness of ARMs, and the effectiveness of streamlining and annual rate review measures to allow policymakers to make determinations as to whether to adopt or continue these measures in the commonwealth.

Research Tasks

Over the course of the study, LRC staff conducted the following research tasks related to background research, legal review, interviews, and information requests:

- Reviewed literature concerning utility ratemaking including traditional cost of service and alternative ratemaking
- Reviewed cases pertinent to the development of regulatory concepts used in ratemaking proceedings
- Reviewed proposed legislation, statutes, administrative regulations, orders from regulatory proceedings, and newspaper articles concerning various ARMs
- Reviewed relevant committee testimony regarding specific ARMs or legislative proposals for ARMs
- Reviewed KYPSC orders relating to the adoption and implementation of ARMs and streamlined ratemaking procedures
- Reviewed multistate data on ARMs adopted by various PUCs
- Reviewed any available, relevant utility rate and expense data for utilities and for the PUCs for the years that an ARM was in effect
- Interviewed staff at the KYPSC regarding ratemaking and the use of ARMs in the commonwealth
- Interviewed utility staff with ratemaking responsibilities

Major Conclusions

This report has the following major conclusions:

- The ratemaking procedure in Kentucky has been modified several times over the years through the adoption of various ARMs by statute, by administrative regulation, or by order of the Kentucky Public Service Commission. Demand-side management plans, various cost trackers, future test years, and infrastructure surcharges have all been adopted to modify the ratemaking process in Kentucky.

- There is a wide range of additional ARMs adopted in other states that Kentucky policymakers may be interested in pursuing to make further adjustments to the current ratemaking procedure in Kentucky.

- To the extent that ARMs have been able to achieve their purposes in influencing traditional cost of service ratemaking, the degree of their effectiveness depended on their particular

design and how tailored they were to the needs and deficiencies of the ratemaking procedures where they were adopted.

- The current ratemaking procedure in Kentucky relies on intervenor and public involvement to scrutinize utility filings and to establish records on which the KYPSC can make informed decisions in rate cases.

- Measures adopted in other states to streamline and regularize rate proceedings, including annual rate review mechanisms, have been successful in decreasing the time, expense, and administrative burden associated with rate proceedings in those states, but there is a risk that a poorly designed streamlined ratemaking procedure could inhibit intervenor and public involvement and reduce regulator ability to ensure fair, just, and reasonable rates.

Chapter 2

Utility Ratemaking In Kentucky

To understand the changes that alternate rate mechanisms could impose, it is necessary to first understand how the ratemaking process is currently accomplished. This chapter discusses the general ratemaking principles that guide regulators in making rate determinations, the current ratemaking process in Kentucky, and common critiques of traditional ratemaking that may be addressed through the adoption of ARMs.

General Ratemaking Principles

Ratemaking is the process by which the KYPSC reviews and approves the rates and terms for utility service for the public utilities under its jurisdiction. In Kentucky, ratemaking is governed by the statutes in KRS Chapter 278, the administrative regulations in 807 KAR Chapter 5, case law, and the rules and procedures adopted by the KYPSC pursuant to its statutory authority.

Establishing "fair, just and reasonable" utility rates requires the balancing of sometimes competing policy interests.

The foundational principle underlying any ratemaking determination is whether the resulting rate will be "fair, just and reasonable" as required by KRS 278.030. Accomplishing this goal requires the balancing of sometimes competing policy interests, including

- allowing utilities to recover their costs of service and, in the case of investor-owned utilities, to earn reasonable returns on their capital investments;
- maintaining stable and predictable prices;
- providing for nondiscriminatory rates that fairly allocate costs across customer classes;
- promoting the efficient use of the service provided;
- providing reliable service as measured by the frequency, duration, and magnitude of customer service outages;
- maintaining affordable prices for customers;
- providing for the construction and maintenance of adequate facilities to provide safe and reliable utility service for customers;
- ensuring the utility is managed with fiscal responsibility;
- promoting the provision of utility services that minimize their environmental impacts, to the extent practicable; and

- minimizing regulatory burden, including reducing the frequency and expense of regulatory proceedings.[9]

In a ratemaking proceeding, the utilities, the attorney general (on behalf of the ratepayers), and various intervening stakeholders advocate for rates that reflect the policy considerations they have prioritized. The KYPSC makes a determination based on those competing interests as to what constitutes a fair, just, and reasonable rate.

The Current Ratemaking Process In Kentucky

The KYPSC makes decisions on utility rate changes through rate cases, where utilities and intervening parties offer evidence on what the rates should be.

The KYPSC approves or disapproves utility rate changes through regulatory proceedings called rate cases, which commence when a regulated utility files a request for a rate change with the KYPSC. Rate cases typically last 6 to 7 months, with a cost of roughly $200,000 to more than $1.5 million. These are proceedings through which the KYPSC gathers information from the utilities and qualifying intervening parties through a process that includes discovery, discretionary public meetings, public comment, evidentiary hearings, sworn testimony, and posthearing filings in order to make the determinations described below and to ultimately issue a final order on what the rate should be.[a] [10]

Revenue Requirement

In a rate case, a utility's revenue requirement must first be calculated to determine how much revenue will be necessary to recover all of its expenses.

The first step in a rate case is computing the utility's revenue requirement, which is the total amount of revenue a utility needs in order to recover all of its KYPSC-approved expenses. The KYPSC uses data from both a historical and a forecasted 12-month test year to determine those expenses, and applies the following formula to determine a utility's revenue requirement:[11]

$$R = O + (V - D)r$$

In this formula:

- R = the total revenue requirement.
- O = the utility's operating and maintenance expenses, which include routine construction costs, equipment purchases, customer billing and service, salary and benefit costs for employees, major construction once the project is in service, and borrowing costs. Not included are sports sponsorships,

[a] Officials from the Public Service Commission submit that rate cases in Kentucky are shorter than in most states, and that they are shorter than the litigation of a typical civil or criminal matter.

executive bonuses, charitable donations, club memberships, fines, or any other expense deemed unreasonable by the KYPSC.[12]

- V = the gross value of the utility's tangible and intangible property.
- D = the utility's accrued depreciation. Combined (V − D) constitutes the utility's rate base, also known as its capital investment.
- r = the rate of return (ROR) a utility is allowed to earn on its capital investment, which will be prorated by its debt-to-investment ratio and will include the interest rate the utility pays on its debt.

The following are not included in the calculation of a utility's revenue requirement:

- Fuel cost adjustment, which allows electric utilities to immediately recover increases or rebate decreases in fuel costs subject to later review by the KYPSC[13]
- Commodity costs of natural gas
- Environmental compliance costs[14]
- Energy efficiency programs[b] [15]
- Low-income assistance program fees[16]
- Franchise fees
- Other costs recovered through riders
- Local pass-through taxes based on utility service

Current Revenue From Service

The next step in a rate case is determining how much revenue will be generated based on the utility's current rates, taking into account the forecast demand for the utility service.

Once the utility's total revenue requirement has been calculated, the next step in a rate case is determining how much revenue will be generated based on the utility's existing rates. This requires an understanding of the usage of the utility service and which factors may influence either an increase or decrease in that service. Various factors influence future utility service demand in both the short term and the long term including weather, household size, technology, household appliance efficiencies, building efficiencies, and new or eliminated uses for utility service.[17]

The difference between the revenue requirement and the revenue from service is the amount of the overall revenue adjustment that will be authorized in the rate case. This step also provides the demand or usage to be expected from customers, which is taken into account in the next step to determine what rates, applied to

[b] Referred to as demand-side management surcharges.

that expected usage, will achieve the necessary revenue for the revenue requirement.[18]

Rate Design

Through rate design, the revenue requirement is allocated to each customer class served by the utility so that each one pays its share for the cost of providing the service.

Once the utility's total revenue requirement has been calculated and the overall revenue adjustment has been determined, the next step in a rate case is determining how that revenue will be collected through the rate design. This requires allocating the revenue requirement to each customer class that the utility serves so that each customer class pays its share of the costs of providing utility service. Utilities ordinarily have at least three rate classes—commercial, industrial, and residential—but they may have more depending on the types of customers they serve. The differences in the rates assigned to the different rate classes are meant to reflect the differences in the costs of the utility to provide service to those rate classes. The KYPSC uses utility-submitted and intervenor-submitted cost of service studies to determine what those cost differences are. Residential customers do not generally use utility service equally across any given day, week, or even month of the year, so utility providers plan to be able to meet the peak demands for their service. Industrial customers, on the other hand, frequently require utility service at a constant rate. Generally, cross-subsidization between rate classes is to be avoided, but it has historically been common in Kentucky for the cheaper-to-serve industrial class to subsidize the more diffuse and price-sensitive residential class to some degree.[c] [19]

Another aspect of rate design is the allocation of fixed costs (which are independent of usage) and variable costs (which are based on usage) in each of the rate classes. Residential and commercial classes typically have two-part rates: a customer or meter charge for fixed costs and a volumetric charge for usage costs. Industrial rates typically have the customer and volumetric charges and an additional demand charge, which is based on the cost of the industrial customer's peak electricity use during a billing cycle. In traditional ratemaking practice, fixed and variable costs are not allocated on strictly proportional bases to fixed and variable charges, which has the practical effect of causing larger users within a class to pay more than the fixed costs they impose on

[c] Kentucky Public Service officials partially dispute this claim: "Although this applies for some utilities, even a change in study methodology indicates the opposite, and for those utilities, this is not a constant phenomenon. Cross-class subsidization ebbs and flows across time and utilities. This gives the impression that historically, industrial subsidization is a constant, but that is not the case, and is not the case today for many utilities."

the system, with small users paying less than their share of fixed costs.[20] However, the KYPSC in recent years has made changes so that those costs and charges more closely align.

Final Rate Determination

At the end of the rate case, the KYPSC approves a rate that it believes to be "fair, just and reasonable" in light of the evidence.

In making its final determination in a rate case, the KYPSC must decide on approving a rate that is fair, just, and reasonable considering all of the evidence gathered on the record throughout the proceeding. The KYPSC attempts to arrive at a rate that is not unduly burdensome to customers, is sufficient to support safe and reliable service, provides a fair return to utilities and their investors, and will be adequate to recover future costs of service until a new rate case is filed.[21]

Costs Of Rate Cases Using Traditional Ratemaking

Expenses for rate cases under traditional ratemaking can vary greatly depending on the size and type of the regulated utility, the complexity of the issues under consideration, and the amount of intervenor involvement. Information gathered from the KYPSC shows that, in recent cases involving investor-owned electric and gas utilities, KYPSC-approved rate case expenditures ranged from roughly $200,000 to over $1.5 million, with an average of approximately $630,000 per rate case.[22] The largest approved expenditures for rate cases were mostly legal expenses, but for a few utilities, consulting expenses were the largest. These KYPSC-approved expenditures are amortized over a number of years and are charged to the utilities' customers.

Table 2.1
Recent KYPSC-Approved Rate Case Expenses

KYPSC Case Number	Utility	KY PSC Approved Rate Case Expense Total Unamortized
2019-00271	Duke—electric	$339,168.00
2020-00174	Kentucky Power	$336,763.00
2020-00349	KU—electric	$1,569,189.00
2020-00350	LG&E—electric	$865,723.24
2020-00350	LG&E—gas	$213,378.31
2021-00185	Delta—gas	$947,339.08
2021-00183	Columbia—gas	$555,556.00
2021-00190	Duke—gas	$224,969.00
2021-00214	Atmos Energy—gas	$301,880.75
Total cost for utilities listed		$5,353,966.38
Average cost for utilities listed		$631,510.70*

* Averages determined by adding the PSC rate case expense divided by the number of utilities.
Source: Kent Chandler, chairman, Kentucky Public Service Commission. Email to Tanya Monsanto, Oct. 4, 2022.

Critiques Of Traditional Ratemaking

If left unchanged over a long enough period of time, certain aspects of the traditional ratemaking process may lead to suboptimal policy outcomes as the economic, social, technological, and environmental landscapes in which ratemaking decisions are made continue to evolve. Several alternative rate mechanisms have already been adopted in Kentucky to address some of these issues, as is discussed in the following chapters.

Efficiency Gains And Changes In Demand

Technological advances have resulted in improvements in the efficiency and performance of electric utilities customers' electricity-using devices, which has led to a reduction in electricity consumption.[23] As a result of these technological advances as well as a general shift in the US economy from manufacturing to more service-oriented industries in recent decades, electricity consumption relative to gross domestic product (GDP) has fallen substantially. The growth rate of electricity consumption has fallen to less than one-half of the growth of GDP in the period of 1975 to 1995, when the growth rates were approximately the same. Per capita retail electricity sales have also lagged far behind the rate of growth of per capita real GDP since 1992.[24] Energy consumption per real dollar of GDP has also fallen steadily in the United States over the past 20 years.[25]

Utilities can reduce their variable costs in response to low sales, but they cannot as easily reduce fixed costs. As sales revenues fall, the per-unit charge for recovering fixed costs must go up. The continuing decline of sales growth, coupled with the increase of distributed generation resources such as rooftop solar, has caused utilities to be concerned about their ability to recover their fixed costs under traditional ratemaking.[26]

Transition To Renewable Generation Sources

In response to customer demand and the possibility that carbon dioxide emissions may be priced or otherwise constrained in the future, electric utilities are transitioning to renewable, emissions-free generation sources more quickly than they otherwise would.[27] This transition entails the retirement and replacement of carbon-intensive coal-fired generation resources that can provide electricity as needed with renewable generation sources such as wind and solar that provide intermittent generation that is available only at certain times. This accelerated transition has complicated

resource adequacy and reliability planning that is inherent in the traditional ratemaking process for electric utilities.

Time And Expense

Another common criticism of traditional ratemaking is the time, expense, and regulatory burden involved in a rate case determination for regulated entities, the regulating agency, and the ratepayers who ultimately bear the costs. As discussed in further detail in Chapter 4, some utilities have advocated for ways to reduce this time and expense by implementing mechanisms, including annual rate review mechanisms, whereby rates or certain aspects of rates can be adjusted between rate cases when certain criteria and regulatory requirements are met.

However, public advocacy groups and regulators can be reluctant to agree to changes that may curtail public involvement in and oversight of the ratemaking process. Officials from the KYPSC maintain that while the costs of fully litigating a rate case may seem high, those costs pale in comparison to the money that ratepayers are saved by challenging utilities' revenue increase requests through full rate case proceedings. Table 2.2 presents the differences between approved and requested revenue increases for the rate cases shown in Table 2.1.

Table 2.2
Recent KYPSC-Approved Utility Revenue Increases Versus Requested Revenue Increases

Case No.	Utility	Requested Revenue Increase	Approved Revenue Increase	Difference
2019-00271	Duke—electric	$45,634,456	$28,506,249	$17,128,207
2020-00174	KY Power	$70,096,743	$52,419,332	$17,667,411
2020-00349	KU	$169,900,000	$110,626,795	$59,273,205
2020-00350	LG&E—electric	$128,400,000	$73,721,524	$54,678,476
2020-00350	LG&E—gas	$33,000,000	$23,241,950	$9,758,050
2021-00185	Delta—gas	$9,135,000	$5,497,332	$3,637,668
2021-00183	Columbia—gas	$26,694,986	$18,331,404	$8,363,582
2021-00190	Duke—gas	$15,228,161	$9,170,880	$6,057,281
2021-00214	Atmos Energy—gas	$16,389,804	$2,612,525	$13,777,279
Total average		$57,164,350	$36,014,221	$21,151,235

Source: Kent Chandler, chairman, Kentucky Public Service Commission. Email to Tanya Monsanto, Oct. 4, 2022.

ARMs Make Changes To Traditional Ratemaking To Accomplish Policy Goals

Chapter 3 discusses how ARMs have been adopted in Kentucky and other states to address critiques of traditional ratemaking and to accomplish at least one of the following policy goals:

- Reduce regulatory lag and utility financial risk for operational and investment activities.
- Reduce the frequency of rate cases.
- Promote certain social goals such as efficiency and conservation.
- Make utility service affordable to low-income customers.
- Promote investment in new technologies.
- Optimize usage over different times of day, or reduce a peaking problem.
- Lessen the price rigidity of regulation, and promote cost efficiency.
- Avoid rate shock.
- Promote specific activities such as expanding infrastructure investment, enhancement of environmental control technologies, resource loss audits, or quality of utility service.[28]

Chapter 3

Alternative Rate Mechanisms

An alternative ratemaking mechanism (ARM) is any ratemaking mechanism that modifies traditional cost of service ratemaking to accomplish a policy goal. As used in this chapter, *traditional ratemaking* means cost of service ratemaking.

An alternative ratemaking mechanism is any modification to traditional cost of service ratemaking adopted by a state to accomplish a specific policy goal.[29] This chapter discusses eight commonly used ARMs: cost trackers, future test years (FTYs), lost revenue adjustment mechanisms (LRAMs), revenue decoupling mechanisms (RDMs), straight fixed-variable rates (SFVs), earning-sharing mechanisms (ESMs), formula rate plans (FRPs), and multiyear rate plans (MRPs).[30] For each ARM, the following questions are answered:

- What is the policy objective of the ARM?
- How does the ARM work in practice?
- What are the ARM's limitations and benefits?
- Which states use the ARM, and when was the ARM adopted?
- Has Kentucky adopted the ARM? If so, when?

There is no universal yardstick for measuring the value of an ARM. The value depends on the proponents' objectives and whether the ARM meets those objectives.

There is no universal yardstick for measuring the value of an ARM. The value depends on how effectively it achieves its policy goals in the state where it was adopted, relative to traditional ratemaking and/or relative to other alternatives that may be adopted to accomplish the same goals. Although they do so in different ways, ARMs generally have the effect of shifting the costs and benefits of how rates are calculated and allocated, relative to traditional ratemaking, among the parties to a ratemaking proceeding.[a] These parties include the utility (and its shareholders if investor-owned), the ratepayers (often represented by consumer advocates and the Office of Attorney General), and the state public utility commission.

The regulatory objective tells us what the proponents of the ARM wants to achieve.

Appendix A is a comprehensive table of the different ARMs, by type, adopted by each state. Some of the ARMs are adopted exclusively for one sector, such as electricity, while others may

[a] In the course of gathering information for the study, on September 1, 2022, staff submitted a questionnaire on ARMs to KYPSC Chairman Kent Chandler and KYPSC Executive Director Linda Bridwell. Their response—received via email to Tanya Monsanto on October 4, 2022—included the following: "Regardless of whatever benefit derived from an alternative rate mechanism [may be, it] is almost always reflected as a corresponding detriment to customers. If a utility recovers a cost faster because of an ARM, customers are paying it faster. The same is true for ARMs that reduce the utility's risk; the risk does not disappear by virtue of a particular mechanism, but instead is shifted, and is likely shifted to customers."

be adopted for all public utilities regulated by the state's PUC. The date that the ARM was adopted is listed for each type of ARM except for cost trackers, which had several dates for each type and were too numerous to list.

Cost Trackers

Cost trackers allow expedited recovery of a specific cost, approved by the public utility commission (PUC) outside of a general rate case.

Cost trackers are a type of ARM that allows expedited recovery of specific costs that the state PUC has approved outside of a general rate case. Examples of cost trackers include surcharges or riders for fuels, certain mandated taxes, or mandated environmental compliance.[31]

What Are The Policy Objectives Of Cost Trackers?

The regulatory objective of cost trackers is to reduce the time between utility cost increases and the recovery of those costs in rates. That lag is called "regulatory lag."

Cost trackers are designed to reduce "regulatory lag," which is the time between when the utility's costs rise and when it is allowed to recover those costs through its rates. Reducing regulatory lag makes the operational and investment activities of a utility less risky.

The regulatory target of cost trackers is to make recovery of a cost match the time when the cost is incurred.

Cost trackers reduce the number of general rate cases and the customer's rate shock, because they allow the utility to recover certain variations from cost projections as they are incurred. Under traditional ratemaking, unless the utility goes through a general rate case, the base rates does not change when the cost to provide the utility service changes. So, unless there is a rate case, the utility may be incurring costs unaccounted for in the base rates. This is especially true when prices for significant inputs, such as fuel costs, are increasing. Under traditional ratemaking, the utility bears the risk to its bottom line between rate case filings. With cost trackers, customer bills more accurately reflect the current cost of providing utility service.

Additionally, traditional ratemaking does not allow for recovery of an asset until it has been put in use. This can lead to rate shock when the customer's rate suddenly folds in excessive capital costs for large physical plants, infrastructure, or equipment.

Finally, certain non-revenue-producing costs, such as decommissioning costs, may be recovered via a cost tracker to enhance compliance and promote modernization of the infrastructure.[32]

How Do Cost Trackers Work In Practice?

Cost trackers shift the risk associated with the recovery of an expense from the shareholders to the ratepayers.

Cost trackers accomplish their objectives "by shifting the risk associated with recovery of the expense in question from shareholders to customers because the company is able to change its rates to recover its costs on a current basis, without any negative effect on the bottom line and without the expense and delay that accompanies a rate case."[33] This will be true of all public utilities regardless of whether they are investor-owned or cooperatives in terms of their organization and governance structure.[b]

A cost tracker is basically a bookkeeping system. The utility maintains a "balancing account" in its ledger system that inputs the projected cost and the actual cost of the specific items procured by the utility. It also tracks any related inputs approved by the PUC via a rider. The utility calculates the cost of a specified item, such as fuel costs, during a prior month's usage and then directly passes the cost on to the ratepayer on the next month's bill. The amount on a customer's bill is based on customer usage and is normally listed as a surcharge on the bill. With a cost tracker, the aim is to bring revenue and cost growth into balance and reduce the need for frequent rate cases.[34]

What Are The Limitations And Benefits Of Cost Trackers?

Limitations of cost trackers include reduction in utility innovation, cost control, and oversight. They also shift the risk from the utility to the ratepayer.

Limitations of cost trackers include the following:

- They can thwart utility innovation and internal cost control.
- They tend to reduce the oversight of a utility's costs and investments.
- They tend to proliferate use of trackers for other costs, some of which might not be appropriate.
- They shift risks from the utility to the ratepayer.
- Reductions in a utility's financial risk often are not offset by reductions in return on equity (ROE).[35]

Benefits of cost trackers include utility cash flow, accuracy of price signals, and ease of application to different sectors. They also reduce the utility's financial risk, and they reward compliance with government mandates.

Benefits of cost trackers include the following:

- They improve the utility's cash flow and reduce the utility's financial risk.
- Customer charges more accurately reflect the costs of providing the utility service.
- They encourage utility investment in infrastructure and reward compliance with governmental mandates.
- They are easily applied to different utility sectors and different types of costs.[36]

[b] In both types, there is some sort of ownership structure that bears the risk.

Which States Use Cost Trackers?

As of 2022, all 50 states and the District of Columbia have adopted some type of cost tracker.

Most states have adopted cost trackers to recover the cost of utility procurement of fuel inputs such as coal or natural gas, purchased power, environmental compliance equipment, specific taxes and franchise fees, pension contributions, uncollectable bills, and infrastructure construction costs. As of 2022, all 50 states and the District of Columbia have adopted at least some cost trackers for the electric and natural gas utilities.[37] The majority of these cost trackers are fuel adjustment clauses, but a number of states also use cost trackers for environmental compliance and infrastructure. Some states have even applied the methodology to recover nonrevenue expenses for water infrastructure.[38]

Has Kentucky Adopted Cost Trackers?

The KYPSC has authorized a significant number of cost trackers for fuel, purchase power, environmental compliance, infrastructure improvements, and excessive water loss and conservation programs.

The KYPSC has authorized a significant number of cost trackers for fuel, purchase power, environmental compliance, infrastructure improvements, excessive water loss, and recovery for conservation program expenses.

The fuel adjustment clause authorizes recovery via a surcharge on the customer bill for purchases of fuel and purchased power. The cost recovery is reviewed 6 months after the purchase and again in 2-year intervals.

The KYPSC has authorized a separate gas cost recovery for purchased gas in the tariffs for local natural gas distribution utilities. This is approved when gas supplier costs have increased, and the approval period is for 30 days. The KYPSC audits the gas cost adjustment every quarter.

Kentucky uses a capital expenditure tracker for water, natural gas, and electric utilities that include

- a qualified infrastructure program rider that recovers costs for water infrastructure that has exceeded its service life and a pipeline modernization mechanism that recovers costs for compliance with federal safety regulations; and
- accelerated main replacement, pipeline replacement, and service line replacement for gas utilities.

Future Test Years

Future test year (FTY) is an ARM designed to make the test year data that is used to create the utility rate more reflective of actual conditions when the utility rate goes into effect.

A test year is a 12-month period that a utility uses to determine its revenue needs for the purposes of ratemaking.[39] It is a snapshot intended to foretell the utility's short-term revenue needs. It should not contain data for extraordinary events that can skew cost and revenue estimates.

The test year is the foundation for calculating the utility's revenue requirement and determining whether the state PUC should order a change in base rates. There are three main types of test years:

- Historic test year (HTY), which looks at actual revenues and costs for 12 months prior to the rate case
- Future test year, which forecasts future anticipated revenues and costs for 12 months after the new rate is in effect
- Partially forecasted test year or hybrid test year, which uses both HTY and FTY to capture a 12-month period

FTY is an ARM designed to make the test year data more reliable and give a more accurate approximation of revenues and costs. In a strict sense, FTY looks only at the hypothetical future period, but in practice PUCs may use a blend of a future test period and a historic test period, and perhaps an additional historic or normalized reference period.[40]

What Are The Policy Objectives Of Using Future Test Years?

FTY authorizes current rates based on estimates or forecasts for revenues and expenses that will occur in the future.

Traditional ratemaking typically relies on HTYs to predict the future cost of operations and investment needs for calculating the revenue requirement, planning, and cost recovery. There is typically a 2-year lag time between the HTY and when the new rate on which it is based is approved, during which time economic conditions can significantly change.[41] By using an FTY, utilities seek to reduce the distortion caused by the lag time from the HTY and make more current and accurate calculations for their revenue requirements and the rates needed to generate those revenues. FTYs are most useful when fiscal conditions are changing and HTYs would not be as reliable to predict future revenue needs.

When changing cost and revenue conditions are built into the ratemaking model opportunities, the operational and investment activities of a utility can become less risky. States that use FTYs tend to have utilities with better credit ratings, which improves the utility's opportunity to attract capital.[42]

How Do FTYs Work In Practice?

The regulatory objective of FTYs is to reduce the distortion caused by the 2-year period that it takes for the PUC to approve new rates.

Most PUCs rely on the utility to provide the forecast and demonstrate that its forecast is a sound predictor for base rates. Those rates would be then be deemed "just and reasonable" unless the PUC's staff or intervenors build a record of evidence to the contrary. For that reason, PUCs often improve their confidence in the data by requiring utilities to also submit historic data as a reference or guideline.

Some PUCs are exploring the use of FTYs to encourage investment in new technologies, many of which account for current environmental goals.[43] This is because environmental technologies tend to flatten revenue growth by controlling consumption. Some Colorado electric utilities recently sought use of FTYs for investment in carbon-free generating technologies.[44]

What Are The Limitations And Benefits Of FTYs?

Limitations of FTYs include errors in forecasts, difficulty in predicting certain costs, and higher regulatory costs.

Limitations of FTYs include the following:

- Forecasts are susceptible to error, and utilities have incentive to produce biased forecasts.
- It is difficult to predict certain cost and sales elements in the forecast.
- There are higher regulatory costs for using this method, because PUCs must review forecasts and data.
- There is difficulty in determining where the burden of proof lies in rate proceedings.
- FTYs may not reduce rate case frequency when fiscal pressures are chronic.[45]

Benefits of FTYs include rates that more accurately reflect current business conditions, insulation against rate shock, and improved return on equity (ROE) and credit rating.

Benefits of FTYs include the following:

- Rates tend to more accurately reflect current business conditions.
- FTYs insulate against rate shock by building in gradual increases.
- FTYs can fully compensate utilities when revenues are flat or declining relative to costs.
- FTYs move the utility closer to its authorized rate of return and improves the utility's credit rating.
- FTYs reduce operating risk for the utility.[46]

Which States Use FTYs?

There are 31 states that authorize use of FTYs.

There is some discrepancy in reports of the number of states using FTYs. A 2019 order of the Maryland PUC stated that 35 states

have experience with using FTYs, but the order does not identify the states.[47] An earlier study identified 31 states using FTY in some form for electric utilities.[48] Of that number, 13 states have approved utilities operating under FTYs.

Ten other states occasionally use fully forecasted test years, and seven states plus the District of Columbia use partially forecasted test years.[49] Indiana's electric utilities and Colorado and Nebraska's natural gas companies are legally allowed to use FTYs, but their state PUCs have not approved a utility request on that basis and continue to rely on HTYs.

Even though some states have reported a positive experience in using FTYs, some PUCs argue that there is a need for auditing the utility's forecasts to disclose bias.[50] Many state PUCs derive their legal authority for using FTYs from the authority to set fair, just, and reasonable rates for public utilities. However, some states have passed specific alternative rate-setting mechanisms that include the use of FTYs for certain utility sectors such as electric or natural gas. Therefore, some state legislatures have granted the authority for their PUC to allow use of FTY, but the PUC may not have yet authorized the use of FTY for a utility in the state.[c] [51]

Table 3.1 lists the states that have the authority to use FTYs and the year that the authority was granted or the first known incidence when the state PUC ordered an FTY.

Table 3.1
FTY By State, Utility Type, And Year Adopted

State	Utility Type	Year Adopted
Alabama	Natural gas	1982
Arkansas	Electric; natural gas	2008
California*	Electric	1982
Colorado*	Electric; gas	2008
Connecticut	Electric	2013
	Gas	1995
Delaware	Electric	N/A
District of Columbia	Electric	1999
Florida	Electric	1981
Georgia	Electric	2002
Hawaii	Electric	2008
Idaho	Electric	2012
Illinois	Electric	1982
Indiana	Electric; gas	2014
Kentucky	Electric	1992

[c] Some states such as Indiana, New Mexico and Pennsylvania allow FTY but have no or minimal experience with it.

State	Utility Type	Year Adopted
Louisiana	Electric	2014
Maine	Electric	1996
Maryland	Electric	1999
	Natural gas	2007
Michigan	Electric; natural gas	1939
Minnesota	Electric; natural gas	1974
Mississippi	Electric	2000
Missouri	Electric	N/A
New Jersey	Electric	N/A
New Mexico	Electric	2013
New York	Electric	1972
North Dakota	Electric	1995
Ohio	Electric; natural gas	2011
Oregon	Electric	1971
Pennsylvania	Electric; natural gas	1989
Rhode Island	Electric	N/A
Tennessee	Electric	1986
Utah	Electric	1972
Wisconsin	Electric; gas	2009
Wyoming	Electric; natural gas	2003

Note: N/A = secondary sources or the state PUC has identified the state as having the authority and using FTY, but the state has not responded to information requests concerning when that authorization was granted or used.
*Authority derived from statutory and legal authority to set fair, just, and reasonable rates.
Sources: Janine Migden-Ostrander et al. "Decoupling Case Studies: Revenue Regulation Implementation In Six States." Regulatory Assistance Project, July 2014; Public Service Commission of the District of Columbia. Order No. 20273: Formal Case No. 1156 In The Matter Of The Application Of Potomac Electric Power Company For Authority To Implement A Multi-Year Rate Plan For Electric Distribution Service In The District Of Columbia, Dec. 20. 2019; New Mexico Public Regulation Commission. In The Matter Of The Adoption Of A Proposed Role Governing Public Utility Rate Applications Based On Future Test Year, Docket No. 12-00029-UT, Feb. 8, 2012; James H. Cawley and Norman J. Kennard. *A Guide To Utility Ratemaking.* Pennsylvania Public Utility Commission, 2018 ed., p. 87; Mark Lowry, Matthew Makos, and Gretchen Waschbusch. "Alternative Regulation For Emerging Utility Challenges: 2015 Update." Edison Electric Institute, 2015.

Has Kentucky Adopted FTYs?

In 1992, the Kentucky General Assembly amended KRS 278.190 to allow regulated utilities to use FTYs. This statute, along with its mandate to set "fair, just and reasonable rates," constitutes the basis of the Public Service Commission's authority for FTYs.

Kentucky's utilities must choose to use either FTYs or HTYs in applications for a rate change. After FTY or HTY is chosen, all the data for revenue and expenses submitted with the application must use that test period. The KYPSC also requires financial data for the 5 most recent calendar years in order to generate a normalized view of the revenues and expenditures. The goal is for all the data to be historical when rates go into effect. Using FTY theoretically lowers the utility's financial risk, but the KYPSC has not lowered the utility's authorized ROE or ROR.

Kentucky allows utilities to use either FTY or historic test data, but not both. This restriction prevents utilities from cherry-picking data when setting rates.

Although HTY and FTY data may be used to examine costs, revenues, and investment activities to create a 12-month test period, Kentucky does not use a hybrid test year.[52] The concern is that a hybrid test year would allow utilities to "cherry-pick" test periods to maximize expenses beyond the level that the utility normally incurs after setting its rates.[53]

The KYPSC reports it has not experienced problems when evaluating FTY forecasts. The KYPSC relies on the utility to conduct the forecast and demonstrate that the forecast and the proposed rates are fair, just, and reasonable. The KYPSC does not have a formalized auditing process for FTY, but when irregularities are found in the data, an adjustment based on historic data is made. The adjustment is called a "pro forma" adjustment and is issued through a KYPSC order.[54]

Lost Revenue Adjustment Mechanisms And Revenue Decoupling Mechanisms

LRAMs and RDMs are both ARMs that seek to eliminate or reduce the dependence of a utility's revenues on utility service sales. LRAMs are specifically used for a utility's loss of sales resulting from energy efficiency programs; RDMs are more broadly applicable to losses of sales revenues from other causes.[55]

Lost revenue occurs when actual utility sales are less than the projected sales used to calculate the utility's revenue requirement.

Lost revenue occurs when actual utility service sales are less than the projected sales that are used to calculate the revenue that the utility needs to provide service to the customer.[56] These losses in sales revenue can be caused by changing economic conditions that impact demand, unforeseen weather conditions, or technological developments that have the effect of reducing customer demand.[57]

When sales revenues fall, utilities can face difficulty in recovering their fixed costs (independent from sales) for providing their utility service, because under traditional ratemaking, utilities recover these fixed costs partially through their variable sales charges, as explained in Chapter 2.[58]

Lost revenue adjustment mechanisms (LRAMs) and revenue decoupling mechanisms change how the utility recovers lost revenue.

Under traditional ratemaking, there is a direct link between sales and revenues, which makes the utility dependent on increasing its sales and focused on the buildout of infrastructure to deliver more service. LRAMs lessen the direct impact of utility sales and infrastructure buildout on the utility's profit margin. Decoupling goes further to sever the linkage between utility revenue and the

sales volume by addressing the linkage between the two in the variable rate on the utility bill.[59]

What Are The Policy Objectives Of LRAMs And RDMs?

The regulatory objectives of LRAMs and decoupling are to eliminate the disincentive for efficiency and conservation, promote renewable resources, and lower the demand for utility service during periods of high demand.

LRAMs and RDMs seek to eliminate the disincentive for efficiency and conservation, promote renewable resources, and lower the demand for utility service during periods characterized by the highest demand ("peak" periods) and increase it during periods characterized by the lowest demand ("nonpeak" periods).[60]

Removing Disincentives From Investing In Energy Efficiency

Under traditional COS ratemaking, utilities are disincentivized from investing in energy efficiency for three main reasons:

- The costs of energy efficiency programs themselves constitute financial losses unless they are recovered through rates or fees.
- The programs reduce demand for investments in capital assets such as power plants, which are investments on which utilities are allowed to earn a reasonable rate of return.
- The programs result in lower electricity sales but do not reduce the fixed costs of providing service.[61]

LRAMs, and to a lesser extent RDMs, seek to remove these disincentives by allowing a utility to recover its lost revenue resulting from energy efficiencies.

Reducing Peak Demand. Utility service such as electricity is a complex interconnected grid where producers are connected via transmission and distribution wires. When demand for electricity is too high during peak periods, the result can be brownouts or rolling blackouts, because the demand exceeds the capacity to provide service. For the electric grid in such circumstances, the authority that dispatches the generators must pull them offline or cut service to certain types of large users, such as industrial customers. This result occurred in California, and throughout the area under the control of the Midcontinent Independent System Operator, during the summer of 2022.[62]

Promoting Adoption Of New Technology. LRAMs and RDMs also may promote investment in new technologies such as advanced metering, distributed generation, and grid modernization, which provide a greater certainty that utilities will recover their fixed costs.

How Do LRAMs And RDMs Work In Practice?

Full decoupling RDMs guarantee that utilities earn an exact amount of revenue based on a regulatory formula rather than on the amount of energy their customers use. Revenue requirements for full decoupling RDMs are established in rate cases, and decoupling true-up adjustments occur outside of rate cases to rebate oversales or to impose surcharges or increase rates for undersales based on actual sales since the last true-up.[63] Partial RDMs can also be utilized to guarantee the recovery of only a portion of a utility's revenue requirement.

Under an LRAM, the utility recovers some or all lost revenue when it adopts an efficiency or conservation management program.

LRAMs allow utilities to recover only revenues lost due to energy efficiency programs.[64] Regulators calculate the energy savings associated with the efficiency measures installed by the utility, and then they allow the utility to recoup the revenues it has lost due to those energy savings. If the utility has higher sales than predicted, no adjustment is made.

Common LRAMs include demand-side management (DSM) programs that pay ratepayers to reduce their usage during peak demand when the supply of the service is constrained. DSM programs are principally used for electric and gas utilities, but states such as California and Arizona are extending DSM for the conservation of water and sewer services.[65]

What Are LRAMs' And RDMs' Limitations And Benefits?

Limitations of LRAMs and decoupling include PUC reliance on complex forecasts for lost revenues, as well as shifting risk from the utility to the ratepayer.

Limitations of LRAMs include the following:

- The PUC relies on complex forecasts for anticipated lost revenues.
- The revenue adjustment includes only shortfalls.
- The cost of these utility programs may not be covered.
- Because the throughput incentive continues to incentivize sales, programs may be designed and implemented in a less meaningful manner.[66]

Limitations of RDMs include the following:

- They shift the risk of running the utility from the utility's shareholders to the ratepayer.
- They make the base rate unresponsive to the demand for the utility service.
- They reduce transparency in the ratemaking process.
- They constrain economic development by reducing the incentive to increase infrastructure buildout by the utility.

Benefits of LRAMs and decoupling include improving the ability to meet the revenue requirement, greater investment in efficiency and conservation.

Benefits of LRAMs include the following:

- The concept can be applied to utility sectors that need to promote conservation or more efficient use of the utility resource.
- States with LRAMs have greater investment in energy efficiency, renewable resources, and conservation.
- LRAMs may be a method to promote energy efficiency in places where revenue decoupling is unwanted by utilities, PUCs, or other stakeholders in the ratemaking process.[67]

Benefits of decoupling include the following:

- A utility is more likely to meet its revenue requirement with full decoupling than without it.
- Decoupling removes the disincentive for energy efficiency, distributed generation, and energy conservation.
- It provides more predictable prices to customers than COS ratemaking does.
- It creates greater financial certainty for the utility, reducing its operating risk.
- It is easier to implement and reduces rate case frequency.[68]

Which States Use LRAMs And RDMs?

As of 2022, 25 states have adopted LRAMs. Most are demand-side management programs for electric or natural gas utilities. Thirty-three states have adopted decoupling mechanisms.

As of 2022, 25 states have adopted LRAMs, most of which are demand-side management programs for electric utilities, natural gas utilities, or both.[69] Thirty-three states have adopted decoupling mechanisms for electric, natural gas, or both.[70]

Because LRAMs require the utility design and implementation, do not allow for customer refunds higher than expected sales, and do not completely delink revenue from sales, states have begun to transition from LRAMs to decoupling.[71] New Hampshire adopted an LRAM program in 2017 but later replaced it with revenue decoupling. Other states, such as Montana, decide whether to approve an LRAM or decoupling ARMs on a case-by-case basis for the utility making the request.

Table 3.2
LRAMs And Decoupling By State And By Authorization Or Implementation Date

State	LRAM	Decoupling
Alabama	—	2007
Arizona	2012 electric and gas	2011
Arkansas	2010 electric and gas	2007
California	2014 water	2004
Colorado	2008 gas	2017
Connecticut	2013 gas	2013

State	LRAM	Decoupling
Delaware	2009	2014
Georgia	2010 electric	—
Hawaii	—	2010
Idaho	—	2007
Illinois	—	2007
Indiana	2016 electric	—
Iowa	—	2006
Kansas	2007 electric	2008
Kentucky	1994 electric and gas	—
Louisiana	2014 electric	—
Maine	—	2009
Maryland	—	2005
Massachusetts	2013 gas	2008
Michigan	—	2008
Minnesota	—	2009
Mississippi	2014 electric and gas	—
Missouri	2011 electric	—
Montana	2004 electric and gas	2019
Nevada	2011 electric	2008 gas
New Hampshire	2017 electric and gas	2019
New Jersey	2020 electric	2018
New Mexico	—	2019
New York	—	2007
North Carolina	2007 electric	2007
Ohio	2007 electric	2012
Oklahoma	2008 electric and gas	—
Oregon	—	2009
Pennsylvania	—	2019
Rhode Island	—	2011
South Carolina	2008 electric	—
South Dakota	2009 electric; 2011 gas	—
Utah	2009 electric	2010 gas
Vermont	—	2006
Virginia	2020 electric	2008 gas
Washington	—	2014
Wyoming	—	2009

Sources: Annie Gilleo, Marty Kushler, Maggie Molina, and Dan York. "Valuing Efficiency: A Review Of Lost Revenue Adjustment Mechanisms." American Council for an Energy-Efficient Economy, Report U1503, June 2015. Also see Megan Cleveland, Logan Dunning, and Jesse Heibel. "State Policies For Utility Investment In Energy Efficiency." National Conference of State Legislatures, April 2019; American Council for an Energy Efficient Economy. State And Local Policy Database: Utility Business Model. Web.

Has Kentucky Adopted An LRAM Or RDM?

Kentucky has adopted LRAMs since 2008 for electric and natural gas utilities. Kentucky has not authorized the use of decoupling.

Kentucky has not authorized a decoupling mechanism.[72] In 2008, Kentucky approved use of LRAMs for utilities, which was first authorized by legislation in 1994 allowing utilities to implement DSMs. The authorizing legislation for DSMs was supplemented with performance incentives to make its adoption more appealing to the regulated utilities in 2008 and 2010. Kentucky's DSM

programs include financial incentives or shared net benefits between the utility and the ratepayers.[73]

Straight Fixed-Variable Rate Structure

Straight fixed-variable (SFV) rates break the link between a utility's revenue and sales. SFV rates recover the entirety of a utility's fixed costs by increasing the fixed monthly charges on the customer bill.

Under SFVs, the utility separates the fixed and variable charges on the customer bill. All of the PUC-approved fixed costs—which in some instances can include distribution costs and a portion of generation-related costs—are completely recovered through a fixed monthly charge. The approved variable costs are recovered only through the customers' variable charges. This practice differs from traditional ratemaking, which allows for the collection of some fixed costs through variable charges, as discussed in Chapter 2.

What Are The Policy Objectives Of SFVs?

The regulatory objective of SFVs is to eliminate the disincentive for energy efficiency and conservation.

As with LRAMs and RDMs, the objective of SFVs is to eliminate the disincentive for energy efficiency and conservation by making a utility's revenue less reliant on sales, or separate from sales.[74] The design induces maximum recovery of lost revenue but is not dependent on the adoption of a utility-based conservation program, as LRAMs are. SFVs are also easier to administer than LRAMs and decoupling because there are no forecasts and audited statements to ensure that the utility is not recovering costs that are unauthorized.

How Do SFVs Work In Practice?

Under SFVs, the customer's usage affects only the variable portion of the monthly bill. The fixed costs are collected through a separate customer or demand charge.

Under SFV rates, the change in the amount of a customer's monthly bill depends solely on the amount of the utility service used during the billing period. The fixed component of the SFV rate is not reliant upon the utility's total sales.[75]

The only changes to fixed costs under SFVs would be due to inflation, in which case the utility must adjust its rates by filing a general rate case.[d]

Table 3.3 shows three scenarios of expected usage, low usage, and high usage for a hypothetical electric utility customer. The commodity usage is measured in kilowatt-hours—1 kilowatt of usage per hour. Each scenario demonstrates how a customer's bill will differ under SFV rates and traditional rates.

[d] Unless there is an inflation-adjusting mechanism or add-on put in place during the regulatory proceeding during which the SFV rate structure is established.

Table 3.3
Comparing Customer Bills Under Traditional And SFV Rates

Usage In Kilowatt Hours	SFV	Traditional	Difference
Expected usage (800 kWh)	$117.00	$117.00	—
Low usage (700 kWh)	$106.13	$103.00	$3.13
High usage (900 kWh)	$127.88	$131.00	($3.12)

Source: Christina Simeone. "Rate Decoupling: Economic And Design Considerations." Kleinman Center for Energy Policy, 2016.

Customers have a greater fixed charge under SFV rates than under traditional rates, but their variable charge is smaller and their bill varies less according to usage.

In the low-usage scenario, a customer pays more under the SFV structure than under the traditional rate structure. Compare this outcome to the high-usage scenario, where a customer pays less under the SFV structure than under the traditional rate structure. This difference occurs because, with SFV rates, a utility recovers all of its fixed costs through fixed charges, so customers have a greater fixed charge than under traditional rates, but the customer's variable charge is smaller.

What Are The Limitations And Benefits Of SFVs?

Limitations of SFVs include reduced benefit to low-usage and perhaps low-income ratepayers; non-utility-initiated efficiency projects; and customer-initiated innovations. SFVs also may require price revision due to inflation.

The limitations of SFVs include the following:

- They reduce the benefit to customers who use less, because overall rates are less responsive due to higher fixed demand charges.
- Advocates for low-income ratepayers contend that SFVs hurt such ratepayers if they are also low-usage customers.[c] [76]
- They discourage energy efficiency if they are not initiated by the utility.
- They are indifferent to time of use, so they may not shave peaking demand.
- They discourage customer-initiated innovations such as net-metering and distributed generation.
- They may require price revision due to inflation.

Benefits of SFVs include enhanced financial certainty for utilities; reduced frequency of rate cases; and support for utility-initiated buildout of green technologies.

The benefits of SFVs include the following:

- They enhance financial certainty for the utility.
- They reduce the need for frequent rate cases.
- They are easier to administer than LRAMs or decoupling.
- They can enhance utility buildout of programs or technologies that support energy efficiency, conservation, and distribution generation.[77]

[c] Christensen Associates Energy Consulting suggests, "To the extent that there is a correlation between customer size and customer income, SFV rates could adversely affect-low-income customers."

Which States Use SFVs?

Twenty-two states have implemented SFVs. Kentucky does not have SFVs for any of its utilities.

Twenty-two states have implemented SFV for gas utilities, and five states have implemented SFV for electric utilities. Interest in SFV continues to grow; a 2016 report by Synapse shows 34 states plus the District of Columbia have at least requested to recover fixed costs only through fixed charges.[78] Table 3.4 shows when each state adopted this mechanism. Of the states that border Kentucky, the ones with an SFV mechanism for an electric or natural gas utility are Illinois, Ohio, and Tennessee.

Table 3.4
Straight Fixed-Variable Rates By State And Adoption

State	Utility Sector	Year Adopted
California	Gas	1996
Connecticut	Gas	2007
Florida	Gas	2009
Georgia	Gas	2015
Illinois	Electric and gas	2008
Kansas	Gas	2007
Maine	Gas	2014
Missouri	Gas	2002
Mississippi*	Electric	N/A
North Dakota	Gas	2005
Nebraska	Gas	2012
New Hampshire	Gas	2014
New York	Electric and gas	2010
Ohio	Gas	2008
Oklahoma	Electric and gas	2015 and 2004
Pennsylvania	Gas	2013
Tennessee	Gas	2012
Texas	Gas	2011
Vermont	Gas	N/A
Virginia	Gas	N/A
Wisconsin	Gas	2015
Wyoming	Electric and gas	2009

* Christensen Associates Energy Consulting suggests Mississippi has had a form of straight fixed-variable rate in place for Mississippi Power Co. that has been overtaken by formula rate plans.
Sources: Connecticut. Public Act No. 07-242, An Act Concerning Electricity and Energy Efficiency; Illinois Commerce Commission. Commonwealth Edison Company: Proposed General Increase In Electric Rates, Docket No. 10-0467; New York Public Service Commission. Order Requiring Proposals For Revenue Decoupling Mechanisms, Cases 03-E-0640 and 06-G-0746, April 20, 2007; Wyoming Public Service Commission. Memorandum Opinion, Findings And Order Approving Stipulation, In The Matter Of The Amended Application Of Rocky Mountain Power For Approval Of A General Rate Increase Of Approximately $28.8 Million Per Year (6.1 Percent Overall Average Increase), Docket No. 20000-333-ER-08 (Record No. 11824), May 20, 2009, p. 21; Mark Lowry, Matthew Makos, and Gretchen Waschbusch. "Alternative Regulation For Emerging Utility Challenges: 2015 Update." Edison Electric Institute, 2015, pp. 29-30.

Has Kentucky Adopted SFVs?

Although the majority of Kentucky's residential gas and electric utilities recover most or all of their customer-related fixed costs through monthly fixed customer or demand charges, the KYPSC states that Kentucky has not authorized an SFV mechanism for electric or natural gas utilities.[79] The customer charge is the basic fee for the provision of utility service and the demand charge is the monthly cost of maintaining the infrastructure needed to deliver the utility service.

Earning-Sharing Mechanism

An earning-sharing mechanism (ESM) tracks revenues and determines whether they are enough to maintain a certain ROE.

Through the ratemaking process, investor-owned utilities are entitled to recover all of their prudently incurred costs for providing utility service and to earn a reasonable, PUC-approved return on equity. Under an ESM, if the actual ROE falls outside of an approved range, a rate change will be triggered outside of the ratemaking process to either collect additional amounts or rebate excess amounts to customers so that the actual ROE falls within the approved range.[80]

What Is The Policy Objective Of ESMs?

ESMs reduce the risk from changing fiscal circumstances and the rate being charged utility customers.

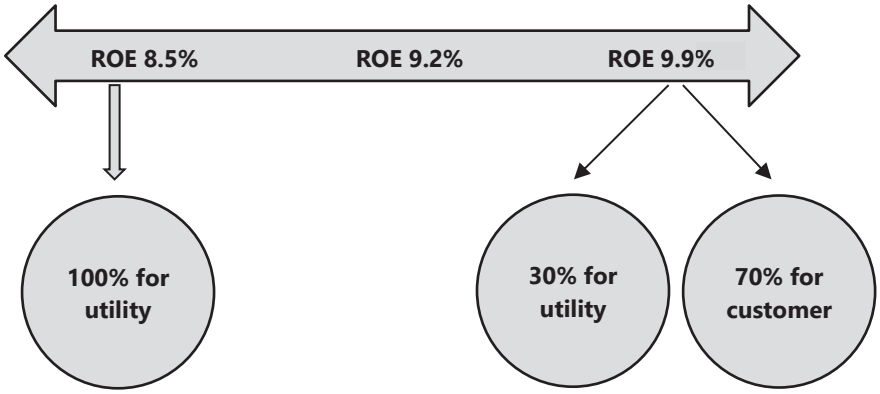
ESMs reduce the need for general rate cases by using automatic rate change mechanisms to adjust rates if actual ROEs stray too far from what the PUC has approved. Because they focus on actual earnings, there is no need to track specific costs and revenues under ESMs, which reduces administrative burden.[81]

How Do ESMs Work In Practice?

The regulatory objective of an ESM is the reduction of financial risk, improvement in utility creditworthiness, and the reduction of the number of general rate cases.

The PUC and the utility set a band above and below the approved ROE. As shown in Figure 3.A, an ESM adopted by the Virginia legislature established a 9.2 percent ROE for its utilities. It also established an earnings band of 70 basis points around the ROE. So, the revenue coming into the utility could be from 8.5 percent to 9.9 percent before triggering a change in the utility's base rate.

Figure 3.A
Virginia's ESM Range



Source: LRC staff compilation of data from E9 Insight, "Reward Without Risk: A Look At Imbalances in Virginia's Unique Regulatory Construct, Aug. 2020. pp 4-6.

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ESMs set a ROE target and upper and lower limits. The rate does not change until it moves outside or the upper or lower limit.

Within the established range, the utility and its shareholders bear the risk for earnings from 8.5 percent to 9.1 percent; those are the earnings below the approved ROE. The ratepayer bears the risk for earnings from 9.3 percent to 9.9 percent; those are the earnings above the approved ROE. All earnings within the range are kept by the utility.

ESMs also have sharing formulas for overearnings and underearning. These formulas can be very complicated.

If ROE falls below 8.5 percent, the base rate is changed to recover 100 percent of the underearnings to bring the ROE back to 9.2 percent. If the utility collects more than 9.2 percent, a sharing formula is triggered. It would appear that the sharing formula allows utility shareholders to retain 30 percent and the ratepayers are refunded 70 percent of the overearnings.[82] In practice, however, the formula is complicated by offsets for utility investments in utility grid modernization.[83]

PUC orders from various states show there are often complicated sharing schemes to distribute revenue surpluses or deficits between shareholders and ratepayers. Some ESMs are designed so sharing is done only for overearnings, so that ratepayers are not subject to surcharges as is done when an ESM is symmetric. When the underearnings are not shared, there is usually a price cap or some mechanism that stairsteps the rate increase so it does not occur all at once. An ESM can have an "off-ramp" feature too, which allows the PUC to suspend use of the ARM when the ROE is unusually high or low.

What Are The Limitations And Benefits Of ESMs?

Limitations of ESMs include the shift of risk from shareholders to ratepayers, less cost control, and difficulty in sharing overearnings.

The limitations of ESMs include the following:

- They shift risk from shareholders to ratepayers.
- They may not induce cost control.
- They can be contrived to make it difficult for ratepayers to share in the overearnings.

Benefits of ESMs include lowering the cost of ratemaking, reducing financial risk for the utility, and reducing the time between a rate request and a rate change.

The benefits of ESMs include the following:

- They can lower the cost of ratemaking procedures for both utility and regulator.
- They can reduce financial risk to the utility and improve the utility's creditworthiness.
- They can make adjustments more automatic, thereby reducing the time between a rate request and a rate change.[84]

Which States Use ESMs?

Twenty-five states have adopted ESMs. Most of them also adopt multiyear rate plans (MRPs) or formula rate plans (FRPs). Only five states have adopted an ESM alone.

Table 3.5 lists the states that have adopted ESMs. It also shows state that have adopted multiyear rate plans and formula rate plans, which are discussed below. The table includes all three ARMs because states often adopt ESMs in conjunction with MRPs or FRPs. Only five states have adopted an ESM without an MRP or FRP: Michigan, Minnesota, Missouri, New Mexico, and Rhode Island.

Table 3.5
ESM, FRP, And MRP By State, Sector, And Year

State	ESM	FRP	MRP
Alabama	✓	1982 electric and gas	—
Arizona	X	—	2012 electric
Arkansas	✓	2015 electric	—
California	✓	—	1994 electric and gas
Colorado	✓	—	2015 electric and gas
Connecticut	✓	—	2004 electric and gas
Florida	X	—	2013 electric
Georgia	✓	2012 gas	2014 electric
Hawaii	✓	2021 electric	2012 electric
Illinois	✓	2011 electric; 2021 gas	—
Indiana	✓	—	2015 gas
Iowa	✓	—	2014 electric and gas
Louisiana	✓	1996 electric; 2005 gas	2009 electric and gas
Maine	✓	—	2013 gas and electric
Massachusetts	X	—	2002 gas
Michigan	✓	—	—
Minnesota	✓	—	—
Mississippi	✓	1985 electric; 1990 gas	—
Missouri	✓	—	—
New Hampshire	✓	—	2014 gas; 2010 electric distribution

State	ESM	FRP	MRP
New Jersey	✓	—	2021 electric and water
New Mexico	✓	—	—
New York	✓	—	1991 gas; 2010 electric distribution
North Carolina	✓	—	2021 electric and water
North Dakota	✓	—	2013 electric and gas
Ohio	✓	—	2009 electric
Oklahoma	✓	2004 gas	—
Oregon	✓	—	1998 electric distribution
Rhode Island	✓	—	—
South Carolina	✓	2005 gas	—
Vermont	✓	—	2007 electric
Tennessee	✓	2015 gas	—
Texas	✓	2008 gas	—
Virginia	X	—	2014 electric
Washington	X	—	1997 gas and electric

Source: Mark Lowry, Matthew Makos, and Gretchen Waschbusch. "Alternative Regulation For Emerging Utility Challenges: 2015 Update." Edison Electric Institute, 2015 (Table 7 for multiyear rate plans and earning-sharing mechanisms; Table 8 for formula rate plans).

Has Kentucky Adopted ESMs?

Kentucky has not approved an ESM for a utility outside of a general rate case.

The KYPSC reports that it has not approved an ESM for a utility outside of a general rate case proceeding. However, in 2000 the KYPSC allowed Louisville Gas & Electric (LG&E) an optional ESM as an incentive in performance-based ratemaking. The plan set an ROE of 11.5 percent with a range of 100 basis points. If the utility earned outside of the range, then the overearnings were to be shared, with 40 percent to ratepayers and 60 percent to the utility.

The KYPSC terminated the plan in 2004 after an audit showed no difference in LG&E's fiscal profile due to the ESM, which was sufficient for the KYPSC to conclude that it had not been an effective performance incentive. The KYPSC reports that there are other mechanisms that share earnings from the utility's "off-system sales," which are wholesale or retail sales outside the utility's certified territory.

Natural gas utilities have an ESM if they meet or exceed specific benchmarks established by the PSC as performance measures.[85] Kentucky statutes establish an earning-sharing mechanism for their demand-side management program, but this is different from having an ESM to adjust base rates.

Formula Rate Plans And Multiyear Rate Plans

Formula rate plans (FRPs) and multiyear rate plans allow the utility to adjust the base rate beyond a single 12-month period outside of a general rate case.

FRPs and MRPs are two ratemaking methods that allow a utility to adjust its base rate for projected cost growth beyond a single 12-month period without going through a general rate case.

An FRP tracks actual costs and makes an automatic adjustment to the base rate, usually in the form of a tariff rider, to account for utility's revenue needs. The formula is the rate, and the "earning true-up mechanism" is an audit performed by the PUC to keep the revenue on target.

In contrast, an MRP is an "allowance for cost growth rather than a reimbursement for actual growth" in between periodic general rate cases.[86] Unlike the practice with an FRP, the utility will agree to periodic rate cases, which normally occur every 3 to 5 years. In between rate cases, there is an ESM in place that apportions the overearnings, underearnings, or both between ratepayers and shareholders. MRPs may also include price caps and other performance measures to control costs between rate cases.

What Are The Policy Objectives Of FRPs And MRPs?

FRPs and MRPs target the weak incentives that COS ratemaking creates for cost efficiency, innovation, and planning practices.

MRPs in particular seek to incentivize utilities to act more like competitive firms by including performance incentive mechanisms to provide awards or penalties, or both, for performance in targeted areas. Performance incentive mechanisms are used to incentivize maintenance or improvement of reliability and customer service quality.[87]

Regulatory objectives of FRPs and MRPs include reducing regulatory lag, the frequency of rate cases, and ratepayer shock from rate increases.

FRPs and MRPs aim to reduce regulatory lag and generally reduce the frequency of rate cases by allowing rate adjustments outside of rate case proceedings. Better utility performance can be encouraged due to stronger performance incentives and increased operating flexibility.[88]

How Do FRPs And MRPs Work In Practice?

FRPs and MRPs use a formula to identify whether the utility is generating enough revenue to meet its requirement.

Both FRP and MRP use an attrition relief mechanism, which is a formula pricing mechanism to calculate whether the utility is generating enough or too much revenue from sales to cover its revenue requirement. Sometimes the attrition relief mechanism is the ESM described above. Other times, it is a custom formula that can include various indices along with cost trackers and other ARMs.

Rather than the results of a full cost of service study, either the ROR or the ROE serves as a proxy for the revenue requirement. The PUC and the utility use the attrition relief mechanism along with various indices and detailed forecasts to determine whether projected or actual revenue will satisfy the PUC's approved ROR or ROE.

FRPs or MRPs may add other ARMs to the plan, such as ESMs, cost trackers, and revenue decoupling. Both FRPs and MRPs require some use of FTYs in order to create detailed revenue and cost forecasts. There are also monitoring and reporting requirements.

What Are The Limitations And Benefits Of FRPs And MRPs?

Limitations of FRPs and MRPs include shifting financial risk to the ratepayer, reducing incentives for cost control, decreasing transparency, and putting the utility on autopilot.

The limitations of FRPs and MRPs include the following:

- Both plans shift financial risk from the utility to the ratepayer.
- Both plans reduce the incentive to control costs and eventually pass on those increases to the ratepayer.
- There is less transparency compared to COS, due to reduced PUC oversight.

Benefits of FRPs and MRPs include reducing frequency and cost of general rate cases and financial risk for the utility. ESMs can reflect the needs of the parties to a rate case.

The benefits of FRPs and MRPs include the following:

- Both plans reduce the frequency and cost of rate cases to both utilities and PUCs.
- Both plans reduce the financial risk to the utility and improve access to capital.
- Utilities and PUCs can negotiate the specifics of the ESMs to address ratepayer needs, utility needs, and PUC concerns.
- Rates better reflect changes in current market conditions for commodities.
- They reduce rate shock to the ratepayer.

Which States Use FRPs And MRPs?

Eleven states, mostly in the southeast, use FRPs.

Only 11 states, most of which are in the Southeast, have adopted FRPs for their utilities. Most are for natural gas utilities or for those that offer both electric and gas. That is because those companies sought to avoid the continuous rate cases that occurred because of declines in the use of natural gas.

Twenty-two states have authorized the use of MRPs for their utilities.

Twenty-two states have used MRPs.[89] Of those 22 states, 16 imposed ESMs. Most distribute some portion of overearnings to both ratepayers and shareholders. Only a few instances of an ESM were found for specific utilities in California, Massachusetts,

and Maine where overearnings were not shared, and those plans have since terminated. Rate caps (which prevented the rate from exceeding a specified limit) and revenue stairsteps (which allowed rates to rise gradually in a stairstep fashion) were also common features of the MRPs examined in this study.

Table 3.5, above, lists the states that use FRPs and MRPs and when those plans were authorized or first adopted by their respective PUCs.

Has Kentucky Adopted An FRP Or MRP?

Kentucky has not adopted either an FRP or an MRP for its utilities. However, a streamlined ratemaking plan was adopted for small natural gas and water utilities with size being measured as less than $5 million in gross annual revenue. More recently, a similar pilot program was adopted for electric cooperatives to seek small increments in their rates to ensure compliance with loan covenants.[90] Both of these streamlined ratemaking plans are discussed in Chapter 4.

Chapter 4

Annual Rate Review Mechanisms And Other Regulatory Streamlining Measures

In recent years, several jurisdictions, including Kentucky, have adopted policies to streamline the ratemaking process for at least some regulated utility sectors in order to attempt to reduce the time, expense, and regulatory burden associated with adjusting utility rates only through a conventional rate case proceeding. This chapter discusses recent proposals and adopted policies to implement regular rate adjustments and otherwise streamline the ratemaking process for at least some categories of regulated utilities in Kentucky. Measures adopted in other states to streamline their ratemaking procedures through annual rate review mechanisms are also discussed.

Streamlined Ratemaking Procedures Adopted In Kentucky

Streamlined Ratemaking Procedures For Small Water And Natural Gas Utilities

The KYPSC has approved streamlined ratemaking processes for certain regulated utility sectors to encourage timelier rate filings.

The Kentucky Public Service Commission has adopted streamlined ratemaking procedures by administrative regulation for small natural gas utilities and water districts organized under KRS Chapter 74.[91] To be eligible for these procedures, a natural gas utility or water district must have generated less than $5 million in gross revenue for the previous year, maintained separate recordkeeping from commonly owned enterprises, and filed complete annual reports with the KYPSC for the previous 2 years.

Due to their governance or their size, small water districts and natural gas utilities tend to be reluctant to request rate increases from the KYPSC until they have already begun to experience financial difficulties, service problems, or both. Furthermore, small water districts and natural gas utilities can have the additional challenges of lacking the technical expertise and resources to complete the extensive filing and procedural requirements of a full ratemaking proceeding, which can also lead to further rate filing procrastination. To address these issues, in addition to shortening and simplifying the ratemaking process, the alternative rate adjustment procedure allows eligible water districts and natural gas utilities to use KYPSC staff to assist with

preparing and filing the necessary documentation to complete the rate proceeding.[92]

Streamlined Ratemaking For Electric Distribution Cooperatives

Following a series of meetings with stakeholder groups throughout 2017 and 2018, the KYPSC issued an order, which was finalized in 2019, to streamline certain aspects of the ratemaking process only for regulated electric distribution cooperatives.[93] There are 19 KYPSC-regulated electric distribution cooperatives that could be eligible for the streamlined ratemaking process.[94] To be eligible, a distribution cooperative must have had a base rate increase sometime in the previous 10 years, at least 12 months must have elapsed since its most recent rate base increase, and its cost of service study must be less than 5 years old, among several other requirements. The approved streamlining order for eligible electric distribution cooperatives contained the following key provisions:

- Shortened the rate case processing time—which previously could have taken up to 10 months to complete—to under 75 days
- Limited the maximum requested rate increase to no more than 4 percent and no more than 0.75 percent for each year since the cooperative's last rate adjustment
- Changed the distribution cooperative's notice requirements for customers when seeking a rate change to make providing notice less costly
- Reduced the number of filings that the distribution cooperative would need to make in its streamlined rate case application

The KYPSC also retained the authority to deny an application for streamlined ratemaking and to end the availability of the streamlined ratemaking procedure altogether.

Electric distribution cooperatives can be more reluctant to file rate cases than investor-owned utilities because they are nonprofit business owned by the members they serve.

Why Does The Order Apply Only To Electric Distribution Cooperatives? Electric distribution cooperatives differ from other regulated electric utilities under the commission's jurisdiction in that they are organized as nonprofit businesses that are owned by the members they serve, who live mostly in less densely populated rural or semi-rural areas.[95] Because they are operated without a profit motive and are under pressure from their member-owners to keep rates as low as possible, electric distribution cooperatives may seek to avoid increasing rates through rate cases for as long as they can. This reluctance to submit to the ratemaking process to increase rates can mean that a cooperative's necessary maintenance and infrastructure investments are deferred to an extent that could

endanger their financial standing, negatively impact service, or cause a sudden large increase in rates when they finally do undertake a rate case.[96]

With this in mind, the KYPSC issued the streamlined ratemaking order to reduce some of the administrative burden of filing a rate case for electric distribution cooperatives and to help simplify and reduce the costs of their ratepayer notification requirements, which are some of their largest expenses for rate cases. By removing some of the administrative impediments and costs of the ratemaking process, the KYPSC hoped that electric distribution cooperatives would be less reluctant to file rate cases in a timely manner. [97] Appropriately timed rate case filings could help ensure their financial soundness, maintain reliable service to their ratepayers, and reduce the risk of sudden large rate increases.

Proposed Streamlined Ratemaking Procedures In Kentucky

There have been several proposals in recent years to streamline aspects of the ratemaking process for additional regulated utility sectors outside of electric distribution cooperatives and small water districts and natural gas utilities. Different proposals have been made to both the Public Service Commission and the General Assembly, but they have not been adopted.

Annual Review Mechanisms

The KYPSC rejected a 2017 proposal from an investor-owned gas distribution company to implement a type of annual rate review mechanism similar to what has been adopted in Tennessee.

In 2017, Atmos Energy Corporation, an investor-owned gas distribution company that serves approximately 176,000 customers in western and central Kentucky, proposed as part of its rate adjustment application to implement a streamlined mechanism to allow for annual rate adjustments based on filings that would be reviewed and approved by the KYPSC each year.[98] The proposed annual review mechanism would be similar to one adopted by the Tennessee Public Utility Commission (TPUC) for Atmos's operations in that state, as discussed below.

In support of its proposal, Atmos argued that an annual review mechanism would create a more efficient and less costly process to review rates annually, resulting in customer rates that more accurately reflect current costs. Atmos proposed to make annual filings on projected revenue requirements for the coming test year by December 1 of each year, with rates becoming effective on April 1 of the following year. To ensure that actual revenues and costs matched what were projected, an annual reconciliation filing

would be submitted to remedy any discrepancies. Atmos argued that data it submitted from other jurisdictions where it operated, where similar annual rate review mechanisms had been adopted, demonstrated the accuracy and efficiency of the process.[99]

The Kentucky Attorney General's Office of Rate Intervention opposed the plan, citing the following reasons:

- It was not necessary to achieve annual or more frequent rate increases.
- It was not necessary to reduce the length of time required to prepare and conduct a rate case and receive a regulatory decision, since Atmos could already use a forecasted test year in determining its revenue requirement and costs.
- More frequent rate increases without the traditional rate case process review could harm ratepayers.
- There was not sufficient evidence to conclude that an annual review mechanism would result in a reduction in ratemaking costs that would be passed on to ratepayers.
- Atmos's incentive to exercise management control and maintain its authorized return between rate cases would be removed.

In response to these objections, Atmos maintained that the annual review mechanism would provide adequate regulatory oversight of its expenses and investments. The annual review and reconciliation process conducted by the KYPSC and third parties such as the attorney general would ensure frequent review of costs and revenues. To address the concern that the proposed annual review mechanism would result in decreased oversight compared to the traditional ratemaking process, Atmos offered to amend its proposed process to develop a procedural schedule for each filing, which would include multiple rounds of discovery and the opportunity for intervenor testimony.

The KYPSC ultimately rejected the proposed annual review mechanism. While not necessarily finding that it lacked statutory authority to implement the plan, the KYPSC noted that the current ratemaking process aligned with the current statutes and regulations, ensured that the public interest was served, and was fair to Atmos and its shareholders. The KYPSC was not persuaded by the fact that the process had been adopted in other jurisdictions, and it was skeptical that there was any clear benefit in the plan for ratepayers, other than a decrease in regulatory expense and a predictable annual increase in rates. The KYPSC further expressed concern that if all of the other regulated gas, electric, water, and sewer utilities requested and were approved for similar plans, there

would be little saved administrative resources by the commission, its staff, or intervenors.[100]

2022 House Bill 341

2022 HB 341 proposed significant changes to the ratemaking process for electric, natural gas, and water utilities regulated by the KYPSC.

Although withdrawn before being taken up for consideration during the 2022 Regular Session of the General Assembly, HB 341 proposed significant streamlining of the ratemaking process for electric, water, and natural gas utilities regulated by the KYPSC. The bill proposed changing the ratemaking process for an eligible utility that had gone through a traditional rate proceeding within the previous 5 years by

- allowing for more publication options for giving public notice of a rate increase request, which would include but no longer require publication of the notices in local newspapers;
- reducing the amount of time for outside parties to intervene in rate increase requests and limiting the number of information requests that the intervenors and KYPSC staff could make;
- allowing the utility to request evidentiary hearings only where all sides can present expert testimony and data while under oath;
- reducing the number of public hearings needed during a rate proceeding to one for every 250,000 utility customers;
- requiring the KYPSC to review and approve rate increases within 120 days of receiving a streamlined ratemaking application so that the utility can earn the authorized rate of return on equity established in its most recent full rate case; and
- requiring the KYPSC to approve riders (adjustments added between general rate cases) for infrastructure improvements, pipeline replacement and safety modifications, enhancements in safety system and reliability, and economic development initiatives, among other things.

Prior to the withdrawal of HB 341, opponents argued that it would do too much to undermine the ability of the KYSPC and intervening parties to scrutinize and challenge the bases for rate increases requested by utilities during the ratemaking process.[101]

Annual Rate Review Mechanisms Adopted In Other States

Several southeastern states have adopted procedures that allow eligible utilities to make more regular adjustments to their rates based on annual filings of their actual expenses and revenues. Their experiences could be useful in understanding the impact

of adopting streamlined ratemaking procedures in Kentucky on utilities, ratepayers, and the commission.

Tennessee

Tennessee's annual rate review mechanism was authorized by statute, but the Tennessee Public Utility Commission worked with utilities and stakeholder groups to implement the requirements of the process.

In 2013, Tennessee adopted a statutory framework to allow its Public Utility Commission to implement a variety of alternative regulatory methods in lieu of general rate case proceedings, including allowing utilities to file for annual reviews of their rates based upon the methodologies in their most recent rate cases.[102] Because the annual rate review procedure was not established in statute, the TPUC worked with stakeholder groups to adopt procedural, documentation, and filing requirements to implement an annual rate review process that streamlined the ratemaking process while maintaining intervenor rights, public hearings, full discovery, and the taking of sworn testimony.[103]

All public utilities, except market-regulated telecommunications carriers, are eligible for annual rate reviews as long as they have engaged in a general rate case in the past 5 years. The TPUC is required to review an annual filing within 120 days of receipt and to order the public utility to make the adjustments to its tariff rates to provide that the public utility earns the authorized return on equity established in the public utility's most recent general rate case. As part of its filings for an annual rate review application, the TPUC also requires a utility to file an annual revenue reconciliation, which compares the actual adjusted cost of service from the just-completed historic test period with the actual, adjusted gross margin from the same period to true up any discrepancies between the forecasted and actual costs of service for the year. Public utilities and the TPUC have the ability to terminate or modify approved annual review plans.

Several regulated utilities in Tennessee that have used the annual rate review process view its adoption and implementation as a success.[104] They believe that adopting annual rate reviews has alleviated some of the administrative burden on the TPUC and has created a transparent, collaborative process that saves the regulated utilities and their ratepayers money through reduced legal fees and reduced costs of capital compared to the other states in which they operate that have not adopted annual rate mechanisms. However, as discussed above, the KYPSC was skeptical of these purported benefits when it considered a similar annual rate review mechanism proposal by Atmos in 2017.

Alabama

In 1982, Alabama adopted a formula rate plan called the rate stabilization and equalization (RSE) plan, which significantly streamlined the ratemaking process, first for its regulated electric utilities and later for others. Under RSE, the Alabama Public Service Commission (APSC) annually reviews a utility's expected return on equity, compares it to the authorized range, and then adjusts base revenues and rates if necessary, to keep the return on equity within that range. The RSE limits the maximum annual rate increase to 5 percent, and the average of two consecutive annual increases to not more than 4 percent, which has the intended effect of smoothing the rate increase trajectory over time to help ratepayers adjust to the increases.[105]

Alabama's rate stabilization and equalization plan provides for only minimal public or intervenor involvement.

Unlike a traditional ratemaking proceeding, there are no evidentiary hearings, and there is otherwise little public or intervenor involvement. The utility must submit to an informal hearing where it must answer questions posed by the APSC, its staff, or other interested parties, but there is no opportunity to submit discovery questions or to file sworn expert testimony.[106] The result is a ratemaking process that differs significantly from the current one in Kentucky, which relies on adversarial parties challenging each other's claims to develop a record on which the KYPSC can make its determinations.

Support For RSE. Alabama's regulated utilities and other proponents of RSE contend that it is superior to traditional ratemaking for the following reasons:

- **Increased Frequency Of Cost Review**. A public service commission would normally conduct an in-depth examination of costs only on a sporadic basis as part of a rate case, but under RSE, the commission examines cost components both in the context of the annual test of the projected return on equity as well as on an ongoing basis throughout the year when it is checking cost benchmarks against those of other utilities.
- **Rate Smoothing**. Under traditional ratemaking, rates may be adjusted infrequently and the rate applications may reflect a backlog of cost pressures. As a result, in an environment of rising unit costs, infrequent rate adjustment can produce large rate increases that ratepayers do not expect.
- **Reduction In Regulatory Lag**. The length of time required to prepare and conduct a rate case and receive a regulatory decision means the costs being recovered in the new rates typically are out of date, although this danger is mitigated in Kentucky by using a hybrid historic/future test year, as

> discussed in more detail in Chapter 3. To the extent that regulatory lag can be further reduced, it could lead to a more stable financial performance by the utility, which in turn supports better credit ratings and access to capital on the most reasonable terms possible.[107]

RSE proponents further argue that the results speak for themselves. Since its adoption, RSE has produced 12 upward adjustments, 3 downward adjustments, and 15 nonadjustments.[108] During that time, Alabama electric utility rates have been on average 14 percent below the national average, there have been very few customer complaints regarding service or rates, and in terms of total system performance, Alabama's largest electric utility has a reliability rate of 99.9 percent.[109]

Opposition To RSE. Opponents of RSE argue that circumstances have changed substantially since the years leading to the adoption of RSE in 1982, when demand for electricity was growing at a rate of 8 percent per year, overall inflation peaked at 13.5 percent in 1980, and utility financing costs were very high, with 10-year Treasury yields on the order of 10 percent and higher.[110] It was under those circumstances, and under an order from the Alabama Supreme Court to set rates that allow for more reasonable returns on investment for its electric utilities, that the Alabama Public Service Commission adopted the RSE for its largest electric utility, Alabama Power.[111] In order to address the growing financial pressures and falling creditworthiness of Alabama Power, the APSC adopted the RSE to ensure more regular and certain rate increases for the utility and to reduce the time and expense of regular rate proceeding, which came at the cost of public involvement and scrutiny.

Since that time, demand for electricity has fallen, inflation is lower, and utility financing costs have decreased. RSE detractors argue that current conditions no longer justify the lack of transparency in the ratemaking process for how the APSC balances the interests of ratepayers against those of the utilities and their shareholders.[112] Through RSE, the APSC allows Alabama Power to earn a return of 13.0 percent to 14.5 percent on common equity investment, which is significantly higher than the returns other utility companies earn.[113] For example, the 13.3 percent average return on equity that Alabama Power earned from 2008 to 2011 was more than 40 percent higher than the average of 9.4 percent earned by 76 other domestic US utility operating companies, and its return on total capitalization during

these 4 years was 30 percent higher than the average return of the 76 other utility operating companies.[114]

Mississippi

In 1986, Mississippi adopted an annually reviewed formula rate plan for Mississippi Power Company, and in 1992 extended it to Entergy Mississippi.[115] Both plans use set formulas to adjust base rates between rate cases in response to changes in economy-wide inflation rates, overall economic activity, and utility costs. Near the end of each year, the utilities file updates to their plans for the coming year, which determines whether rates need to be changed to be within 0.5 percent of the return on equity targets. The returns on equity targets are adjusted for each utility's performance rating, which is based on three performance metrics:

- the utility's average retail electricity price relative to other comparable investor-owned utilities in the Southeast;
- the result of the average of the two most recent customer satisfaction surveys conducted by independent professional survey firms; and
- service reliability as measured by the percentage of time that service was available to customers during the previous 36 months.[116]

Mississippi's annual rate review plan allows public hearings, but only for major rate changes.

Unlike in Alabama, public hearings are held, but only for major changes to rates. Statute defines *major rate change* as either

- a change in rates that would increase the annual revenues of the public utility by more than $100,000 or 2 percent, or
- a change in the rate design that has a significant impact on a class or classes of ratepayers.[117]

Under Mississippi Public Service Commission (MPSC) rules, any person may be permitted to intervene in a rate proceeding when the person has a substantial interest to be protected relating to the property, transaction, or outcome of the proceeding at issue.[118] A public witness who has not been permitted to intervene in a rate proceeding cannot examine witnesses or otherwise participate in the proceedings, but the MPSC may allow public witnesses to introduce evidence at a hearing by written or oral statements and exhibits.[119]

Utilities must annually submit calculations of their actual returns on equity for the preceding year, and if the actual returns deviate by more than 0.50 percent from the targets, the utilities must either refund the amount to current customers or change current customer rates to bring the actual returns within 0.50 percent of the targets.

However, the revenue adjustment for the prior year plus any other revenue adjustment for the same prior year cannot exceed 4 percent of the utility's annual aggregate retail revenues for that prior year.[120]

South Carolina

In 2005, South Carolina passed the Natural Gas Rate Stabilization Act to create an annual rate review mechanism for natural gas utilities regulated by the South Carolina Public Service Commission (SCPSC). To be eligible, a regulated natural gas utility must have had a general rate case in the previous 5 years.[121] Eligible regulated natural gas utilities submit annual monitoring reports detailing their actual operating and maintenance costs, all of their rate base input components, and all other components of income for return on equity.[122] If the information submitted in the report shows that a natural gas utility's actual return on equity is 0.5 percent more or less than what the SCPSC has authorized, then the utility is eligible for a rate adjustment, and the report is audited by SCPSC staff for accuracy. Interested parties may submit written comments only in response to a utility's monitoring report and the SCPSC's staff audit.[123]

South Carolina's annual rate review mechanism allows for only limited public or intervenor participation until it issues an initial order for a rate change, after which aggrieved parties can appeal the decision and an evidentiary hearing is held.

If the staff audit does not find deficiencies in the utility's submitted report, the SCPSC issues an initial order making the required adjustment to the utility's rates. An aggrieved party may, within 30 days of the issuance of the initial order, petition the SCPSC to review the order. After the petition is received, all interested parties of record are given the opportunity to be heard at an evidentiary hearing on the matter. After the evidentiary hearing is held, the SCPSC issues a final order.

Appendix A

Comprehensive Table Of States That Authorized ARMs

ARM Adoption Or Authorization By State For Electric, Natural Gas, Or Water Utilities

State	LRAM	RDM	CTK	FTY	FRP	MRP	SFV	ESM
Alabama		✓	✓	✓	✓			✓
Alaska			✓					
Arizona	✓	✓	✓			✓		
Arkansas	✓	✓	✓	✓	✓			✓
California	✓	✓	✓	✓		✓	✓	✓
Colorado	✓	✓	✓	✓		✓		✓
Connecticut	✓	✓	✓	✓		✓	✓	✓
Delaware	✓	✓	✓	✓				
Florida			✓	✓		✓	✓	
Georgia	✓		✓	✓	✓	✓	✓	✓
Hawaii		✓	✓	✓	✓	✓		✓
Idaho		✓	✓	✓				
Illinois		✓	✓	✓	✓		✓	✓
Indiana	✓	✓	✓	✓		✓		✓
Iowa			✓			✓		✓
Kansas	✓	✓	✓				✓	
Kentucky	✓		✓	✓				
Louisiana	✓		✓	✓	✓	✓		✓
Maine		✓	✓	✓		✓	✓	✓
Maryland		✓	✓	✓				
Massachusetts	✓	✓	✓			✓		
Michigan		✓	✓	✓				✓
Minnesota		✓	✓	✓				
Mississippi	✓	✓	✓	✓	✓		✓	✓
Missouri	✓		✓	✓			✓	✓
Montana	✓	✓	✓					
Nebraska			✓				✓	
Nevada	✓	✓	✓					
New Hampshire	✓	✓	✓			✓	✓	✓
New Jersey	✓	✓	✓	✓		✓		✓
New Mexico		✓	✓	✓				
New York		✓	✓	✓		✓	✓	✓
North Carolina	✓	✓	✓			✓		✓
North Dakota			✓	✓		✓	✓	✓
Ohio	✓	✓	✓	✓		✓	✓	✓
Oklahoma	✓		✓		✓		✓	✓
Oregon		✓	✓	✓		✓		✓
Pennsylvania		✓	✓	✓			✓	
Rhode Island		✓	✓	✓				
South Carolina	✓		✓		✓			✓
South Dakota	✓		✓					
Tennessee			✓	✓	✓		✓	
Texas			✓		✓		✓	✓
Utah	✓	✓	✓	✓				
Vermont	✓	✓	✓			✓	✓	✓

State	LRAM	RDM	CTK	FTY	FRP	MRP	SFV	ESM
Virginia	✓	✓	✓			✓	✓	
Washington		✓	✓			✓		
West Virginia			✓					
Wisconsin			✓	✓			✓	
Wyoming		✓	✓	✓			✓	

Note: LRAM = lost revenue adjustment mechanism; RDM = revenue decoupling mechanism; CTK = cost tracker; FTY = future test year; FRP = formula rate plan; MRP = multiyear rate plan; SFV = straight fixed-variable rate; and ESM = earning-sharing mechanism.
Source: Compiled by LRC staff.

Appendix B

Abbreviations And Acronyms

APSC—Alabama Public Service Commission

A governmental administrative body, located in Alabama, which regulates the rates and terms of service for public utilities under its jurisdiction.

ARM—Alternative Rate Mechanism

Any change to traditional cost of service ratemaking that has been adopted by a state to accomplish a specific policy goal.

COS—Cost Of Service

Cost of service is used in this study to refer to the traditional ratemaking process, which entails the regulator determining the regulated utility's total revenue requirement (its costs of service) plus a reasonable return on investment, then allocating a rate to each customer class the utility serves to achieve the required revenue.

DSM—Demand-Side Management

The most common LRAMs include programs such as demand-side management, which pays ratepayers to reduce their usage during peak demand when the supply of the service is constrained.

ESM—Earning-Sharing Mechanism

An ARM under which, when the ROE is above or below a set amount, the utility must collect additional amounts or make refunds to ratepayers. Often used in collaboration with other ARMs.

FRP—Formula Rate Plan

An ARM that allows a utility to adjust the base rate for projected cost growth beyond a single 12-month period without going through a general rate case, and which tracks actual costs and makes automatic adjustment to the base rate by utilizing a predetermined formula.

FTY—Future Test Year

An ARM type that forecasts future anticipated revenues and costs for 12 months after the new rate is in effect.

GDP—Gross Domestic Product

The total value of goods produced and services provided in a country during a year.

HTY—Historic Test Year

An ARM type that looks at actual revenues and costs for 12 months prior to the new rate.

KYPSC—Kentucky Public Service Commission

A governmental administrative body, empowered by the Kentucky General Assembly, to regulate the rates and terms of service for public utilities under its jurisdiction. Also referred to as "the commission."

LG&E—Louisville Gas & Electric

A utilities company based in Louisville, and a subsidiary of PPL Corp.

LRAM—Lost Revenue Adjustment Mechanism

An ARM that seeks to eliminate disincentive for efficiency and conservation, promote renewable resources, and optimize usage of utility service during nonpeak hours by lessening the direct impact of utility sales and infrastructure buildout on the utility's profit margin.

MPSC—Mississippi Public Service Commission

A governmental administrative body, located in Mississippi, that regulates the rates and terms of service for public utilities under its jurisdiction.

MRP—Multiyear Rate Plan

An ARM that allows a utility to adjust the base rate for projected cost growth beyond a single 12-month period without going through a general rate case, and under which periodic rate cases occur every 3 to 5 years. MRPs may also include price caps and other performance measures.

PUC—Public Utility Commission

A governmental administrative body in a state other than Kentucky that is empowered to regulate the rates and terms of service for public utilities under its jurisdiction.

RDM—Revenue Decoupling

An adjustable price mechanism with the goal of eliminating the disincentive for energy efficiency, that makes revenues and profits independent of sales volume through an adjustable variable distribution rate.

ROE—Return On Equity

The measure of a company's net income divided by its shareholders' equity.

ROR—Rate Of Return

The net gain or loss of an investment over a specified time period, expressed as a percentage of the investment's initial cost.

RSE—Rate Stabilization And Equalization

A type of formula rate plan under which a public utility commission reviews a utility's expected return on equity, compares it to the authorized range, and then adjusts base revenues and rates to keep the return on equity within that range if necessary.

SCPSC—South Carolina Public Service Commission

A governmental administrative body, located in South Carolina, that regulates the rates and terms of service for public utilities under its jurisdiction.

SFV—Straight Fixed-Variable

An ARM with the goal of eliminating the disincentive for energy efficiency that makes revenues and profits independent of sales volume by recovering all a utility's fixed costs through customers' fixed rates.

TPUC—Tennessee Public Utility Commission

A governmental administrative body, located in Tennessee, that regulates the rates and terms of service for public utilities under its jurisdiction.

Appendix C

Authorizing Memorandum

TO: Jay D. Hartz, Director

FROM: Senate President Robert Stivers
House Speaker David Osborne

DATE: April 13, 2022

RE: ARM Study

Utility infrastructure modernization and investment requires statutory reforms to improve the Public Service Commission's processes for recovery of legitimately incurred costs, which will serve to expedite investment of public and private capital in Kentucky infrastructure, make government more efficient, and protect customers from rate shock.

The creation of an alternative rate mechanism (ARM) has the potential to streamline a cumbersome and inefficient ratemaking process and reduce costs to the Public Service Commission, the commission staff, interveners, and utility customers while continuing to promote the safety, reliability, and resiliency of Kentucky's energy infrastructure and enhance the economic development of the Commonwealth.

Therefore, the Director of the Legislative Research Commission is directed to assign appropriate nonpartisan staff to conduct a study during the 2022 Interim examining the costs, mechanisms for, and benefits of implementing an ARM for public utilities regulated by the Public Service Commission.

The study shall examine states that currently utilize ARMs, including the mechanisms used, the length of time those mechanisms have been in place, and whether those mechanisms have produced just and reasonable rates, promoted the safety, reliability, and resiliency of energy infrastructure, and enhanced the economic development opportunities in those states.

The final report of the study shall be submitted to the Legislative Research Commission no later than November 1, 2022.

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