RRA Regulatory Focus
Alternative ratemaking plans in the U.S.

A key to reducing regulatory lag and providing certainty for investors

In these increasingly volatile times, when investors are struggling to understand what the ongoing COVID-19 pandemic and the related recessionary pressures will mean for utility cash flow and profitability, alternative ratemaking plans can provide some degree of protection.

For Detailed Data

Click here to see supporting data tables.

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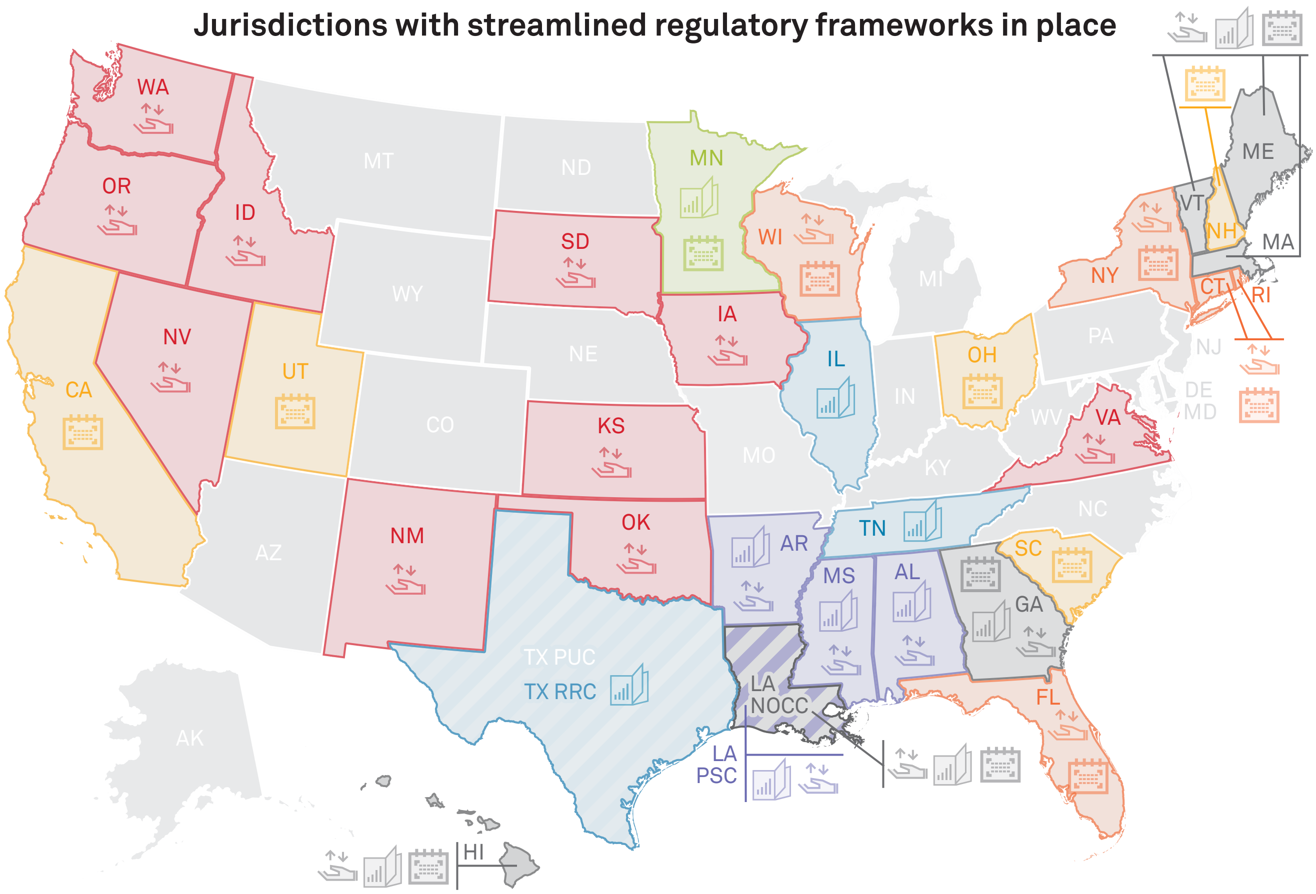
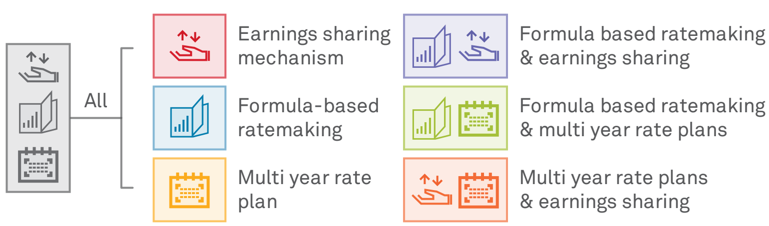
Jurisdictions with streamlined regulatory frameworks in place





S&P Global
Market Intelligence

As of March 31, 2020.
Map credit: Ciaralou Agpalo Palicpic
Source: S&P Global Market Intelligence

Even before the current global crisis, Regulatory Research Associates, a group within S&P Global Market Intelligence, had taken note of an uptick in state regulators' and policymakers' interest in pursuing innovative forms of regulation to address challenges associated with expanding utility capital spending plans, modest to flat sales growth in most parts of the country, regulatory lag and changes in the way the utilities are expected to do business.

Alternative ratemaking plans is a term applied to a wide-ranging complement of mechanisms that are generally outside of the traditional base rate case model.

These plans can be broadly or narrowly focused. Broad-based plans like formula based ratemaking, multi-year rate plans and earnings sharing mechanisms streamline the regulatory process, lessen the burden on regulatory commissions, their staff and stakeholders and reduce regulatory lag for utilities. These type of mechanisms may be implemented on a stand-alone basis or in combination. Many of these arrangements also include an opportunity for earnings enhancement.

As of this writing, 13 of the 53 jurisdictions followed by RRA had formula based ratemaking plans in place for at least one company in the jurisdiction, including jurisdictions where such plans were combined with other mechanisms. There are 17 jurisdictions in which a multi-year rate plan is in place for at least one utility, including instances where it is combined with other types of plans. Earnings sharing mechanisms are in place for at least one utility in 25 jurisdictions, on a stand-alone basis or as part of either a multi-year plan or a formula-based ratemaking mechanism.

Alternative regulation plans in the US[1]

Formula-based ratemaking	Multi-year rate plans	Earnings sharing	Incentive ROEs	Electric fuel/ Gas costs	Capacity release/ Off-system sales
Alabama	California	Alabama	Colorado	Indiana	Colorado
Arkansas	Connecticut	Arkansas	Iowa	Idaho	Delaware
Georgia	Dist. of Columbia[2]	Connecticut	Kansas[2]	Iowa	Florida
Hawaii	Florida	Florida	Mississippi	Illinois	Indiana
Illinois	Georgia	Georgia	Montana[2]	Kansas	Iowa
Louisiana—NOCC	Hawaii	Hawaii	Nevada	Kentucky	Kentucky
Louisiana—PSC	Louisiana—NOCC	Idaho	Ohio	Maryland	Louisiana
Maine	Maine	Iowa	Virginia	Missouri	Massachusetts
Massachusetts	Maryland[2]	Kansas	Washington[2]	Montana	Missouri
Minnesota	Massachusetts	Louisiana—NOCC	Wisconsin	New Jersey	New Jersey
Mississippi	Minnesota	Louisiana—PSC		Oregon	New York
Pennsylvania[2]	New Hampshire	Maine		Tennessee	North Dakota
Tennessee	New York	Massachusetts		Rhode Island	New Jersey
Texas—RRC	Ohio	Mississippi		Utah	Oklahoma
Vermont	Pennsylvania[2]	Nevada		Vermont	Pennsylvania
	Rhode Island	New Mexico		Virginia	Rhode Island
	South Carolina	New York		Wyoming	South Dakota
	Utah	Oklahoma			Tennessee
	Vermont	Oregon			Texas—PUC
	Washington[2]	Rhode Island			Texas—RRC
	Wisconsin	South Dakota			Utah
		Vermont			
		Virginia			
		Washington			
		Wisconsin			

As of March 31, 2020.
NOCC=New Orleans City Council; PSC=Public Service Commission; PUC=Public Utility (ies) Commission; RRC=Railroad Commission.
[1]Mechanism in place for at least on utility in the state, unless otherwise noted.
[2]Specifically permitted by rule, law or commission order; no mechanism currently in place.
Source: Regulatory Research Associates, a group withinn S&P Global Market Intelligence

In certain jurisdictions, legislation or commission rules permit these types of plans, but the commission has yet to approve a specific plan for one of the utilities.

Narrowly focused plans generally target a specific type of behavior or investment on the part of a utility. For example, some may allow a company to retain a portion of cost savings relative to a base level of some expense type, such as fuel, purchased power or pension costs.

Others might permit a company to retain for shareholders a portion of off-system sales or capacity release revenues.

Still others provide a company an enhanced equity return, or ROE, for achieving operational performance targets, customer service metrics, reliability standards, demand reduction targets under energy conservation programs or for meeting or exceeding renewable portfolio standards.

In some instances, commissions have approved ROE premiums for specific types of plant investment when there was a preference for in-state generation versus wholesale power purchases, or in order to incent the deployment of renewable resource facilities.

While narrowly focused plans do not necessarily stream line the regulatory process the way that more broadly focused plans do, they do provide the utilities with the opportunity for earnings enhancement that could offset the impact of regulatory lag.

RRA generally views the presence of alternative ratemaking plans as constructive from an investor viewpoint.

A more detailed discussion of the various types of plans in place is provided in the sections that follow, and a listing of the plans that are currently in place across the U.S. is provided in the related data file.

For additional information, refer to the Alternative regulation section of the Commission Profile for each jurisdiction.

Setting the stage

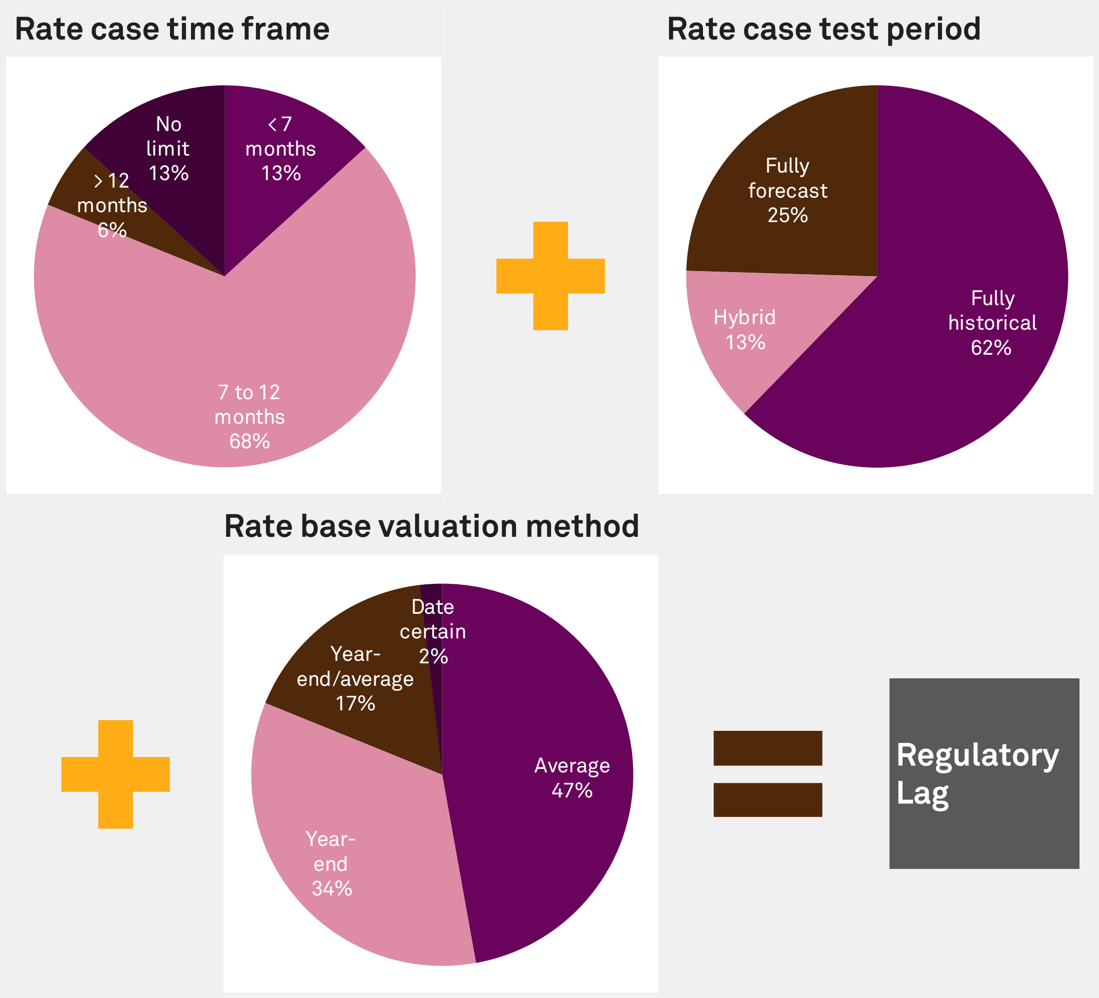
A quick word on regulatory lag

Regulatory lag refers to the time it takes for an investment or cost change to be reflected in rates after that change has occurred. This lag is an inherent part of the rate case process and comes in different forms.

First, is the sheer amount of time it takes for a rate case to be completed. Most states have rules in place that require rate cases to be completed within seven to 12 months of filing, but in some the time frame is substantially longer than 12 months and in others there is no statutory time frame at all.

Aside from processing time, there are the issues of whether the test year is historical, whether the commission employs an average or test-year-end rate base and/or to what extent adjustments to test year data are permitted. For information concerning how these policies are addressed in each state, refer to the Rate Case Timing/Interim Procedures and Rate Base and Test Period sections of RRA's Commission Profiles.

Changes to the basic components of the traditional process are often difficult to achieve, requiring legislative authority. Even in situations where the legislature is on board, stakeholders and commissioners may be slow to embrace the new concepts and there may be unintended consequences, such as a reduction in authorized ROE — whether implicit or explicit — to reflect the perceived reduced risk associated with these mechanisms.



Data gathered as of March 31, 2020.
Source: Regulatory Research Associates, and a group within S&P Global Market Intelligence

Capital spending trends reviewed

Robust capital spending in recent years has been a driver of regulators' interest in and acceptance of alternative forms of regulation.

Based on a study conducted by RRA in October 2019, it was estimated that capital spending for the 52 power and gas utility holding companies in RRA's Financial Focus coverage universe would exceed $134 billion in 2019.

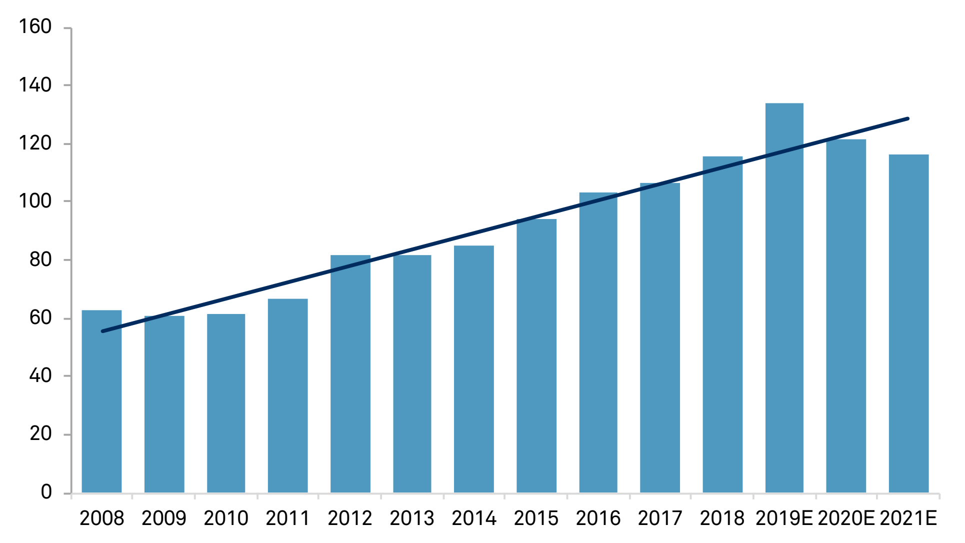
That figure is more than double 2008 capital spending for the group of $63 billion.

These expenditures are largely dedicated to projects such as grid modernization, deployment of advanced technologies, physical safety, reliability, environmental remediation and cyber security.

Such programs are aimed at improving service to existing customers, rather than expanding business into unserved territories or increasing per customer usage.

Up until this point, utilities have been able to achieve rate recognition of the increased investment, despite relatively flat load growth, without much complaint from regulators, because low interest rates and low gas and power market prices kept customer bills from rising precipitously.

Energy utility actual and estimated capital expenditures ($B)

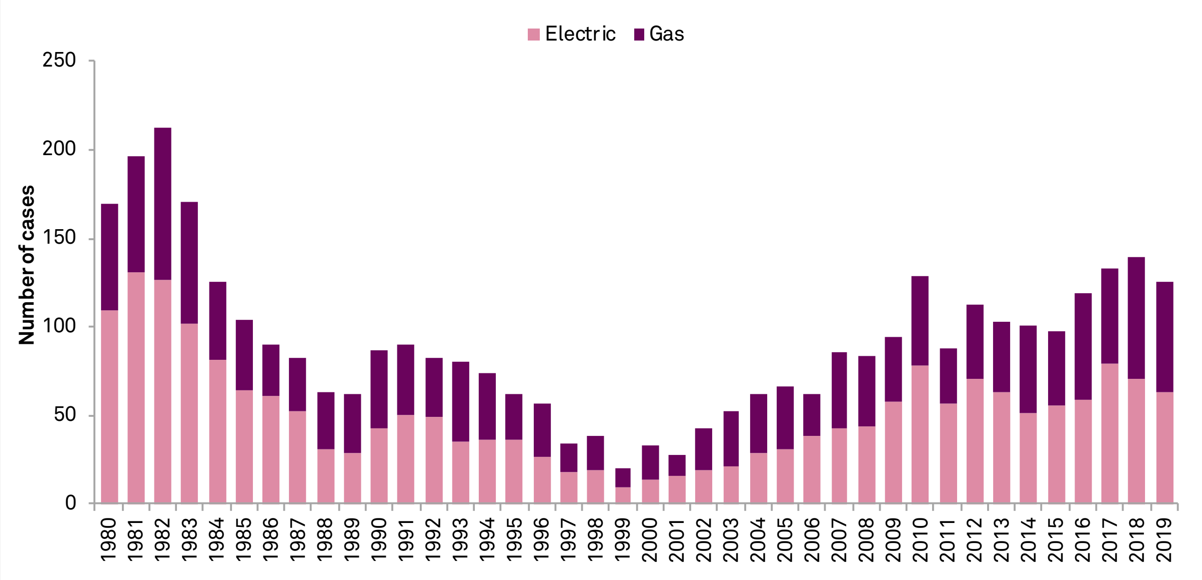


Data compiled Oct. 16, 2019.
E=Estimated
Source: S&P Global Market Intelligence

But that headroom has been eroding, there has already begun to be some pushback from regulators and stakeholders. The costs associated with maintaining service during the pandemic and the burgeoning recession will further erode that headroom. These added pressures may well result in changes to capital spending plans, at least in the near term.

Be that as it may, these increases in capital spending have been a major driver of the heightened level of rate case activity RRA has observed since 2010, as well as a driver of the increasing proliferation in alternative ratemaking frameworks.

Major rate case decisions, 1980-2019



Data gathered as of Jan. 2, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Ingelligence

There were almost 400 state-level electric and gas rate cases followed by RRA that were completed during the three years 2017 through 2019 — the busiest stretch since the generation construction boom of the 1980s.

Refer to RRA's report Major Rate Case Decisions — January - December 2019 for a discussion of rate case trends.

As of March 31, 2020, there were 31 electric and gas rate cases that had been decided nationwide and another 80 cases were pending. Thus, prior to the pandemic becoming so widespread, RRA had expected that 2020 could be another year where more than 100 rate cases were adjudicated.

In response to the financial strain on customers posed by the pandemic, schedules for several pending proceedings are already being delayed, others may be withdrawn and expected filings may be postponed for the time being, pushing the rate case cycle out to next year or perhaps longer.

Alternative ratemaking frameworks a closer look

As noted earlier, alternative ratemaking plans can be either broad-based or narrowly focused. In years passed these plans may have been referred to as incentive regulation because many were designed to accord the utility the ability to achieve incremental earnings relative to its authorized ROE for doing something regulators wanted them to do.

The term performance-based ratemaking was also used interchangeably with incentive regulation. The concept of mitigating regulatory lag is a newer phenomenon. As time has gone on, states have used a patchwork of these mechanisms. The discussion below is designed to provide a broad overview of what the plans currently in place entail, with some key examples for illustrative purposes. For detail concerning the specifics of the plans in place in a given jurisdiction, refer to the Alternative regulation section of the Commission Profile for that jurisdiction.

Formula based ratemaking plans

Formula based ratemaking plans generally refer to frameworks where the commission established a revenue requirement, including a target ROE, capital structure and rate of return for an initial rate base as part of a traditional cost or service base rate proceeding.

Once the initial parameters are set, rates may adjust periodically to reflect changes in expenses, revenue and capital investment. These changes generally occur on an annual basis, and there may be limitations on the percentage change that can be implemented in a given year or period of years.

The plans may remain in place until changed or rescinded by the commission, or there may be a set term. In some instances there are earnings sharing provisions and/or performance metrics the companies are required to meet with penalties/rewards embedded in the periodic rate adjustment to reflect the failure to meet or the ability to exceed the benchmark.

Alabama was the first state to embrace formula-based ratemaking and is perhaps the quintessential example of this construct. All three of the major utilities in the state have a formula ratemaking plan in place and they are all slightly different.

Taking Southern Company subsidiary Alabama Power Co.'s Rate RSE as an example—the framework was first implemented in 1982 and with the exception of a review several years ago to address allegations that the ROE incorporated in the plan was excessive, has operated uninterrupted since.

Under the plan, Alabama Power is permitted to adjust rates annually using a forward-looking test year. Rate changes are capped at 5% for any single year, and the two-year rolling average increase cannot exceed 4%.

The adjustment are designed to keep Alabama Power's earnings within a pre-established weighted cost of equity range — the ROE multiplied by the equity component of the capitals structure — of 5.75% to 6.15%. The Alabama Public Service Commission order approving the framework did not specify the ROE and capital structure; so, using this metric allows the utility added degree of financial flexibility.

Just to provide some perspective on the range, the average ROE authorized for vertically electric utilities in rate cases decided during 2019 was 9.73%, as calculated by RRA. According to RRA, the average authorized equity ratio for electric utilities that year was of 49.94%, which would equate to a 4.86% weighted average cost of equity.

Refunds are required of earnings in excess of the upper end of the range, but the utilities cannot recoup under-earnings below the lower end of the band. The company may earn a seven-basis-point return adder for achieving an "A" credit rating.

In addition to the Rate RSE mechanism, adjustment mechanisms are in place for energy costs and new generation facilities that are separate from the RSE framework.

This framework is viewed as constructive from an investor viewpoint. The automatic annual adjustments take into account changes in costs and sales volumes, up or down, and can also accommodate sea changes such as the federal tax overhaul that occupied so many of the states' time and energy during 2018 and 2019.

The rate change caps provide incentive for the companies to operate efficiently and the use of a target earnings range provides some upside potential.

The use of the weighted average cost of equity, rather than a straight ROE percentage takes into account the impact of changes in capital structure on the required ROE, while discouraging the utility from bulking up the capital structure to increase earnings. Conversely, the premium for maintaining a certain credit rating discourages the company from over-levering the utility.

Another example of formula based ratemaking is Southern Company subsidiary Mississippi Power Co.'s Performance Enhancement Plan, or PEP. The PEP was implemented in 1986.

The plan was amended recently, but prior to the latest changes. The plan allowed for annual annual changes, capped at 4%, based on a forecast test year; in future a historical test year will be used, with interim changes of up to 2% allowed while an adjustment proceeding is pending.

The ROE is adjusted each year. Prior to the latest changes, a benchmark ROE was established using the Discounted Cash Flow, or DCF, Capital Asset Pricing Model and Risk Premium methods, plus flotation costs; now the DCF and regression analysis will be used. The base ROE is then adjusted based on company's performance in terms of price, reliability and customer satisfaction; this part has not changed.

No rate change is implemented if the company's actual ROE is within 50 basis points of the target. Outside of the range, there is a graduated sharing of the costs/benefits based on the company's performance on those same metrics.

There are separate mechanisms in place for fuel/purchased power and environmental compliance, with adjustments for the latter capped at 2% per year.

Similar mechanisms are in place for the other major utilities in the state.

While a bit more prescriptive than the Alabama plan the Mississippi plan is similarly viewed as constructive by investors even though the ROEs under the plan have been somewhat below prevailing industry averages when established. Like the Alabama plan, it can accommodate a variety of changes that affect the cost of service that may or may not be within the company's control. The price change cap and sliding scale ROE hold the utility accountable for operational efficiency, but provide opportunity for upside potential.

Mississippi Power PEP
Target ROE formula

Base ROE	
Discounted cash flow	33%
Capital asset pricing model	33%
Risk premium	33%
+Flotation costs	
+/- Company performance rating	
Price indicator	40%
Reliability	40%
Customer satisfaction	20%

Data gathered March 31, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Multi-year rate plans

As the name suggests, under multi-year rate plans, the commission approves a succession of rate changes that are designed to take into account anticipated changes in revenues, expenses and rate base. The PSC may approve a static authorized ROE or the plan may provide for adjustments to the ROE during the plan's term.

These plans often include true-up mechanisms to ensure that the company makes the investments it has committed to make at the inception of the plan. The plans often include earnings sharing mechanisms and may also include performance-based ratemaking provisions.

Generally, the company cannot come in for a new rate case during the term of a multi-year plan unless extraordinary circumstances occur, but there may be certain volatile costs that are addressed via adjustment clauses or deferral mechanisms.

New York has been one of the most prolific states when it comes to multi-year rate plans, as this framework has been used for virtually all of the state's major investor-owned utilities for decades.

Notably, there is no stated policy or statute that calls for the use of these types of plans. The plans have been approved following settlement negotiations among the parties to the affected company's rate case. One could make the argument that because they are the result of settlements, they represent a balance of stakeholder interests by definition.

New York uses fully forecasted test years, so the entire plan is forward looking. The rate changes, rate of return and updated rate bases for each year of the plan are identified up front, and are subject to true-up. The ROEs incorporated in the plans have generally been significantly below prevailing industry averages when established.

While the plans do vary from company to company, the most recent electric and gas rate plans, adopted for Consolidated Edison Co. subsidiary Consolidated Edison Co. of New York, or CECONY, in January 2020, provide a fair representation of how the plans generally work. The plans cover the calendar years 2020 through 2022.

CECONY is authorized an aggregate $810 million three-step electric base rate increase that includes a $113.3 million increase effective Jan. 1, 2020, a $370.3 million increase effective Jan. 1, 2021, and a $326.4 million increase effective Jan. 1, 2022.

For CECONY's gas operations, the company is authorized a $373 million aggregate three-step rate increase, consisting of an $83.9 million rate increase effective Jan. 1, 2020, a $122 million increase effective Jan. 1, 2021, and a $167.1 million increase effective Jan. 1, 2022.

Consolidated Edison ROE sharing provisions

Earned ROE	Sharing of incremental earnings
Up to 9.3%	None
Between 9.3% and 9.8%	50% ratepayers/50% shareholders
Between 9.8% and 10.3%	75% ratepayers/25% shareholders
Above 10.3%	90% to ratepayers/10% shareholders

As of Jan. 16, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

The plan incorporates an 8.8% return on equity (48% of capital) and overall returns of 6.61% in rate years one, two and three for both electric and gas operations.

The 8.8% stipulated ROE is significantly below the electric and gas industry average authorizations nationwide for rate cases decided in recent years for similar utilities. Refer to RRA's report Major Rate Case Decisions — January - December 2019 for a discussion of trend in authorized ROEs.

The plan includes earnings sharing provisions under which actual earnings above a threshold ROE are to be allocated between shareholders and customers.

CECONY is to continue to defer and reconcile through future rate proceedings the following expenses: pension and other post-employment benefits expense, variable-rate tax-exempt debt, major storms, property taxes, municipal infrastructure support costs and the impact of new laws, and environmental site investigation and remediation.

In addition, CECONY will be permitted to earn incentives for electric and gas energy efficiency. The company will be subject to penalties if certain performance targets related to reliability, safety and other matters are not met.

The joint proposal reflects a productivity adjustment ranging from 1% to 2% over the three-year rate plan as well as an imputation for "business cost optimization" savings. The PSC has a long-standing policy of imputing a productivity adjustment, which typically has been calculated as 1% of total labor expense, all employee benefits and payroll taxes.

CECONY is also subject to incentive mechanisms related to the utility's achievement of the state's clean energy targets and advancement of distributed resources, as well as reliability initiatives, including the deployment of non-wires and non-pipes alternatives to meet demand growth.

The company's existing revenue decoupling mechanisms as well as adjustment clauses for renewables expense and other items will continue to operate during the term of the multi-year plan.

In effect, the plan contains many of the constructive attributes of the formula rate plans discussed previously. The ROE sharing mechanism provides the potential to accelerate recovery of certain assets and for earnings enhancement tied to improving efficiency. Additional earnings enhancement is offered for attaining certain performance objectives. The plan recognizes planned new future new investment without the need for additional rate cases.

California has used multi-year rate plans for many years as well, although the framework is more of an established policy and so the process is more defined.

Until recently, the energy utilities filed general rate cases every three years. In the context of these cases, the PUC generally approved a rate change for the current rate year, reflecting a future test year and two subsequent test years, referred to as attrition years. In January 2020, the PUC voted to change the three-year cycle to a four-year cycle in the hopes of making rate cases more efficient and predictable. The change is intended to allow utilities more time to implement risk-mitigation and accountability structures and devote less time to litigating issues with stakeholders in Investor-owned utilities in California had pushed for the change, citing challenges that have prevented the commission from resolving general rate case proceedings in a timely fashion.

In the past, the amounts of the out-year rate changes and rate bases were specified, but in recent cases, the commission has approved overall percentage rate changes without specifying the amount or the rate base. Cost of capital is not an issue in these cases, as the cost of capital for each utility is reset annually through a separate formulaic process. This process is discussed more fully in the relevant section below.

In Connecticut, the Connecticut Public Utility Regulatory Authority has in recent years adopted earnings sharing mechanisms as part of multi-year rate plans approved for the utilities as part of settlements in rate cases.

In a plan approved in 2018 for Eversource Energy Inc. subsidiary Connecticut Light and Power Co., the company was authorized a series of three rate increases aggregating to $124.7 million during the years 2018 through 2020.

The plan reflects expected changes in rate base, senior capital cost rates and includes a static 9.25% authorized ROE. This ROE was below the averages authorized in cases decided during 2018 and 2019.

The company is subject to an earnings sharing mechanism under which any earnings above the stipulated 9.25% ROE are allocated evenly between ratepayers and shareholders.

Connecticut Light & Power Co. rate plan

Year	Rate change ($M)	ROE (%)	ROR (%)	Rate base ($B)
2018	64.3	9.25	7.15	3.701
2019	31.1	9.25	7.04	3.780
2020	29.2	9.25	7.09	3.861

As of April 18, 2018.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Any amounts due customers under the terms of the earnings sharing mechanism are first applied to reduce various regulatory assets associated with certain unamortized environmental remediation costs. Remaining amounts due customers would then be used to offset the cost of catastrophic storms.

The plan also included a capital tracking mechanism for the recovery of core capital, system resiliency and grid modernization costs.

Rate freeze/stayout

Rate freezes, otherwise known as "stayouts," may be required as part of multi-year rate plans explicitly or implicitly, since the plan sets out the revenue requirements or a methodology for calculating the revenue requirements for the years covered by the plan. However, various other riders and adjustment mechanisms may be permitted to operate even if base rates are frozen.

By that definition, utilities in California, Connecticut, Massachusetts, New Hampshire, New York, Rhode Island, South Carolina and Wisconsin that are operating under multi-year rate plans that include specified latter year rate adjustments can be said to be subject to a stayout because they cannot file for rates that differ from those specified in the plan, unless some extraordinary event occurs. For purposes of this report, those instances have been excluded from the discussion.

Rate freezes currently in place for US utilities

State/company	Ultimate parent ticker	Freeze is the result of	Ending date	State/company	Ultimate parent ticker	Freeze is the result of	Ending date
DISTRICT OF COLUMBIA				**OHIO**			
Potomac Electric Power*	EXC	Merger	May 2020	Cleve. Elec. Illum./Ohio Ed./ Toledo Ed.	FE	Electric industry restructuring transition	6/1/2024
Washington Gas Light Co.*	ALA	Merger	Jan. 2021	Dayton Power & Light Co.	AES	Electric industry restructuring transition	5/31/2023
FLORIDA				Duke Energy Ohio Inc.	DUK	Electric industry restructuring transition	5/31/2024
Florida Power & Light Co.	NEE	Rate case settlement	1/2/2021	Ohio Power	AEP	Electric industry restructuring transition	6/1/2024
Duke Energy Florida LLC	DUK	Rate case settlement	1/1/2022	**SOUTH DAKOTA**			
Peoples Gas System	EMA	Rate case settlement	1/2/2021	Black Hills Power Corp.	BKH	Approval of adjustment clause	1/1/2023
Pivotal Utility Holdings	NEE	Rate case settlement	6/22/2020	NorthWestern Corp.	XEL	Federal tax reform	1/1/2021
Tampa Electric Co.	EMA	Rate case settlement	1/1/2022	**TEXAS**			
KANSAS				Oncor Electric Delivery	SRE	Merger	Aug. 2020
Evergy Kansas Central Inc.	EVRG	Merger	Dec. 2023	Sharyland Utilities, LP	--	Merger	Dec. 2020
Evergy Kansas South Inc.	EVRG	Merger	Dec. 2023	**VIRGINIA**			
Evergy Metro Inc.	EVRG	Merger	Dec. 2023	Appalachian Power Co.*	AEP	Mandated by law	Nov. 2020
MAINE				Virginia Electric & Power Co.	D	Mandated by law	Nov. 2021
Emera Maine	EMA	Merger	10/1/2021	**WISCONSIN**			
				Northern States Power Co. -Minnesota	XEL	Rate case settlement	12/31/2021
				Wisconsin Power & Light Co.	LNT	Rate case settlement	2021

Data gathered as of March 31, 2020.
* Rate case pending.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Stayouts may also be a part of a settlement adopted in a traditional base rate case where no specific multi-year rate plan is implemented. In South Dakota, Black Hills Power, a subsidiary of Black Hills Corp., is subject to a rate freeze that runs through July 2023 that was approved as part of a 2017 settlement addressing recovery of certain transmission facility and environmental investments.

Also in South Dakota, Xcel Energy subsidiary Northern States Power Co. and Northwestern Corp. are operating under rate freezes that extend to Jan. 1, 2021; the stayouts were included in the terms of settlements adopted in 2018 that addressed the revenue requirement impacts of the 2017 federal tax reform.

Rate freezes have also commonly been part of the conditions placed on mergers. With less merger activity going on, many of the merger-related rate freezes and stayouts have expired. However, in Texas, Oncor Electric Delivery Co. LLC is subject to a stayout that expires later this year related to its 2018 acquisition by Sempra Energy Inc.

Rate freezes and stayouts are a subtle form of performance-based regulation and can be a double-edged sword. Generally, in addition to the company agreeing to refrain from filing a rate case, the intervenors will agree to refrain from filing complaints against the company's existing rates.

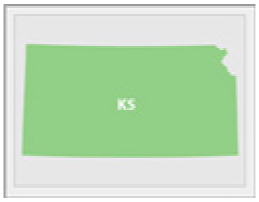
There is an incentive for the company to control its costs because to the extent costs are lower than the levels reflected in rates, the company would be able to retain the benefits. If costs are higher, then the utility would not have the ability to seek a rate increase.

In RRA's view the benefits for utilities of such programs are limited in times like these when capital spending is increasing at a steady pace, interest rates are at or near all-time lows, employee-related costs are on the rise and demand growth is limited at best.

Earnings sharing mechanisms

As the name implies, earnings sharing mechanism provide for the allocation between ratepayers and shareholders of earnings that differ from a target or target range established by the commission. As noted in the preceding sections, these mechanisms can be approved as part of formula based ratemaking plans.

They can also be implemented as part of multi-year rate plans, in conjunction with a rate freeze, as part of a merger-related filing, or on a stand-alone basis as part of a rate case.



For example, in Kansas, in 2018, the Kansas Corporation Commission, or KCC, approved a settlement related to the merger of Great Plains Energy Inc. and Westar Energy Inc.; the combined entity is now known as Evergy Inc.

The settlement incorporates a rate plan under which, following the conclusion of a then-pending rate case for Kansas City Power and Light, now Evergy Metro Inc., the utility's rates and those of then-Westar, subsidiary Kansas Gas and Electric, now Evergy Kansas Central Inc. are to be subject to a five-year base rate moratorium. However, the companies are permitted to seek rate changes under existing rate riders and to reflect the impact of new KCC rules or policies.

The companies are also subject to an earnings review and sharing plan. The companies were each awarded a 9.3% ROE in subsequently completed rate cases. For each of the years 2019 through 2022, the utilities are to file a report with the KCC. If in any year, the difference between the authorized 9.3% ROE and Evergy Metro's earned Kansas jurisdictional ROE, subject to certain adjustments, multiplied by the equity portion of rate base and grossed up for taxes, exceeds a $2.8 million rate credit, the company's ratepayers would receive one half of the difference. For Evergy Kansas Central, a similar calculation would apply, relative to an $8.6 million bill credit for the company.

In a 2019, rate case decision for Sierra Pacific Power Co., or SPP, the Public Utilities Commission of Nevada approved a settlement authorizing the company a 9.5% ROE and instituting an earnings sharing mechanism under which the company may retain earnings up to a 9.7% ROE, 20 basis points above the authorized return. Incremental earnings in excess of a 9.7% ROE are to be allocated evenly between ratepayers and shareholders.

Similarly in a 2017 decision for SPP affiliate Nevada Power Company, or NVP, the commission approved an earnings sharing mechanism as part of a rate case decision. The agreement and order specified a 9.51% ROE that included certain incentives for reliability performance. NVP may retain 100% of earnings up to a 9.7% ROE. Any earnings that exceed a 9.7% ROE would be shared evenly by ratepayers and shareholders.

These plans are to remain in place until the companies' next base rate proceeding is completed, at which time the commission may decide to terminate the plan, modify it, or replace it with some other mechanism.

SPP and NVP are subsidiaries of NV Energy Inc., which is a subsidiary of Berkshire Hathaway Energy and do business in Nevada as NV Energy. Berkshire Hathaway Energy is owned by a consortium of investors, including Berkshire Hathaway Inc.

While earnings sharing mechanisms are generally considered to be constructive from an investor viewpoint, there are some factors to consider. One consideration is how the benchmark ROE compares to the industry average. In the Kansas and Nevada plans discussed in this section and the Connecticut and New York plans discussed in the multi-year rate plan section, the benchmark ROEs were somewhat below the industry average when established.

Another consideration is whether there are provisions to allow the companies to recoup a portion of earnings below the authorized ROE. In the plans described so far, no such provisions exist, and for that reason RRA refers to these mechanisms as asymmetrical. So, they would be considered less constructive than the earnings sharing provisions in place as part of the formula rate plans for the Alabama and Mississippi utilities that contain symmetrical sharing mechanisms that allow the companies to adjust rates upward if earnings are below the benchmark.

Formulaic ROEs

Typically, the authorized ROE is one of the most, if not the most, highly contested issue in a rate case. While the commissions rely on generally accepted formulas, such as the discounted cash flow, risk premium and capital asset pricing models, the parties can vary widely as to the proxy group to which the analyses should apply, the weighting to granted each methodology employed and the inputs that go into many of the models.

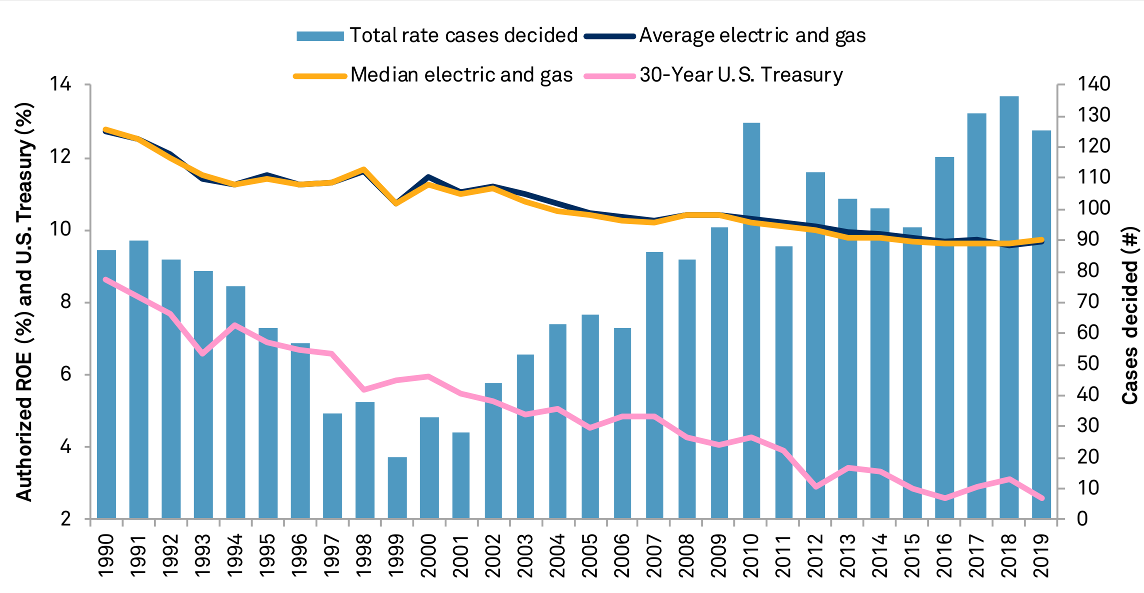
As a result, the recommendations from the different parties can differ by as much as 100 basis points versus the ROE sought by the company. This disparity increases the uncertainty when a utility does its internal analysis to decide whether it is worthwhile for the company to file a rate case at a particular time.

In order to reduce this uncertainty and lessen the amount of time it takes to complete rate cases, some states are taking a formulaic approach to selecting an authorized ROE. The idea being that establishing certain guidelines that must be adhered to will reduce or eliminate the variations among the parties and lessen the resource devoted to litigating these issues.

RRA generally views these mechanisms to be constructive for ratepayers; however, these formulaic plans may produce ROEs that are lower than prevailing industry averages at the time established.

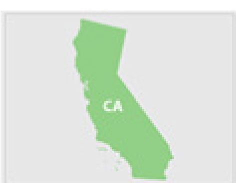
As noted in the formula base ratemaking proceeding section, the Mississippi Power PEP plan employs a formulaic ROE in the sense that the plan specifies how much weight each of the calculation methodologies, but this only addresses a portion of the issues cited above.

Composite electric and gas authorized ROEs and number of rate cases, 1990-2019



Data compiled Jan.29, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Plans in place in Alabama, Illinois, California and Virginia take a more proscriptive approach. In Alabama, the formula rate plans in place of Spire Inc. subsidiaries Spire Alabama Inc. and Spire Gulf Inc. include a static ROE range, but the company may request a review of the authorized ROE should the interest rate for 30-year U.S. Treasury Bonds increase by more than 300 basis points. Conversely, the PSC may reexamine the authorized ROE should the interest rate for 30-year Treasury Bonds decrease by more than 200 basis points.



In California, automatic cost of capital, or COC, adjustment mechanisms are in place for Pacific Gas and Electric Co., or PG&E, Southern California Edison Co., or SCE, San Diego Gas & Electric Co., or SDG&E, and Southern California Gas Co., or SCG.

Under the mechanism, authorized ROEs are reviewed annually and reset if changes in the 12-month average of a Moody's long-term utility bond index yield, relative to a benchmark based on the same Moody's index yield, are greater than plus or minus 100 basis points.

If the ROE reset provision is triggered, the equity return would be adjusted, effective the following Jan. 1, by one-half of the difference in the 12-month average bond yield and the benchmark yield; in addition, long-term debt and preferred stock costs would be updated, but the authorized capital structure would not be adjusted. In any year in which the ROE is reset, the new 12-month average bond index yield would become the new benchmark.

A similar mechanism is in place for Southwest Gas Corp., or SWG, under which the authorized ROE is adjusted annually if utility bond yields change by more than 100 basis points.

SWG is a subsidiary of Southwest Gas Holdings Inc., PG&E is a subsidiary of PG&E Corp., SCE is a subsidiary of Edison International and SDG&E and SCG are subsidiaries of Sempra Energy.

In Illinois, the formula-based ratemaking plans in place for Exelon Corp. subsidiary Commonwealth Edison Co. and the electric operations of Ameren Corp. subsidiary Ameren Illinois incorporate ROEs that are updated annually and are equal to the 12-month average 30-year Treasury Bond yield for the prior calendar year, plus 580 basis points.

Hence, there is no controversy surrounding the ROE to be used for any give rate adjustment; however, the ROEs approved have been below industry averages when established. In the most recent adjustment, which was approved in December 2019, the formula produced an 8.91% ROE. The average ROE approved in electric delivery rate cases nationwide that were decided during 2019 was 9.37%.

In Virginia, in setting the base ROE for APCO's and VEPCO's rider mechanisms and for purposes of period earnings reviews for these companies, the SCC may "use any methodology to determine such return it finds consistent with the public interest." However, the ROE "shall not be set lower than the average of the returns on common equity reported to the Securities and Exchange Commission for the three most recent annual periods for which such data are available by not less than a majority, selected by the Commission ... of other investor-owned electric utilities in the peer group of the utility subject to such ... review." The selected ROE cannot be more than 300 basis points higher than the aforementioned average.

Incentive ROEs

Several states have approved "adders" to a company's overall ROE for achieving certain performance targets. As noted in the section on formula-based rate plans, the frameworks in place for the Mississippi utilities take certain performance metrics into account when setting the ROE benchmark for a given year. In Iowa, a utility may be awarded an ROE premium for achieving certain management efficiency goals.

In Indiana and Kansas the ROE may be adjusted to the extend the company meets certain renewable energy targets.

In Kansas and Wisconsin, ROE incentives may be awarded based on performance of some or all of company's generation units.

In Ohio one of the utilities has the opportunity to earn an enhanced ROE to the extent it meets certain grid modernization targets and in Washington, ROE premiums are available for meeting or exceeding certain distributed generation deployment targets.

In other instances, the utilities are permitted to earn an enhanced ROE on specific assets or asset classes.

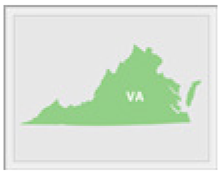
For example, in Iowa, state law requires that the Iowa Utilities Board, or IUB, specify ratemaking principles — in advance of utility construction — to be applied to new baseload generation facilities of 300 MW or more for combined-cycle plants, alternative energy production facilities and certain investments to significantly alter an existing generation facility.

The IUB is not limited to traditional ratemaking with conventional cost recovery mechanisms and may authorize a rate of return on a new facility that is different than the return the utility is permitted to earn on existing generation assets. The enhanced ROEs remain in place for the life of the projects

Most recently, in 2016, the IUB approved an 11% ROE for Interstate Power & Light's, or IP&L's, New Wind Project, which will consist of up to a total of 500 MW. In 2013, for IP&L's 600-MW gas-fired Marshalltown plant, which went into commercial operation in April 2017, the IUB approved an 11% ROE. In 2008, the IUB adopted an 11.7% ROE for IP&L's 200-MW Whispering Willow-East Wind Farm, which was ultimately completed in 2009. IP&L is a subsidiary of Alliant Energy Corp.

Between 2002 and 2016, the IUB approved enhanced ROEs for a series of wind facilities constructed by MidAmerican Energy Co., or MEC, and these facilities were accorded ROEs ranging from 11.35% to 12.2%. MEC's 540-MW combined-cycle gas plant, the Greater Des Moines Energy Center, which was ultimately completed in 2004, was awarded a 12.23% ROE. MidAmerican's investment in a coal-fired generation facility, Council Bluffs Energy Center Unit 4, which was placed into service in 2007, was authorized a 12.29% ROE. MEC's ultimate parent is Berkshire Hathaway Energy.

The incentive ROEs are reflected in rates as part of base rate cases, where the IUB approves a blended ROE that represents the weighted average of the ROEs applied to the various categories of rate base.



In Virginia, state law allows the Virginia State Corporation Commission to authorize Appalachian Power Co. or APCO and Virginia Electric and Power Co., or VEPCO to recover certain types of investment through limited-issue rider mechanisms.

The riders include incentives for certain types of new generation, including a cash return on construction work in progress and an ROE premium that applies during construction and through up to the first 20 years of the plant's life.

The statute initially allowed premiums of up to: 200 basis-points on new nuclear generation facilities through the first 12 to 25 years of the plant's operation; 200 basis points on new carbon-capture compatible, clean-coal-powered facilities through the first 10 to 20 years of commercial operation; 200 basis points on new renewable resources through the first five to 15 years of commercial operation; and 100 basis points on new conventional coal or combined-cycle combustion turbine plants through the first 10 to 20 years of commercial operation.

The SCC approved ROE incentives for several VEPCO facilities prior to 2013, when legislation was enacted limiting the prospective availability of incentive ROE premiums to new nuclear and offshore wind facilities.

Such facilities could be eligible for premiums of 100 basis points that would apply during construction and continue through the first 12 to 25 years of a nuclear facility's useful life or the first five to 15 years of an offshore wind facility's useful life.

The SCC has yet to address any requests for ROE incentives for new nuclear or offshore wind. VEPCO has several other riders in place for generation and other types of investment that do not include ROE incentives.

Virginia Electric & Power Co. power plants with incentives

Plant Name(s)	Fuel source	ROE premium (basis points)	First year of operation	Duration of premium (years)
Altavista	Biomass	200	2013	5
Bear Garden	Gas	100	2011	10
Brunswick County Power Station	Gas	100	2016	10
Hopewell	Biomass	200	2013	5
Southampton Power Station	Biomass	200	2013	5
Virginia City Hybrid Energy Center	Coal/gas	100	2012	12
Warren County Power Station	Gas	100	2014	10

As of March 31, 2020
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

A limited issue rider is in place for APCO related to its investment in the natural gas-fired Dresden Energy Facility, but no ROE incentive is included.

VEPCO does business as Dominion Energy Virginia and is a subsidiary of Dominion Energy Inc., while APCO is a subsidiary of American Electric Power.

It goes without saying that ROE premiums in and of themselves are viewed as constructive from an investor standpoint, but the Virginia program that allows for expedited recovery through a limited issue rider, and recognition of construction work in progress goes a step even beyond the premium itself.

Cost savings sharing/performance based ratemaking

Many of the broader-based, holistic alternative regulation plans discussed so far contain performance-based components for achieving cost savings, management efficiency, meeting or exceeding public policy goals and the like. However, in many instances these type of mechanisms are separate from those plans, or where those plans do not exist, were adopted on a stand-alone basis.

RRA generally views these mechanisms as constructive from an investor viewpoint.

While the attached data tables provide a listing of what type of incentives are in place for each utility in each state, they are too numerous to go into detail here; the sections that follow are designed to provide some color about these mechanisms. Further details about the specific provisions in place in a given state can be found in the Commission Profiles.

Fuel/Purchased Power/Gas costs — Mechanisms that segregated commodity costs, i.e., fuel and purchased power for electric utilities and the gas commodity for gas utilities, are employed for all the utilities covered by RRA in each of the 53 state-level regulatory jurisdictions.

These mechanisms, which are separate from base rates, were implemented in the 1970s to address dramatic increases in commodity costs that were outside of the utility's control. The mechanisms were designed to allow the company's to adjust rates outside of a base rate case, hence on an accelerated basis, to reflect these rising costs that would otherwise threaten the utilities' solvency.

The costs were recovered on a dollar for dollar basis. Once commodity prices became less volatile, there was little incentive for the utilities to actively seek out lower cost alternatives, because any benefit would be passed on to ratepayers. In response, many states modified the recovery mechanisms to include a performance component, whereby the company could share in the benefit associated with lowering its commodity costs, and in many instances would be at risk of non-recovery if the costs rose beyond a certain point.

Commodity cost recovery mechanisms that include incentives are currently in place in close to 20 jurisdictions and RRA generally views these mechanisms as constructive, provided that there is a symmetrical sharing of risk i.e., the opportunity to achieve benefits is equal to the potential for non-recovery.

Capacity release/off-system sales sharing — These types of mechanisms arose largely due to the difficulty in timing capacity additions — be it gas pipeline or electric generation — with demand growth and also the need retain at least some reserve capacity on the system.

While there was a great deal of controversy in the 1990s surrounding major new generation additions that were seen as excess capacity when they were initially brought on line, the facilities were eventually recognized in base rates. Once they are there, customers within the utility service territories continue to pay the portion of fixed costs included in rates regardless of whether where demand goes from there on.

Under traditional ratemaking, were an electric utility to sell power to another utility that was in a load crunch or if a gas utility were to lease pipeline capacity on its system to another utility, the related revenues would be used to offset the cost to provide service to native load customers, thus flowing 100% of the benefit to customers.

Hence, there would be no incentive for the utility to actively pursue this type of activity. By allowing the utility to retain a portion of the benefit, regulators reasoned that the companies would increase their level of such activity to the benefit of both customers and shareholders.

Demand-side management program costs — The rationale here is similar to that for off-system sales. All else being equal utilities would not be amenable to instituting programs to encourage customers to use less power or gas. In the short-term revenues are lower. Presumably the lower volume would be reflected in the revenue requirement in a rate case and costs per unit sold would rise to make sure fixed costs were recovered, but there would be a lag. In addition, in the longer term there would be no need to add incremental facilities to the system and grow rate base, thus eroding future earnings potential.

Fixed vs. variable costs

Fixed	Variable
Depreciation	Gas commodity
Delivery O&M	Electric commodity
Property taxes	Generation O&M
Return on investment	
Customer service	

As of March 31, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence.

In order to encourage utilities to pursue these types of programs, many commissions implemented mechanisms that allow the utility to recover the direct program costs and recoup the lost revenues on an expedited basis. These mechanisms remove the disincentive to pursue such programs, and are discussed further in later sections of this report. However, they do not provide an affirmative incentive to pursue these initiatives.

In RRA's view, an incentive would entail the ability to earn a higher ROE for achieving certain demand reduction goals, the ability to earn a return on program costs, which are usually considered expenses rather than "rate base," and/or the ability to retain a portion of the avoided marginal costs. About 20 jurisdictions currently have these types of mechanisms in place for at least one utility in the jurisdiction.

Reliability/customer satisfaction — The regulatory compact that forms the basis for utility regulation in the U.S. requires the utility to provide safe, reliable service at just and reasonable rates. In exchange the utility is provided the sole right to operate within its franchised service territory and regulators are to provide the company the opportunity to earn a just and reasonable return commensurate with the level of risk for shareholders.

This begs the question of why the company would need an incentive to provide reliable service, and many consumer advocates have asked this same question. The answers are both simple and complex.

When faced with a choice between upgrading an existing asset that will provide better service to existing customers but will not, at least until the next rate case, generate any new revenue and investing in projects that will increase penetration into unserved areas or accommodate new customers in existing areas thus generating new revenue sources and ultimately growing rate base in the next rate case, utilities will choose the latter every time.

Also, in the context of a base rate proceeding it is easier for the utility to provide objective proof of why an investment is/was needed to serve new customers which can be documented than it is to show that an investment is needed to forestall some catastrophe that may or may not occur in the future.

However, as weather volatility has increased with severe storms and wildfires becoming both more frequent and more widespread, failures of aging infrastructure leading to well publicized catastrophes and advanced technologies of the digital age requiring higher quality more consistent power flows, reliability has become a front burner issue.

As will be discussed in the next section of this report, these realities have given rise to the spread of expedited cost recovery mechanisms that remove some of the disincentives to investments in these non-growth related projects.

Some jurisdictions are going a bit further and providing companies incentives for meeting exceeding deployment targets, or for hitting certain benchmarks for service interruptions and customer satisfaction. There are four states with explicit incentives in place for at least one utility associated with reliability and two with customer satisfaction.

RRA finds these mechanisms to be constructive from an investor viewpoint, provided that there is as much of an opportunity for the utility to achieve benefit a benefit for shareholders as there is to incur a penalty.

Productivity — Productivity is a broad term that can include: achieving overall operations maintenance cost or a specific expense, such a pension costs; lowering commodity costs; demonstrating superior generation plant operational performance; meeting or exceeding energy conservation program participation or demand reduction targets; attaining or exceeding goals with respect to clean energy or advanced technology deployment; or, beating benchmarks associated with reliability and customer service.

Incentives are generally in the form or ROE enhancement, sharing of incremental revenues or retention of cost savings. Several examples were included in the preceding discussions of the other types of alternative forms of regulation that are in place.

Adjustment clauses — Alternative ratemaking by another name?

While the above-discussed mechanisms are generally what comes to mind when the phrase "alternative ratemaking" is used, adjustment clauses, also known as limited issue riders, are another approach to reducing regulatory lag, and using a broad definition could be considered "alternative ratemaking."

Adjustment clauses were first introduced in the 1970s to mitigate volatile fuel costs that were threatening company earnings and cash flows. In the ensuing years, the use of these mechanisms expanded to include other expenses that were outside of a company's control or were mandated by government regulation.

More recently, they have become increasingly prevalent to address capital investment, be it gas main replacement, electric grid modernization or in some cases new generation — particularly when a state wanted to foster construction of a particular type of generation or the deployment of new technologies. It is because of this "incentive" aspect and the use of these mechanisms to address regulatory lag that they are included in this discussion.

Select adjustment clauses in the US[1]

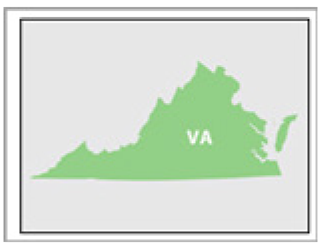
Generation		Infrastructure			
		Electric		Gas	
Traditional	Renewable				
Alabama	Colorado	Colorado	New Hampshire	Colorado	Mississippi
Coloradao	Florida	Connecticut	New Jersey	Connecticut	Missouri
Florida	Louisiana—PSC	Delaware	New Mexico	Delaware	Montana
Georgia	Massachusetts	Dist. of Columbia	New York	Dist. of Columbia	Nebraska
Hawaii	Minnsesota	Hawaii	North Dakota	Florida	Nevada
Indiana	North Carolina	Illinois	Ohio	Georgia	New Jersey
Kansas	North Dakota	Indiana	Oklahoma	Illinois	North Carolina
Kentucky	Oregon	Kentucky	Pennsylvania	Indiana	Ohio
Louisiana—NOCC	Virginia	Louisiana—PSC	Rhode Island	Iowas	Pennsylvania
Louisiana—PSC		Maryland	South Dakota	Kansas	Rhode Island
Minnsesota		Massachusetts	Texas—PUC	Kentucky	Tennessee
Mississippi		Minnsesota	Virgnia	Louisiana—PSC	Texas—RRC
North Dakota		Missouri	West Virginia	Maine	Utah
Oregon				Maryland	Virginia
South Dakota				Massachusetts	Washington
Virginia				Michigan	West Virginia
West Virginia				Minnsesota	Wyoming

As of March 31, 2020.
NOCC=New Orleans City Council; PSC=Public Service Commission; RRC=Railroad Commission.
[1]Mechanism in place for at least on utility in the state, unless otherwise noted.
Source: Regulatory Research Associates, a group withinn S&P Global Market Intelligence

Like the broader-based alternative regulation plans discussed earlier, these mechanisms tend to reduce regulatory lag, but only as it pertains to the assets, asset classes, or expenses that are permitted to be recovered through these mechanisms. It is also noteworthy that the presence of a broad based alternative ratemaking does not preclude the use of stand-alone adjustment mechanisms for certain items.

However, in some instances, where these mechanisms are used heavily, RRA has observed some degree of pushback from customers, consumer advocates and commissions.

Virginia, Texas and Pennsylvania are states that rely heavily on limited issue with or without "alternative ratemaking" per se.



Virginia's electric utilities have remained vertically integrated. Retail choice is only available for large volume industrial customers and commercial customers that can aggregate load to reach a 5MW threshold.

For the two largest electric utilities, "base rates" have largely been frozen for several years pursuant to a statutory periodic earnings review process. In this instance, "base rates" refers to legacy generation and distribution assets.

The periodic earnings review process incorporates an ROE-based earnings-sharing mechanism. The ROEs are set based on a formula laid out in state law.

Back in 2007 when other mid-Atlantic states were grappling with congestion issues, Virginia embarked on a course to incent "inside the fence" generation in order to avoid incurring PJM Interconnection congestion charges, and specifically targeted gas-fired baseload generation.

State policy allowed these investments to be recovered through plant-specific generation riders that included a cash return on construction work in progress while the facilities were being constructed and an incentive ROE premium of as much as 200 basis points on the investment for a fixed term.

Adjustments under the riders are based on forward-looking "rate years," that are the first year the new rates are in effect. As noted above certain types of plants are eligible for and have received ROE premiums within the riders.

This paradigm was ultimately expanded to include other types of capital investment including utility-owned renewables, certain types of electric infrastructure and environmental compliance costs.

Riders are also permitted for demand-side management program costs, and the utilities are awarded a return on these expenses as an incentive to pursue the programs.

At the same time, Virginia allows certain expenses to be passed through to ratepayers using an adjustment clause – examples include fuel, renewable energy credit costs and FERC transmission charges.

For the most part these riders are updated annually and the capital investment related riders are essentially mini rate cases that take eight to nine months to adjudicate. Each adjustment includes a true-up for prior period over- and under-recoveries.

Over the last couple of years, there has been some backlash with regard to this approach, including legislative changes to the framework, some successful, others not. There has also been a push by large commercial customers to aggregate load in order to qualify to obtain their supply competitively. See the [Virginia Commission Profile] for additional detail.

In Texas, electric utilities and gas utilities are regulated by different agencies and the policies are very different. On the electric side, part of the state is restructured and part is not.

There are adjustment clauses to pass-through costs such as fuel and purchased power, wholesale transmission costs assigned to the utility by regional transmission organizations, demand-side management and storm costs.

Annual and semi-annual adjustments are permitted for distribution investment and transmission investment for both vertically integrated and delivery only companies.

State law allows for adjustment mechanisms for incremental generation facilities in the areas of the state that have not implemented retail competition.

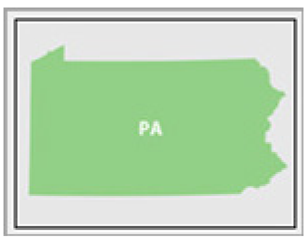
The adjustments rely on the ROE approved in the company's most recent rate case and a historical test year, consistent with the policy for base rate cases in the state. A prudence determination does not occur until the next base rate case, when related investments and revenue requirement roll into base rates and the adjustment clause is reset to zero.

Notably, there have been instances where the Public Utility Commission of Texas has in the context of a base rate case, disallowed recovery of assets that were reflected in the adjustment mechanism.

In addition, state law requires the PUC to maintain a schedule so that there is no more than four years between utility base rate cases. Also, the PUC staff conducts an earnings analysis for each utility at the end of each calendar year and then makes recommendations to the PUC regarding whether a full earnings investigation is warranted.

For additional information, see the Texas PUC Commission Profile.

Pennsylvania is one of the states that allows retail competition for all generation service customers. In 2012, Pennsylvania transitioned from using a historical test period to a fully forecasted test period. At the same time, the state adopted the distribution system improvement charge, or DSIC, framework for incremental infrastructure spending between rate cases.



Adjustments under the mechanism occur quarterly and are forward looking. The ROEs used are either those established in the companies' most recent base rate case, or if the last fully litigated ROE is more than three years old, a "generic" ROE set by the PUC for each industry based on a quarterly review the utilities' earnings is used.

A utility may only adjust rates under the DSIC if it is earning below the established ROE, a provision that offers some assurances for stakeholders that the utilities are not "gaming the system."

The costs reflected in each adjustment are subject to prudence review in the company's next base rate case. So, despite the frequency of the adjustments, it does not appear that the framework places an undue burden on the participants.

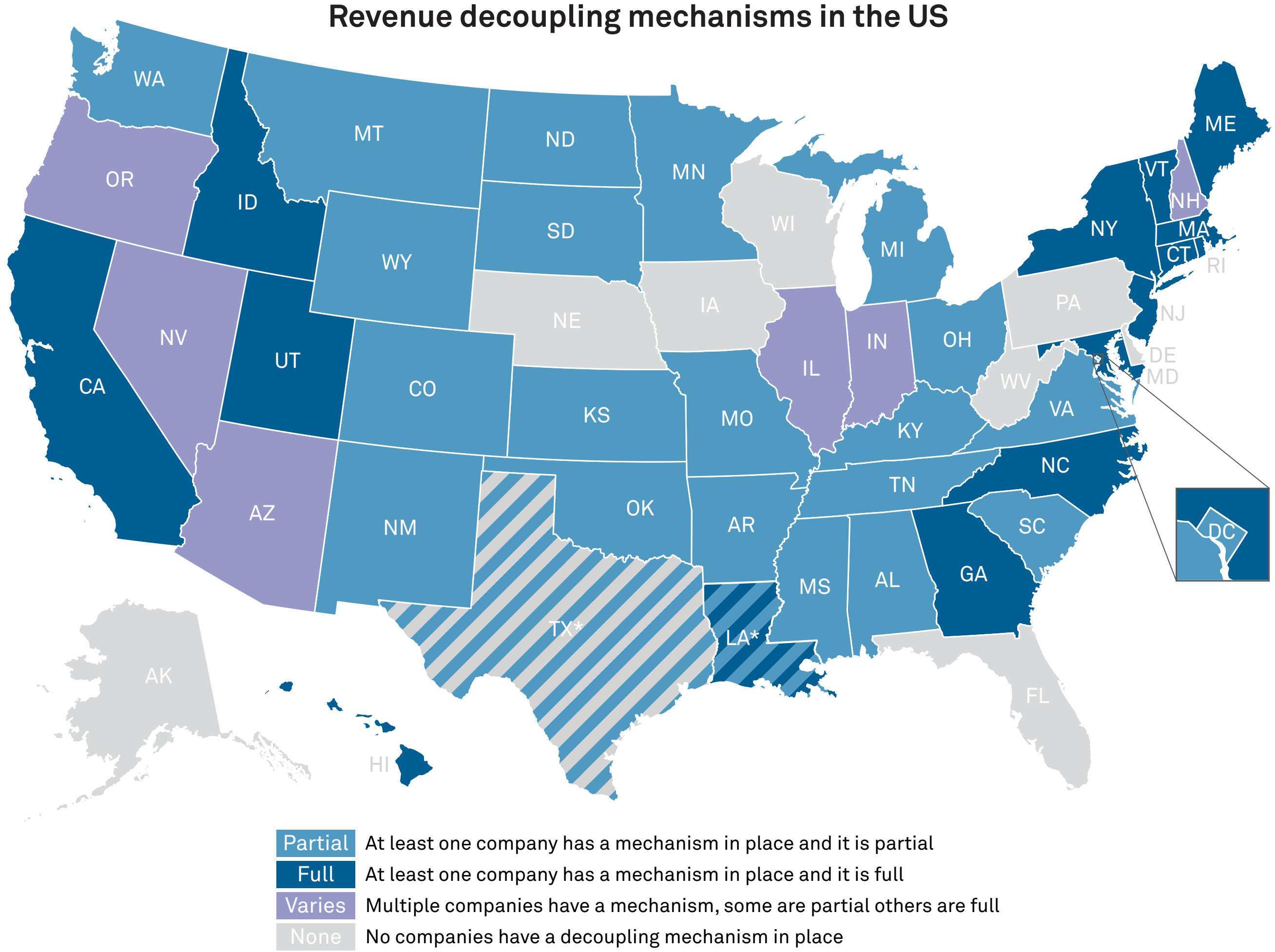
Until recently, Pennsylvania had eschewed "alternative ratemaking." However, legislation permitting various forms of alternative regulation was enacted recently and the commission has adopted rules for implementing these mechanisms on a company-specific basis. No alternative ratemaking plans have been requested or approved to date.

Revenue decoupling mechanisms

Decoupling mechanisms allow utilities to adjust rates between rate cases to reflect fluctuations in revenues versus the level approved in the most recent base rate case that are caused by a variety of factors.

Some of these factors, such as weather are beyond a utility's control and the mechanism can work both ways — in other words it can allow the company to raise rates to recoup revenue losses associated with weather trends that reduce customer usage and can also require the company to reduce rates when weather trends cause usage to be higher than normal.

Revenue decoupling mechanisms in the US



As of March 31, 2020.
* In Louisiana and Texas, there are two different regulatory commissions, with differing policies.
Map credit: Jose Miguel Fidel C. Javier
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

S&P Global
Market Intelligence

As clean energy policies have gained momentum, driving ever-expanding energy efficiency initiatives, decoupling mechanisms have been implemented to reduce the disincentive for utilities in pursuing energy conservation programs by making the utilities whole for reductions in sales volumes and revenues associated with customer participation in these programs.

Some of these mechanisms also allow the utility to adjust rates to reflect fluctuations in customer usage that are brought about by broader economic issues, such as demographic shifts, the migration of large commercial/industrial customers to other service areas, the shutdown of such businesses due to changes in their respective industries, recessions and theoretically, crises such as the current COVID-19 pandemic.

RRA considers a decoupling mechanism that adjusts for all three of these factors to be a "full" decoupling mechanism and designates those that address only one or two of these factors as "partial" decoupling mechanisms.

Some the mechanisms include a cap on the percentage rates can change under the mechanism. Others only permit adjustments if the utility is earning below the authorized ROE or include performance criteria, such as achieving a targeted demand reduction level. RRA also classifies these type of plans as partial decoupling even if they do address all of the three factors.

Similar to the investment-related adjustment clauses noted above, decoupling mechanisms are included in this discussion of alternative regulation because they streamline the regulatory process and allow the company to reflect changes in usage/revenues in rates without the need for a rate case.

Also, in many instances the mechanisms were intended to encourage the utilities to pursue energy efficiency/demand side management programs rather building new generation, even if there were no specific demand reduction goals in the state, or in cases where there were goals to exceed those goals.

In addition, keeping revenue stable despite changes in these exogenous factors provides something of an "incentive" for management efficiency, as achieved cost savings can be retained until the next rate case, unless there is return cap built into the mechanism.

As of this writing, 21 jurisdictions had full decoupling mechanisms in place for at least one company, including six states that have different types of mechanisms for different companies. Partial revenue decoupling mechanisms were in place for companies in 28 jurisdictions, including six states that have different types of mechanisms for different companies and there are no decoupling mechanisms in place in 10 jurisdictions.

A more comprehensive discussion of adjustment clauses and rider mechanisms is provided in RRA' November 2019 report Adjustment Clauses — A State by State Overview and related data tables.

This information is also available in the Adjustment clauses sections of the state Commission Profiles.

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*Report was updated on April 28, 2020, to reflect revisions to the Mississippi formulat rate plan that were adopted as the report was being produced.