ML 226375

ORDER NO. 89226

EXPLORING THE USE OF ALTERNATIVE RATE PLANS OR METHODOLIGIES TO ESTABLISH NEW BASE RATES FOR AN ELECTRIC COMPANY OR GAS COMPANY	* * * * * * *	BEFORE THE PUBLIC SERVICE COMMISSION OF MARYLAND PC51
IN THE MATTER OF ALTERNATIVE RATE PLANS OR METHODOLOGIES TO ESTABLISH NEW BASE RATES FOR AN ELECTRIC COMPANY OR A GAS COMPANY	* * * * * *	CASE NO. 9618

ORDER ON ALTERNATIVE FORMS OF RATE REGULATION AND ESTABLISHING WORKING GROUP PROCESSES

Before: Jason M. Stanek, Chairman
Michael T. Richard, Commissioner
Anthony J. O'Donnell, Commissioner
Odogwu Obi Linton, Commissioner
Mindy L. Herman, Commissioner

Issued: August 9, 2019

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I. INTRODUCTION

On February 14, 2019, the Maryland Public Service Commission issued a Notice of Technical Conference on Alternative Forms of Rate Regulation ("Notice"), initiating Public Conference 51 ("PC51") to allow stakeholders and interested persons to submit information and comments on the various alternative rate plans (i.e., "Alternative Forms of Regulation" or "AFORs").[1] The Notice requested comment on (1) the manner in which other state regulatory commissions determined which alternative rate plans were acceptable; (2) the implementation period to transition from one form of regulatory ratemaking principles to the alternative rate plan; (3) any restrictions placed by other state regulatory commissions on the use of alternative rate plans including whether a utility can switch between alternative rate plans in subsequent rate cases; (4) the frequency with which the utility may file for rate increases under an alternative rate plan; (5) how reconciliations and refunds may be made when the utility is using a forecasted test year or other forecasted methodology; and (6) the impacts on the ratepayers resulting from the use of the alternative rate plans.[2] The Commission also indicated its interest in learning whether other states, in implementing alternative rate plans, required additional staff resources or staff with different skills than previously utilized prior to implementing.[3]

The Commission noted that "[h]istorically, during a base rate case proceeding to determine whether the rates are just and reasonable, the Commission has directed the companies to employ a historic test year method to determine the company's operating revenue

[1] ML 223975 (Feb. 14, 2019 Notice).
[2] *Id.* at 2-3.
[3] *Id.* at 3.

deficiency."[4] However, the Commission acknowledged that other states have implemented alternative rate plans to determine just and reasonable rates using a number of concepts and methodologies to adjust base rates.[5]

Filed initial comments were due by March 29, 2019, with any reply comments due by April 18, 2019.[6] The Commission held a two-day Technical Conference on Monday, April 29, and Tuesday, April 30, 2019, to hear testimony from interested stakeholders and interested parties.[7] After the Technical Conference, parties were provided an opportunity to file final comments by May 21, 2019.

II. BACKGROUND AND MARYLAND'S EXISTING RATEMAKING AUTHORITY

Rapid changes in the economy and energy industry, coupled with changing State policy goals and calls for grid modernization, have impacted utility operations. In response, some states have examined and adopted alternate forms of ratemaking aimed at accelerating utility cost recovery. This Commission has taken many proactive steps (such as allowance of expenses and capital investments for periods after the historic test year, the approval of Bill Stabilization Adjustments, and the authorization of surcharges related to the recovery of infrastructure costs associated with reliability of the distribution system) to address cost recovery issues for Maryland utilities while balancing the interest of ratepayers and the State.

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[4] *Id.* at 1.
[5] *Id.* at 2.
[6] *Id. See* Appendix A- List of Parties Providing Written Comments.
[7] *Id. See also, Notice of Additional Hearing Date for Technical Conference on Alternative Forms of Rate Regulation*, PC51, Apr. 4, 2019.

In furtherance of these prior actions, the Commission convened the above-referenced Technical Conference in PC51 to examine the various AFORs that have been implemented in other states and how they could be employed in Maryland.[8]

Pursuant to the Public Utilities Article ("PUA"), *Annotated Code of Maryland*, the Commission has the authority to regulate the activities of all public services companies operating in Maryland,[9] including the authority to establish and set the distribution rates that utility companies are permitted to charge their customers. Under PUA § 4-102, the Commission has the power to set a "just and reasonable rate of a public service company." According to PUA § 4-101, the term "just and reasonable rate" means a rate that:

> (1) does not violate any provision of this article;
>
> (2) fully considers and is consistent with the public good; and
>
> (3) except for rates of a common carrier, will result in an operating income to the public service company that yields, after reasonable deduction for depreciation and other necessary and proper expenses and reserves, a reasonable return on the fair value of the public service company's property used and useful in providing service to the public.

The statute affords the Commission discretion to determine rates in any manner that is consistent with this standard.[10] Historically, the Commission generally has chosen to

[8] During the 2019 Maryland legislative session, Senate Bill 572 and cross-filed House Bill 653 were introduced to require the Commission to allow an electric or natural gas utility company to seek recovery of its costs of service under one or more AFORs of the utility's choosing. As filed, the proposed legislation contemplated several AFORs, including a fully forecasted test year, multi-year rates, formula rates, and rate designs, but it was later amended to encompass only the fully forecasted test year and formula rates. Ultimately, the legislation was not enacted.

[9] *Md. Ann. Code*, Pub. Util. Art., §§ 2-112 to 2-113.

[10] Nothing in this Order discussing the Commission's general authority under its enabling legislation is meant to contravene the authority of the General Assembly to establish specific rate-setting mechanisms that the Commission is required to follow in certain circumstances. For example, STRIDE sets forth specific rate setting mechanisms, including a $2.00 maximum monthly surcharge on residential customers, related to the accelerated recovery of natural gas infrastructure replacement.

determine rates based on a cost of service methodology using a historic test year, with a number of opportunities for out of test year expenditures.

The Commission has express authority to adopt alternative AFORs. In 1999, the Maryland General Assembly enacted PUA § 7-505(c)(1), which expressly provides that the Commission may regulate the regulated services of an electric company through alternative forms of regulation. Specifically, PUA § 7-505(c)(2) provides that the Commission "may adopt an alternative form of regulation … if the Commission finds, after notice and hearing, that the alternative form of regulation: (i) protects consumers; ensures quality, availability, and reliability of regulated services; and is in the interest of the public, including shareholders of the electric company." The Commission has exercised its authority under PUA § 7-505(c)(1) in various ways for electric companies including price regulation, such as rate freezes, caps, or floors.[11] While the authority extended under PUA § 7-505(c)(1) does not expressly apply to Maryland's natural gas utilities, the Commission finds that PUA § 4-102 and appellate case law grant the Commission the inherent authority to determine a just and reasonable rate for natural gas utilities using any formula or approach that is in the public interest.[12]

In addition to statutory authority, the Maryland Courts have recognized and upheld the Commission's discretionary authority in setting just and reasonable rates. In *Building Owners & Managers Ass'n of Metro Balt., Inc. v. Pub. Serv. Comm'n.,* the Maryland Court of Special

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[11] *Comment of the Staff of the Public Service Commission of Maryland Regarding Alternative Forms of Ratemaking and the Implementation Thereof,* Docket No. PC51, filed March 29, 2019 ("Staff Initial Comments") at 8-9. Concomitant with the Commission's authority to accept an AFOR that is in the public interest and otherwise consistent with Maryland law and Commission regulations is the authority to deny a proposed AFOR that is not in the public interest or is not consistent with Maryland law or the Commission's regulations.
[12] *See In the Matter of the Application of Sandpiper Energy, Inc.,* 107 Md. PSC 635 (2016).

Appeals held that the only statutory imperative is to construct and approve "just and reasonable" rates, and those are rates which, among other things, fully consider and are consistent with the public good.[13] In *Md. People's Counsel v. Heintz,* the Court explained that "a great deal of discretion is left in the Commission to determine just and reasonable rates that will be consistent with the public good."[14] The General Assembly, in adopting § 4-101, did not provide a specific formula to calculate utility rates. Instead, it constructed the statute in a manner that would allow the Commission significant regulatory flexibility in analyzing both the rates charged and the manner in which those rates are imposed, provided that they are consistent with the public good.

In the landmark case of *Duquesne Light Co. v. Barasch*,[15] the United States Supreme Court addressed the broad authority of public utility commissions to regulate utility rates.[16] The Court rejected Duquesne's argument that the Fourteenth Amendment's Due Process Clause guarantees full rate recovery of all prudent investment or otherwise limits state public utility commissions to specific ratemaking methodologies. The Supreme Court held:

> We think that the adoption of any such rule would signal a retreat from 45 years of decisional law in this area which would be as unwarranted as it would be unsettling. *Hope* clearly held that "the Commission was not bound to the use of any single formula or combination of formulae in determining rates." ... The designation of a single theory of ratemaking as a constitutional requirement would

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[13] *Building Owners and Managers Ass'n of Metropolitan Baltimore, Inc. v. Public Service Comm'n*, 93 Md. App. 741, 762 (1992) ("BOMA").
[14] *Maryland People's Counsel v. Heintz*, 69 Md. App. 74, 93 (1986). *See also* 63 Op. Att'y Gen. (1978).
[15] *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 315-16 (1989). The case involved the partial construction of a nuclear plant. Although the Pennsylvania Commission found that Duquesne's decisions both to begin and to stop construction were prudent, it disallowed recovery of Duquesne's plant costs based on a statute that limited cost recovery to investment that was "used and useful." The Supreme Court upheld the decision of the Pennsylvania Commission.
[16] The Supreme Court did not address Maryland's authority under the PUA directly.

> unnecessarily foreclose alternatives which could benefit both consumers and investors. The Constitution within broad limits leaves the States free to decide what rate-setting methodology best meets their needs in balancing the interests of the utility and the public.[17]

III. MARYLAND'S CURRENT RATEMAKING APPROACH

To determine "just and reasonable rates" for electric and gas distribution, the Commission has primarily relied on a cost of service methodology using a historic test year ("HTY"). This methodology is known as traditional ratemaking. The HTY evaluates the costs incurred by the utility in a recent 12-month period and serves as a reference period for developing the utility's costs for the prospective period when rates will be effective. Under this approach, should the utility experience a revenue deficiency over the course of the HTY, the regulator calculates the revenue required to make up the deficiency.[18] Advantages of using an HTY approach include ensuring that rates are based on actual costs that have been verified and that utility investments are consistent with cost minimization principles.

In its comments, Commission Staff notes that "[w]hile the Commission has at various points in time relied on a pure HTY as the basis on which rates are determined, over the past

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[17] *Id.*, 488 U.S. at 315-16 (1989) (citations, footnotes omitted) (referring to *Hope Natural Gas v. Fed. Power Comm'n*, 320 U.S. 591 (1944)).

[18] Staff Initial Comments at 6; *see*, *e.g*. Case No. 9230, *In the Matter of the Application of BGE for Revisions in its Elec. And Gas Base Rates,* (BGE limited its electric rate case request from a purported $110 million revenue requirement deficiency to $46.9 million based upon the terms of a prior restructuring settlement that froze rates and limited subsequent requests for increase); *see also* Case No. 9410, *In the Matter of the Application of Sandpiper Energy, Inc. for a General Increase in its Natural Gas and Propane Rates,* (authorizing Sandpiper to charge rates that automatically adjust every year in response to Sandpiper's actual mix of natural gas and propane customers); 107 Md. P.S.C. 636 (2016). The Commission has also approved several surcharge mechanisms to accelerate recovery of reliability spending. *See*, *e.g.*, Case No. 9326, *In the Matter of the Application of BGE for Revisions in its Elec. And Gas Base Rates,* (Commission approved BGE's request to implement an Electric Reliability Initiative ("ERI") mechanism designed to recover additional reliability plant expenditures). For a more comprehensive list of the Commission's use of AFORs in Maryland, see Staff Reply Comments at 28-46.

several decades the Commission has relied extensively on partially forecasted test years during rate cases."[19] Staff points out that since the 1990s, the vast majority of electric and gas rate applications before the Commission have been developed based on the use of partially forecasted data and that, recently, the Commission has allowed the inclusion of at least four months of projected data provided that the forecasted data is replaced with actual data prior to the hearing of the rate case.[20] In addition, the Commission recently allowed the use of an inflation adder to utility rates.[21]

Thus, the Commission has already employed AFORs to determine just and reasonable rates. As discussed above, the Commission has demonstrated an increasing willingness to approve partially forecasted utilities' rate recovery requests in conjunction with the Commission's use of the HTY approach. A few recent examples of the Commission's willingness to use AFORs include its approval of decoupling mechanisms to allow BGE, Pepco, and Delmarva Power & Light to offer energy efficiency programs to its customers; approval of both electric and natural gas surcharges for infrastructure improvements to increase reliability and safety; use of an inflation adjustment in BGE's most recent rate case to reflect the impact of general inflation on certain operating and maintenance costs; and approval of certain expenses and capital investments for a period after the historic test year.

Additionally, Staff points out that the Commission has employed a wide variety of AFORs that account for future conditions, including an:

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[19] Staff Initial Comments at 7.
[20] Staff Initial Comments at 8.
[21] *See* Order No. 88975, *In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Gas Base Rates*, Case No. 9484 (Jan. 4, 2019) at 19.

> allowance of annualized reliability improvements into rate base for improvements that become used and useful through the date of the base rate case hearing, incorporation of Bill Stabilization Adjustments into base rates, inclusion of known and measurable adjustments that will occur during the rate effective period … use of construction work in progress ("CWIP"), and alternative rate designs that take into account projected changes in conditions during the rate effective period.[22]

These examples reflect the Commission's flexibility and its recognition of the need to adjust to a changing economic environment, while balancing the interests of both the ratepayers and the utilities. These examples also demonstrate that the Commission has considered adjustments to address particular circumstances of Maryland's electric and natural gas utilities on a case-by-case basis.

However, while the Commission has consistently declined to make major changes to its ratemaking polices in individual rate cases, it has adopted a more forward-looking approach to ratemaking in recent years.[23] In addition, the Commission has encouraged utilities to both "innovate and make prudent and cost effective investments that benefit ratepayers."[24] To that end, the Commission indicated that its primary goal for the PC51 Technical Conference was to collect sufficient testimony and record evidence to allow the Commission to review and consider whether it should allow the use of any, all, or none of the alternative ratemaking methods.[25]

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[22] Staff Initial Comments at 8.

[23] *See* Order No. 88944, *In the Matter of the Application of Wash. Gas Light Co. for Authority to Increase Existing Rates and Charges*, Case No. 9481 (Dec. 11, 2018) at 7 ("although the Commission has statutory authority to consider alternative ratemaking proposals, such as a projected future test year, the Commission declines to deviate from its adherence to a traditional test year in this [ratemaking] proceeding.").

[24] PC51 Hr'g Tr. at 8 (Stanek).

[25] Hr'g Tr. at 10 (Stanek).

IV. POTENTIAL AFORs

The record in this case centered around five forms of alternative ratemaking, including the use of Fully Forecasted Test Years ("FTY"), Multi-Year Rate Plans ("MRP"), Formula Rates, Performance-Based Ratemaking ("PBR"), and Surcharges and Riders.

Commission Staff conducted a survey of state utility regulators in approximately 35 states that have actual experience with four of the above-referenced AFORs—namely, FTY, MRP, Formula Rates, and PBR. The survey allowed Staff to gather substantial data to provide a thorough review and analysis of each of these AFORs, which included establishing working definitions, identifying potential advantages and disadvantages of each, and outlining considerations for the Commission as it determines whether AFORs should be permitted in Maryland. Staff's survey instrument included both a questionnaire that contained 20 questions designed to gather information in assessing and evaluating regulatory paradigms that authorize AFORs in the development of utility rates, and a follow-up call with each of the states responding to the questionnaire. Staff's analysis provides working definitions of the AFORs considered in this proceeding and highlights certain considerations that resonate throughout the written comments and testimonies of the parties in this proceeding.

A. Fully Forecasted Test Year

The use of a FTYs allow utilities to submit, for review, reasonable forecasts of future conditions that will help to improve planning and cost recovery.[26] "A FTY is a ratemaking tool that allows the utility to fully forecast all costs and sales revenue over the course of a

[26] MEA Initial Comments at 3.

hypothetical future 12-month period. The FTY is typically the first year of the rate effective period that follows a base rate case."[27] Staff notes that regulators have traditionally set rates using historical data because HTYs are based on incurred costs and revenues that are fully known and measurable at the time of the ratemaking proceeding, providing certainty to regulators and parties to a rate case. However, the utility's historic costs and revenues are likely to be different from its costs and revenues over the future "rate-effective" period, thereby increasing regulatory lag[28] and potentially affecting the ability of the utility to earn its authorized return.[29]

1. Potential Benefits of FTYs

Proponents of FTYs suggest that this method mitigates the impacts of regulatory lag, enables the utility to move closer to its authorized rate of return, provides customers with more accurate pricing signals, and allows utilities to better manage risk and expenses.[30] Additionally, supporters state that given the high upfront costs of utility investments, the deferment of current expenses may result in higher costs in the future because the opportunity cost of foregoing current investments is often difficult to quantify during a rate case.[31] Proponents also contend that in a rapidly changing market, a future test year approach is needed "to provide a reasonable basis for future rates, particularly because empirical research …

[27] Staff Initial Comments at 13. Staff notes that in certain instances, a public utility commission may allow the use of a hybrid test year, which uses several months of historic data but allows for adjustments based on known and measurable costs.
[28] Staff defines regulatory lag as "the delay between a change in a regulated utility's costs and the inclusion of that change in rates due to the regulatory process." Staff Initial Comments at 9.
[29] Staff Initial Comments at 13-14.
[30] Staff Initial Comments at 14.
[31] Staff Initial Comments at 14.

shows that utilities operating under forward [future] test years realize higher returns on capital and have credit ratings that are materially better than those of utilities operating under historical test years."[32] It is also argued that a FTY is beneficial to customers and regulators alike because the distribution rates established using a FTY reduce the frequency of rate cases and the approved rates reflect a more accurate level of the utility's revenue expenses and permit more proactive investment in the distribution system.[33] According to Potomac Edison, fewer rate cases mean greater rate stability for customers and fewer resources spent related to rate case litigation.[34]

2. Potential Disadvantages of FTYs

Staff's analysis reveals that "critics of FTYs state that the main disadvantage of FTYs is the information asymmetry[35] intrinsic to the forecasting process (since the utilities generate and present all the information to the Commission), which makes it difficult for regulators to accurately forecast utility operations, and may lead to misaligned incentives that unfairly benefit the utility at the expense of the ratepayer."[36] Staff argues that under a FTY, utilities have an incentive to overestimate costs in order to ensure appropriate future funding, and they may over-spend in order to meet such a forecast if the forecast is subject to a true up. This may lead to unnecessary rate increases.[37] "Additionally, FTYs increase the regulatory liability

[32] MEA Initial Comments at 3.
[33] Potomac Edison Initial Comments at 14.
[34] Potomac Edison Initial Comments at 14.
[35] Staff commented that asymmetry of information exists because utilities "have first hand knowledge of their finances and have substantial control over the timing and scope of base rate cases," while regulators and intervening parties have substantially diminished access to such information and reduced control over timing, all of which "can make meaningful auditing of utility data during base rate proceedings difficult." Staff Initial Comments at 20.
[36] Staff Initial Comments at 14.
[37] Staff Initial Comments at 14.

of a utility if projected costs and revenues subject to a true-up increase the number of required compliance filings make it difficult to determine where the burden of proof lies in a rate proceeding, and increase the resources and time required for review due to the complexities inherent in performing and reviewing forecasts for accuracy. The last issue may pose a particular problem in Maryland, given the short statutory time-frame in which a rate case must be completed."[38]

B. Multi-Year Rate Plans

An MRP is defined as "an alternative form of regulation that sets rates intended to extend beyond the traditional rate effective period, which begins with the issuance of a final Commission Order and ends only when a new rate is set following the processing of a subsequent rate case."[39] Additionally, the extension in rates is accomplished either by incorporating a formula or index, or by setting specific changes to rates or revenue requirements derived from forecasts to become effective in future years. Staff further explains that "[b]y forecasting for changes in conditions, a utility subject to an MRP may no longer need to file a new base rate case when conditions actually change."[40] Staff's analysis shows that "[r]egulators face three principal decisions when establishing an MRP. First, regulators must establish a baseline HTY, Hybrid test year, or FTY to determine costs and revenues. Second, regulators must establish the mechanism by which base rates will change beyond the first year of the rate effective period through formulas, indexes, or other predetermined mechanisms. Third, regulators must determine the duration of the MRP."[41]

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[38] Staff Initial Comments at 14-15.
[39] Staff Initial Comments at 21-22.
[40] Staff Initial Comments at 21-22.
[41] Staff Initial Comments at 22.

1. <u>Potential Benefits of MRPs</u>

Proponents of MRPs cite several primary advantages. "First, MRPs reduce regulatory lag through the use of forecasts in a manner similar to FTYs. Unlike FTYs, however, rates established through an MRP are not frontloaded to account for forecasts, but rather change over time as forecasted conditions occur."[42] The Joint Exelon Utilities assert that MRPs thereby result in more predictable rate changes to customers.[43] The Joint Exelon Utilities further claim that MRPs ensure that customers pay "no more and no less than the actual costs and investments to serve them," assuming a reconciliation process is part of the MRP methodology.

Staff suggests that use of MRPs limit the number and frequency of rate cases, depending on the length of the plan established by the regulator when setting rates. "Second, proponents of MRPs suggest that MRPs may allow for increased rate transparency because under an MRP, utilities and customers know with certainty the timing and scale of rate increases, providing utilities [with] an improved ability to plan future projects and allowing customers to budget better."[44] Third, when paired with certain other features, MRPs can provide performance incentives to utilities.[45]

2. <u>Potential Disadvantages of MRPs</u>

Similar to FTYs, critics cite information asymmetry as the primary disadvantage of MRPs.[46] However, Staff points out that MRPs have the additional complication of ensuring

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[42] Staff Initial Comments at 22.
[43] Joint Utilities Initial Comments at 14. *See also* Hr'g. Tr. at 80 (McGowan), stating that MRPs have effectuated a "smoothing of costs and rates" over the three-year time period established by the District of Columbia PSC.
[44] Staff Initial Comments at 22-23.
[45] Staff Initial Comments at 23.
[46] Staff Initial Comments at 23.

post-test year information is forecasted accurately for several years in advance, depending on the length of the approved plan. "The increased complexity of multi-year forecasts creates a wider opportunity for utilities to overestimate costs or underestimate revenues, and decreases the possibility that regulators discover improprieties in estimation over the course of a base rate case."[47] Finally, since MRPs are designed to be in effect for several years, any potential issues with the forecasting can have a lasting impact that may not be corrected for several years. As a result, reducing asymmetries of information under MRPs is particularly important.[48]

Staff notes that Maryland has never implemented a fully developed MRP. However, in Case No. 9410, the Commission approved a settlement between Sandpiper Energy, Inc., Commission Staff, and the Maryland Office of People's Counsel ("OPC"), which set annual rates for six years.[49] The ratemaking plan provided Sandpiper with an incentive to convert customers as quickly as possible to natural gas service to maximize its revenue and earn its authorized return on equity.[50]

C. Formula Rates

Similar to MRPs, formula rates allow utilities to make prospective, annual adjustments to base rates outside of a general rate case.

Under formula rate regulation, utilities make the prospective rate adjustment pursuant to an agreed upon formula established as part of a base rate case. Usually, the formula is primarily based on a utility's allowed rate of return ("ROR"). Since the rate effective period

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[47] Staff Initial Comments at 23.
[48] Staff Initial Comments at 23.
[49] Staff Initial Comments at 25.
[50] Staff Initial Comments at 25.

of formula rates spans multiple years, rates may change annually based on projected allowed RORs set at the time of hearing. Thus, the formula is set to allow the utility the opportunity to earn an ROR within a specified "band." While adjustments to base rates are pre-specified by the formula, regulators usually place limitations on the amount that rates can change year-over-year in order to minimize the risk of rate shock.[51]

1. Potential Benefits of Formula Rates

Proponents argue that formula rates reduce regulatory lag and frequency of rate cases relative to HTY. Staff notes that formula rates are conceptually closer to MRPs than FTYs. Therefore, formula rates are often more efficient than FTYs at reducing regulatory lag. However, formula rates are not as transparent as MRPs.[52] Under formula rates, utilities receive an additional benefit from a reduction in financial risk because formula rates reduce the uncertainty surrounding the future status of exogenous financial metrics.[53]

2. Potential Disadvantages of Formula Rates

Critics argue that formula rates might require less complex forecasting than other AFORs, but information asymmetries remain. Additionally, formula rates do not provide robust incentives for utilities to pursue cost efficiency because the use of a range of RORs incentivizes the utility to spend enough to earn the highest possible ROR within the range. Staff's analysis found that to temper the utilities' efforts to game the system, successful implementation of formula rates are often paired with performance-based metrics to ensure the utility only spends the amount of money it needs to operate efficiently based on just and

[51] Staff Initial Comments at 26.
[52] Staff Initial Comments at 27.
[53] Staff Initial Comments at 27.

reasonable rates.[54] Successful formula rates may include revenue sharing mechanisms that ensure the risk burden is adequately balanced between the utility and its customers.[55] Further, formula rates can take several years to be developed and could differ substantially for each utility.[56]

D. Performance-Based Rates

Performance-based ratemaking [or PBRs] is an approach to regulation designed to attempt to more effectively foster improved utility performance as compared to traditional regulation. PBR ties growth in utility revenues or rates to a metric other than costs, providing the utility with opportunities to earn greater profits by constraining costs rather than increasing sales.[57] Under PBR, the regulator sets performance standards, and tracks actual utility performance against the standard through defined metrics. PBR provides incentives and penalties for a utility where superior performance is rewarded with increased profits (increased rate of return), while inferior performance may lead to decreased profits, or penalties.

PBR focuses on outcomes and results instead of cost recovery. Staff's analysis reveals that "while the details of most PBRs vary substantially, all of them are established in a similar manner."[58] First, goals and priorities to be accomplished under the PBR are clearly defined. Second, metrics and standards to measure utility performance are developed. Third, financial

[54] Staff Initial Comments at 27.
[55] Staff Initial Comments at 27-28.
[56] For example, Mr. Stewart, former Managing Director and Advisor to the New York Public Service Commission, stated that it took the New York Commission ten years to effectively implement a formula rate. Hr'g Tr. at 325 (Stewart).
[57] MEA Initial Comments at 9.
[58] Staff Initial Comments at 32.

rewards and penalties are established to provide utilities with adequate incentives.[59] Finally, a process to monitor rates is critical to ensure the PBR is working as designed.[60]

1. Potential Benefits of PBRs

Advocates claim that PBRs carry a higher risk/reward potential for utilities. PBR regulation seeks to provide financial incentives focused primarily on operational efficiency and cost reduction, and not cost recovery. Like the other AFORs, PBRs reduces regulatory lag because the return is tied directly to the utility's performance and not other factors that may be out of the utility's control.[61]

PBRs also have some specific advantages that other AFORs do not. Since PBRs are flexible and can be adjusted to meet the needs of a particular jurisdiction, PBRs can be designed to directly support operational efficiency and reduced cost.[62] Under PBRs, utilities have a vested interest in supporting regulator imposed policy initiatives—not only to comply with commission mandates, but also because utilities are properly incentivized to do so. Finally, there are also a number of administrative and procedural advantages to PBRs because the frequency of rate cases is set ahead of time allowing parties the opportunity to prepare prior to the start of the case.[63]

2. Potential Disadvantages of PBRs

Opponents of PBRs argue that it forces regulators to give up some oversight relative to traditional ratemaking, since cost, the main driver of rates under other forms of regulation, is

[59] Staff Initial Comments at 32.
[60] Staff Initial Comments at 32.
[61] Staff Initial Comments at 32.
[62] Staff Initial Comments at 33.
[63] Staff Initial Comments a 32-33.

second to performance.[64] The PBR mechanism also has to be properly designed from the start to avoid unintended consequences. If the metrics and standards are not adequately defined, and proper mechanisms are not employed to cap prices or revenue and establish earnings sharing, then it is possible for the utility to either lose money or realize profits disproportionate to the benefits gained by customers.[65]

Additionally, like other AFORs, PBR suffers from information asymmetry because absent an extensive, time consuming oversight mechanism, utilities may manipulate data to effectuate favorable outcomes.[66] The incentive to alter performance data exists because, unlike traditional regulation, under PBR revenues are not guaranteed and underperforming utilities may run into financial problems."[67]

E. Surcharges and Riders

Surcharges allow for cost recovery for large capital projects prior to completion and spread over time, based often on the utility reaching specified milestones.[68] Generally, these are projects with significant capital costs that the utility can prioritize when there is increased certainty of cost recovery. A benefit of infrastructure surcharges is they can be used to move the implementation of these projects forward in a way that benefits ratepayers and utility shareholders. The projects can be marked by milestones; the attainment of these milestones results in customer surcharges being implemented. Proponents of this mechanism argue that

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[64] Staff Initial Comments at 33.
[65] Staff Initial Comments at 33.
[66] Staff Initial Comments at 33.
[67] Staff Initial Comments at 33-34.
[68] MEA Initial Comments at 9.

it has the "added benefit of increased transparency related to costs collected."[69] However, some commenters caution that surcharges are prone to "duplication or conflict" with existing surcharges or other rate mechanisms and that it is important for commissions to stay vigilant to avoid double recovery.[70] Additionally, any rate mechanism, including surcharges, that increases fixed cost recovery will necessarily reduce volumetric charges, thereby reducing the customers' control over their bills and reducing the incentive for conservation.[71]

V. THE CASE *FOR* MARYLAND'S ADOPTION OF AN ALTERNATIVE FORM OF REGULATION

Although the Commission has been open to alternative ratemaking methodologies, Maryland utilities have argued that the Commission's various adjustments, while they may meet the immediate need for a specific utility, often fail to adequately address persistent regulatory lag. Some characterize regulatory lag as the byproduct of traditional ratemaking that can help ensure end users' rates are just and reasonable.[72] However, it is also recognized that regulatory lag may make it difficult for regulated utilities in a rising cost environment to earn their authorized rate of return following a rate increase. In contrast, in an environment where costs are falling, regulatory lag may allow utilities to over recover revenues.[73]

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[69] Potomac Edison Initial Comments at 3.
[70] Hr'g Tr. at 24-25 (Spivak); Hr'g Tr. at 423 (Carmody).
[71] Hr'g Tr. at 341-42 (Struck).
[72] Staff Initial Comments at 9.
[73] Staff Initial Comments at 9.

A. Joint Exelon Utilities

Baltimore Gas and Electric Company ("BGE"), Potomac Electric Power Company, and Delmarva Power & Light Company (collectively the "Joint Exelon Utilities" or "Joint Utilities") argue that for the Maryland utility customer to fully benefit from a modernized distribution system, "it is critical that Maryland join the overwhelming majority of other states utilizing modernized rate setting process."[74] Specifically, the Joint Utilities endorse formula rate models and AFORs that utilize future test years for ratemaking in Maryland. The Joint Utilities note that these two AFORs provide important benefits for Maryland utilities and customers while taking advantage of aspects of traditional ratemaking practices with which the Commission, its Staff, utilities, and other stakeholders are most experienced.[75]

During the PC51 hearing, Mark Case, BGE's Vice President of Regulatory, Strategy and Policy, outlined five benefits of the use of formula rates as a next step for Maryland. First, he argued that formula rates have "worked well in setting transmission rates for more than a decade" and the State has experience in that area.[76] Second, he stated that "the rates will be based on public audited FERC financial statements – the FERC Form 1 and the FERC Form 2," which Mr. Case argues may be helpful to address the issues of asymmetry of information.[77] Third, Mr. Case testified that "the true-up or reconciliation mechanisms that are typically part of formula rates help to ensure that ultimately utilities can recover their costs, no more, no less, and that customers only pay for the actual cost of service that they are

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[74] *Joint Initial Comments of Baltimore Gas and Electric Company, Potomac Electric Power Company, and Delmarva Power & Light Company*, PC51, filed March 29, 2019 ("Joint Utilities Initial Comments") at 1.
[75] Joint Utilities Initial Comments at 3.
[76] Hr'g Tr. at 76 (Case).
[77] Hr'g Tr. at 76 (Case). "FERC" stands for the Federal Energy Regulatory Commission.

receiving."[78] In contrast to forward test years or multi-year rates, formula rates "rely on historic cost data to set the rates."[79] However, he noted that there is typically some forecasting of rate base additions in the year that the rate proceeding is taking place. Consequently, Mr. Case indicated that "another benefit we see to the formula rates, is the reduction in Staff time and attention to forecasting methodologies and accuracy of forecasts since more reliance is on that historic Form 1, Form 2 data."[80]

The Joint Utilities engaged The Brattle Group ("Brattle") to undertake a review of select other states that have implemented different forms of alternative rate plans.[81] During its review of alternative rate plans across the country, Brattle discovered "28 states have implemented multi-year rate plans, 23 allow the use of forward test years and 10 have utilities with formula rates."[82] Brattle undertook a "deep dive" as to utilities across 10 different jurisdictions for review[83] to gather data and information relevant to the specific questions that the Commission raised in its Notice. Utilizing Brattle's report, the Joint Utilities argued the following.

1) **The implementation period to transition from one form of regulatory rate making principle to the alternative rate plan is relatively quick**. Brattle researched the regulatory timelines for the implementation of alternative rate plans such as formula

[78] Hr'g Tr. at 76 (Case).
[79] Hr'g Tr. at 77 (Case).
[80] Hr'g Tr. at 78 (Case).
[81] Joint Utilities Initial Comments at 5-6.
[82] Joint Utilities Initial Comments at 8.
[83] Joint Utilities Initial Comments at 6.

rates, fully forecasted test years and multi-year rate plans.[84] Brattle's research found that eight of the ten states implemented alternative rate plans in 13 months or less.[85]

2) **The frequency by which the utility may file for rate increases under an alternative rate plan is dependent on the alternative rate plan implemented.** Formula rates provide for an efficient annual filing process that is predetermined, defined, and importantly allows for both rate increases and decreases as dictated by the approved formula."[86] In the instance of a plan with a single fully forecasted test year, the frequency of annual filings would not typically be pre-determined.[87] "Plans with multiple fully forecasted test years, or multi-year rate plans, once implemented do have a predefined rate plan period, typically three to five years."[88]

3) **Reconciliations and refunds are dependent on the alternative rate plan implemented.** For instance, for formula rates the reconciliation is generally done by using a historic test year, possibly adjusted for forecasted capital investments to serve as the basis for an initial revenue requirement.[89] The initial revenue requirement is then later reconciled to a final revenue requirement based upon actual costs and investments, and the ensuing difference is included in a future year's annual update filing.[90] On the other hand, for fully forecasted test year plans, if they are based on a single test year, do not typically have full reconciliations or refunds associated with them. However,

[84] Joint Utilities Initial Comments at 8-9.
[85] Joint Utilities Initial Comments at 9.
[86] Joint Utilities Initial Comments at 11.
[87] Joint Utilities Initial Comments at 12.
[88] Joint Utilities Initial Comments at 12.
[89] Joint Utilities Initial Comments at 12.
[90] Joint Utilities Initial Comments at 12.

they will perform a review of utility planning results for purposes of determining whether the forecast used to set rates was reasonable.[91]

4) **The impacts on the ratepayers resulting from the use of the alternative rate plans are difficult to discern.** Brattle's research found that the impact on ratepayers from the implementation of one or more AFORs is not easily determined because changes in rates are driven by underlying costs.[92] Thus, Brattle states that determining whether an increase in rates caused by the adoption of an alternative rate mechanism requires the development of a counterfactual ("but for") case, i.e., what would have happened to rates if the alternative regulatory mechanism had not been adopted.[93]

5) **Whether additional staff resources or staff with different skills are needed prior to implementing alternative rate plans depends on the alternative rate plan implemented.** Brattle's research shows that the three AFORs reviewed in its study—FTY, Formula Rates, and MRPs—are extensions of traditional ratemaking rather than a fundamental shift in regulatory approach.[94] As a result, the core skills required by the Commission staff to implement these AFORs are skills already associated with traditional regulatory plans. Nonetheless, Brattle acknowledges that during the transition from traditional ratemaking to any of these AFORs, staff may need additional training to gain skills in evaluating cost projections.[95] The Joint Utilities noted,

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[91] Joint Utilities Initial Comments at 13.
[92] The Brattle Group's Report Exploring the Use of Alternative Regulatory Mechanism to Establish New Rates, Response to PC51 Request for Comments, Prepared for the Joint Utilities, March 29, 2018 ("The Brattle Group Report") at 20.
[93] The Brattle Group Report at 20-21.
[94] The Brattle Group Report at 9.
[95] The Brattle Group Report at 9.

however, that "Brattle found multiple commissions that cited existing staffing concerns as a *motivation* to enact an alternative rate plan."[96]

The Joint Utilities filed Supplemental Comments, stating that "[a]fter listening to and participating in the two days of hearings on [AFORs] and the experience which other states have had with formula rates, fully forecasted test years and multi-year rate plans, the Joint Utilities continue to support the implementation of formula rates in Maryland."[97] The Joint Utilities contend that formula rates balance the Maryland experience with the historical test year approach, customer protections and benefits, and improvements to the rate-setting process which [AFORs] bring.

The Joint Utilities' Supplemental Comments also requested that the Commission issue an order as soon as possible that (1) sets forth clear goals, objectives, direction and a timeline for utilities and other interested parties to follow in regard to the AFORs; and (2) directs the establishment of a stakeholder working group process to provide a recommendation regarding how AFORs should be implemented, including robust details related to protocols, filing requirements, and other procedural decisions to facilitate efficiency and transparency in AFORs filings made in Maryland.[98] The Joint Utilities recommended the use of a multi-phased approach and timeline as a means by which the implementation of various forms of AFORs can be thoroughly assessed.[99] The Joint Utilities also suggested that a multi-phased

[96] Joint Utilities Initial Comments at 15.
[97] *Supplemental Comments of Comments of Baltimore Gas and Electric Company, Potomac Electric Power Company, and Delmarva Power & Light Company*, PC51, filed March 29, 2019 ("Joint Utilities Supplemental Comments") at 1.
[98] Joint Utilities Supplemental Comments at 9.
[99] Joint Utilities Supplemental Comments at 10.

approach would allow the proper level of due diligence and a full review of each AFOR in more manageable work streams than if all AFORs are concurrently assessed.[100] The Joint Utilities recommended a multi-phased approach and a proposed timeline that envisions completion of a Phase 1 Working Group Report by October 2019, and the Commission issuing a final AFOR order by December 2019.[101]

B. Columbia Gas

Columbia Gas of Maryland ("Columbia") filed comments that support the use of the FTY.[102] Columbia is a subsidiary of NiSource Inc., an energy holding company whose subsidiaries provide natural gas and electric distribution service in seven states.[103] Within the NiSource footprint, four of its gas distribution companies (i.e., NIPSCO, Columbia Gas of Kentucky, Columbia Gas of Pennsylvania and Columbia Gas of Virginia) currently recover costs using a forecasted test year.[104]

Columbia noted that "[i]n this era of large capital investments by gas distribution companies to modernize their distribution systems, the use of a historic cost structure for establishing rates does not provide the utility an adequate opportunity to earn its allowed rate of return."[105] Columbia argued that the historic test year used "in current rate cases limits recovery of investments that are made prior to the rate effective date, resulting in severe

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[100] Joint Utilities Supplemental Comments at 10.

[101] In its Supplemental Comments, the Joint Utilities noted that "Washington Gas Company ("WGL") and Columbia Gas of Maryland ("Columbia") have authorized the Joint Utilities to report that they fully support and sign on to the proposed [multi-phased] approach and schedule." Joint Utilities Supplemental Comments at 10.

[102] Columbia Initial Comments at 3.

[103] Columbia Initial Comments at 3.

[104] Columbia Initial Comments at 3.

[105] Columbia Initial Comments at 4 – 5.

regulatory lag for rate relief sought through a base rate proceeding."[106] Columbia noted that filing a FTY would follow a similar process as filing a base rate case using the historic test year, as it would file for a rate increase that is accompanied with an evidentiary record that supports the costs to provide service to customers at levels experienced in the test year.[107] "The utility would be required to provide detailed testimony and sufficient documentation for all revenues, expenses and rate base elements included in the [FTY] to meet its burden of proof requirements under PUA § 3-112."[108]

C. Potomac Edison ("PE")

PE acknowledges that Maryland has already had several positive experiences with several types of AFORs. Specifically, PE highlights Maryland's use of alternative rate plans that allow expenses and capital investments for periods after the historic test year, as well as surcharges related to recovery of infrastructure costs. PE asserts that these alternative mechanisms "permit a more forward-looking approach to the collection of known and measurable costs which better aligns in time the expenditures and their recovery."[109] PE remarked that "surcharge recovery provides the added benefit of increased transparency related to the costs collected via the surcharges due to the regular filings at the Commission regarding the amount that has been or will be collected."[110] PE noted that surcharge recovery has traditionally been limited to reliability-related investments, but PE encourages the Commission

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[106] Columbia Initial Comments at 5.
[107] Columbia Initial Comments at 4.
[108] Columbia Initial Comments at 4.
[109] *Comments of the Potomac Edison Company*, March 29, 2019 ("PE Initial Comments") at 3.
[110] PE Initial Comments at 3.

to consider expanding its use of surcharges as it evaluates the expansion of alternative rate plans.

D. Washington Gas Light Company ("WGL")

WGL states that its principal concern with the Commission's current ratemaking approach is that reliance on a historic test year "inherently denies the Company the opportunity to earn its authorized return."[111] WGL proposes that AFORs allow utilities to overcome this concern, which it defines as regulatory lag, and cites Virginia as a state where WGL has made successful use of AFORs. WGL states that under the current Virginia statute, it has been able to utilize a forecasted test year for each of its two most recent base rate proceedings in Virginia, and argues that its use has been instrumental in reducing regulatory lag.[112] WGL also found that the same Virginia staff that processed prior base rate applications based on a historic test year are used to process forecasted test year cases. Therefore, WGL states that Virginia Staff needed no additional resources in its transition from historic test year to future test year.[113]

WGL also states that formula rates should be considered by the Commission, and notes that formula rates have been used by FERC for many years.[114] WGL states that while it has never used this ratemaking method, it believes that "formula rates enacted pursuant to a Commission-approved tariff would reduce the size of necessary rate increases and permit the Company to adjust its base rates more efficiently to achieve its Commission-approved

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[111] *Comments of Washington Gas and Light Co.*, March 29, 2019 ("WGL Initial Comments") at 2.
[112] WGL Initial Comments at 4.
[113] WGL Initial Comments at 5.
[114] WGL Initial Comments at 6.

ROR."[115] WGL contends that formula rates allow for more gradual change of customer rates, avoiding sudden large rate increases.[116] Even though WGL expresses support for a formula rate approach, it suggests several restrictions that the Commission should implement to make a formula rate model effective.[117]

E. Southern Maryland Electric Cooperative, Inc. ("SMECO") and Choptank Electric Cooperative, Inc. ("Choptank")

SMECO and Choptank noted that the majority of states "do not require full rate-regulation of their electric cooperatives" but suggested the Commission may find helpful the alternative ratemaking plans of two states—Virginia and Kentucky—that have been adopted for their rate-regulated electric cooperatives.[118] Virginia has adopted an alternative, or "hybrid regulation-style," rate plan for electric cooperatives.[119] SMECO and Choptank noted that "the Virginia statute provides for two sensible alternatives for the Maryland Commission to consider as it wrestles with deciding what just and reasonable base rates are appropriate for individual public utility companies in Maryland."[120] First, the Virginia Electric Utility Regulation Act, § 56-585.3 (regulation of cooperative rates after rate caps) "allows cooperatives to institute changes in their distribution rates, provided that the changes will not affect a cumulative net distribution rate increase or decrease of more than 5 percent in any

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[115] WGL Initial Comments at 6.
[116] WGL Initial Comments at 6-7.
[117] WGL Initial Comments at 7. For example, WGL suggested that utilities operating under formula rates should be required to file a scheduled rate case every four to five years to "assur[e] the Commission and stakeholders that relevant financial, operational and regulatory information remains current." WGL Initial Comments at 8.
[118] *Joint Comments of Southern Maryland Electric Cooperative, Inc. and Choptank Electric Cooperative, Inc.*, PC51, filed March 29, 2019 ("SMECO and Choptank Initial Comments") at 1.
[119] SMECO and Choptank Initial Comments at 2.
[120] SMECO and Choptank Initial Comments at 2.

three-year period."[121] Second, the statute allows a cooperative to make rate adjustments that are reasonably calculated to collect through a fixed charge any or all of its distribution system related fixed costs.[122] The fixed costs would have been identified as customer-related in a cost of service study.

F. Montgomery County

Montgomery County states that it has consistently advocated for reliability, innovation, and grid-side solutions, coupled with performance-based compensation for utilities.[123] Montgomery County states that it supports various forms of alternative ratemaking, but focuses its comments on performance-based ratemaking.[124] Montgomery County notes that in prior testimony before the Commission, it advocated for a "mix of penalties and incentives to provide the proper economic signals to utilities to achieve the highest levels of customer service while simultaneously addressing societal outcomes."[125]

Montgomery County identifies several states including Hawaii, Pennsylvania, and New York to illustrate where PBR has been implemented, with a focus on Hawaii to highlight how a PBR scheme can be used to align utility interests with desired societal outcomes. Montgomery County identifies three main areas in which stakeholders should concentrate efforts to include in its design and implementation of alternative ratemaking mechanisms: (1) advancement of societal outcomes; (2) improvement of utility performance; and (3) enhancement of customer service.[126]

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[121] SMECO and Choptank Initial Comments at 3.
[122] SMECO and Choptank Initial Comments at 3.
[123] *Montgomery County, Maryland Comments,* March 29, 2019 ("Montgomery County Comments") at 1.
[124] Montgomery County Comments at 1.
[125] Montgomery County Comments at 3.
[126] Montgomery County Comments at 5-7.

G. The Coalition for Performance Incentive Mechanisms ("Coalition")

In its comments, the Coalition argues that "the traditional cost of service ratemaking model is now an archaic paradigm that is aligned with shareholder as opposed to consumer interests, and fails to adequately ensure that Maryland's policy priorities are being met."[127] The Coalition asserts that adopting performance-based ratemaking, including specifically performance incentive mechanisms, "is the most logical, proven, and most widely-supported alternative ratemaking methodology in this proceeding."[128] The Coalition believes that "there is a solid, well-defined path forward for the Commission's ultimate consideration that has the greatest potential to benefit all consumers."[129]

The Coalition comments that "there is a growing realization that the traditional cost-of-service ratemaking model, borne in a different era, is not the most effective means to accommodate those changes or, more broadly, serve the public interest."[130] The Coalition further states:

> The state's electric utility and regulatory framework were developed in an era in which demand for electricity consistently increased, technology changed incrementally, customers exerted little control over their electricity demand, electricity flowed one-way from the utility to customers, and the risks of climate change were unknown. Today, none of those factors is true: demand for electricity has plateaued; many customers generate their own power; electricity flows to and from customers; technologies are being introduced at rapid pace; and the need to mitigate and adapt to climate change is real. In these new circumstances, the traditional regulatory

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[127] *Final Comments of The Coalition for Performance Incentive Mechanisms,* PC51, filed May 21, 2019 ("Coalition Final Comments") at 1. The Coalition for Performance Incentive Mechanisms consists of the following parties: DMC Strategic Advisors, LLC; Sunrun, Inc.; Simple Energy; and the Maryland-DC-Virginia Solar Energy Industries Association.
[128] Coalition Final Comments at 1.
[129] Coalition Final Comments at 1.
[130] Coalition Final Comments at 3.

> framework will not continue to serve the public interest. It will continue to push consumer prices upward without a corresponding increase in value for customers.[131]

The Coalition argues that "[t]raditional cost-of-service regulation is particularly out-of-date in Maryland, where the General Assembly has established a number of statewide energy goals, including specific provisions and/or statutes designed to promote affordability, reliability, environmental performance and customer choice."[132] Consequently, the Coalition contends that "the traditional regulatory structure fails to align utility incentives with the state's energy goals."[133]

The Coalition believes that PBR is best suited to address the weakness of traditional ratemaking and better align utility incentives with state energy goals and customer needs. "The fundamental goal of Performance-Based Ratemaking is to shift the focus – and the economic incentives – away from how much a utility spends to how well the utility performs in meeting our most urgent objectives. By definition, it has the capacity to be much more aligned with consumer interests, public policy, and operational efficiency."[134] The Coalition notes that at the heart of PBRs are Performance Incentive Mechanisms ("PIMs"), which are financial rewards and penalties designed to motivate a utility to meet specific targets and metrics.[135] During the Technical Conference, a witness for the Coalition, the Honorable

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[131] Coalition Final Comments at 2-3, quoting Rhode Island Div. of Public Util., Office of Energy Resources & Public Util. Comm'n Rhode Island Power Sector Transformation, p.7, (Nov. 2017).
[132] Coalition Final Comments at 3-4. In footnote 6 of its Final Comments, the Coalition referenced the following Maryland legislative initiatives: The Maryland Healthy Air Act, the EmPOWER Maryland Act, the Greenhouse Gas Solutions Act, and the Clean Energy Jobs Act.
[133] Coalition Final Comments at 4.
[134] Coalition Final Comments at 4.
[135] Coalition Final Comments at 4.

Roger Berliner, reiterated support for PBR and reminded the Commission of Maryland's own experience with this method:

> It is a proven model here in Maryland. When utilities subject to this Commission's purview persistently failed to perform their most basic responsibility—keeping the lights on—the Commission set metrics that the utilities are now required to meet or face financial consequences. And not surprisingly, it worked.[136]

Should the Commission decide to move forward with exploring an alternate ratemaking approach regarding PBR, the Coalition contends that the Commission should create a stakeholder group that would address and offer recommendations on the following questions: "(a) what are the regulatory goals and desired outcomes that support the state's priorities; (b) what metrics and targets are appropriate; and (c) what form should the rewards/penalty incentive mechanism take."[137] The Coalition further suggests that the Commission direct the stakeholder group to look at broad categories that could be subject to PIMs similar to what was employed in the Minnesota and Hawaii.[138]

VI. <u>THE CASE *AGAINST* MARYLAND'S ADOPTION OF AN ALTERNATIVE FORM OF REGULATION</u>

A. Commission Staff

As noted above, Staff conducted a survey of state utility regulators with experience using AFORs. Staff stated that its survey showed that there is considerable variety in the

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[136] Hr'g Tr. at 231 (Berliner). *See also* submitted written testimony *"Aligning Utility Returns with the State's Priorities: The Case for Performance Based Ratemaking,"* DMC Strategic Advisors LLC, Docket PC51, April 29, 2019, p.1.
[137] Coalition Final Comments at 6.
[138] Coalition Final Comments at 6.

AFOR implemented, which is a result of differing needs and policy goals among the states.[139] Consequently, there is no consensus on the type of regulation or best approach to implement generically. Nonetheless, Staff reached the following conclusions based on its research:[140]

1. There is no "one size fits all" approach to regulation across states, or even across utilities in the same state. As a result, should the Commission implement AFORs in Maryland, a case-by-case basis approach that takes into account the individual needs and characteristics of each utility and its customer base would be appropriate.

2. When implementing AFORs that use forecasts, a major concern for Staff is the asymmetry of information inherent to the review of forecasts in a short time period. As a result, should the Commission implement AFORs in Maryland that use forecasts, it should institute mechanisms and incentives that ensure effective review of forecast methodology and data inputs, ensure shifts in risk are appropriate, and promote just and reasonable rates to end users.

3. Regardless of the methodology used going forward, the Commission should ensure that the burden of proof continues to fully reside with the utilities.

4. There are advantages and disadvantages to the different regulatory frameworks, which, regardless of the method employed, should be examined carefully by the Commission with due consideration of the impact of rates on all parties.[141]

Staff indicated that "[t]he survey responses show that a change in the regulatory paradigm will almost undeniably result in the need for additional resources that depend on the nature and number of AFOR mechanisms the Commission adopts."[142]

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[139] Staff Initial Comments at 60.
[140] Staff Initial Comments at 60.
[141] Staff Initial Comments at 60.
[142] Staff Initial Comments at 21.

Staff also testified that "AFORs have the potential to impact rates over several years; as such emphasis on the utilities' burden of proof is even more important."[143] Staff made clear that burden of proof is "more than allowing parties to ask questions about a proposal" but rather requiring utilities "to fully demonstrate in very certain and transparent terms why its proposal is legally sufficient, superior to its current regulatory model," and is otherwise consistent with the public good.[144] Further, Staff argued that any AFOR plan should express clear goals, identify clear and measurable metrics, be transparent, and align benefits and rewards.[145] Specifically, Staff recommends that the Commission "direct parties to engage in the development of revised filing requirements that would discuss the types of data to be included in an AFOR plan and perhaps the manner in which data should be presented."[146]

B. Office of People's Counsel

OPC surveyed counterpart consumer advocate agencies in 27 states to inquire about their individual experiences with alternative ratemaking. OPC then supplemented what it learned from its counterpart offices with its own research of relevant statutes, regulations, and commission orders.[147] OPC stated that its research has revealed that "no two states are alike in terms of alternative ratemaking."[148] Moreover, of the states that employ some form of alternative ratemaking, their respective motivations for employing such methods vary.[149]

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[143] Hr'g Tr. at 402 (Garofalo).
[144] Hr'g Tr. at 402 (Garofalo).
[145] Hr'g Tr. at 405 (Valcarenghi).
[146] Hr'g Tr. at 405 (Valcarenghi).
[147] *Maryland Office of People's Counsel's Comments on Alternative Forms of Rate Regulations*, PC51, March 29, 2019 ("OPC Initial Comments") at 1.
[148] OPC Initial Comments at 1.
[149] OPC Initial Comments at 1.

OPC found that the states it studied are at different stages of implementing alternative ratemaking. Some of the states are just beginning, based on newly enacted statutes or commission orders. Other states have employed alternative forms of ratemaking for decades, while still other states have laws that authorize alternative ratemaking, but their commissions have yet to approve alternative rate structures.[150]

OPC concluded that "the experience in other states teaches that the transition to some form of alternative ratemaking requires careful analysis and sufficient time for design and implementation of such structures."[151] OPC cautioned that if, in consideration of the practices of other states, the Commission determines that reforms to Maryland's current ratemaking structure are necessary, "such reforms should be carried out with the goal of ensuring that any changes can be reasonably expected to deliver identifiable and measurable benefits to utilities, customers, and the distribution system."[152]

In its Reply Comments, OPC stated that the various stakeholders' initial comments confirmed that "[t]here is no 'one size fits all' form of alternative ratemaking that Maryland needs to adopt in order to meet the needs of the State's utilities or to keep pace with current trends."[153] OPC found that "no party has presented a compelling case for why Maryland, based on its specific characteristics, needs to adopt any new forms of alternative ratemaking beyond those which it has already implemented."[154] OPC stated that even though stakeholders cited

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[150] OPC Initial Comments at 2.
[151] OPC Initial Comments at 47.
[152] OPC Initial Comments at 47.
[153] *Maryland Office of People's Counsel Reply Comments On Alternative Forms of Rate Regulation*, PC51, April 18, 2019 ("OPC Reply Comments") at 1.
[154] OPC Reply Comments at 1.

various justifications for adopting other forms of ratemaking, "no party has explained how Maryland's current ratemaking practices have hampered the provision of safe and reliable service or the financial health of Maryland utilities. In other words, the comments have not identified a problem in need of a solution."[155] Therefore, OPC recommended that before the Commission adopts or allows certain new forms of ratemaking, the "Commission should carefully consider its goals for the future, identify the goals it seeks to achieve through a change in the ratemaking approach, and only adopt those modifications necessary to achieve those goals."[156]

During the PC51 Technical Conference, the People's Counsel, Paula Carmody, testified that should the Commission decide to move forward with pursuing adoption of an AFOR, it should be mindful that it would impose a significant resource burden on OPC staff to provide a rigorous review within the statutory 210-day timeframe of a rate case proceeding timeframe.[157] She stated that in her judgment, the Technical Conference is the beginning of the discussion, and the Commission does not have sufficient information to make a firm decision to adopt or alter significantly the ratemaking process that has been used successfully in Maryland for decades.[158]

C. Maryland Energy Administration

The Maryland Energy Administration ("MEA") states that "the current ratemaking method in Maryland was developed under an integrated utility business model where each

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[155] OPC Reply Comments at 1.
[156] OPC Reply Comments at 17.
[157] Hr'g Tr. at 416 (Carmody).
[158] Hr'g Tr. at 524-525 (Carmody).

utility, as a singular entity, provided generation, transmission, and distribution services to its customers."[159] MEA argues that "[t]raditional regulation requires prudence by the utilities and allows stakeholders the opportunity for complete examination of the utilities' practices and management during rate cases before the Commission."[160] MEA notes that this traditional ratemaking approach has been tested and proven.[161] Citing a 2014 National Regulatory Research Institute report, MEA listed four continued benefits of traditional ratemaking:

> (1) its perceived fairness to all parties under most market and business conditions; (2) its ease of understanding; (3) the public's general acceptance of average-cost pricing that relates prices to costs, even if not the correct costs from an economic perspective; and (4) its attempt to achieve a balanced outcome that avoids, in most circumstances, extreme discontent by individual stakeholders.[162]

Regardless of these perceived and often realized benefits, MEA points out that traditional ratemaking does have its limitations, such as "sometimes fail[ing] to distribute risk, monitor costs, and achieve policy outcomes that otherwise would promote the public interest."[163] Additionally, "traditional ratemaking … may encourage utilities to increase capital investments and incur operating costs between rate cases."[164] Furthermore, "[u]nder traditional ratemaking the benchmark of 'used and useful' can limit the incentives of utilities to adopt new methods or technologies due to cost recovery concerns."[165]

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159 MEA Initial Comments at 1.
160 MEA Initial Comments at 1.
161 MEA Initial Comments at 1.
162 MEA Initial Comments at 1-2.
163 MEA Initial Comments at 2.
164 MEA Initial Comments at 2.
165 MEA Initial Comments at 2.

MEA argues that "any consideration of an alternative form of rate regulation must ensure that the regulation would improve the accessibility and availability of enhanced energy services, such as increased ability to integrate distributed resources and facilitate customer specific demands, without unduly burdening any rate class or segment of a rate class."[166] MEA acknowledges that as the nature and usage of utility systems have evolved, there has been an increased demand for services which has "affected the utilities' ability to recover costs, changing the risk profile of the utility while shifting the burden of costs to traditional users of the system."[167] In response to energy market changes, MEA notes that some states have implemented incremental changes to the traditional ratemaking model including FTYs, Earning Sharing Mechanisms, Cost Trackers, Infrastructure Surcharges, and Performance Incentive Regulations.[168] MEA cautions that "[a]lthough alternative rate plans can improve cost recovery and streamline administration, each mechanism also can negatively impact risk distribution, the ability for thorough review of utility cost, and full evaluation of impact on policy objectives."[169] Further, MEA recommends that "[a]ny possible implementation in Maryland of an alternative method of rate design would require a careful review and assessment of current utility charges and management practices to identify appropriate mechanisms for providing utility customers with improved access to affordable, reliable, and flexible energy infrastructure."[170]

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166 MEA Initial Comments at 1.
167 MEA Initial Comments at 2.
168 MEA Initial Comments at 2.
169 MEA Initial Comments at 3.
170 MEA Initial Comments at 7.

D. Office of the Attorney General

John B. Howard, Jr., Special Assistant Attorney General for the Maryland Office of the Attorney General ("OAG"), testified during the PC51 Technical Conference that PUA § 7-505 already provides the Commission with all the authority it needs to adopt AFORs, if it chooses. He stated that "the law places the burden of proof in a rate case on the proponent of the new rate or change in rate, and that any approach that requires the Commission to justify deviating from a proponent's preferred AFOR functionally shifts the burden of proof and tilts the regulatory process in favor of utilities."[171] He concluded that any AFOR approved by the Commission "should be designed to promote the state's clean-energy and energy-efficiency goals [and] that any AFOR must be accompanied by robust consumer protection mechanisms."[172]

In its Supplemental Comments, the OAG notes that during the hearings in this proceeding, the utility companies presented the case for how the adoption of AFORs would more effectively ensure that they receive a fair rate of return. However, the OAG observes that:

> "[m]issing entirely from the hearing . . . were advocates arguing that the adoption of AFORs in place of traditional ratemaking procedures would advance the public good. Absent a clear demonstration that AFORs would *both* better serve the public good *and* result in a more reasonable rate of return, the Commission should decline to abandon its traditional procedures."[173]

[171] Hr'g Tr. at 510-511 (Howard). *See also, Office of the Attorney General's Comments on Alternative Forms of Rate Regulations* ("OAG Comments") at 1.
[172] Hr'g Tr. at 510-511 (Howard). *See also,* OAG Comments at 1.
[173] OAG Comments at 2 (original emphasis).

The OAG expressed concern that many of the AFORs discussed during the PC51 Technical Conference may result in a functional burden shifting that disadvantages other stakeholders in the regulatory process.[174] In particular, OAG notes that the very nature of an AFOR using forecasted or formula rates relies on projections made by the utilities, "who will always enjoy an inherent informational advantage"[175] with such methods. The OAG states:

> [a] healthy skepticism about the need for AFORs is in order: there is no evidence that the utility companies are struggling financially or that traditional ratemaking has fallen short as a means of setting just and reasonable rates. In contrast, the experience of other states shows that AFORs have typically been adopted to address a particular deficiency or need and that the process of implementing AFORs took a considerable amount of time.[176]

The OAG maintains that, "if AFORs are to be used, the public good requires, at a minimum, that procedures and protections be in place to prevent alternative ratemaking from giving utilities a blank check for cost-overruns or over-investment. For example, establishing a threshold trigger for re-evaluating prudence may provide transparency and clear signals from the outset."[177]

E. Apartment and Office Building Association of Metropolitan Washington ("AOBA")

AOBA submitted comments that reviewed the recent assessment conducted by several state utility commissions regarding alternative ratemaking mechanisms in their jurisdictions. Those states included Michigan, Texas, Vermont, and Illinois. Additionally, AOBA

[174] OAG Comments at 2.
[175] OAG Comments at 2.
[176] OAG Comments at 4.
[177] OAG Comments at 2-3.

recommended that not only should the Commission look to see what other states are doing regarding the adoption, implementation and evaluation of alternative ratemaking mechanisms, it should also consider the mechanisms for alternative ratemaking under FERC jurisdiction that "are intended to incentivize utility company investments while also protecting ratepayers from unwarranted rate increases."[178] In its conclusion, AOBA recommended that any alternative ratemaking mechanism considered by the Commission should (1) "encompass needed projects and services;" (2) "[be] cost effective for all ratepayers;" (3) "respect the finite resources of ratepayers to accommodate escalating financial demands for essential energy services in their individual and corporate budget;" and (4) "recognize that all the customer primarily wants is electric and natural gas delivered reliably, safely, and affordably for all classes of ratepayers …"[179]

F. AARP Maryland

AARP disagrees with the underlying premise of the Commission's Notice initiating this proceeding, suggesting there is a problem with traditional regulation.[180] AARP argues that "alternative regulation" is merely an imprecise buzzword for going around the Commission review process and handicapping its ability to protect consumers.[181] AARP notes that it "considers all of the noted forms of alternative regulation to create new risks for consumers and for prudent utility management, while purporting to solve 'problems' that do not in fact exist."[182]

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[178] AOBA Initial Comments at 21-23.
[179] AOBA Initial Comments at 33.
[180] *Comments of AARP*, March 29, 2019 ("AARP Initial Comments") at 1.
[181] AARP Initial Comments at 1.
[182] AARP Initial Comments at 1-2.

AARP expresses skepticism of a utility's need for AFORs, given the current financial climate and prevailing options for case-specific adjustments to actual costs and revenues. AARP acknowledges that there was a period in the 1970s and 1980s when utilities invested large capital in plants that were not cost effective and were difficult to get financing on terms favorable to consumers, but that time has passed.[183]

Lastly, AARP suggests that forward looking AFORs reduce the incentive for cost efficiency and prudent utility management, to the extent the utility receives revenues before a full audit or reconciliation.[184] AARP also cautions that there are no universally accepted definitions for these alternative ratemaking mechanisms. "[T]hus it can be hazardous to draw too many conclusions from one state to another without a deeper examination of the details regarding how those alternatives may have been implemented."[185]

G. Dr. Carl Pechman

Dr. Carl Pechman[186] testified that effective regulation "requires ongoing readjustment in order to meet new and changing industry and societal requirements," and noted that each of the regulated industries is currently facing significant change.[187] For example, the natural gas industry is facing substantial costs to rehabilitate its distribution infrastructure, and the electric industry is facing a transformation where customers are transcending their roles as passive consumers to "prosumers who participate in the supply of power and operation of the electric

183 AARP Initial Comments at 3.
184 Staff Reply Comments at 25-26.
185 AARP Initial Comments at 5.
186 Dr. Pechman is the Director of the National Regulatory Research Institute ("NRRI"). However, he filed comments on his own behalf rather than on behalf of NRRI.
187 Comments of Dr. Carl Pechman at 1.

system."[188] Given those significant transformations, Dr. Pechman recommended that the Commission move cautiously in adopting alternative forms of ratemaking, for example by calculating rates based on a historic test year while simultaneously calculating rates under an AFOR. This would allow the Commission to "see what the variation is in terms of the rates."[189] Dr. Pechman also observed that utilities are typically the initiators of regulatory modification, making it important for commissions to investigate whether a proposed modification to ratemaking will benefit consumers, in addition to utilities. In particular, he noted that the utilities' promotion of an AFOR that relies on future test years[190] benefits utilities by "essentially provid[ing] a predetermination of prudence, arguably raising the bar for disallowance and refund."[191] Finally, he urged caution regarding the utilities' endorsement of reconciliation for rates of return that fall below a particular threshold. He argued that Maryland's utilities already benefit from low risk, due to the removal of their generation plants to unregulated entities, such that low returns evidence poor management. He believes that authorizing a reconciliation of the rate of return would remove an important market feedback mechanism and shift the regulatory paradigm from simply providing the utility with the opportunity or "ability to earn a fair rate of return" to "guaranteeing a rate of return."[192]

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[188] Comments of Dr. Carl Pechman at 2.
[189] Hr'g Tr. at 262-63. Dr. Pechman observed that New York requires that utilities file revenue requirement analysis based upon both historic test years and future forecast values to "provide a check on the reasonableness of the future test year." Comments of Dr. Carl Pechman at 3-4.
[190] If the Commission ultimately approves some form of future test year, Dr. Pechman recommended that Commission Staff devote additional time to increased monitoring, oversight, and reconciliation. For example, Commission Staff will need to respond to ensure that revenues are not over-collected and consumers overcharged if the utility fails to timely complete construction that was included in its revenue requirement forecast.
[191] Comments of Dr. Carl Pechman at 3.
[192] Comments of Dr. Carl Pechman at 6.

VII. LESSONS LEARNED: STATE AND FEDERAL IMPLEMENTATION EXPERIENCES

At the PC51 Technical Conference, several regulators from other states and a federal regulatory agency shared their experiences with respect to certain AFORs they employ. The participating regulators included representatives from Pennsylvania, New York, Illinois, Virginia, Massachusetts, and the Federal Energy Regulatory Commission ("FERC"). While no representative from the District of Columbia participated in the PC51 Technical Conference, several parties referenced the District of Columbia Public Service Commission's recent efforts to move forward with an alternative form of ratemaking during their testimony, and thus it is also described below.

A. Pennsylvania

Matthew Wurst, Advisor to Chairman Brown Dutrieuille of the Pennsylvania Public Utility Commission ("Pennsylvania PUC"), testified that the Commonwealth of Pennsylvania has been utilizing fully projected future test years since 2012 and other mechanisms, such as weather normalization adjustment or weather normalization rider.[193] Mr. Wurst explained that "historically, Pennsylvania utilized . . . a future test year which would start about three months prior to the filing of a rate case. And rate cases in Pennsylvania take generally nine months."[194] In 2012, the Pennsylvania General Assembly passed Act 11, which gave the utilities the authority to file rate requests based on fully projected future test years, and it gave the Pennsylvania PUC the authority to consider such filings.[195] Mr. Wurst stated that the

[193] Hr'g Tr. at 312 (Wurst).
[194] Hr'g Tr. at 313 (Wurst).
[195] Hr'g Tr. at 314 (Wurst).

legislation did not mandate use of the fully projected future test year, and structured it in such a way that the rates are effective on January 1, but the future test year would include 12 months beginning on the first start date of rates.[196] Mr. Wurst testified that since 2013, all major utilities in Pennsylvania that have filed a rate case have utilized the mechanism and over 50 rate cases have been filed.[197] He indicated that the Pennsylvania PUC issued an implementation order which was light on details and it is currently promulgating regulations that will seek to prescribe filing requirements and formulate more uniform standards.

Mr. Wurst noted that the primary goal of Pennsylvania Act 11 was infrastructure remediation because much of the state has old, dilapidated, and degraded infrastructure. [198] He further shared that Act 11 has three key prongs—the fully projected future test year, a long-term infrastructure improvement plan ("LTIP"), and a distribution service improvement charge ("DSIC").[199] The LTIP outlines—over a course of five to ten years—how the utilities plan to accelerate their existing infrastructure remediation plans. [200] The DSIC allows capital expense recovery outside of the norm of a regular rate case and the prerequisite for utilizing the DSIC is having an LTIP approved by the Pennsylvania PUC. Mr. Wurst stated that the LTIP acts as a benchmark for the Pennsylvania PUC to monitor how the DSICs match up, or do not match up, with the distribution system improvement change spending.[201] The DSIC is a rider that is applied quarterly to a customer's distribution rates, which may not exceed a 5% cap.[202]

[196] Hr'g Tr. at 314 (Wurst).
[197] Hr'g Tr. at 314 (Wurst).
[198] Hr'g Tr. at 315 (Wurst).
[199] Hr'g Tr. at 316 (Wurst).
[200] Hr'g Tr. at 316 (Wurst).
[201] Hr'g Tr. at 317 (Wurst).
[202] Hr'g Tr. at 317 (Wurst).

Mr. Wurst acknowledged that customer protection continues to be a key component, and that the Pennsylvania PUC addresses this by maintaining full discretionary authority to assess FTY filings, requiring utilities to file reports showing how FTY estimates match up to actuals, restricting the use of DSIC mechanism to recover only the cost of existing infrastructure, limiting the DSIC mechanism to start when the company has fully reached the Cap Ex numbers established in the FTY, and monitoring the utilities' earnings in Pennsylvania through reports.[203]

Mr. Wurst testified that overall the Pennsylvania PUC finds the change has been successful, mainly because of the infrastructure upgrades. However, he acknowledged an increase in workload for Commission staff and that there has not been a marked decrease in rate case filings. He advised that should the Maryland Commission decide to adopt a FTY, that the Commission should not eliminate its discretion over the information contained in the projections.

B. New York

Mr. John Stewart, the former managing director and advisor to the New York State Public Service Commission, testified that "the form of alternative regulation in New York is mostly three-year, multiple-year rate plans with three-year duration."[204] Mr. Stewart explained that the general model for alternative ratemaking in New York started with a "historic test period where you normalize the expenses, forecast from the historical period through a link

[203] Hr'g Tr. at 318-320 (Wurst).
[204] Hr'g Tr. at 325 (Stewart).

period to a future rate year, future test year, and once you get there you have the ability to forecast in that test year to additional test years in the future."[205]

Mr. Stewart stated that this form of alternative regulation "keeps pace with changing conditions" and "accommodates some strategic planning for management to have targets to shoot at, try to beat as far as expenses are concerned."[206] Mr. Stewart shared that this alternative regulation "requires a lot of detailed information" and admitted that "it took the [New York] Commission ten years to figure out what information had to be part of those filings before we really got it right."[207] He cautioned that the multi-year AFOR is "labor and resource intensive only if you've got a lot of companies filing at the same time. Because it is a lot more work."[208] Mr. Stewart indicated that an upside to the multi-year AFOR is that "if you have a three-year rate plan it means there's two years where you don't have the company in," which makes it not as labor or resource intensive.[209] Finally, Mr. Stewart advised that if the Commission was serious about employing an alternative regulation plan, "the best way to do it … [is] to go to projected rate years that basically sets targets for management to realize earnings, and eventually benefits to customers."[210]

C. Illinois

Mr. Scott Struck, Assistant Director of the Financial Analysis Division at the Illinois Commerce Commission, testified that Illinois utilizes four alternative ratemaking models: fully forecasted future test year, formula rates, infrastructure improvement riders, and revenue

[205] Hr'g Tr. at 324 (Stewart).
[206] Hr'g Tr. at 325 (Stewart).
[207] Hr'g Tr. at 325 (Stewart).
[208] Hr'g Tr. at 325 (Stewart).
[209] Hr'g Tr. at 325 (Stewart).
[210] Hr'g Tr. at 332 (Stewart).

decoupling riders. For the fully forecasted future test year, there are two rate case models: (1) a historical one, which needs to end before the utility can file a rate case and pro-forma forward looking adjustments can be made; and (2) a fully forecasted test year, where the test year begins after the rate case is filed so everything is forecasted and cannot extend beyond 24 months.[211] Mr. Struck stated that Illinois has been using the FTY mechanism for about 40 years and the context surrounding its adoption was that in the 1970s and 1980s, Illinois had high inflation, there were a lot of nuclear power plants going into rate base, and construction costs were rising. Consequently, Mr. Struck further indicated that utilities were dealing with a lot of regulatory lag. He commented that FTYs have been a useful tool to reduce regulatory lag during those times of significant expansion and inflation.[212] Mr. Struck noted that formula rates were implemented about 2011 only for electric utilities, and based on his observations, the approach has reduced the number of issues Illinois has had in rate cases. Mr. Struck advised that the Commission should not be afraid to experiment with different AFORs.[213]

D. Virginia

Mr. Arlen Bolstad, Deputy General Counsel for the Virginia State Corporation Commission, testified that Virginia does not use multiple test years or future test periods.[214] "In base rate cases, the rate year contains costs that are reasonably predicted to occur and the reasonably predicted costs may include actual predicted costs."[215] Mr. Bolstad noted that the Virginia General Assembly elected not to deregulate generation but also did not go back to

[211] Hr'g Tr. at 333-335 (Struck).
[212] Hr'g Tr. at 337 (Struck).
[213] Hr'g Tr. at 341 (Struck).
[214] Hr'g Tr. at 345 (Bolstad).
[215] Hr'g Tr. at 344 (Bolstad).

traditional cost of service rate regulation. Instead, for electricity, Virginia uses a hybrid model where it started out as two years, a biennial review, and now it is going to be a three-year, triennial review of earning.[216] The utilities are able to earn within a band of their fair rate of return plus or minus 70 basis points.[217] Last, Mr. Bolstad commented that the overall takeaway for Virginia is that the ratemaking structure in Virginia is highly driven by an active legislature.[218]

E. Massachusetts

Mr. Paul Afonso, former Chair of the Massachusetts Public Utilities Commission, testified regarding his experience with the implementation of alternative ratemaking including PBR and revenue decoupling. Regarding alternative ratemaking, Mr. Afonso stated that "avoiding regulatory lag and reducing the cost of capital by adopting alternative rate plans not only benefits the utility companies but it benefits the entire system, ecosystem of firms that have developed innovative energy technology and are producing [a] more modern, cleaner and resilient energy system."[219] He stated that under alternative ratemaking plans, the fundamentals of ratemaking will not change, meaning the Commission maintains the authority to determine whether any rate proposed is just and reasonable, and there would be continued opportunity to review and comment by stakeholders. Mr. Afonso advised that at the outset of the state's transition to an alternative rate plan, the Massachusetts Commission staff benefited

[216] Hr'g Tr. at 345 (Bolstad).
[217] Hr'g Tr. at 345 (Bolstad).
[218] Hr'g Tr. at 351 (Bolstad).
[219] Hr'g Tr. at 354 (Afonso).

from outside consultants. The Massachusetts staff subsequently developed the necessary skills to move to the alternative rate plans.[220]

F. The Federal Energy Regulatory Commission ("FERC")

Ms. Linda Patterson, the Director of the Technical Division at FERC, provided a high level overview of formula rates. First, she defined a formula rate as a "class-based rate scheme that uses an equation to update a utility's revenue requirement and determine per unit charges on an annual basis. A well designed formula rate will recover the cost of providing service during the year the rate is in effect."[221] Once approved by FERC, the formula may not be modified absent a filing with the Commission.[222] She noted that transparency is a critical factor in assuring that a formula rate is just and reasonable.[223] She explained that transparency requires that input data be sourced from publicly available documents or reconcilable to information specified in publicly available documents.[224] Ms. Patterson stated that "a formula rate should be sufficiently transparent so that an interested party with the information could calculate the rate."[225] In addition to a transparent formula rate, FERC requires formula rate protocols, which specify the procedures for notice, review and challenges to the utilities' annual updates, and protocols that also must be transparent.[226] She also noted that the utility is obligated to demonstrate that the formula rate is being implemented correctly and that the inputs are correct.[227]

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[220] Hr'g Tr. at 355 (Afonso).
[221] Hr'g Tr. at 357 (Patterson).
[222] Hr'g Tr. at 357-358 (Patterson).
[223] Hr'g Tr. at 358 (Patterson).
[224] Hr'g Tr. at 358 (Patterson).
[225] Hr'g Tr. at 359 (Patterson).
[226] Hr'g Tr. at 361 (Patterson).
[227] Hr'g Tr. at 362 (Patterson).

G. District of Columbia

In July 2017, the District of Columbia Public Service Commission ("DC PSC") adopted an order allowing Pepco to file a multi-year rate plan in its next rate case (a rate case which was filed in May of 2019). The DC PSC's Order in Formal Case 1139 stated: "The Commission is not averse to allowing Pepco to include in its next rate case a request for a fully forecasted test year and or a multi-year rate proposal, in addition to a traditional test year filing."[228] The DC PSC set forth the following conditions under which it would consider a proposal:

> (1) there must be a baseline revenue and cost evaluation which is equivalent to a historical test year; (2) Pepco must explain how to escalate or trend a myriad of revenues and expenses; (3) additional time must be allowed for the first examination of the new paradigm; thus, we foresee that and advise Pepco that the schedule for any rate case that includes a fully forecasted test year for the first time will require an appropriate extension of time to ensure that the Commission and all participants have the necessary time to fully examine any new proposal; (4) Pepco needs to provide a mechanism which allows parties to reconcile any forecasted components to subsequent actuals for the same test year.[229]

The DC PSC also indicated that its focus for considering any alternative rate regulation includes review of the benefits that will accrue to customers as opposed to solely focusing on the utility.[230]

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[228] Order No. 18846 (Formal Case 1139) at 187.
[229] *Id.*
[230] *Id.*

VIII. COMMISSION DECISION

The Commission is mandated to ensure continued just and reasonable rates which balance the interest of utilities, ratepayers and changing State policy goals. Therefore, the potential adoption of AFORs must be deliberative and carefully constructed. The Commission's principles of ratemaking balances utility cost recovery, rate impact, consumer interests, and public policies as demonstrated in its flexibility to implement adjustments when prudent and appropriate. The traditional ratemaking method based on a historic test year, as modified by the Commission over time, has resulted in just and reasonable rates for many years. Nonetheless, the Commission is cognizant that traditional ratemaking and the Commission's case-by-case approach to adjusting base ratemaking warrants a closer examination in view of the changing needs of Maryland's public service companies. Notably, the traditional ratemaking method does have certain perceived drawbacks such as a failure to equitably distribute risk, limited capabilities to monitor costs, limited ability to achieve policy outcomes and potential restrictions on utility innovation, and arguably regulatory lag, which can impede the utilities' ability to earn their authorized ROR.[231]

Today, the Commission reviews costs and investments by primarily looking backwards—using a historical approach—which means what utilities have planned for future investments are not typically a major part of the rate case review process.[232] The Commission

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[231] It is important to acknowledge that utilities, under long-standing Supreme Court holdings, are authorized, not guaranteed, a specific rate of return. Thus, there is no regulatory promise that a utility will earn its authorized rate of return, it is an opportunity, not a promise. *See Bluefield Water Works & Improvement Co. v. Public Service Comm'n of the State of W. Va*, 262 U.S. 679 (1923).

[232] *Initial Comments of the Greater Washington Hispanic Chamber of Commerce*, PC51, filed March 29, 2019, ("GWHCC Initial Comments") at 6.

finds that one or more forms of AFOR may be helpful, if carefully implemented, in facilitating the achievement of the State's ambitious goals regarding electrification, renewable development, pipeline replacement, development of new consumer solutions, grid resiliency, and other state goals. Since deregulation of generation in the early 2000s, the Commission no longer engages in integrated resource planning. Apart from the STRIDE gas and the electric surcharge infrastructure programs, there has been a lack of transparency in utilities' short-term planning for grid modernization and integrating distributed resources. Traditional ratemaking has also led to utilities favoring "iron in the ground" investments. For these reasons, the Commission finds that it is now appropriate to move forward cautiously in implementing an AFOR in Maryland.

Based on the extensive record developed in this proceeding, the Commission does not seek to develop the formula rate AFOR proposed by the utilities at this time. As discussed above, a formula rate does not address the central issue of regulatory lag. In fact, BGE witness Case testified that one of the downsides to formula rates is it still has a cash flow lag.[233] The Commission also is concerned that moving forward on formula rates would be complex and likely to require additional and lengthy analysis and proceedings to implement.[234] Other shortcomings of formula rate mechanisms raised during the PC51 Technical Conference include the tendency to shift financial risks toward customers, a concern that automatic adjustments may curtail the thorough review of utility costs, and reduced incentives for utilities to control costs.

233 Hr'g Tr. at 114 (Case).

234 The Commission notes that it would also require additional Staff resources that it does not currently possess in order to properly develop and administer a formula rate.

In contrast, the Commission finds that pursuing the implementation of a multi-year rate plan based on a historic test year is appropriate considering our experience in Case No. 9410, *Sandpiper Energy*, which was an approved settlement between Sandpiper Energy Inc., Commission Staff, and the OPC and represents our limited yet successful foray into a multi-year rate plan.[235] The Commission, through PC51, can build upon and expand its current experience in the Sandpiper case into a full-blown MRP, which the Commission finds may be accomplished reasonably quickly given that the Commission currently has some of the needed staff resources to transition to this AFOR.[236]

The record shows several benefits for MRPs such as shortening the cost recovery period, providing more predictable revenues for utilities and more predictable rates for customers, spreading changes in rates over multiple years, and decreasing administrative burdens on regulators by staggering filings over several years.[237] MRPs also allow adjustments to reflect changes in the business environment, rather than changes in the utility's actual revenue and costs. A key element of an MRP is that it provides more transparency into a utility's planning process. An MRP will require significant detail into utility planning that is not available to interested parties today. Combined with an annual true-up to actual expenses, an MRP provides added transparency with minimal risk to utility customers. Based on these benefits, the Commission finds multi-year rate plans based on a historic test year would combine the stability of traditional ratemaking while permitting adjustments that better reflect

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[235] *In the Matter of the Application of Sandpiper Energy, Inc.,* 107 Md. PSC 635 (2016).

[236] Kevin McGowan, Pepco's Vice President, Regulatory Strategy and Policy, testified that certainly the multi-year rate plan is an option that the Commission should consider and that it is "essentially three or four test years kind of linked together." Tr. at 121-122 (McGowan).

[237] MEA Comments at 5.

the changing energy market. The Commission also finds that it can draw on the experiences of states like Pennsylvania which, like Maryland, determined a need for investments in the state's infrastructure and established a distribution system improvement charge that is being implemented and has been compatible with using a fully forecasted test year mechanism since 2012. Pennsylvania's model may be instructive as this Commission has had several years of implementing grid modernization and resiliency charges and the STRIDE program, but now seeks to incorporate forecasting, which will provide more transparency into the utility planning process and allow the Commission an opportunity to question the customer benefits of projects in advance of capital commitments.

Concerning MRPs, The Brattle Group report found that "multi-year rate plans typically have reconciliations more limited in scope and focused on capital expenditures, to the extent that reconciliations are included at all."[238] Another feature of MRP is the stay out provision. "Stay-out requirements prevent utilities from refiling for a change in base rates (or regulatory plan) for a certain number of years, typically three to five years. Stay-out requirements frequently include clauses to account for unanticipated events with significant financial impact and may allow a utility to refile if earnings fall below a certain threshold."[239] The Brattle Group also indicated that some jurisdictions adopting multi-year rate plans implement filing dates for utilities that are staggered to spread the burden of work on the commission.[240] Finally, the Coalition argued that MRPs may be particularly well suited to pair with PBRs, which is a feature important to the Commission and discussed later in this decision.

[238] The Brattle Group Report at 20.
[239] The Brattle Group Report at 16.
[240] The Brattle Group Report at 10.

Accordingly, based on the record developed in this proceeding as well as Commission experience, the Commission finds that a properly constructed multi-year rate plan based on a historic test year and allowing up to three future test years can produce just and reasonable rates and can be implemented at this time, subject to developing the accommodating processes and procedures.[241] To assist in this transition, the Commission delegates to the Public Utility Law Division the authority to lead a working group of interested parties ("Working Group") charged with of developing and submitting a detailed implementation report ("Implementation Report"). Staff shall assist the assigned Public Utility Law Judge in establishing the Working Group.

The Working Group Implementation Report should include the following:

(1) details regarding the forecasts that must be filed for subsequent years after the initial historic base year, including capital expenditures;

(2) a complete list of the proposed reporting requirements, measures, and timelines;[242]

(3) proposals for staggering filings to prevent overburdening Commission Staff resources;

(4) identifying ways to make the utilities' planning process more transparent and open to the Commission and the ratepayers as suggested by Dr. Pechman;[243]

(5) recommendations on requirements to decrease information asymmetries between the utility and the affected parties;

(6) identifying ways to ensure that the burden of proof remains with the utilities to show that a proposed rate change is just and reasonable;

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[241] This does not restrict a utility from including whatever proposals it wishes in rate applications.
[242] Included therein is a requirement that any utility filing an MRP must also file a report detailing how the fully projected future test year estimates match up against actuals.
[243] Hr'g Tr. at 252-253 (Pechman).

(7) proposals for an annual true-up mechanism;

(8) proposals for stay out provisions;

(9) proposed revisions to COMAR Title 20 regulations for filing MRPs;

(10) recommendations to ensure that existing COMAR metrics (such as SAIFI, SAIDI, customer call metrics, stray voltage metrics, vegetation management, etc.) are not eroded and remain intact through AFOR adoption; and

(11) advice on whether additional conditions for filing an AFOR need to be developed for utility companies on an individual basis and, if so, what approach would be most efficient.

The Working Group should begin immediately on developing the process for, and revised regulations to, implement multi-year rate plans upon issuance of this Order and file its report by December 20, 2019, and the Commission will endeavor to issue a ruling on next steps by January 30, 2020.[244]

Finally, the Commission finds that aligning state policy goals and utility rate increases is an important objective. Regarding performance based AFORs, the Commission finds that PBRs can strike a balance between imposing additional obligations on the utilities that meet State policy goals and obtaining measurable benefits and providing value to customers. However, the record suggests that determining the State policies and goals to consider in developing the performance metrics and incentive mechanisms will require additional time. For this reason, the adoption of the full performance-based mechanism *at this stage* would only further delay implementation of a multi-year rate plan. Nonetheless, the Commission agrees

[244] The Commission cautions gas and electric utilities not to file such base rate cases simultaneously or even within months of each other.

with the Coalition that an important step forward in adopting a PBR component to a multi-year rate plan is to direct the stakeholder group to address the following: "(a) what are the regulatory goals and desired outcomes that support the state's priorities; (b) what metrics and targets are appropriate; and (c) what form should the rewards/penalty incentive mechanism take."[245]

Accordingly, the Commission directs the PULJ to continue the Working Group after submission of the Implementation Report. The Working Group shall commence discussions on how best to integrate performance-based measures into a multi-year rate plan by identifying goals and outcomes (e.g., integrating more renewable resources and energy efficiency, encouraging peak demand reductions, facilitating storage, supporting grid modernization, and any other State policy goals that may be in place or enacted) that align utility performance with State policy objectives that are not already addressed through existing regulatory measures.

To this end, the Working Group should evaluate metrics that are clearly defined, verifiable, quantifiable, subject to the utility's control, and be able to be incorporated into a multi-year rate plan. The Working Group should file a Report identifying the areas where metrics are appropriate, without proposing actual metrics, by April 1, 2020, so that the Commission may provide additional guidance on the completeness of the list and metric setting.[246]

IT IS THEREFORE, this 9th day of August, in the year of Two Thousand Nineteen, by the Public Service Commission of Maryland,

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[245] Coalition Final Comments at 6.
[246] Appendix B sets out the Implementation Timeline that the Commission will endeavor to follow in this proceeding.

ORDERED: (1) That the assigned Public Utility Law Judge should convene, with the assistance of Staff, a working group of the affected stakeholders and interested parties as discussed herein;

(2) That the working group shall develop a detailed Implementation Report and procedures for filing a multi-year rate plan involving forecasted test years in accordance with this Order and the timeline described herein;

(3) That upon submission of the Implementation Report, the working group shall begin discussions on the integration of performance-based measures into a multi-year rate plan; and

(4) That Docket No. 9618 is hereby initiated; the Implementation Report and further filings in regard to alternative forms of rate regulation shall be filed therein.

/s/ Jason M. Stanek

/s/ Michael T. Richard

/s/ Anthony J. O'Donnell

/s/ Odogwu Obi Linton

/s/ Mindy L. Herman
Commissioners

LIST OF PARTIES PROVIDING WRITTEN COMMENTS

AARP Maryland

Apartment and Office Building Association of Metropolitan Washington

Baltimore Washington Laborers' District Council of the Laborers'
International Union of North America ("LIUNA")

Brown Rudnick LLP

The Coalition for Performance Incentive Mechanism (DMV Strategic Advisors LLC)

Columbia Gas of Maryland Inc.

Office of Staff Counsel

Edison Electric Institute

Greater Washington Hispanic Chamber of Commerce

Joint Exelon Utilities (Baltimore Gas and Electric Company and Pepco Holdings)

Maryland Energy Administration

Montgomery County, Maryland

Dr. Carl Pechman

Office of the Attorney General of Maryland

Office of People's Counsel

The Potomac Edison

Southern Maryland Electric Cooperative, Inc. and
Choptank Electric Cooperative

Sunrun, Inc.

Washington Gas Light Company

IMPLEMENTATION TIMELINE

Date	Task
August 2019	Commission issue PC51 Order on AFORs which initiates a Work Group Process
December 20, 2019	PC51 Work Group issues detailed implementation report and recommendations addressing each of the areas outlined in this Order
January 1, 2020	Begin Phase 2 Working Group to determine and propose appropriate performance incentive metrics for Maryland utilities
January 30, 2020	Commission issues ruling on next steps based on the Working Group's Implementation Report
February 1, 2020, and thereafter	Subject to the Commission's ruling, utilities may file to implement a multi-year rate for up to three years.
April 1, 2020	Phase 2 Working Group files report and recommendations regarding performance incentive metrics with the Commission.