Implementing PBR with Customer Protections in North Carolina

E-100, Sub 178

Prepared on Behalf of the
Carolina Utility Customers Association

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CONTENTS

EXECUTIVE SUMMARY 1
Requirements for Utility PBR Applications 2
Criteria for Evaluating a PBR Application 3
Technical Conference Prior to PBR Application 4
Process for Addressing Rejection of PBR Application 4

INTRODUCTION 5

COST CONTAINMENT INCENTIVES IN REGULATORY FRAMEWORKS 6
Cost of Service Regulation 6
Common Multi-Year Rate Plans 7
MYRP Requirements of G.S. § 62-133.16 7
Comparison of Incentives and Risks under Regulatory Frameworks 8

PROPOSED REQUIREMENTS FOR UTILITY PBR APPLICATIONS 9
Transparency in Cost Forecasts 9
Transparency During the PBR Plan 11
One-Way Cost Reconciliations 12
Performance Incentive Mechanisms 13

PROPOSED CRITERIA FOR EVALUATING A PBR APPLICATION 13

PROPOSED TECHNICAL CONFERENCE PROCESS PRIOR TO PBR APPLICATION 14

PROPOSED PROCESS FOR ADDRESSING REJECTION OF PBR APPLICATION 15

Executive Summary

On October 14, 2021, the Commission issued an Order in Docket E-100, Sub 178 initiating a rulemaking proceeding to implement the provisions of N.C. Gen. Stat. § 62-133.16, which authorizes the North Carolina Utilities Commission (Commission) to approve performance-based regulation (PBR) upon application of an electric utility. The Commission opened this docket to solicit comments regarding implementation of PBR. Synapse Energy Economics, Inc. (Synapse) developed this report in response to the Commission's order on behalf of the Carolina Utility Customers Association (CUCA).

Historically, PBR has been implemented to encourage utilities to operate more efficiently and to better align utility incentives with the public interest. As described by the Vermont Public Utilities Commission in 1996,[1] PBR "encourages companies to reduce their costs over time, by providing profit incentives to stimulate innovation, efficiency, and service quality improvements."[2] These objectives are accomplished largely through multi-year rate plans (MYRPs), which divorce a utility's revenues from its actual costs for a set period of time (the "stay-out period" between rate cases). During this period, utilities have an opportunity to enhance profits by reducing their costs between rate cases. However, this potential upside is traditionally balanced by prohibiting the utility from filing another rate case if its costs exceed its revenues. In this way, PBR has historically assigned more of the risk and reward associated with utility operations to utility management.

The elements set forth in North Carolina's PBR statute, if implemented, constitute a significant departure from both traditional ratemaking and the typical application of MYRP principles. Through shifting the balance of risk between customers and the utility, the statute's provisions could increase costs and risk substantially for utility customers if not balanced with robust customer protections.

Although MYRPs typically adjust revenues between rate cases, the PBR statute deviates from common MYRP design by omitting elements that would otherwise serve to incentivize utility cost control and reduce risk to customers. Most notably, the statute allows the utility to file a rate case if its return on equity falls below authorized levels, rendering the "stay-out period" of the MYRP moot. Further, the MYRP's annual revenue increases are based on utility cost forecasts, which further erodes the utility's incentives to constrain spending, while also exacerbating information asymmetries between the utility and regulator.

The Commission can, and should, mitigate the potential for adverse impacts on ratepayers by establishing clear standards that a utility's PBR application must satisfy up front, as well as robust utility filing requirements, reporting requirements, and other measures to enhance transparency and ensure the utility provides value for customers' dollars. Further, the Commission should return any utility under-

[1] The Vermont Public Utilities Commission was then known as the Vermont Public Service Board.

[2] Vermont Public Service Board. Report and Order. Docket No. 5854, *Investigation into the Restructuring of the Electric Utility Industry in Vermont.* December 31, 1996, page 36. Available at https://puc.vermont.gov/sites/psbnew/files/orders/1996/5854RPT.pdf.

spend to ratepayers, thereby mitigating the risk of overstated cost forecasts. Ultimately, the Commission retains the authority and responsibility to ensure that any rate increases are just and reasonable.

Requirements for Utility PBR Applications

Utilities always have more information regarding their costs and system needs than regulators, the Public Staff, and stakeholders. To overcome information asymmetries and adequately vet utility cost forecasts, the transparency of utility planning processes and cost information should be enhanced, and utilities must be required to file this information as part of their PBR application. The filing should also include the methodology proposed by the utility for calculating important metrics, such as the utility's weather-normalized return on equity.

Once the PBR plan is underway, the utility should also report on any deviations from its cost forecasts to ensure that ratepayers receive value for their money. If the utility does not complete projects and underspends its budget, the associated revenues should be returned to ratepayers. If the utility overspends its budget, the utility should not be allowed to recover such costs during the MYRP, since the utility has an opportunity to file a new rate case if needed.

Synapse recommends that the Commission require a utility filing a PBR application to:

1) Document the need for all capital projects, and, where appropriate, reference the utility's integrated resource plan, integrated distribution plan, or internal capital investment plan.

2) Include a prioritization of projects in its investment plan that accounts for the risk reduction or policy objective accomplished by each project.

3) Evaluate and document alternatives to the utility's proposed investments, including solutions offered by third parties, where appropriate.

4) Evaluate how the plan conforms with the Company's Carbon Reduction Plan.

5) Submit a cost benchmarking study using data from the largest group of peer utilities available that are electric-only investor-owned utilities with ownership of generating resources and at least 400,000 customers.

6) Include a proposal for how weather-normalized earnings will be calculated, including an example calculation and the underlying data used.

7) Include a proposal for returning any under-spend to customers through a rider or other mechanism and refrain from seeking recovery of any utility over-spend through the MYRP. This proposal would provide greater protection for ratepayers than the statute's proscribed 50 basis point cap on overearnings.

8) On an annual basis:

    a. Report unit cost metrics on an annual basis.

    b. Make a filing that identifies differences between projected investments and actuals, in both cost and quantity, and the reasons for any significant deviations.

c. Respond to discovery requests from intervenors regarding the annual reconciliation filing.

d. Implement annual rate changes only following a public hearing and prudence determination by the Commission.

9) Accompany any performance incentive mechanism (PIM) proposals with:

a. Estimates of quantitative and qualitative benefits and costs associated with meeting the PIM's targets;

b. At least three years of historical baseline data; and

c. A discussion of any investments contained in the utility's MYRP that are expected to enhance performance in the area addressed by the PIM.

Criteria for Evaluating a PBR Application

The Commission should adopt specific criteria for determining whether a utility's PBR application would result in just and reasonable rates and is in the public interest, as required by statute.[3] To assess the reasonableness of utility's proposed revenue requirement increases, the Commission should require that a utility proposing a PBR plan demonstrate that:

1) The PBR plan is more likely than current regulation to advance the goals of utility cost control, lower rates, and reduced administrative burden.[4]

2) Post-test year cost increases do not exceed forecasts of regional public utility cost escalation rates or historical average rates of increase.[5]

3) It appropriately considered and evaluated alternatives to its proposed investments, including third-party provided solutions.

4) Average customer rates (by class) and bills (for residential customers) will be within a reasonable range of peer utilities' rates and bills during and at the conclusion of the rate plan.

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[3] N.C. Gen. Stat. § 62-133.16 (d)(1)

[4] This requirement is based on those established by the Massachusetts Department of Public Utilities in D.P.U. 94-158. In that order, the Department required a petitioning utility "to demonstrate that its approach is more likely than current regulation to advance the Department's traditional goals of safe and reliable energy service and to promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden in regulation." Massachusetts Department of Public Utilities Investigation by the Department on its own motion into the theory and implementation of incentive regulation for electric and gas companies under its jurisdiction, 1995, page 48. Available at https://www.mass.gov/doc/94-158pdf/download.

[5] For example, Southern California Edison uses IHS Global Insight escalation rates to calculate post-test year revenue requirements for non-labor O&M costs, while capital costs are escalated, in part, based on a composite escalation rate developed from IHS Global Insight forecasts of the Handy-Whitman Index of Public Utility Costs. *See:* Southern California Edison (U 338-E) 2018 General Rate Case Application, A. 16-09-001 (SCE-09, Vol. 1) at 85.

5) The benefits of achieving any approved PIMs are likely to outweigh the costs of doing so (including any financial rewards paid to the utility), and the targets represent measurable improvements over the utility's historical or expected performance.

Technical Conference Prior to PBR Application

The Commission should require that an electric utility convene a technical conference at least 60 days prior to the utility's submission of a PBR application. The utility's presentation slides for this conference should be made available on the utility's website at least 24 hours prior to the conference to allow stakeholders time to review and offer substantive feedback.

At this technical conference, the utility should:

- Present its proposed investments, including an appendix detailing the total cost of each project, identifying the primary driver of costs for each project (e.g., reliability, new customers, load growth), and the risk or policy goal that the project addresses (where applicable).
- Summarize the alternatives that it considered (including third-party owned or operated non-wires alternatives).
- Explain the utility's load forecasting methodology underpinning the need for any load-related investments.

Process for Addressing Rejection of PBR Application

In addressing the Commission's rejection of a PBR application, the Company should be required to:

- Satisfactorily address each of the Commission's identified deficiencies in a refiled application with all supporting schedules and testimony discussing the changes made.
- Work with stakeholders where appropriate to remedy deficiencies and present the proposed changes to stakeholders in a technical conference.
- Respond to discovery requests filed by the Commission or intervenors regarding the modifications made.

Stakeholders should then have an opportunity to file responsive testimony addressing whether the modifications made by the Company are reasonable.

INTRODUCTION

On October 13, 2021, North Carolina Governor Roy Cooper signed into law House Bill 951 (Session Law 2021-165), which enacted N.C. Gen. Stat. § 62-133.16. This new statute authorizes the North Carolina Utilities Commission to approve performance-based regulation upon application of an electric utility.

On October 14, 2021, the Commission issued an Order in this docket initiating a rulemaking proceeding to implement the provisions of G.S. § 62-133.16. In that Order, the Commission requested that parties file comments and proposed rules that address the following issues, as well as any other relevant issues that the Commission must address to implement PBR:

1. The specific procedures and requirements that an electric public utility shall meet when requesting approval of a PBR application.

2. The criteria for Commission evaluation of a PBR application.

3. The parameters for a technical conference process to be conducted by the Commission prior to submission of any PBR application consisting of one or more public meetings at which the electric public utility presents information regarding projected transmission and distribution expenditures and interested parties are permitted to provide comment and feedback.

4. The process by which an electric public utility may address the Commission's reasons for rejection of a PBR application, which process may include collaboration between stakeholders and the electric public utility to cure any identified deficiency in an electric public utility's PBR application.

The elements set forth in the PBR statute, if implemented, constitute a significant departure from traditional ratemaking. The PBR statute also contains two provisions that shift the balance of risk toward customers and undermine the utility's cost control incentives:

- The utility is allowed to file a rate case if its return on equity (ROE) falls below its allowed level. This provision renders the stay-out period moot and shifts risk to customers of any over-spend.

- The revenues for each year are to be based on utility cost forecasts, rather than external indices. This further erodes the utility's cost control incentives and, due to asymmetry of information, shifts the risk of over-forecasting to customers.

The Commission can, and should, mitigate the potential for adverse impacts on ratepayers by establishing clear standards that a utility's PBR application must satisfy up front, as well as robust utility filing requirements, reporting requirements, and other measures to enhance transparency and ensure the utility provides value for customers' dollars.

Cost Containment Incentives in Regulatory Frameworks

Historically, PBR has been implemented to encourage utilities to operate more efficiently and to better align utility incentives with the public interest. For example, in its Notice of Inquiry into performance-based regulation, the Massachusetts Department of Public Utilities emphasized that the primary objective of such framework would be to provide benefits to customers through "(1) more efficient utility operations, (2) stronger utility incentives for better cost control, and (3) enhanced opportunities for lower rates." [6]

The MYRP is generally the key means of providing efficiency incentives to utilities. As described by the Vermont Public Utilities Commission in 1996,[7] prices are not set "strictly on the basis of historic (or accounting) costs, but rather in a way that encourages companies to reduce their costs over time, by providing profit incentives to stimulate innovation, efficiency, and service quality improvements."[8] The MYRP sets "rates, or components of rates, for a period of time based on external indices rather than directly on a utility's cost-of-service," which is intended to enhance operational efficiency incentives relative to traditional cost-of-service regulation.[9] By divorcing a utility's revenues from its actual costs for a set period of time (the "stay-out period"), utilities have an opportunity to enhance profits by reducing their costs between rate cases. Customers are also protected, as the stay-out provision prevents the utility from filing another rate case if costs exceed its revenues. In this way, PBR has historically assigned more of the risk and reward associated with utility operations to utility management.

However, the extent to which an MYRP provides incentives to operate efficiently is dependent on the specific design of the framework. Below we briefly discuss the incentives provided by an MYRP compared to traditional cost of service regulation (COSR) and important considerations for the Commission to consider when implementing PBR in North Carolina.

Cost of Service Regulation

Traditional cost of service regulation creates an inherent cost containment incentive by setting rates based on a test year and then holding those rates fixed[10] until the utility files another rate case. Assuming that sales remain the same each year, the utility can increase profits by reducing costs during the period

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[6] For example, in its Notice of Inquiry into performance-based regulation, the Massachusetts Department of Public Utilities emphasized that the primary objective of such framework would be to provide benefits to customers through "(1) more efficient utility operations, (2) stronger utility incentives for better cost control, and (3) enhanced opportunities for lower rates." Massachusetts Department of Public Utilities, D.P.U. 95-158, Investigation by the Department on its own motion into the theory and implementation of incentive regulation for electric and gas companies under its jurisdiction, 1995. Available at https://www.mass.gov/doc/94-158pdf/download.

[7] The Vermont Public Utilities Commission was then known as the Vermont Public Service Board.

[8] Vermont Public Service Board. Report and Order. Docket No. 5854, *Investigation into the Restructuring of the Electric Utility Industry in Vermont.* December 31, 1996, page 36. Available at https://puc.vermont.gov/sites/psbnew/files/orders/1996/5854RPT.pdf.

[9] *Id.,* page 136.

[10] With the exception of certain cost trackers that adjust rates as costs change.

between rate cases, since the utility generally keeps any difference between revenues and costs. On the other hand, if costs increase under COSR, the utility's profits will decline until the higher costs are reflected in rates in a subsequent rate case. This delay in reflecting new costs in rates is referred to as "regulatory lag," and it helps incentivize efficient utility operations. However, utilities can also file a rate case as needed, blunting the incentive to control costs.

Under traditional cost of service regulation, there is rarely any sharing of utility under-earnings (i.e., earnings below the utility's allowed ROE), although there may be sharing of over-earnings.

Common Multi-Year Rate Plans

In contrast to COSR, an MYRP typically institutes a rate case moratorium or "stay-out period" often lasting from three to five years. This stay-out period ensures that the utility cannot simply come in for a new rate case if costs and revenues diverge, thereby providing cost containment incentives. In return, the utility's allowed revenues are typically increased annually according to some pre-set formula or set of variables. The utility is frequently allowed to retain some or all of the savings that it achieves through cost reductions during the duration of the rate plan, while being required to absorb some or all of any costs that exceed its allowed revenue requirement.[11] This shifts the risk and reward associated with utility cost management to utility management and shareholders, rather than ratepayers, which strengthens the utility's cost containment incentives.

How the allowed revenues for each year are set in an MYRP impacts the strength of the cost containment incentives substantially. Annual revenue adjustments may be based on an external cost index (such as inflation), cost forecasts, or a combination of the two. If utility cost forecasts are used, care must be taken to ensure that the forecasts are reasonable and in the public interest, increasing the need for regulatory oversight and information transparency.

Under an MYRP, there is rarely any sharing of utility under-earnings (i.e., earnings below the utility's allowed ROE), although there is frequently sharing of over-earnings.[12]

MYRP Requirements of G.S. § 62-133.16

The PBR statute diverges from both common MYRP practice and traditional cost of service regulation in several important ways. First, there is no requirement for the utility to refrain from filing a new rate case if its earnings fall below the authorized rate of return on equity. Thus, the utility has little incentive to manage its costs, as it can simply file a new rate case if needed.

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[11] However, as discussed later, when the utility's allowed revenues for capital investments are based on capital cost forecasts rather than external indexes, jurisdictions often require the utility to return any under-spend to ratepayers.

[12] Of 19 utilities in the United States with earnings sharing mechanisms, only one is reported to have a symmetrical earnings sharing mechanism. The others share over-earnings only. Mark N. Lowry, Matthew Makos, and Gretchen Waschbusch. *Alternative Regulation for Emerging Utility Challenges: 2015 Update*. Edison Electric Institute. November 11, 2015, page 37-38.

Second, the statute requires that the utility's base rates in the second and third years of the MYRP be based on utility cost forecasts. Specifically, the statute states that, after the initial year, base rates should be "based on projected incremental Commission-authorized capital investments that will be used and useful during the rate year and associated expenses, net of operating benefits, including operation and maintenance savings, and depreciation of rate base associated with the capital investments, that are incurred or realized during each rate year of the MYRP period."[13] Under this provision, the utility has an incentive to inflate its cost forecast so that its allowed revenues are guaranteed to be sufficient to cover its costs.

However, the statute contains two important restrictions on the MYRP revenue adjustments:

1) the rate increase in the second and third years is capped at four percent of the utility's first year revenue requirement, excluding any revenue requirement for the capital spending projects to be placed in service during the first rate year.

2) the revenue requirements associated with any single new generation plant exceeding five hundred million dollars placed in service during the MYRP shall not be included in the MYRP revenue requirements. Instead, the utility may request, and the Commission may grant at its discretion, a deferral for such costs to a future rate case.[14]

Under the statute, earnings exceeding 50 basis points above the utility's allowed ROE are required to be returned to ratepayers.[15]

Comparison of Incentives and Risks under Regulatory Frameworks

The table below compares the key components of traditional cost of service regulation, common MYRPs, and the MYRP framework authorized under G.S. § 62-133.16.

[13] N.C. Gen. Stat. § 62-133.16 (c)(1)(a).

[14] Ibid.

[15] N.C. Gen. Stat. § 62-133.16 (c)(1)(c).

	Traditional Cost of Service Regulation	MYRP	MYRP Under G.S. § 62-133.16
Stay-Out Period	None	Typically 3-5 years	None – the utility can file a rate case if earnings are below the authorized ROE
Adjustments to Base Rates Between Rate Cases	Typically none	Revenue adjustments are based on a pre-set formula, often using external indexes for all or part of the adjustment	Revenue adjustments are based on utility forecasts (with some limits)
Cost Containment Incentives	**Moderate**. Largely tied to regulatory lag and prudence review	**Moderate-High**. Cost efficiencies driven by stay-out period and de-linking revenues from utility costs	**Low**. Utility has incentive to overestimate its cost forecast. If utility spends more than forecast, it can file a rate case.
Customer Protections	Rates only adjusted based on actual costs prudently incurred. Sometimes upside earnings sharing.	Stay-out period limits utility's ability to increase rates. Some or all of the annual revenue adjustments based on external forecasts. Frequent upside earnings sharing.	Cap on revenue adjustments of 4%. Excess earnings above 50 basis points returned to ratepayers.
Risk to Utility	**Moderate.** Utility bears risk that test year revenues will not be sufficient to cover future costs, but can file a rate case if needed.	**Moderate**. Utility bears risk that costs may increase above allowed revenues during the rate plan.	**Low**. Rate increases are capped at 4%, but utility has incentive to develop cost forecasts that result in cost increases up to the cap each year.
Risk to Customers	**Moderate**. Customers bear risk of frequent rate cases (and associated rate increases and administrative costs).	**Moderate**. Customers bear risk that allowed revenues are set too high, although this can be mitigated by up-side earnings sharing and use of external cost indexes.	**High**. Customers bear risk that allowed revenues are set well above the efficient level and have low ability to identify overstated forecasts.

Proposed Requirements for Utility PBR Applications

Transparency in Cost Forecasts

An MYRP as authorized by G.S. § 62-133.16 eliminates regulatory lag, while posing a significant risk to customers that cost forecasts will be inflated above efficient levels. Specifically, by requiring that rates be set based on utility forecasts rather than an external index, the statute places a substantial burden on the regulator and stakeholders to ensure that the utility's cost forecasts are reasonable, which is challenging due to asymmetry of information. The National Regulatory Research Institute describes this issue as follows:

> Information asymmetry reflects the relatively less knowledge that a regulator has (relative to the utility's) on the correlation between forecasted costs and utility-management competence. When a utility files a cost forecast, how does the regulator know whether it reflects competent management? The analyst or auditor can evaluate the forecast applying state-of-the-art techniques; still, however, a level of uncertainty remains that leaves unknown the utility's level of managerial competence embedded in the forecast.[16]

In short, the use of utility cost forecasts suffers from information asymmetry. To mitigate information asymmetry as much as possible, many regulators have sought to increase the transparency of utility planning practices and filings to ensure the *right investments* are made, and some regulators have implemented statistical benchmarking to ensure the *right costs* are used. Further, regulators generally require that utilities submit detailed annual reports that identify any differences between projected costs and actuals.[17] We recommend that the Commission adopt these practices. Specifically, we recommend that the Commission require a utility filing a PBR application to:

- Document the need for all capital projects, and, where appropriate, reference the utility's integrated resource plan, integrated distribution plan, or internal capital investment plan. Examples of such documentation include load forecasts supporting the need for any load growth-related investments and equipment condition assessments for any reliability replacement projects.
- Include a prioritization of projects in its investment plan that accounts for the risk reduction provided by each project where applicable. Risks should be quantified where possible so that each project that is made to enhance system reliability has an associated risk reduction per dollar spent. If the objective of the investment is not risk reduction, the policy objective of the investment should be identified.
- Evaluate and document alternatives to the utility's proposed investments, including solutions offered by third parties, where appropriate. This should include a summary

[16] Ken Costello. *Multiyear Rate Plans and the Public Interest*. National Regulatory Research Institute. October 2016, pages 35–36. Available at https://pubs.naruc.org/pub/FA86999D-D03F-2858-7228-A6353560E5B9.

[17] In New Hampshire, Liberty Utilities is required to make annual filings with detailed project descriptions including the initial budget, the final cost, and the date each project was booked to plant in-service, and must include substantial documentation. *See:* New Hampshire Public Utilities Commission, Docket No. DE 19-064, Stipulation and Settlement Agreement Regarding Permanent Rates, May 25, 2020. Similarly, in New York, ConEdison files an annual report providing (1) a list of all projects and/or programs that were eliminated, with supporting explanation; (2) a list of all new projects and/or programs that were added, with supporting explanation; (3) for all projects and/or programs, the actual amount spent as compared to the forecasted budget amounts with explanations for substantial variances. *See:* Appendix 22 of the Joint Proposal for Consolidated Edison Company of New York, Inc. Cases 16-E-0060 and 16-G-0061, September 19, 2016. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={971AFDDE-A9A3-437B-8283-543762C5514B}

discussion of any solicitations made for third-party solutions and the high-level results of such solicitations.

- Submit a cost benchmarking study using data from the largest group of peer utilities available that are electric-only investor-owned utilities with ownership of generating resources and at least 400,000 customers .[18]

Transparency During the PBR Plan

Throughout the implementation of a PBR plan, the utility should also demonstrate that customers are receiving value for their investments, and that the utility's return on equity is calculated transparently. Annual rate increases should only be implemented upon adequate documentation of the reasonableness of costs incurred, a public hearing, and a prudence determination by the Commission. Ultimately, the Commission retains the authority and responsibility to ensure that any rate increases are just and reasonable.

Thus, the utility should be required to:

- Include in its application a proposal for how weather-normalized earnings will be calculated, including an example calculation and the underlying data used, and file reports with the utility's actual earnings during the annual reporting process.

- Report unit cost metrics on an annual basis for subcategories of O&M and capital costs.[19] The units for these costs may be in terms of cost per customer or other measure of scale such as cost per mile of line.[20]

- Make an annual filing that identifies differences between projected investments and actuals, in both cost and quantity, and the reasons for any material deviations. In these filings, the utility should provide project status details for projects subject to an MYRP plan. These details should include the initial budget, the final cost, and the date each project was booked to plant in-service. In addition, for each of these projects, the Company should provide all Company project documents including, but not limited to, business cases, capital project expenditure applications, change order forms, project close out reports, and work orders.[21]

- Respond to discovery requests regarding its annual reconciliation filing.

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[18] An example of such a study was recently conducted for Florida Power and Light, and includes Duke Energy Progress and Duke Energy Carolinas in its peer group. *See:* Direct Testimony of John J. Reed before the Florida Public Service Commission, Docket No. 20210015-EI, March 12, 2021. Available at https://www.fpl.com/content/dam/fpl/us/en/rates/pdf/14%20John%20J.%20Reed%20-%20Direct%20Testimony%20and%20Exhibits%20-%2020210015-EI.pdf

[19] At a minimum, these costs should be reported on a FERC account basis. Additional categories may also be reasonable.

[20] For example, see the presentation from Pacific Economics Group here: https://www.oeb.ca/sites/default/files/APB-Working-Group2-PEG-presentation-20181029.pdf

[21] These requirements are based on those in New Hampshire, as documented in Docket No. DE 19-064, Stipulation and Settlement Agreement Regarding Permanent Rates, May 25, 2020.

- Implement annual rate changes only following a public hearing and prudence determination by the Commission.

One-Way Cost Reconciliations

Another issue that arises with MYRPs based on cost forecasts is whether to return any savings to ratepayers resulting from utility under-spend. We note that the statute does not address this, but that regulators in other states often require that the utility return any under-spend to customers.[22]

A key challenge associated with the use of cost forecasts is that the utility has an incentive to inflate cost projections. As the Alberta Public Utilities Commission noted, unless there is a reconciliation mechanism, basing revenues on cost forecasts "creates the opportunity for the distribution utility to benefit from exaggerating its forecasts and puts more pressure on the Commission to ensure the forecasts are reasonable." Further, the Alberta Commission notes its "concerns about over-forecasting and asymmetrical information and finds that an incremental capital mechanism that includes a forecasting component but lacks a true-up is problematic because it incorporates the unacceptable forecasting incentives…"[23]

Although a one-way reconciliation mechanism removes the utility's incentive to reduce costs below its forecasts, it helps protect customers from bearing the costs associated with inflated cost forecasts. Further, if the utility exceeds its cost forecasts such that its rate of return is negatively impacted, the statute permits the utility to file a new rate case. Therefore, we recommend that the Commission require the utility to return any under-spend to ratepayers. In the utility's PBR application, the utility should:

- Include a proposal for returning any under-spend to customers through a rider or other mechanism and refrain from seeking recovery of any utility over-spend.

Minnesota and New York both use cost forecasts to project revenue requirements associated with capital investments, but they have coupled the forecasts with a one-way (downward) reconciliation mechanism. New York's approach is referred to as the "Net Plant Reconciliation Mechanism" or "claw-back mechanism." The New York Public Service Commission describes this mechanism for Consolidated Edison as follows:

> If the Company's actual average net plant in service for each of the three categories of capital expenditures is less than that category's projected average plant-in-service balance…, the Company will defer the carrying costs associated with the difference for the benefit of ratepayers. If the Company exceeds the net plant-in-service targets, it must absorb the related carrying costs during the term

[22] Minnesota and New York are two examples of states that require any under-spend to be returned to customers. *See:* Minnesota Public Utilities Commission, Findings of Fact, Conclusions, and Order, Docket E-002/GR-15-826, June 12, 2017; and Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal, Case 13-E-0030, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, February 21, 2014, at 29-30.

[23] Alberta Utilities Commission, Decision 20414-D01-2016, December 16, 2016, at 53.

> of the rate plan. Con Edison must justify the need for, the reasonableness of, and its inability to reasonably avoid any such over-target expenditures in its next rate case filing. In addition, the revenue requirement associated with any such Commission-approved over-target expenditures from Rate Year 1, after the term of the rate plan and for the book life of the investment, will be calculated based on an assumption that the over-target expenditures were not financed by both common equity and debt, but rather solely by debt.[24]

Performance Incentive Mechanisms

It is important that any rewards provided to utilities through PIMs be fully justified in terms of the value that customers receive. Rewards should not be used to further incentivize baseline performance requirements, which should be seen as the minimum standards a utility must meet regardless of the type of regulation by which rates are set. Instead, the utility should demonstrate that its proposed PIMs represent an improvement in performance over historical or projected performance levels.

Further, the Commission should require that the utility demonstrate that the PIM is likely to provide net benefits to customers (i.e., that the benefits associated with meeting or exceeding the PIM target exceed the costs of doing so, including the costs of any utility rewards.)

Information asymmetry is also a significant concern for developing PIMs. Therefore, PIMs proposed by the utility should be accompanied by:

- Identification of the quantitative and qualitative benefits and costs associated with meeting the PIM's targets;
- At least three years of historical baseline data; and
- A discussion of any investments contained in the utility's MYRP that are expected to enhance performance in the area addressed by the PIM.

PROPOSED CRITERIA FOR EVALUATING A PBR APPLICATION

Deviating from traditional cost of service regulation represents a significant change to traditional practice and presents numerous risks to ratepayers, as documented above. The statute requires that the Commission approve a PBR application "only upon a finding that a proposed a proposed PBR would result in just and reasonable rates, is in the public interest, and is consistent with the criteria established in this

[24] New York Public Service Commission, Order Establishing Three-Year Electric Rate Plan, Case 09-E-0428, March 26, 2010, at 11.

section and rules adopted thereunder."[25] It also provides that the Commission shall consider whether the PBR application assures that no customer or class of customers is unreasonably harmed, that the rates are fair, and that the application will not result in sudden substantial rate increases to customers.[26]

We urge the Commission to adopt specific criteria for determining whether a utility's PBR application meets these standards.

To assess the reasonableness of utility revenue requirement increases, the Commission should require that a utility proposing a PBR plan demonstrate that:

1) The PBR plan is more likely than current regulation to advance the goals of utility cost control, lower rates, and reduced administrative burden.
2) Post-test year cost increases do not exceed forecasts of regional public utility cost escalation rates or historical average rates of increase.
3) It appropriately considered and evaluated alternatives to its proposed investments, including third-party provided solutions.
4) Average customer rates (by class) and bills (for residential customers) will be within a reasonable range of peer utilities' rates and bills during and at the conclusion of the rate plan.
5) The benefits of achieving any approved PIMs are likely to outweigh the costs of doing so (including any financial rewards paid to the utility), and the targets represent measurable improvements over the utility's historical or expected performance.

Proposed Technical Conference Process Prior to PBR Application

The PBR statute requires the Commission to adopt rules regarding a technical conference to be held in advance of the filing of a PBR application.[27] Specifically, the statute provides for "a technical conference process to be conducted by the Commission prior to submission of any PBR application consisting of one or more public meetings at which the electric public utility presents information regarding projected transmission and distribution expenditures and interested parties are permitted to provide comment and feedback; provided, however, no cross-examination of parties shall be permitted. The technical conference process to be established shall not exceed a duration of 60 days from the date on which the electric public utility requests initiation of such process."

[25] N.C. Gen. Stat. § 62-133.16 (d)(1)

[26] N.C. Gen. Stat. § 62-133.16 (d)(1)(a)-(c)

[27] N.C. Gen. Stat. § 62-133.16 (j)(3).

This statutory stakeholder process appears intended to provide a formal mechanism for the electric utility to receive feedback from stakeholders concerning any proposed PBR plan in advance of the formal commence of proceedings on a specific plan. For this opportunity to be meaningful, the Commission should adopt rules to ensure that sufficient and adequate information is provided to stakeholders in advance of the technical conference such that stakeholders can offer substantive feedback concerning the proposal.

Such a process will be helpful in providing stakeholders with an overview of the investments the utility is proposing and the need for such investments. Synapse recommends that this technical conference be held as early as possible, i.e., 60 days prior to the utility submitting its PBR application. The presentation slides for this conference should be made available on the utility's website at least 24 hours prior to the conference.

At this technical conference, the utility and accompanying presentation materials should:

- Identify the utility's proposed investments. The utility should provide an appendix identifying the total cost of each project, the primary driver of costs for each project (e.g., reliability, new customers, load growth), and the risk or policy goal that the project addresses (where applicable).
- Summarize the alternatives to these investments that the utility considered (including third-party owned or operated non-wires alternatives).
- Explain the utility's load forecasting methodology underpinning the need for any load-related investments.

PROPOSED PROCESS FOR ADDRESSING REJECTION OF PBR APPLICATION

The statute provides that, if the Commission rejects a PBR application, there may be a process by which an electric public utility may address the Commission's reasons for rejection of a PBR application, which may include collaboration between stakeholders and the electric public utility to cure any identified deficiency in an electric public utility's PBR application.

Synapse cautions that the act of curing deficiencies in the utility's PBR application may entail substantial revisions to the application. In this case, the Commission should afford intervenors and opportunity to testify regarding the revised application.

In addressing the Commission's rejection of a PBR application, the Company should be required to:

- Satisfactorily address each of the Commission's identified deficiencies in a refiled application with all supporting schedules and testimony discussing the changes made to address the Commission's identified deficiencies.

- Work with stakeholders where appropriate to remedy deficiencies and present the proposed changes to stakeholders in a technical conference.
- Respond to discovery requests filed by the Commission or intervenors regarding the modifications made.

Stakeholders should then have an opportunity to file responsive testimony addressing whether or not the modifications made by the Company are reasonable.