Performance Based Regulation

Study Group Work Products

2020 NC Energy Regulatory Process

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NERP FACT SHEET

PERFORMANCE BASED REGULATION

ALIGNING UTILITY SYSTEM PERFORMANCE WITH REGULATORY OR PUBLIC POLICY GOALS

The 2020 North Carolina Energy Regulatory Process prioritized energy reforms that would drive affordability, carbon-reduction, and align regulatory incentives with policy goals.

WHAT IS PERFORMANCE BASED REGULATION?

Performance based regulation (PBR) is a regulatory approach that more precisely aligns utilities' profit interests with customer and societal interests through regulatory mechanisms that incentivize utilities to improve operations and management of expenses, increase program effectiveness, and otherwise align system performance with identified regulatory or public policy goals.

WHAT IS THE OPPORTUNITY?

While North Carolina is a leader in clean energy, with the second highest installed solar capacity in the nation, more than 40% of in-state generation being provided by carbon free resources, and over 110,000 clean energy sector jobs,[1] the future success of the state's clean energy transition will require, among other things, substantial greenhouse gas emission reductions; increased electric energy conservation savings over and above current savings of 1%[2]; continued grid modernization investments in storm hardening, targeted undergrounding of transmission and distribution power lines, and advanced metering; and increased integration of innovative distributed energy solutions, including customer sited solar and energy storage. Indeed, both Duke Energy and Dominion Energy have established ambitious mid-century clean energy targets. Duke's own Queue Reform Proposal calls for more than "5,390 MW of additional proposed North Carolina-sited utility-scale solar projects."[3]

Furthermore, existing utility incentives under the current ratemaking system are not always aligned with achieving these outcomes. Under the current system, utilities make more money by increasing their electric sales, which dis-incentivizes increased energy conservation. In addition, grid modernization investments are often not in a utility's financial best interest, at least in the short to medium term, as considerable time may pass between when (1) a utility first incurs financing costs to fund grid modernization investments and (2) it can stand to potentially recover all of those costs in a rate case.[4] Furthermore, a utility typically earns no profits on distributed energy, with profits being earned instead from infrastructure the utility owns and uses to provide electric services, in particular generation assets. Therefore, utilities may be incentivized to prioritize investments in utility owned generation over

[1] *See* https://www.e2.org/wp-content/uploads/2019/07/E2-Clean-Jobs-North-Carolina-2019.pdf

[2] *See* https://nicholasinstitute.duke.edu/sites/default/files/publications/North-Carolina-Energy-Efficiency-Roadmap-Final.pdf

[3] *See* https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=f83235af-6c15-4a08-ab04-7d03ef047383

[4] A rate case is a process through which a utility can adjust the rates it collects from customers by seeking approval from the North Carolina Utilities Commission.

investments that might, over the long term, reduce the amount of utility generation and result in cleaner energy.

If the Clean Smokestacks Act, Senate Bill 3, House Bill 589, and other landmark state clean energy legislation are any indication, further state legislative action will be crucial to the future of the state's clean energy transition. In particular, performance based regulation can help catalyze clean energy innovation.

WHAT IS BEING RECOMMENDED?

The North Carolina Energy Regulatory Process (NERP) has identified three mechanisms that should be adopted as a package:

1. Decoupling – a ratemaking mechanism that severs the link between utility sales and revenues by authorizing allowed revenues separate from utility sales and adjusting prices periodically to ensure actual revenues match allowed revenues.

2. Performance incentive mechanisms (PIMs) – a ratemaking mechanism that ties some portion of a utility's revenues or earnings to its performance on measurable customer, utility system, or public policy outcomes.

3. Multi-year rate plan (MYRP) with an earnings sharing mechanism – a ratemaking mechanism through which base rates and revenues are fixed for a multi-year term and a utility is barred from filing a rate case during that term (often referred to as a rate case moratorium). Rates or revenues are then periodically adjusted in non-rate case proceedings according to a predetermined formula or set of variables (e.g. inflation).

   An earnings sharing mechanism allocates to customers a portion of utility overearnings that exceed (or under-earnings that fall short of) the earnings approved under a multi-year rate plan.

HOW DOES PERFORMANCE BASED REGULATION WORK? HOW IS IT DIFFERENT FROM THE CURRENT SYSTEM?

For a multi-year rate plan, which NERP recommends should be combined with decoupling and PIMs, a utility would still be required to file an initial base rate case to adjust its authorized electric rates and submit cost of service studies. These studies would in turn serve as the basis through which the North Carolina Utilities Commission would determine (1) the total revenue required for the utility and (2) how the revenue would be allocated and collected from the utility customer classes. The proposed performance based regulations, specifically decoupling, PIMs, and the revenue adjustment mechanisms within a MYRP, would adjust, through increments or decrements, any base rates approved in the base rate case.

Decoupling

Once the revenue requirement is established, a decoupling mechanism would provide for periodic rate adjustments to ensure that the utility's actual revenues match its allowed revenues. Therefore, in contrast to the current system, where sales increases result in increased utility revenues, if a utility's sales increased under decoupling, rates would instead be adjusted downward to ensure parity between the utility's actual revenues and allowed revenues. If utility sales decreased, rates would be adjusted upwards to ensure the utility's actual revenues equaled its allowed revenues. As a result, changes in utility sales would have no impact on a utility's revenues, and a utility would no longer be dis-incentivized to pursue energy efficiency savings.

NERP recommends that the legislature authorize the Commission to adopt decoupling. Among other things, NERP suggests that the Commission limit the application of an approved decoupling mechanism to base rates and the residential, small and medium general service customer classes. Detailed suggestions for the Commission are contained in the NERP Guidance on Performance-Based Regulation.[5]

Performance Incentive Mechanisms

Performance incentive mechanisms would condition some portion of a utility's earnings on its performance on certain measurable consumer, utility system, or public policy outcomes. For example, if a utility were to meet identified distributed energy integration or energy efficiency performance targets, it could receive a fixed cash reward, a basis point adjustment to its return on equity, a percentage return on any expenses incurred achieving those targets, or a portion of any shared savings or net benefits created through its achievement of those targets. Conversely, depending on the design of the performance incentive mechanism, a utility might be penalized for failing to achieve those targets. As a result, a utility would have a direct incentive to pursue these outcomes.

This is a departure from the current system, where a large portion of utility earnings stems from the allowed rate of return on certain capital expenditures. Certain PIMs can help to mitigate this capital expenditure (or "capex") bias by providing the utility the opportunity to profit from meeting agreed-upon performance targets.

NERP recommends that the legislature authorize the Commission to adopt performance incentive mechanisms. Specifically, NERP recommends that the Commission consider PIMs that incentivize affordability, carbon reduction, customer service, distributed energy, electrification of transportation, energy efficiency, equity, peak demand reduction, reliability,

[5] The Guidance Document is available with all other NERP outputs on the website at the end of this fact sheet.

and resilience. Detailed suggestions for the Commission are contained in the Guidance Document.

Multi-Year Rate Plan and Earnings Sharing Mechanism

A multi-year rate plan usually begins with a rate case that determines a utility's initial revenue requirement and establishes how these allowed revenues should be adjusted each year over the course of the rate plan term, which is typically between three and five years. These adjustments can be based on cost forecasts, external indexes, or a combination of both. In contrast to the current system, where the underlying costs recovered in rates reflect prior costs incurred in some previous twelve-month period (referred to as the historic test year), costs and revenues for a multi-year rate plan are forward-looking.

Accordingly, the utility could prospectively identify grid modernization projects and ensure more timely cost recovery for these projects and other investments. In addition, the rate case moratorium could create significant cost containment pressure. A multi-year rate plan that capped a utility's revenues would also incentivize cost containment by providing the utility the opportunity to keep some or all of its cost savings. Given these cost containment incentives, some experts recommend that states adopt targeted PIMs to prevent potential cost cutting from impacting system reliability and customer service.

Subject to Commission pre-approval, an earnings sharing mechanism could specify a formula for sharing any utility cost savings or losses between customers and utility shareholders when utility earnings exceed or fall short of Commission set levels.

NERP recommends that the legislature authorize the Commission to adopt multi-year rate plans and earnings sharing mechanisms. Detailed suggestions for the Commission are contained in the Guidance Document.

HAS PERFORMANCE BASED REGULATION BEEN DONE BEFORE?

Other states

Several other states and international jurisdictions have pursued performance-based regulation. For example, New York is exploring performance based regulation through the Reforming the Energy Vision proceeding before the New York Public Service Commission. Through this proceeding, the Commission has adopted performance incentive mechanisms for distributed energy and other innovative non-wires solutions. In Minnesota, recent legislation, direction from the Minnesota Public Utilities Commission, and extensive stakeholder involvement have resulted in wide ranging performance-based regulation reforms, including a MYRP and decoupling. For more information on the Minnesota PBR development process and outcomes, see the MN PBR Case Study prepared by NERP.[6]

North Carolina

Natural gas decoupling, which is currently authorized under statute, was implemented in North Carolina in 2005. In addition, the North Carolina Utilities Commission has adopted performance incentive mechanisms pursuant to a separate statute to encourage more utility energy efficiency programs and savings.

This fact sheet represents the work of stakeholders as of 12/18/2020.

About the North Carolina Energy Regulatory Process

Governor Cooper's Executive Order 80 mandated the development of a clean energy plan for the state of North Carolina. The Clean Energy Plan recommended the launch of a stakeholder process to design policies that align regulatory incentives with 21st century public policy goals, customer expectations, utility needs, and technology innovation. The stakeholder process was launched in February 2020 and has led to policy proposals on energy reform.

LEARN MORE

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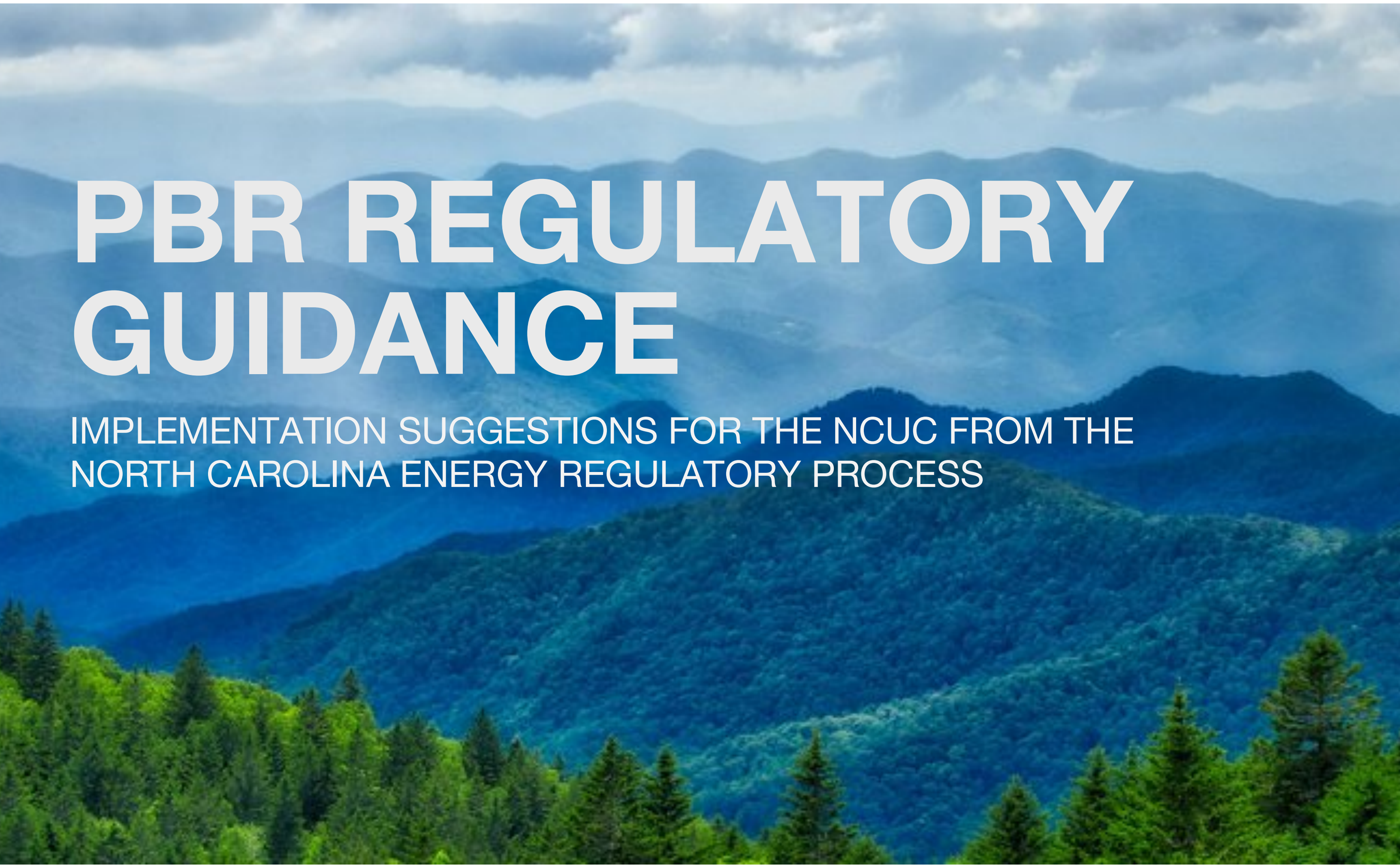
Access the NERP summary report and other NERP documents at:
https://deq.nc.gov/CEP-NERP

[6] See the Minnesota case study, available with all other NERP outputs on the website at the end of this fact sheet.



PBR REGULATORY GUIDANCE

IMPLEMENTATION SUGGESTIONS FOR THE NCUC FROM THE NORTH CAROLINA ENERGY REGULATORY PROCESS

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Governor Cooper's Executive Order 80 mandated the development of a clean energy plan for the state of North Carolina. The Clean Energy Plan recommended the launch of a stakeholder process to design policies that align regulatory incentives with 21st century public policy goals, customer expectations, utility needs, and technology innovation. The stakeholder process was launched in February 2020 and has led to policy proposals on energy reform.

ABOUT THIS DOCUMENT

This guidance document contains a detailed discussion of performance-based regulation mechanisms with a specific focus on revenue decoupling, multi-year rate plans, and performance incentive mechanisms. It includes recommendations for the NCUC to consider if and when it begins a process to implement performance-based regulation. The document represents the consensus work of the NERP process stakeholders as of the above date. However, individual NERP stakeholders do not necessarily endorse all of the ideas or recommendations herein.

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SUMMARY OF RECOMMENDATIONS

This document contains recommendations for implementation of performance-based regulation (PBR) developed by the North Carolina Energy Regulatory Process (NERP) participants. The primary intended audience is the NC Utilities Commission (NCUC), as it may be authorized by the General Assembly to develop regulations for PBR. The document contains detailed descriptions of each of the PBR mechanisms discussed in NERP: revenue decoupling, multi-year rate plans (MYRPs), and performance incentive mechanisms (PIMs). NERP participants met throughout 2020 and developed the following recommendations regarding the implementation of PBR.

PBR implementation

1. PBR should be designed to provide for just and reasonable rates and be consistent with the public interest, including the goals of the Clean Energy Plan.
2. PBR for NC should include all three of the mechanisms studied in NERP, as they can work well together to accomplish a broad set of outcomes and stakeholder objectives.
3. Effective PBR will require ongoing monitoring and possible course corrections.
4. A PBR process at the NCUC should consider the conclusions reached by NERP and make sure to receive comment from as broad a group of stakeholders as possible, including representatives from underserved communities with limited access to traditional docket proceedings.
5. The NCUC should, subject to guidance and timelines provided in legislation, begin as soon as possible a proceeding to develop rules for filing, and criteria for evaluating, a comprehensive PBR package including revenue decoupling, a multi-year rate plan, and performance incentive mechanisms or tracked metrics, as well as provisions for annual or more frequent decoupling and MYRP true-ups and adjustments of PIM metrics, targets, and incentive levels.

Revenue decoupling

1. Revenue decoupling should apply to residential and small and medium general service classes. Large general service and lighting do not necessarily need to be included. However, attention should be paid to how excluding any customer class would impact the design of a multi-year rate plan.
2. Revenue decoupling should include all utility functions (generation, transmission, and distribution).
3. Revenue decoupling should include base rates only, excluding riders that have separate true-up mechanisms.
4. Revenue decoupling should include EV charging sales, but a PIM should be adopted related to EV adoption and/or smart charging to incentivize vehicle electrification.
5. Revenue decoupling should utilize either the revenue-per-customer or attrition method for adjusting revenue between rate cases. Decoupling adjustments to the allowed revenue would be impacted by the MYRP design as well, so the interplay of these two mechanisms should be noted.
6. The amount of adjustment to customer rates under decoupling should be capped, and the design of refunds and surcharges should consider ways to encourage energy efficiency.
7. Rate adjustments should occur once a year.
8. The NCUC will need to consider the above issues, as well as ways to encourage utilities to pursue beneficial electrification when decoupled.

Multi-year rate plan

1. The mechanism for adjusting rates should be defined at the outset of a MYRP.
2. A maximum of three years should be the term of an initial MYRP.
3. A MYRP should not be used to recover costs for large, discrete investments, such as a conventional power plant. Investment programs that are made up of a series of smaller utility assets placed in service over time are well-suited for a MYRP.
4. A MYRP should be accompanied by a pre-set earnings sharing mechanism to share savings between customers and utility stockholders. The mechanism could include sharing tiers and a “deadband” of over- or underearning in which no adjustment is made.

5. The NERP team did not come to consensus on whether MYRP should cover base rates or be more narrowly constructed to cover only certain projected costs.
6. The NCUC should determine the general conditions under which a MYRP may be revised or revisited.

Performance incentive mechanisms

1. PIMs should adhere to a set of principles to help align stakeholders on shared objectives and guide PIM design.
2. At the outset, utilities should track as many metrics as are deemed useful and cost-effective. This document lays out recommended metrics.
3. The utility should track the overall performance for each adopted PIM or tracked metric, and, where possible, separately track the utility's performance in low-income counties, specifically Tier 1 and 2 counties.
4. The utility should establish a public dashboard for reporting performance on PIMs and tracked metrics.
5. The following outcomes should be targeted for PIM and/or tracked metric development:
    a. Peak demand reduction
    b. Integration of utility-scale renewable energy and storage
    c. Integration of distributed energy resources
    d. Low-income affordability
    e. Carbon emission reductions
    f. Electrification of transportation
    g. Equity in contracting
    h. Resilience
    i. Reliability
    j. Customer service
6. The NCUC will need to evaluate the appropriateness of any proposed performance incentive assigned to each potential tracked metric.

INTRODUCTION

Purpose and objectives

The purpose of this document is to communicate the findings of the NC Energy Regulatory Process (NERP) with regard to performance-based regulation (PBR) to the NC Utilities Commission (NCUC) as it may be authorized by the General Assembly to develop rules for PBR. It may also be of interest to the NC General Assembly and other parties who want more information on PBR or the NERP process than is provided in the companion fact sheet.[1]

Duke Energy's Climate Report[2] and Dominion Energy's Sustainability and Corporate Responsibility Report[3] set ambitious goals for reducing carbon emissions. The NC Clean Energy Plan[4] calls for the state's electric power sector to reduce greenhouse gas emissions 70% below 2005 levels by 2030 and attain carbon neutrality by 2050, transitioning to cleaner energy resources while growing the state's economy. As detailed below, however,

[1] All NERP PBR companion documents can be found at the following location: https://deq.nc.gov/CEP-NERP

[2] *Achieving a Net Zero Carbon Future: Duke Energy 2020 Climate Report*, https://www.duke-energy.com/_/media/pdfs/our-company/climate-report-2020.pdf?la=en.

[3] *Building a Cleaner Future for Our Customers and the World, 2019 Sustainability and Corporate Responsibility Report*, Dominion Energy, https://sustainability.dominionenergy.com/assets/pdf/Dominion-Energy_SCR-Full-Report-FY2019.pdf.

[4] *North Carolina Clean Energy Plan: Transitioning to a 21st Century Electricity System*, NC Dept. of Environmental Quality, Oct. 2019, https://files.nc.gov/governor/documents/files/NC_Clean_Energy_Plan_OCT_2019_.pdf.

the current cost of service (COS) ratemaking[5] system for the state's investor-owned utilities (IOUs) does not provide the proper utility incentives for timely and efficient accomplishment of these goals at reasonable cost.

NERP stakeholders have determined that better alignment of incentives would be created by transitioning the state to a comprehensive PBR framework.

This document communicates NERP's recommendations for designing a PBR system that would benefit North Carolina.

Improved Utility Regulations for North Carolina's Energy Transition

PBR offers a suite of reforms that, together, can resolve limitations of COS ratemaking while encouraging utilities to better serve state policy goals and customer interests. In North Carolina, this includes decarbonization of the power system, accelerated adoption of clean energy technologies including new customer service opportunities from distributed energy resources (DER), alleviating low-income energy burden, and reduction of costly administrative burdens and regulatory lag.[6]

Three PBR mechanisms are the focus of this document, and NERP suggests they be jointly considered and designed for NC electric utilities:

- Decoupling to remove the utilities' incentive to grow energy sales
- Performance incentive mechanisms (PIMs) to create new earnings opportunities (or penalties) for targeted outcomes
- Multi-year rate plans (MYRP) to increase the time between utility rate cases in order to introduce cost containment incentives for the utility and reduce regulatory lag

PBR design and adoption is a significant undertaking. Critical details must be considered and worked through, typically through a regulatory proceeding that includes utility proposals, input and counterproposals of other stakeholders, and eventual decision-making by utility regulators. As outlined below, a probable first step will be enactment of PBR-enabling legislation.

Companion documents

In addition to this guidance document, NERP has produced:

- Draft legislation authorizing the NCUC to pursue PBR
- A fact sheet providing an introduction to PBR, an overview of the draft legislation and a summary of this guidance document
- Case studies discussing:
  - how PBR has been implemented in Minnesota, and
  - how North Carolina has implemented revenue decoupling for natural gas utilities.

Context and history

On October 29, 2018, Governor Roy Cooper issued *Executive Order 80: North Carolina's Commitment to Address Climate Change and Transition to a Clean Energy Economy*.[7] The Order established the North Carolina Climate Change Interagency Council and tasked the Department of Environmental Quality (DEQ) with producing a clean energy plan.

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[5] According to NARUC, "In Cost of Service Regulation, the regulator determines the Revenue Requirement—i.e., the 'cost of service'—that reflects the total amount that must be collected in rates for the utility to recover its costs and earn a reasonable return." https://pubs.naruc.org/pub.cfm?id=538E730E-2354-D714-51A6-5B621A9534CB. Under the proposed PBR system, the utility would still file cost of service studies in a general rate case and those studies would be the basis for establishing the total revenue required and the allocation to the customer classes. The PBR adjustments discussed in this document would be increments or decrements to that base.

[6] Regulatory lag results when a utility's costs change, either up or down, in between rate cases. Issues result when regulatory lag creates financial incentives for utilities that are not aligned with public interest. For more detail, see Appendix A.

[7] Executive Order 80. https://governor.nc.gov/documents/executive-order-no-80-north-carolinas-commitment-address-climate-change-and-transition.

DEQ convened a group of stakeholders that met throughout 2019. In October 2019, DEQ released the *North Carolina Clean Energy Plan: Transitioning to a 21st Century Electricity System* (CEP).[8] Recommendation B-1 of the CEP states: "Launch a NC energy process with representatives from key stakeholder groups to design policies that align regulatory incentives and processes with 21st Century public policy goals, customer expectations, utility needs, and technology innovation." That process was launched as NERP, which met throughout 2020.

Also relevant to this document is NC Senate Bill 559,[9] introduced in 2019. SB559 eventually passed and authorized utilities to petition the NCUC to recover certain storm recovery costs through securitization. The initial version of the bill included a separate section that would have authorized the NCUC to accept MYRP proposals from utilities. After concerns were raised by a large number of stakeholders, and no adequate compromise was found, that section of the bill was dropped. NERP has attempted to recognize the advantages of – and resolve the objections to – the MYRP as proposed in SB559.

NERP process

The NERP process, facilitated by Rocky Mountain Institute and the Regulatory Assistance Project, brought together roughly 40 diverse stakeholders to consider four main avenues of utility regulatory reform:

- PBR
- Wholesale market reform
- Competitive procurement of resources
- Accelerated retirement of generation assets

The NERP stakeholder group identified ten desired outcomes of reform in North Carolina, as shown below in Figure 1. Of those, the focus of PBR deliberations were:

- Regulatory incentives aligned with cost control and policy goals
- Carbon neutral by 2050
- Affordability and bill stability

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[8] *North Carolina Clean Energy Plan: Transitioning to a 21st Century Electricity System*, NC Dept. of Environmental Quality, Oct. 2019, https://files.nc.gov/governor/documents/files/NC_Clean_Energy_Plan_OCT_2019_.pdf.

[9] SB559, Storm Securitization, passed Oct. 2019, https://www.ncleg.gov/BillLookUp/2019/s559.

Outcome Category	Outcome
Improve customer value	Affordability and bill stability
	Reliability
	Customer choice of energy sources and programs
	Customer equity
Improve utility regulation	Regulatory incentives aligned with cost control and policy goals
	Administrative efficiency
Improve environmental quality	Integration of DERs
	Carbon neutral by 2050
Conduct a quality stakeholder process	Inclusive
	Results oriented

FIGURE 1: PRIORITY OUTCOMES IDENTIFIED BY NERP STAKEHOLDERS

PBR Study Group

A subset of NERP participants volunteered to serve on a PBR study group and began meeting in May 2020. Three subteams were created to discuss: revenue decoupling, multi-year rate plans (and earnings sharing mechanisms), and performance incentive mechanisms. (See page 2 for a list of PBR study group and subteam members.)

The subteams regularly presented their work to the PBR study group for feedback. The study group presented a straw proposal to the larger NERP group, detailing how a comprehensive PBR package might be designed for NC. Feedback was received from NERP participants and incorporated into the eventual design recommendations detailed below.

What problems is PBR solving?

Performance-based (or outcome-based) regulation is intended to motivate utilities to accomplish outcomes that customers or society deem desirable. In doing so, PBR can help shift utility focus away from certain outcomes that may be inadvertently incentivized by traditional ratemaking.

In the current system, utilities increase their revenues by increasing electricity sales in the short term (known as the throughput incentive) and increase their profits by favoring rate-of-return-based utility capital spending over other options as the method by which to solve identified grid needs (known as the capital expenditure, or capex, bias).

The throughput incentive arises from the fact that, in traditional ratemaking, prices are set primarily on a volumetric basis based on a historic level of costs and sales, normalized and adjusted for known and measurable changes. After volumetric prices are set in the rate case, if utilities sell more electricity than was estimated in the rate case, they increase their revenues and therefore profits (assuming costs do not fluctuate significantly based on sales volume in the short term).

The capex bias originates from the fact that utilities are typically allowed to earn a regulated rate of return (profit percentage) on shareholder capital that they invest in physical assets, such as power plants, transmission wires, distribution grid assets, company trucks, computers, buildings, etc. This results in utility preference for capital expenditures as solutions for grid needs, whereas many cost-saving or emissions-reducing opportunities result from program innovations, such as customer efficiency programs, that fall into the category of operating expenditures (opex), on which no rate of return is earned.

Even as NC's population is growing, the demand for electricity from existing customers continues to remain flat, and in some cases has declined compared to historical years as more customers are investing in their own on-site generation and energy efficiency measures. This changing economic landscape can further drive the throughput incentive and capex bias, the two main limitations of the current framework.

PBR offers a set of tools that can create utility incentives that are more aligned with customer and societal goals. For example, PBR can make it more likely that clean energy, energy efficiency, and carbon reduction goals are achieved. There is no one uniform combination of PBR tools. Some states have implemented one or two reforms; others are examining comprehensive measures. The reforms discussed below were the focus of NERP and have been implemented or are currently being discussed in other states.

See Appendix B for a diagram depicting potential interactions and coordination between the different mechanisms within a PBR framework.

Other ongoing processes and trends impacting PBR

The world in general, and North Carolina in particular, are in an exciting period of transition to a cleaner and more equitable electricity system. As a result, there are emerging technologies, rapidly changing cost dynamics, potential new policies, and revisions of old policies all up in the air at once. NERP has designed recommendations for PBR implementation based on its best estimate of where these balls might land.

In considering any PBR proposal that comes before it, the NCUC will have to evaluate where these processes stand and how the PBR mechanisms interact with them. Some examples of ongoing processes include:

- other proposals emerging from the NERP process (securitization of uneconomic coal assets, all-source competitive procurement, and wholesale market study),
- an analysis of carbon reduction policies under the A-1 recommendation of the CEP including accelerated coal retirements; a Clean Energy Standard or other clean energy policy (e.g., Energy Efficiency Resource Standard or Peak Reduction Standard); an offshore wind requirement; a carbon adder or shadow carbon price for purposes of planning and/or dispatch; and/or a market-based cap and invest program (e.g., joining the Regional Greenhouse Gas Initiative),
- the Southeastern Energy Exchange Market proposal being advanced by Duke Energy and other Southeast utilities,
- the trend toward vehicle electrification and state strategies for accelerating adoption of electric vehicles, including the NC Zero-Emission Vehicle Plan, Duke's EV pilot, distribution of VW Settlement Funds, and NC signing onto the multistate Medium- and Heavy-Duty ZEV MOU,
- the low-income collaborative proposed by Duke Energy in the current NC rate cases,
- the comprehensive rate design study proposed by Duke Energy in the current NC rate cases,
- implementation of changes to the EE/DSM incentive ordered by the NCUC in its October 2020 order, including new incentive levels and use of the Portfolio Performance Incentive and Utility Cost Test,[10]
- any changes to net metering policy,
- NCUC orders that will be issued on DEC and DEP rate cases and Duke's Integrated Resource Plan,

[10] Order Approving Revisions to Demand-Side Management and Energy Efficiency Cost Recovery Mechanisms, Oct. 20, 2020, https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=5aaea5ce-6458-41fe-ab2d-14d86881092d.

- the NC Transmission Planning Collaborative's study of onshore transmission investments necessary to integrate up to 5,000 MW of offshore wind (expected completion in early 2021),
- the newly established nonprofit NC Clean Energy Fund that will make funding available for clean energy projects that are traditionally difficult to finance, and
- Duke Energy's implementation of its Integrated System & Operations Planning (ISOP) process that will allow integration of new technologies and customer programs as technology and policy pertaining to generation, transmission, and distribution continue to evolve.

Some of these factors are flagged in the specific recommendations below.

Statutory authority and rationale for legislation

Legislation has been used in many states to provide explicit authority to utility commissions to implement or approve proposed PBR mechanisms. In the expectation that the NCUC would welcome specific authorizing legislation, NERP has drafted legislation authorizing the NCUC to pursue comprehensive PBR. It specifies deadlines and baseline requirements that any PBR package should meet, but is minimally prescriptive so that the NCUC has leeway to consider the many PBR design parameters in a manner that best meets the needs of the state at the time the mechanisms are established.

NERP RECOMMENDATIONS FOR PBR TOOLS

After studying the PBR mechanisms described below, NERP has come to the conclusion that a comprehensive package of revenue decoupling, multi-year rate plan, and performance incentive mechanisms would best address North Carolina's changing needs. The three sub-sections below explain how each mechanism works, how the mechanisms interact with each other, what recommendations NERP makes for their design, and key issues that need attention from the NCUC. NERP participants offer the following takeaways and recommendations from our deliberations on PBR to inform the NCUC's thinking.

Revenue Decoupling

Definition

Decoupling breaks the link between the amount of energy a utility delivers to customers and the revenue it collects, thus minimizing the throughput incentive described above. Allowed revenue is set in a rate case as usual. Rather than setting prices in the rate case and leaving them unchanged until the next rate case, under revenue decoupling prices are set in the rate case but adjusted up or down over the course of the rate effective period to ensure that collected revenues equal allowed revenues (no more and no less). See Figure 2.

Traditional System:

Revenue = Fixed Price × Sales

Decoupled System:

Price = Fixed Revenue ÷ Sales

Comparison with current system

Currently, for many residential and smaller commercial and industrial rate schedules, there are no demand charges and a majority of fixed costs are recovered through variable energy rates (cents per kWh). When fixed costs are recovered through a variable rate, a utility's margin is higher when it increases its sales and lower when it decreases its sales. Consequently, the utility has a financial incentive to increase sales and a disincentive to reduce sales. Decoupling seeks to break this linkage.

This incentive and linkage have already been recognized by the NCUC in its approval of net lost revenue mechanisms within utility energy efficiency and demand side management riders.

The net lost revenue (NLR) mechanism addresses this issue by removing the financial disincentive to reduce sales when the utility implements an approved DSM/EE program. Decoupling goes a step further by removing the incentive/disincentive to increase or reduce sales in all situations. This would include reduced sales from DER deployment, reduced sales from customer efficiency and conservation efforts that are not part of a utility program, and reduced sales from certain rate designs or other utility programs that may not qualify as an approved DSM/EE program. It would also break the incentive for increases in sales from electric vehicle charging and economic development. Since some of these sales may align with the public interest, it is important to implement decoupling as part of a comprehensive PBR package to ensure that the utility still has an incentive to beneficially grow sales in areas that are aligned with public interest.

Decoupling is one part of broader PBR plan

Many states implement decoupling as part of a broader PBR package and there are synergies between the mechanisms. For example, PIMs can be used to incentivize electric vehicle charging or economic development when decoupling removes these incentives from the current ratemaking structure. Additionally, where decoupling removes a disincentive for the utility to reduce sales through energy efficiency or other means, PIMs can go a step further and create a positive incentive for the utility to reduce sales. Decoupling also works well with multi-year rate plans. The MYRP can provide for small, annual changes in rates, and the decoupling mechanism can true-up the sales that the MYRP rates are based on to actual sales realized during each year of the plan. Thus, decoupling and MYRPs together can reduce the need for frequent rate cases and can break the linkage between utility sales and profit margin.

Alignment with the goals of the Clean Energy Plan

Decoupling is aligned with the broader CEP goals. First, the CEP supports increased DERs, EE, and DSM, all of which decrease sales per customer. Decoupling removes the sales-related disincentive utilities have to promote and utilize these resources. Decoupling is also an alternative to increasing fixed charges in the rate design structures for residential and smaller commercial and industrial customers. If fixed costs are recovered through fixed charges and variable through variable, this also removes the throughput incentive for utilities. However, increasing fixed charges also decreases variable charges, which reduces the incentive for customers to be energy efficient, conserve energy, and/or invest in DERs. Additionally, higher fixed charges, on average, place a higher energy burden on low-income customers, who tend to have lower usage per customer. Reducing the incentives for EE, conservation, and DERs and placing a higher energy burden on low-income customers are contrary to the goals of the CEP. Decoupling is therefore better aligned with the goals of the CEP than increasing fixed charges as a means of removing the throughput incentive.

Experience in other states and jurisdictions

North Carolina has experience with decoupling in the natural gas distribution sector.[11] In addition, electric decoupling has been adopted successfully in 17 states and another 7 states have pending actions. Rate adjustments under decoupling are typically small. According to a 2013 report produced for the American Council for an Energy-Efficient Economy and the Natural Resources Defense Council, almost two-thirds of adjustments made under decoupling were within 2% of the retail rate and 80% within 3%. Such adjustments are modest compared to other utility expenses that influence rates.[12]

Design Details of Decoupling and NERP Recommendations

The utility's proposed decoupling mechanism must be evaluated to ensure that it will produce just and reasonable rates and is consistent with the public interest, including the goals of the CEP. NERP explored several key design components of decoupling mechanisms, and has the following recommendations.

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[11] Case Study: Natural Gas Decoupling in North Carolina, NERP, December 2020, available here: https://deq.nc.gov/CEP-NERP.

[12] https://www.aceee.org/sites/default/files/publications/researchreports/u133.pdf

Decide what is covered

Affected Classes: Because the primary rate schedules that recover fixed costs through variable rates are the residential and small to medium general service, we recommend that these classes be included. The rate design for large general service includes demand charges and other provisions to recover more of the fixed costs through fixed charges. Also, lighting rate schedules generally recover fixed costs through fixed charges. When only variable costs are recovered through variable rates, there is no throughput incentive (revenue and costs go up or down proportionally and there is no impact to margin from higher or lower sales levels). Large general service and lighting do not necessarily need to be included for the decoupling mechanism to be effective and the NCUC may determine that it makes more sense to exclude them from the mechanism. However, attention would need to be paid to how excluding these customers from decoupling might impact the design of a utility's MYRP.[13]

Including small to medium general service in the decoupling mechanism would introduce a complexity that NERP did not have time to work through. Decoupling would replace the current net lost revenue mechanism recovered through the DSM/EE rider for classes participating in decoupling. Because there is only one general service rate in the DSM/EE rider for all three general service classes (small, medium, and large), it may not be feasible to include net lost revenues for only one of the three sizes in the rider. Consideration also needs to be given to small and medium general service accounts that can currently opt out of the net lost revenue mechanism and how that will be addressed with decoupling.

Costs to include:

- Recommend including all functions (generation, transmission, and distribution). In order for the mechanism to be effective and completely address the throughput incentive, it should not exclude any function included in the utility's bundled rate.
- Recommend including base rates only and excluding riders that have separate true-up mechanisms. If a rider already has a mechanism to true-up for sales volume (like fuel), then it should be excluded from the decoupling mechanism. If a rider does not have a separate true-up mechanism for sales, it may be included.
- The PBR study group considered recommending excluding EV charging sales in order to maintain the utility incentive to promote vehicle electrification. However, the only state where we have seen this done is Minnesota, and it may overly complicate the mechanism. Therefore, NERP recommends including EV charging sales in the decoupling mechanism and simultaneously adopting a PIM related to EV adoption and/or smart charging.

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[13] Large industrial customers are excluded from decoupling in some states on account of possible rate volatility should a single very large user leave the utility territory or change operations. Different treatment between customer classes is complicated, however, when decoupling is part of a MYRP framework. In many states with comprehensive MYRPs , such as California, Minnesota, Hawaii, and Massachusetts, decoupling is applied to all major customer classes. See Regulatory Assistance Project, Revenue Regulation and Decoupling: A Guide to Theory and Application, November 2016. http://www.raponline.org/wp-content/uploads/2016/11/rap-revenue-regulation-decoupling-guide-second-printing-2016-november.pdf; Minnesota Public Utilities Commission, "Order Approving True-Ups and Requiring Xcel to Withdraw its Notice of Changes in Rates and Interim Rate Petition," March 13, 2020.

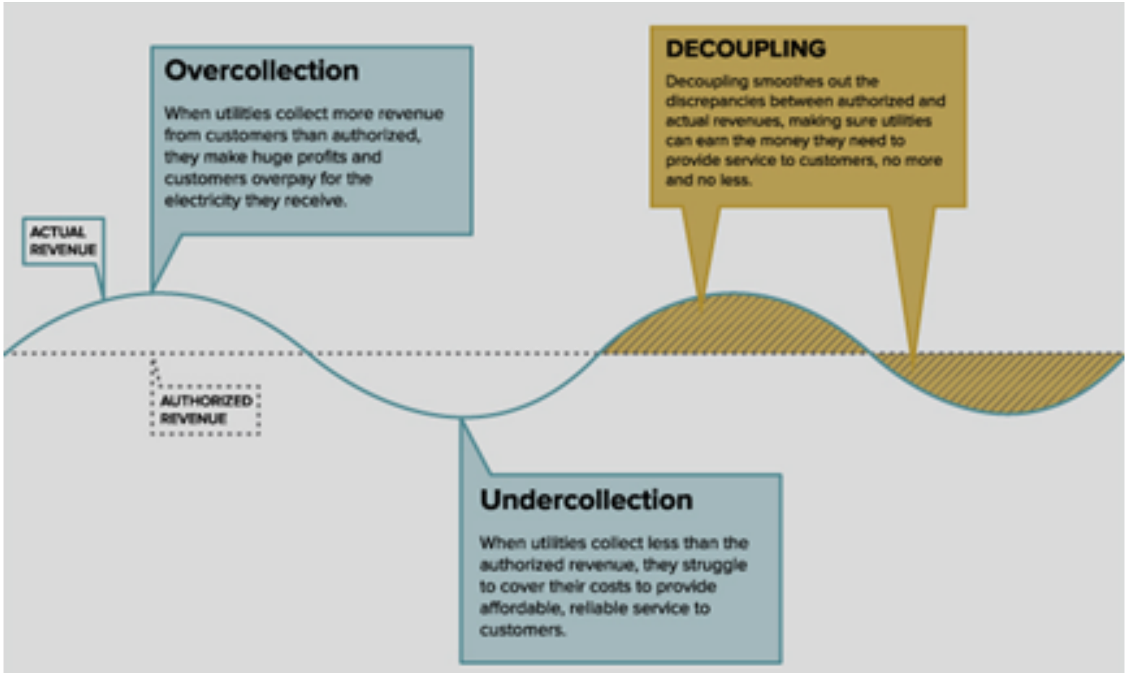

FIGURE 2: HOW DECOUPLING SMOOTHS OUT REVENUE FLUCTUATIONS[14]

Choose how to adjust utility revenue

The team explored several methods of adjusting the annual revenues under a decoupling mechanism and recommends consideration of the following two options: Revenue Per Customer (RPC) and Attrition Adjustment.

- RPC – allows for increases in revenue as new customers are added to the system, but mitigates changes in revenue driven by changes in usage per customer. In the initial base rate case, a revenue requirement per customer is set for the affected classes. Periodically, the actual revenue received from a class is compared to the target revenue per customer times the number of customers. Any excess or shortfall is deferred and returned to or collected from customers over the following year through adjustments to the customer class-specific rates. In addition, the tariff rates used going forward may be adjusted to reflect changes in usage per customer. This going-forward adjustment would need to be made in conjunction with any adjustments in the MYRP.

  Target revenue = number of customers x revenue requirement per customer

  This method is fairly straightforward and consistent with the current mechanism for gas utilities in NC; however, some NERP participants expressed concerns that actual costs per customer may decline over time, especially if generation assets (which depreciate over time) are included in the mechanism. If this is the case, some experts suggest that an attrition adjustment method may be more appropriate.[15]

- Attrition - adjusts the fixed level of revenue to be collected based on changes in costs and sales. This method may be appropriate when generation assets are included in decoupling. Just like with RPC, the actual revenue received from a customer class is compared to a target level of revenue, and any excess

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[14] Nissen Will, "Strategic electrification and revenue decoupling: different purpose, same goal," May 2, 2018, Fresh Energy, https://fresh-energy.org/strategic-electrification-and-revenue-decoupling-different-purpose-same-goal/.

[15] Migden-Ostrander, J., and Sedano, R. (2016). Decoupling Design: Customizing Revenue Regulation to Your State's Priorities. Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/knowledge-center/decouplingdesign-customizing-revenue-regulation-state-priorities

or shortfall is deferred and returned to or collected from customers over the following year through adjustments to the customer class-specific rates. However, the target revenue is based on the actual costs incurred over the same period and may be based on a formula rate template or agreed-upon formula adjustments to the rate case test year cost of service study. These "attrition review" proceedings are sometimes referred to as "mini-rate cases" but are a streamlined alternative to full-blown rate cases.

It should be noted that, under both types of decoupling, the going-forward adjustments would need to be coordinated with adjustments under the multi-year rate plan. This linkage is one way in which decoupling and MYRP work well together. MYRP involves a detailed analysis of how utility revenue should be allowed to adjust over time, while decoupling ensures that the allowed revenue is recovered (but not more or less than the allowed revenue).

If both decoupling and a MYRP with a revenue cap are adopted, the details of the two mechanisms must be determined together. The MYRP will likely inform how allowed revenues adjust each year, while decoupling will adjust customer rates so collected revenues equal allowed revenues. Options to adjust revenues may be based on inflation or other index, multi-year cost forecasts, customer growth, or a hybrid approach.

Select how to handle refunds or surcharges.

The process for the annual adjustment to rates should be efficient and transparent. NERP recommends considering caps on annual impacts to customers, with any additional amounts deferred into a future period. NERP also recommends considering design options for handling refunds and surcharges that encourage greater energy efficiency.

In terms of frequency of adjustments, NERP recommends decoupling price adjustments once a year. Some mechanisms are updated monthly, but that could lead to customer confusion with too-frequent price adjustments. According to a 2012 survey,[16] over two-thirds of electric utility decoupling true-ups were conducted on an annual basis.

Multi-year rate plan & earnings sharing mechanism

Definition

A MYRP begins with a rate case that sets the utility base revenues for the test year, based on the normal ratemaking process.

Under a MYRP, the revenue requirements necessary to offset the costs that are contemplated to occur under a plan approved by the NCUC would be set for multiple years in advance (typically 3–5 years). Utility compensation would be based on forecasted costs that are expected under the NCUC-approved plan, rather than the historical costs of services. Customer rates would be reset annually through NCUC review under the terms set out for the MYRP.

This approach can create added incentives for the utility to contain costs and can also reduce the regulatory costs from more frequent rate cases. The terms of a MYRP often include the following:

- A moratorium on general rate cases for longer periods (the term of the MYRP).
- Attrition relief mechanisms (ARMs) in the interim to automatically adjust rates or revenue requirements to reflect changing conditions, such as inflation and population growth.

[16] Morgan, P. *A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs, and Observations.* Graceful Systems LLC, rev. February 2013, https://www.raponline.org/wp-content/uploads/2016/05/gracefulsystems-morgan-decouplingreport-2012-dec.pdf.

- MYRPs can (1) mitigate the regulatory lag associated with certain utility assets, such as grid investments and DERs, (2) give an incentive for utility cost containment by setting a framework for predictable revenue adjustments into the future.
- To maintain or pursue other regulatory and policy goals, MYRPs should be combined with performance incentive mechanisms (PIMs) (sometimes considered “backstop” protections for reliability or other services), an earnings sharing mechanism, and other tools.

Comparison with current system

The current system in NC is a traditional cost of service (COS) ratemaking system, which uses historical test years for base rate cases. This system has evolved over the years with the additions of selected cost recovery riders/clauses (e.g., fuel, etc.).

The types of assets to be added to the utility system in the future (renewables, energy storage, and grid improvements) will consist of a series of smaller, more frequent projects, and the addition of any large, central station generation assets will become rarer and rarer. The existing base rate case process does not fit this future well – the utility suffers significant regulatory lag, and so must file rate cases frequently, even annually. Utilities do have the incentive to reduce their costs between rate cases, but when rate cases become so frequent that they are almost annual, this cost reduction incentive is reduced. The NCUC still determines in each rate case what a reasonable level of costs is, but there is less incentive for the utility to try to drive costs below this level.

NERP believes that modifying the existing COS regulation to include a combined package of performance-based ratemaking provisions, including establishing MYRPs with an earnings sharing mechanism, revenue decoupling, and PIMs, will facilitate accomplishment of the goals delineated in the CEP.

MYRPs are one part of a broader PBR plan

MYRPs seem to work well with decoupling – many states currently use both at the same time. Additionally, MYRPs can work well with PIMs by establishing the cost recovery plan for investments that will achieve a goal and then creating a financial incentive or penalty for achieving or failing to achieve that goal. For example, to encourage increases in electric vehicle adoption or distributed energy resources, a multi-year rate plan can include the investments the utility must make to achieve these goals and then a PIM can attach a financial incentive to the goal. Neither a PIM without the enabled cost recovery through a MYRP, nor a MYRP without the accountability of a PIM, are as effective as the two mechanisms working in combination.

MYRP alone would not do anything to specifically address other policy goals such as the reduction of household energy burden, however. Addressing these key goals, and others under the CEP, would require the use of specific PIMs, or other requirements being placed on the utility, along with implementing the MYRP. See also the section below on PIMs.

Because of the complementary nature of the mechanisms, NERP recommends that MYRPs, decoupling, and PIMs be implemented in combination as part of a comprehensive PBR package.

Alignment with the goals of the Clean Energy Plan

One of the top three desired outcomes identified by NERP is to create “utility incentives aligned with cost control and policy goals.”

MYRPs may give the utility the incentive to control and reduce its costs by giving it the opportunity to keep some of the cost savings as long as the MYRP is coupled with an earnings sharing mechanism. This cost containment incentive could potentially help address the utility’s capex bias by motivating the utility to choose the most cost-effective solutions for grid needs, regardless whether they are capex or opex.

The effect of MYRPs in reducing regulatory lag on the kinds of new investments needed under the CEP is another key alignment of utility incentives with policy goals.

Also, page 12 of the CEP states:

> *The following overarching recommendations are critical to the transition and will drive the priorities identified by the stakeholders:*
>
> - *Develop carbon reduction policy designs for accelerated retirement of uneconomic coal assets and other market-based and clean energy policy options.*
> - *Develop and implement policies and tools such as performance-based mechanisms, multiyear rate planning, and revenue decoupling, that better align utility incentives with public interest, grid needs, and state policy.*
> - *Modernize the grid to support clean energy resource adoption, resilience, and other public interest outcomes.*

Significant investments will need to be made to modernize the grid consistent with these recommendations. MYRPs are a way to address the current financial disincentive that utilities have to make significant investments in the grid (see Appendix A) and therefore support the CEP priorities.

Experience in other states and jurisdictions

Fifteen US states have adopted electric utility MYRPs. Examples with a longer experience of MYRPs include Central Maine Power, MidAmerican Energy, and utilities in California and New York (MYRPs are also common in Canada, including Ontario). In our region, Georgia Power has been under MYRPs since the mid-1990s, and FP&L has used these repeatedly in Florida. The PBR study team reviewed a series of reports and studies of the other states to attempt to learn from the experiences of others. That review shows that while MYRPs show significant promise, there are many examples that indicate MYRPs must be enacted carefully. While our review was not exhaustive, the following are some of the key insights:

- Setting up MYRPs is a complicated process. It will require a lot of work from all stakeholders, and is fraught with risk of errors in the initial design that can have large consequences. The initial design can and should be improved over the years to correct any initial difficulties. Nevertheless, the PBR study team feels that the benefits of successfully implementing MYRPs – when coupled with an appropriately-designed earnings sharing mechanism – make this worth the effort, and the attendant risks can and should be mitigated and corrected.
- *The oversight of the NCUC should not be reduced.* Under a MYRP, the NCUC would be able to see the utility's business plans for a period of years into the future – which does not happen under the current system. This would allow for discussion of the types and amounts of assets to be added to the grid before the fact, instead of after the fact. Additionally, the NCUC would have detailed reviews of utility costs before each increase under a MYRP is authorized.
- There should be monitoring of utility service levels to mitigate the risk that utilities with a stronger incentive to reduce costs under a MYRP do not let existing service levels suffer. The use of a PIM with penalties for degradation of basic reliability and service levels outside of reasonable norms should be considered.

Examples of comments extracted from one report[17] that the team used as a reference:
"…It can be difficult to design MRPs that generate strong utility performance incentives without undue risk, and that share benefits of better performance fairly with customers. MRPs invite strategic behavior and controversies over plan design."

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[17] Deason, J, et al. "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities." 2017, pp. 7-2,7-3. https://eta.lbl.gov/sites/default/files/publications/multiyear_rate_plan_gmlc_1.4.29_final_report071217.pdf.

"…The strengths and weaknesses of MRPs are not fully understood. Plan design continues to evolve to address outstanding challenges. Areas of recommended future research include impacts of MRPs (and reduced rate case frequency more generally) on service quality, operating risk, and levels of bills that customers pay."
"…We also found that the [productivity] growth of utilities that operated for many years without rate cases, due to MRPs or other circumstances, was significantly more rapid than the full sample norm. Cumulative cost savings of 3 percent to 10 percent after 10 years appear achievable under MRPs."

Design Details of MYRPs and NERP Recommendations

The mechanism for adjusting rates between rate cases must be clearly defined at the outset in the initial rate case. It is crucial for the rate adjustments to be defined at the outset to ensure a high degree of certainty of how the adjustments will be subsequently made. The utility is then clear about the extent to which a successful effort to control costs will result in increased earnings. Rider/trackers, true-ups, deferral accounts, and similar mechanisms are often used to address the need for additional expenditures or investments separately from rate cases to reduce the utility's exposure between rate cases.

The term of the MYRP

NERP recommends using a maximum of three years as the term of an initial MYRP, but this is a key term to be decided. While most MYRPs are 3-5 years, NERP recommends starting on the shorter end of this range until more experience with the mechanism is gained. At the expiration of the MYRP, the utility would have the right, but not the obligation, to come in and seek a base rate increase. The NCUC could also set a period within which the next base rate case must be filed (e.g., within 5 years).

The scope of the MYRP – which utility costs would be included?

The MYRP would not necessarily apply to all utility costs. The selection of which costs should be included in the MYRP is a key term to be decided, and each of the other states studied appears to have made specific decisions that fit their needs best.

MYRPs are not well suited for the ratemaking for large, single discrete investments, such as conventional power plants to be built and rate-based by the utility. These would normally be excluded from the MYRP design and handled separately, through a deferral or separate base rate adjustment.

Costs recovered through existing clauses, such as the fuel clause, would stay in their clause, and not be included in the MYRP.

Investment programs that are made up of a series of smaller utility assets constantly placed in service over time, such as a grid improvement plan, are very well suited to a MYRP.

An earnings sharing mechanism should be implemented

As the MYRP design sets utility revenue adjustments into the future and creates an incentive for the utility to keep its costs lower than those assumed in the MYRP, the possibility of either over- or underearnings during the term of the MYRP should be addressed when the MYRP is designed.

NERP recommends that the MYRP be accompanied by a preset earnings sharing mechanism (ESM). This would set out the details in advance of how the savings will be allocated between the customers and the utility stockholders.

The ESM could be symmetrical, with earnings above and below the allowed return shared between customers and stockholders according to the method set out by the NCUC when the plan is originally approved. The earnings sharing would be calculated on an annual basis.

Key issues requiring further discussion by the NCUC

Some MYRP design decisions that were either controversial or otherwise unresolved during NERP are flagged here as important for continued attention in the course of the PBR design process.

Determination of what costs to include under MYRP

The NCUC will need to determine whether a MYRP should cover base rates or be more narrowly constructed to only cover certain projected costs. This decision will inform the initial utility revenue requirement the NCUC approves at the beginning of a MYRP and how these allowed revenues might adjust in the interim years between rate cases. Commissions have typically allowed MYRPs to cover most utility costs to more comprehensively impact utility spending decisions.

If the scope of the MYRP is too narrow, the utility may not be able to commit to a multiple-year rate case “stay-out” or moratorium, depending on the planned investments over that period.

On the other hand, risks to ratepayers can be minimized by limiting the scope of costs that may be recovered under a MYRP, so some stakeholders favored using the following definition developed during SB559 negotiations:

> "Multiyear rate plan” means a rate mechanism under which the Commission sets base rates and revenue requirements for a multiyear plan period based on known and measurable set of capital investments and all the expenses associated with those capital investments and authorizes periodic changes in base rates during the approved plan period without the need for a base rate proceeding during the plan period.

Course correction if MYRP produces undesired outcomes

The longer stay-out period of a MYRP introduces risk that utility earnings could exceed or be below target levels, resulting in excessive over- or underearning by the utility. This may result from unforeseen events (e.g., tax law changes, economic recession) or from unexpected consequences of regulation design in the MYRP. Provisions can be made in the adoption of a MYRP for regulatory review at interim points in the plan, or for “reopeners” or “off ramps” at the determination of the NCUC, should those be necessary. It is useful for adopted regulations to specify that the NCUC may conduct such reviews or reopeners, including under what general conditions a plan may be revised, although the NCUC does not need to be overly specific on conditions under which this can occur.

Revenue adjustment mechanisms

See above under revenue decoupling for a discussion of the need to consider decoupling and MYRP revenue adjustments together.

Earnings sharing mechanism design

NERP recommends adopting a MYRP in conjunction with an ESM, but did not discuss the particulars of ESM design. Some issues to be resolved include whether there should be a deadband of over- or underearning in which no adjustment is made, and how sharing tiers should be designed.

Performance incentive mechanisms

Definition
Performance incentive mechanisms (PIMs) establish performance targets and tie a portion of a utility's revenue to its performance on meeting those targets. Targets are set to achieve outcomes that align with public policy goals.

Comparison with current system
One of the top three goals identified by NERP is to create "utility incentives aligned with cost control and policy goals." The COS model incentivizes utilities to sell more electricity and to add capital assets to their rate base, but those incentives do not necessarily align with public policy goals such as the need to quickly reduce carbon emissions or alleviate household energy burdens. Introduction of carefully designed PIMs into ratemaking procedures could bring utility incentives more in line with public policy goals, such as meeting the state's targets under the Clean Energy Plan, by linking a portion of utility revenues to utilities' performance in achieving those goals.

If a significant portion of a utility's revenues is tied to performance, PIMs can begin to shift a utility's investment or management focus away from increasing capital assets and toward the accomplishment of the public policy objectives reflected in PIMs, potentially mitigating the utility's capex bias.

North Carolina has already started down the PIMs path, as the shared savings mechanism under the EE/DSM rider is a PIM incentivizing performance in the areas of energy efficiency and demand-side management.

PIMs are one part of broader PBR plan
As described elsewhere in this document, PIMs complement both decoupling and multi-year rate plans. Decoupling removes the utility's disincentive to promote energy efficiency and DERs, and PIMs can be designed to go further and create incentives for utilities to promote these programs. A MYRP creates an incentive for a utility to cut costs, and it can be paired with PIMs designed to make sure the cost-cutting does not occur in a way that negatively impacts essential functions such as customer service and reliability.

Alignment with goals of the Clean Energy Plan
The purpose of PIMs is to align utility incentives with public policy goals, which is one of the main outcomes sought by the CEP. In addition, the PIMs recommended below by NERP address the following CEP goals: carbon reduction, energy efficiency, affordability, and clean energy deployment.

The PIMs recommended below are those that seemed most useful to NERP participants. The NCUC could consider additional PIMs to help meet other goals and ensure successful implementation of PBR, as long as the desired outcomes are ones over which the utility has some level of control.

Experience in other states and jurisdictions
Several other jurisdictions have implemented, or are studying, PIMs. Two resources that relate their experiences are *Utility Performance Incentive Mechanisms: A Handbook for Regulators* (Whited, et al., 2015) and *PIMs for Progress* (Goldenberg, et al., 2020) (see References below).

Design Details of PIMs and NERP Recommendations

Metrics, Targets, and Incentives
The first step in establishing PIMs is to decide on the desired outcomes. For each outcome, it must be determined whether a reward or penalty is necessary. Among other things, this inquiry rests on existing utility

incentives (and disincentives), the existing regulatory environment, and the level of utility control over the desired outcome. The next step is to identify what metrics will be used to measure utility performance. The collection of some amount of baseline data is typically needed in order to determine how a utility's performance is changing over time and how a reward or penalty ought to be implemented.

Depending upon whether a reward or penalty is appropriate, and depending on the level of confidence in a particular metric, performance on selected metrics can be (1) tracked and reported, (2) scored against a target or benchmark that has been set, or (3) tied to a financial reward or penalty, at which point the mechanism becomes a PIM.

For PIMs, if the utility achieves its performance target, it can then receive a financial reward or it can avoid a penalty. PIMs can be either symmetrical or asymmetrical. If the PIM is symmetrical, the utility receives a financial reward for achieving the target as well as a penalty for falling short of the target. An asymmetrical PIM provides only a reward ("upside only") or only a penalty ("downside only").

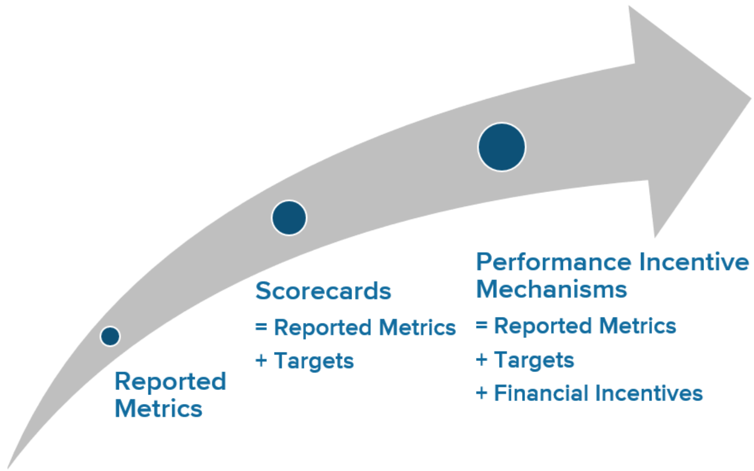

FIGURE 3: STAGES OF PERFORMANCE TRACKING
MCDONNELL, M., PBR DEEP DIVE WEBINAR: EXAMINING THE HAWAII EXPERIENCE, POWERPOINT, APRIL 2 2020.

PIMs principles

Agreeing on underlying principles to follow in designing PIMs can help align stakeholders on shared objectives. NERP agreed on these key principles to consider:

- PIMs should advance public policy goals, effectively drive new areas of utility performance, and incentivize nontraditional methods of operating.
- PIMs should be clearly defined, measurable, preferably using available data, and easily verified.
- PIMs should collectively comprise a financially meaningful portion of the utility's earning opportunities.
- No adopted PIM should duplicate a reward or penalty created by another PIM or other legal or regulatory mechanism.
- PIMs should reward outcomes, not inputs. In other words, the NCUC should avoid using expenditures as PIM metrics unless the desired outcome is increased spending.
- PIMs with metrics not controllable or minimally controllable by the utility should be upside only. A utility might prefer program-based PIMs, i.e., where incentives are awarded based on measurable actions, programs, and resources deployed or encouraged by the utility, over outcome-based PIMs given the risk that external factors may influence utility performance on the incentivized outcome (and therefore its compensation). Basing incentives on specific program results, e.g., kilowatt-hours saved through enrollment in an LED program, as opposed to outcomes, e.g., MWh saved system-wide, also makes symmetrical PIMs more of an option. However, a program-based PIM runs the risk of not achieving the desired outcome or decreasing the utility's flexibility to choose and amend the portfolio of programs and investments that best produces the desired outcomes.[18]

Once a PIM is established, it should be revisited on a regular basis to evaluate whether the selected metric, target, and incentive level are appropriate for achieving the outcome in question. If not, those parameters should

[18] For further discussion of activity-, outcome-, and program-based PIMs, see Goldenberg et al., *PIMs for Progress*, https://rmi.org/insight/pims-for-progress/.

be adjusted to improve performance. The Minnesota PBR case study that accompanies this document includes a diagram showing this iterative process as it was envisioned in Minnesota.[19]

Listed below are a number of performance outcomes discussed by NERP. Under most of the outcomes is listed a preferred metric for achieving that outcome, along with several alternative metrics. NERP recommends:

- At the outset, track as many of the metrics described below as are deemed useful and cost-effective, and any others identified by any stakeholder process or by the NCUC. This data collection will help to determine which metric is actually most useful in measuring performance.
- Track the overall performance for each adopted PIM or tracked metric and, where applicable, separately track the utility's performance in low-income counties, specifically Tier 1 and 2 counties.
- Establish a public dashboard for reporting performance on PIMs and tracked metrics.

Specific PIM outcomes recommended by NERP for NCUC consideration

Outcome: Peak demand reduction (or "Beneficial load-shaping" or "Aligning generation and load")
Preferred metrics: • Measurable load reduced/shifted away from peak based on measurement & verification from time-of-use (TOU) and other new rate designs (upside only, likely as shared savings) (program-based PIM) • Load factor for load net of variable renewable generation (upside only) (= average load not met by variable RE divided by peak load not met by variable RE) (Minnesota selected this as the metric for their PIM incentivizing "Cost-effective alignment of generation and load.")[20] • MW reduced from the utility's NCUC-accepted IRP peak demand forecast (for summer and winter peak) (upside only) (outcome-based PIM)
Alternative metrics: • enrollment (% of load or # of customers) in TOU rates or other advanced rates (symmetrical, likely as ROE adjustment) • MW demand response enrolled with TOU or other advanced rates (upside only, likely as ROE adjustment) • % of peak demand met by renewable energy (RE) or RE-charged storage and non-wires alternatives (upside only or, if symmetrical, set % target low and then progressively increase) • MW demand response utilized during critical peak periods identified for the purpose of utility tariffs using critical peak pricing (downside only with large deadband, i.e., penalty only for falling far short of target)
Notes: • This outcome serves two purposes: system efficiency and reducing need for new fossil fuel generation. • The preferred metrics listed above represent very different ways of looking at the problem. This area is ripe for innovation and requires further study and discussion before settling on an

[19] "Case Study: Minnesota Electricity Performance Based Rates," NERP, December 2020, page 5. Available here: https://deq.nc.gov/CEP-NERP

[20] Initial Comments of Fresh Energy, In the Matter of the Commission Investigation to Identify and Develop Performance Metrics and, Potentially, Incentives for Xcel Energy's Electric Utility Operations, Docket E-002/CI-17-401, pp. 2-6, https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={D012CC6E-0000-C510-A1A9-501BF633BC7D}&documentTitle=201912-157970-01.

approach. Even the definition of “peak” must be examined, as increased renewable generation in the future may lead to overall system peaks that are unproblematic because they are met by renewables, whereas the object of this PIM is to reduce demand that requires fossil fuel generation.
- Time-of-use rate design has been facilitated by the widespread installation of smart meters. Duke Energy is currently examining a suite of rate designs and DSM product bundles tailored to various customer segments that the utility believes can save customers money, drive overall system affordability, expand customer bill control, increase options related to clean energy and technology adoption, and create price signals that could offer significant peak demand reduction opportunities with minimal investment costs. Duke Energy believes that the same mechanism currently used for EE and DSM programs would be highly appropriate for measured and verified peak demand reduction and conservation from new rate designs. PIMs could be used to incentivize rate design that achieves desired NERP outcomes.

Outcome: Integration of utility-scale renewable energy (RE) & storage

Preferred metrics:
- Meeting interconnection review deadlines agreed on in queue reform (downside only)
- MW of RE interconnected over and above that required by law or policy (upside only)
- % MWh generation represented by RE

Alternative metrics:
- MW of utility-scale RE interconnected/yr
- MWh RE curtailment (symmetrical around a reasonable number)
- MWh of power from RE-charged utility-scale storage/yr (upside only)
- % RE capacity (MW) (tracked metric only)
- Avg. no. of days to interconnect utility-scale solar, below target(s) set forth in queue reform (upside only)

Outcome: Integration of DERs (RE/storage/non-wires alternatives)

Preferred metrics:
- 3-year rolling average of net metered projects connected (MW and # of projects) (upside only)

Alternative metrics:
- MW/MWh customer-sited storage in utility management programs
- # customers (and MW) participating in utility programs to promote customer-owned or customer-leased DER
- # customers (and MW) participating in utility programs to provide grid services (including RE, storage, smart thermostat, etc.)
- % of rooftop solar systems passing interconnection screens (upside only)

Notes:
- Revenue decoupling eliminates the throughput incentive but does not actively incentivize DER. Pairing this PIM with decoupling creates an incentive to increase DER.

- Consideration should be given to New York's shared savings program for non-wires alternatives projects, in which the cost of the solution (regardless of ownership) is recoverable in a 10- to 20-year regulatory asset.[21]

Outcome: Low-income affordability
Preferred metric: • % of low-income households, defined as those falling at or below 200% of the federal poverty level, that experience an annual electricity cost burden of 6% of gross household income or higher (upside only)
Alternative metrics: • Total disconnections for nonpayment • Usage per customer vs. historic rolling average, per class • Average monthly bill • % customers past due on their accounts • # customers on fixed-bill programs
Notes: • Why there is a need: In 2016, Duke Energy Carolinas had around 330,000 residential customers with household incomes ≤ 150% of the federal poverty level. They accounted for around 20% of DEC's total residential accounts. Those customers spent on average 10.5% of household income on energy (approximately 83% of which was for electricity and the rest for heating), compared to around 3% for DEC customers system-wide.[22] • There is a need to ensure affordability for other customers as well. Municipal utilities would benefit from any outcome that reduces production costs and commercial and industrial (C&I) customers want to keep NC rates competitive with other Southeast states. Metrics may need to be developed for these other classes of customers and for residential customers who do not qualify as low-income. Some of the alternative metrics listed above might be useful for some of these customers. • If a low-income rate pilot is adopted, it would help to inform the design of this PIM. Participants in the pilot would need to be selected randomly, and results would need to be reported, so that the energy burden of participating and non-participating households could be compared. • A lower fixed charge could help low-income customers and might be possible with decoupling, which shifts more of the fixed costs into rates.

Outcome: Energy efficiency
Notes: • Revenue decoupling eliminates the throughput incentive but does not actively incentivize energy efficiency (EE). Pairing this PIM with decoupling creates an incentive to increase EE. • This was one of the more important outcomes for NERP participants, but no preferred metric was chosen because the NCUC would need to consider any new EE incentives in conjunction with the existing EE/DSM incentive, which is a PIM using a shared savings mechanism. It was

[21] Trabish, Herman K. "Tackling the perverse incentive: Utilities need new cost recovery mechanisms for new technologies," Utility Dive, March 16, 2018, https://www.utilitydive.com/news/tackling-the-perverse-incentive-utilities-need-new-cost-recovery-mechanism/518320/.

[22] Direct testimony of Rory McIlmoil in Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina, Docket No. E-7, Sub 1214, February 18, 2020, p. 35, https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=11d407e8-1a85-487f-8548-ac2fa7cde2a5.

amended in October 2020 under NCUC Dockets No. E-2, Sub 931 and E-7, Sub 1032, with changes to take effect in 2022.[23] • If North Carolina enacts revenue decoupling for electricity, the lost revenue adjustment mechanism (LRAM) associated with the existing EE/DSM incentive will no longer be needed and will need to be removed by the NCUC for the classes included in decoupling. Particular attention will need to be given to how this is done for the general service class, if small and medium general customers are included in decoupling but large general service customers are not. There also needs to be consideration given to small and medium general service accounts that can currently opt out of the LRAM mechanism and how that will be addressed with decoupling. The recommendations below could be considered at that time.
Possible amendments to existing incentive: • The current incentive imposes a penalty for incremental annual savings below 0.5% and offers a bonus above 1%. The NCUC order directed the EE/DSM Collaborative to study the impact of switching to a step approach in which the incentive is scaled up or down linearly above a minimum and maximum level (so that there is a possibility of some bonus between 0.5% and 1% and a possibility of additional bonus above 1%). If the study shows this approach to yield greater savings, such a step approach could be adopted. That incentive should likely be capped at a certain percentage of costs (e.g., Minnesota caps incentives at 30% of program costs).[24] • Consider advantages/disadvantages of shared savings mechanism vs. using as the core metric either kWh saved, Btu saved (to give credit for electrification) and/or greenhouse gas emissions saved. • Most states base their goals on savings in a given year (called incremental annual savings, that measure savings from measures installed in that year). Illinois and, more recently, Virginia measure total annual savings (savings persisting from previously installed measures and new measures installed in that year). Incremental annual savings is a simple place to start, but over time total annual savings may be a good framework, because it addresses the persistent effect of short-term measures such as low-flow showerheads or behavioral EE programs.
Additional metrics to track or incentivize: • Low-income participation in EE programs • % participation per class • # of C&I customers participating (upside only, with the utility rewarded for implementing programs that cause fewer C&I customers to opt out, but not penalized for failing to do so, since the outcome is minimally controllable by the utility)

Outcome: Carbon emissions reduction
Preferred metric: • Tons of CO_2 equivalents reduced beyond what is required by law or policy (with cost-effectiveness test, upside only)
Alternative metrics: • Reduction in carbon intensity (tons carbon/MWh sold) (symmetrical) • Carbon price used in IRP scenarios ($/ton, tracked metric only)
Notes:

[23] Order Approving Revisions to Demand-Side Management and Energy Efficiency Cost Recovery Mechanisms, Oct. 20, 2020, https://starw1.ncuc.net/ncuc/ViewFile.aspx?Id=5aaea5ce-6458-41fe-ab2d-14d86881092d.
[24] "Case Study: Minnesota Electricity Performance Based Rates," NERP, December 2020, Available here: https://deq.nc.gov/CEP-NERP

- Needs to be designed in accordance with any carbon policy resulting from the A-1 process. If no carbon reduction policy is achieved in the A-1 process, a PIM would be essential and could set benchmarks for reduction between now and 2050 that would incentivize meeting CEP carbon reduction goals.
- If this PIM were awarded on a dollar per ton basis, the NCUC could consult with the A-1 stakeholder group, who examined the effects of different carbon prices for future years.
- Consideration should be given to calculating and reporting (but likely not incentivizing) reduction in upstream methane emissions associated with gas burned in North Carolina, as these contribute significantly to climate change yet are not captured by the carbon accounting of the CEP. A PIM could eventually be appropriate if the state wishes to incentivize progress toward Duke Energy's goal, announced October 2020, of reducing upstream methane emissions in its natural gas distribution and power generation supply chains.[25]
- Any PIM in this area would need to be either based on North Carolina consumption with any incremental costs direct assigned to North Carolina customers or agreed to by regulators in both North Carolina and South Carolina.

Outcome: Electrification of transportation

Preferred metric:

- EV customers on TOU or managed charging (include home, workplace, fleets, and public charging) (upside only) OR
- MWh or % of EV charging load at low-cost hours (upside only)

Alternative metrics:

- Utilization of utility-owned public charging stations (upside only)
- Utility-owned charging in low-income areas (# or % chargers) (symmetrical)
- Customers enrolled in programs to encourage private charger installation (upside only)
- EV education (avoid rewarding $ inputs; maybe clicks on a web page; if expenditure metric, then downside only with spending cap)
- EV adoption
- CO_2 avoided in transportation sector by electrification

Notes:

- Design in accordance with Duke Energy's EV pilot as approved November 2020.[26]
- Design depends on whether utility or others own charging infrastructure, since ROE on assets may be incentive enough.
- More research needed on how EVs can help with RE integration and how they can lead to reduced costs for all customers.
- Utility could use credits for off-peak charging but not put customers on TOU, or could use subscription pricing with managed charging. PIM should not constrain what method is used to promote off-peak EV charging.

Outcome: Equity in contracting

[25] "Duke Energy to reduce methane emissions in its natural gas business to net zero by 2030," https://www.duke-energy.com/_/media/pdfs/our-company/methane-reduction-fact-sheet.pdf?la=en.

[26] Order Approving Electric Transportation Pilot, In Part, Nov. 24, 2020, https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=1c1665d0-d645-4293-82d8-ae9d7e672e3d.

Preferred metrics: • % of utility scale RE & storage suppliers that are 51% owned, managed, and controlled by one or more individuals who are socially and economically disadvantaged as defined by 15 U.S.C. § 637 (tracked metric only) • % of utility scale RE & storage suppliers that are 51% owned, managed, and controlled by one or more individuals who are women (tracked metric only)
Notes: • There is also a desire to achieve equity in use of utility programs across income levels, but that needs more discussion.

Outcome: Resilience
Preferred metrics: • Number of critical assets (see note below) without power for more than N hours in a given region (# of assets), N may be set as 0 hours or greater than the number of hours backup fuel is available • Critical asset energy demand not served (cumulative kW) • Critical asset time to recovery (average hrs)
Alternative metric: • Cumulative critical customer hours of outages (hrs)
Notes: • Recommended metrics revolve around impacts on critical community assets since that is the framework used in the PARSG (Planning an Affordable, Resilient and Sustainable Grid) project and in the state Resilience Plan. This approach is also being integrated into the NARUC-NASEO comprehensive system action plan that the NC delegation is considering. • Critical assets may include hospitals, fire stations, police stations, evacuation shelters, community food supply distribution centers, production facilities, military sites, etc. • Since resilience study is very much a work in progress in North Carolina, it is recommended that these initially be tracked metrics, with no incentive attached. • Efforts to develop resilience metrics are currently underway across organizations such as the DOE, FERC, EPRI and multiple state public utility commissions. The industry is lacking agreed-upon performance criteria for measuring resilience, as well as a formal industry or government initiative to develop consensus agreement.[27] As such, there are currently no standardized metrics to measure resilience efforts or to quantify the extent or likelihood of damage created by a catastrophic event. Resilience is addressed state-by-state, and oftentimes event-by-event. If different metrics, benchmarks, rewards or incentives are identified and developed for reliability and resilience,[28] there is a need to properly distinguish each, take into account the benefits for each, and differentiate how to separately determine the benefits, rewards and penalties for each.[29] • The metrics identified above are based on community impact driven resilience needs for critical infrastructure. It is based on current North Carolina state and local government led application of energy vulnerability and risk analysis framework that uses the Resilience Analysis Process (RAP) developed by the Sandia National Lab, which includes prioritization of grid-modernization initiatives that could achieve a desired set of resiliency goals for the community.

[27] IEEE Standards Association (2018) Grid Resilience and the NESC®.

[28] According to DOE, reliability refers to the ability of the system or its components to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components. Resilience refers to the ability of a system or its components to adapt to changing conditions and to withstand and rapidly recover from disruptions.

[29] DOE (2017). See Key Findings at S-13: "There are no commonly used metrics for measuring grid resilience. Several resilience metrics and measures have been proposed; however, there has been no coordinated industry or government initiative to develop a consensus on or implement standardized resilience metrics." https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

PIMs needed in conjunction with a multi-year rate plan

A MYRP provides an incentive to cut costs. Therefore, these two PIMs should accompany a MYRP to guard against detrimental cost-cutting in the areas of reliability and customer service. If there is no MYRP, the metrics could be simply tracked and reported.

Outcome: Reliability
Preferred metric: • SAIDI (performance year-over-year, excluding extreme event days, downside only, feeder-by-feeder) (see note below)
Alternative metrics: • CEMI4 (customers experiencing more than 4 outages of 1 minute or more per year) • SAIFI • Miles of vegetation management (tracked metric only; see note below)
Notes: • The design should be downside only because the utilities' performance on reliability is already high. Providing a reward for further improvement might not provide a net benefit to customers (point of diminishing returns). • The feeder-by-feeder specification prevents selective maintenance. Central Maine Power experienced a drop in reliability on certain feeders when they had a reliability PIM in conjunction with a MYRP. • Tracking miles of vegetation management would give the NCUC a way to ascertain whether the MYRP was resulting in decreased maintenance. But many other factors affect that metric, so a financial penalty could unfairly punish the utility for matters beyond its control, and a financial reward could perversely incentivize unnecessary vegetation work.

Outcome: Customer service
Preferred metric: • Third-party customer satisfaction survey (e.g., JD Power score or Net Promoter score) (downside only)

Key issues requiring further discussion by the NCUC

As the NCUC considers PIM implementation, it will have to consider all of the parameters discussed above. The NCUC will need to review a utility's proposed metrics and PIMs and determine whether they incentivize the right outcomes, whether they employ the best metrics to measure each outcome, whether the targets are at the right level, and whether financial incentives for each metric are at the right level and appropriate to include. NERP hopes that the suggestions made above will help with that process.

Options for designing incentives

NERP did not discuss the form that PIMs should take. The four most common design options are listed here. Each design option has advantages and disadvantages, and some PIMs incorporate aspects of more than one design.

- **Shared savings or shared net benefits**
  Incentives can be based on shared net benefits or savings that allow a utility to keep a portion of the net benefits or savings that are created by the achievement of a performance target. Net benefits are

calculated using the avoided costs that a utility would have incurred without the program minus the cost of the program itself.

- **Percentage adders based on spending**
  PIMs can allow a utility to earn a percentage return on their spending on particular programs, such as energy efficiency or DER initiatives, if they meet performance targets or program goals. This allows utilities to earn a return on expenses that would otherwise be a pass-through.
- **Fixed rewards or penalties**
  Utilities can earn or be penalized a fixed amount based on achievement of targets.
- **Adjustment to a utility's regulated ROE**
  PIMs can make a basis point adjustment of a utility's regulated ROE, which could more fundamentally impact utility investment decisions.

RECOMMENDED PROCESS FOR PBR DEVELOPMENT

PBR requires careful attention to key design details, especially for a comprehensive PBR approach as described here. NERP participants believe that enabling legislation will be beneficial to direct the next stage of PBR development, followed by a NCUC rulemaking process to adopt necessary rules for filing applications and criteria for evaluating them. Effective incentive regulation will also require ongoing monitoring and possible course corrections during a PBR regime (e.g., at the conclusion of a multi-year term, before advancing to the next term). This foretells the need for devoted attention and care from the NCUC and stakeholders to monitor utility performance and system outcomes, then make adjustments to guide utilities to continued improvement and value creation for customers.

Other states have applied a sequential process to develop and refine PBR, for example:

1. Articulate goals
2. Identify desired outcomes
3. Assess how current regulations meet or do not meet desired outcomes
4. Prioritize outcomes and identify PBR tools for further development
5. Design and iterate on PBR tools
6. Determine steps and requirements for implementation, including opportunity for evaluation

The NERP process has made substantial progress on the first four of these steps. A PBR process at the NCUC should seriously consider the conclusions reached by NERP, then follow the steps above, making sure to receive comment from as broad a group of stakeholders as possible, including any other relevant state agencies. Some specific steps that may be necessary are outlined below.

- First, the NCUC would lead a rulemaking process, to set up all of the filing requirements and procedures that any utility would need to follow to file a PBR application, including the criteria to be used by the NCUC in evaluating PBR applications. The NCUC should determine whether and in what form a stakeholder process should take place to gather input prior to a utility filing a PBR application.
- The utility would submit its PBR application as part of an initial base rate case. The utility would still file cost of service studies and those studies would be the basis for establishing the total revenue required and the allocation to the customer classes. The PBR adjustments discussed in this document would be increments or decrements to that base. The utility's accompanying PBR application would include:
  - a decoupling plan including proposed adjustment and true-up mechanisms
  - a multi-year rate plan including the planned investments that the utility proposes to undertake during the term of a MYRP
  - an earnings sharing mechanism
  - a set of proposed PIMs, scorecard targets or reported metrics
- In addition to all the normal rate case activities, the NCUC would need to:
  - review and rule on the proposed decoupling and MYRP designs and proposed PIMs

  - evaluate whether the planned investments are consistent with the goals of the CEP and the public interest and determine which of those planned investments would be allowed and what the allowed revenue increases would be over the term of the MYRP
  - for the customers included in decoupling, amend as needed the lost revenue adjustment mechanism (LRAM) that is part of the existing EE/DSM incentive, since decoupling adjusts revenue in a different manner
- Annually, the NCUC would review the results of the utility's operations during the prior year, including:
  - actual capital projects placed in service
  - utility earnings levels
  - utility sales and any adjustments needed due to a decoupling mechanism, including amounts to be refunded to or collected from customers based on the decoupling true-up mechanism and adjustments to rates going forward as a result of the mechanism
  - other utility revenue adjustments required by the adopted MYRP and ESM
  - utility performance against any adopted PIMs or tracked metrics to calculate penalties and incentives.

  After this review, the NCUC would approve the actual rates to be used in the subsequent year.
- NCUC rulemaking should outline what steps will be taken at the end of the initial MYRP period, including opportunities to add, delete, or adjust the approved set of PIMs to ensure they are capturing and driving desired utility performance.

Theoretical timeline

To help visualize how this process might unfold in North Carolina, NERP developed this entirely theoretical timeline:

- Legislation signed into law: June 2021
- NCUC issues rules for utility PBR applications: December 2021
- PBR application and base rate case filed by utility: July 2022
- NCUC proceeding to evaluate application: July 2022-March 2023
- NCUC order establishing PBR: March 2023
- First annual decoupling/MYRP true-up and PIMs review: March 2024

CONCLUSION

To summarize, NERP recommends that NCUC, subject to any guidance and timelines provided by legislation, begin as soon as possible a proceeding to develop rules under which a utility may file a comprehensive PBR application, including:

- Revenue decoupling excluding the large general service class to reduce the throughput incentive
- MYRP with an ESM and off-ramp to eliminate regulatory lag
- PIMs or tracked metrics to transition the utility revenue model toward achievement of regulatory goals, addressing the following outcomes: peak demand reduction, integration of DER and utility-scale RE and storage, low-income affordability, energy efficiency, carbon emissions, electrification of transportation, resilience, equity and – assuming a MYRP is adopted – reliability and customer service
- Provisions for annual or more frequent decoupling and MYRP true-ups and adjustment of PIM metrics, targets and incentive levels

Members of the NERP stakeholder group, in particular the PBR study group, stand willing to help the NCUC in its implementation of PBR, either in a stakeholder process or in any other way the NCUC deems appropriate.

REFERENCES

There are many resources on PBR. Here are some that NERP found most useful.

Cross-Call, Gold, Goldenberg, Guccione, and O'Boyle, *Navigating Utility Business Model Reform*, Rocky Mountain Institute (2018). Available at https://www.rmi.org/insight/navigating-utility-business-model-reform/.

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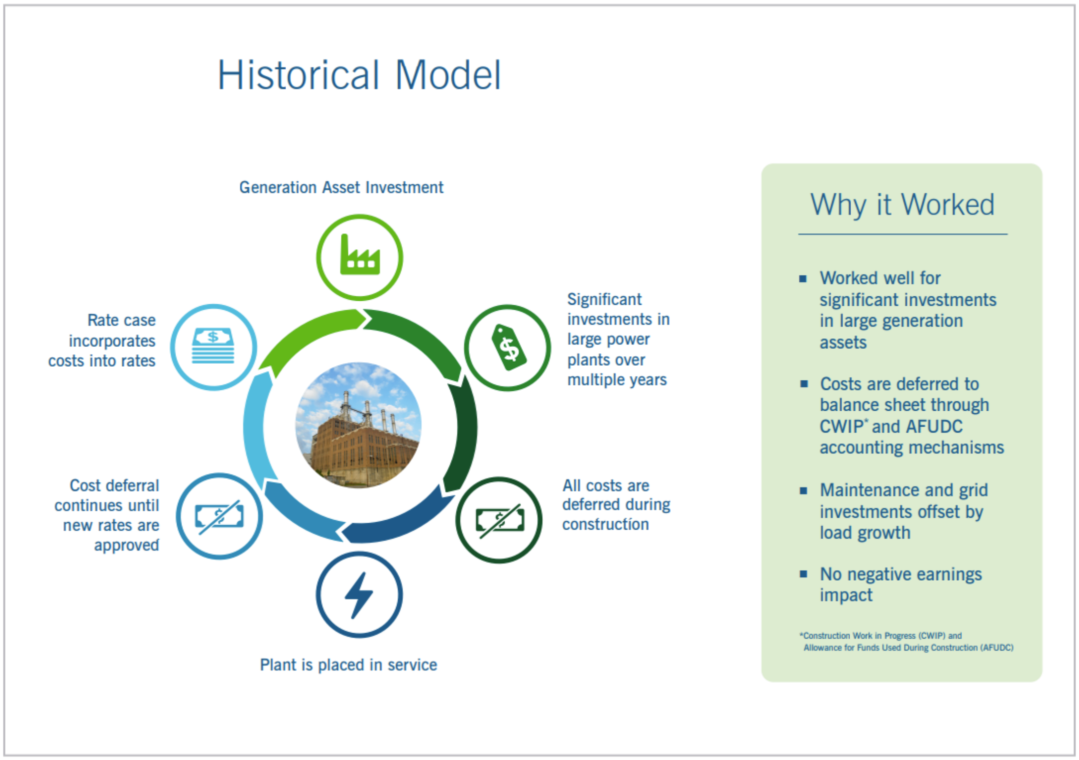
http://www.synapseenergy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf.

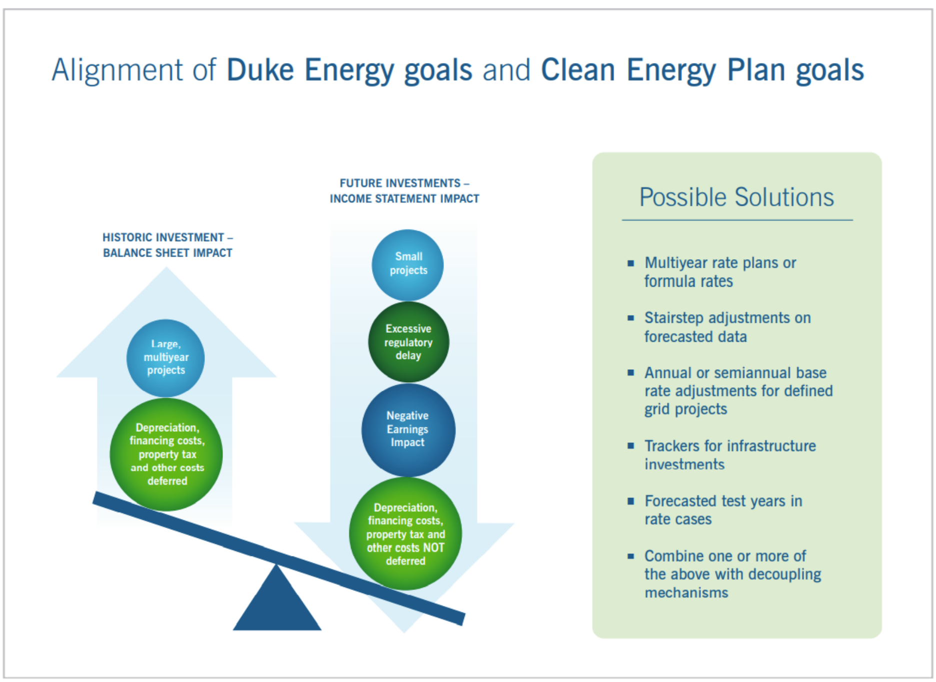
APPENDIX A

Solving for Regulatory Lag (Source: Duke Energy)

North Carolina Ratemaking and Recovery

The current regulatory system has served customers and utilities well for many decades. But today, utilities are shifting away from large-scale power plants toward modernizing the energy grid and adding more distributed energy. Therefore, a new model is needed to align the regulatory framework with investments in a 21st-century energy system.





Modern Cost Recovery for Electric Utilities

Many other states have adopted one or more cost recovery mechanisms that enable higher levels of grid improvement investment:

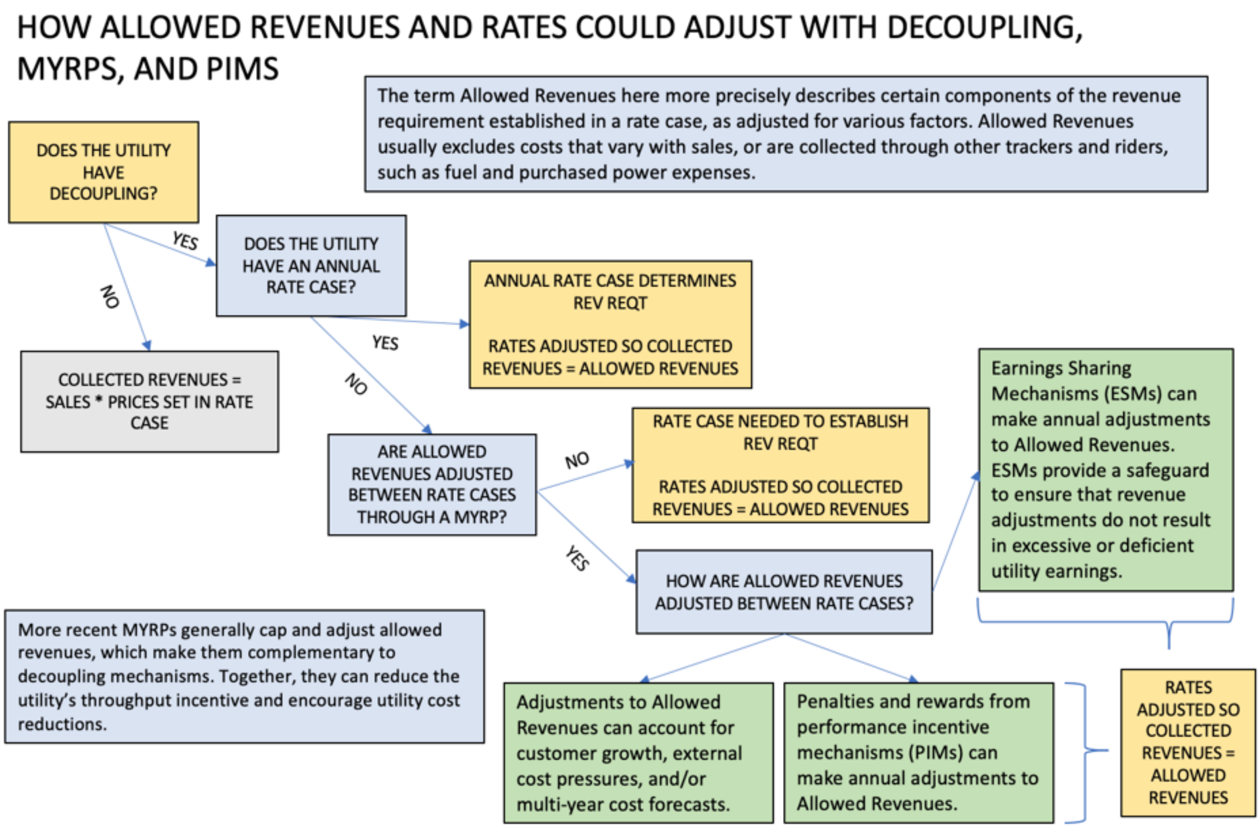
- 24 states have multi-year rate plans or formula rates
- 23 states have trackers for grid/electric infrastructure investments
- 30 states have forward test years (full or partial)
- Only 7 states have none of these mechanisms – including North Carolina

APPENDIX B

Flow Chart Diagram Depicting Potential Interactions and Coordination Between MYRP, Decoupling, and PIMs

Source: Rocky Mountain Institute

The following diagram depicts how several key PBR mechanisms operate together to adjust utility revenues and customer rates. It shows how revenue decoupling could operate with a MYRP that caps and adjusts a utility's revenues in the years between rate cases. Additional revenue adjustments resulting from performance incentives and an earnings sharing mechanism are also included to show how they might ultimately impact the revenues a utility is allowed to collect and the rates then charged to customers.



PART I. AUTHORIZE RATES USING ALTERNATIVE MECHANISMS

Section 1.(a) Article 7 of Chapter 62 of the General Statutes is amended by adding a new section to read:

"§ 62-133A. Performance-based rate methodology authorized.

(a) Declaration of Policy. - The General Assembly declares that utilities in the state have an important role to play in the transition to cleaner energy, and must be fully empowered, through regulatory tools and incentives, to achieve the goals of this policy. In combination with new technology and emerging opportunities for customers, this policy will spur transformational change in the utility industry. Given these changes, the legislature authorizes that the Utilities Commission's statutory grant of authority for rate making includes consideration and implementation of performance-based regulation (PBR) including: multiyear rate plans with earnings sharing mechanism, decoupling of utility revenues from energy sales, and performance incentive mechanisms to achieve just and reasonable rates and achieve its public interest objectives. The General Assembly also finds that the regulatory cost recovery mechanisms should better align the interests of customers and electric public utilities and that improvements should be made in the current rate making process to decrease the number of rate cases and reduce the regulatory lag that currently hinders certain capital investments, such as investments in the electric grid, storage or small scale renewables, and other technologies, necessary to support the clean energy transition. The PBR approach can be used to encourage: (a) alignment of electric utility incentives with customer and societal interests through regulatory mechanisms that motivate utilities to improve operations, increase program effectiveness, and better manage business expenses, (b) electric utility innovation in how it delivers service to customers; (c) electric utility investments to reduce carbon emissions, make the grid smarter, more resilient to adverse weather and to cyber and physical security threats, and capable of accommodating more renewable and distributed energy resources onto the system; (d) more efficient use of energy by customers; and (e) maintaining affordable and more predictable rates through annual rate adjustments spread over time. As such, the General Assembly declares that it is in the public interest to develop standards for performance-based regulation of electric utilities.

(b) Definitions. - For purposes of this section, the following definitions apply:

(1) "Performance-based regulation (PBR)" means an alternative rate making approach that includes (1) revenue decoupling; (2) multiyear rate plans with earnings sharing mechanism; and (3) performance incentive mechanisms.

(2) "Decoupling" means a ratemaking mechanism intended to break the link between a utility's revenue and the level of consumption of electricity by its customers.

(3) "Multi-year rate plan (MYRP)" means a ratemaking mechanism under which the Commission sets base rates based on a historic test year and revenue requirements necessary to cover new Commission-authorized costs that are expected to be incurred over a multi-year period through a plan which authorizes periodic changes in rates without a general rate application.

(4) "Earnings sharing mechanism" means a ratemaking mechanism that shares surplus or deficit earnings, or both, between utilities and customers.

(5) “Performance incentive mechanism (PIM)” means a ratemaking mechanism that links electric utility revenue or earnings to electric utility performance in targeted areas consistent with customer and societal interests and regulatory and public policy goals and includes specific performance metrics and targets against which utility performance is measured.

(6) “Distributed Energy Resource (DER)” means a device or measure that produces electricity or reduces electricity consumption, and is connected to the electrical system, either ‘behind the meter’ on the customer’s premises, or on the utility’s primary distribution system. A DER can include, but is not limited to, energy efficiency, distributed generation, demand response, microgrids, energy storage, energy management systems, and electric vehicles.

(7) “Tracking metric” means a methodology for tracking and quantitatively measuring and monitoring outcomes or utility performance, meaning that the data reflected by the unit of measurement is tracked and published to illuminate progress toward a particular regulatory outcome.

(c) Authorization. - Notwithstanding the methods for fixing rates established under G.S. 62-133, the North Carolina Utilities Commission is authorized to utilize and approve PBR mechanisms proposed by electric public utilities and/or other stakeholders and intervenors, including, but not limited to, revenue decoupling, MYRP with an earnings sharing mechanism, and PIMs.

(d) Rulemaking. - Within six months of the effective date of this act, the Commission shall issue an order adopting rules consistent with this act. The Commission may initiate a stakeholder process to inform its rulemaking. The rules should prescribe the specific procedures and requirements that an electric utility must meet when filing a PBR Application, the criteria for evaluating such an Application, and the process for addressing deficiencies through a remedy that may consist of a collaborative process between stakeholders and the utility to cure any identified deficiency in the Utility’s PBR Application in the event the Commission ultimately rejects a utility’s PBR Application.

(e) Application. - A PBR Application shall be made in a general rate case proceeding initiated pursuant to G.S. 62-133, and must include details of: (1) a decoupling rate adjustment mechanism; (2) a MYRP if desired by the electric utility (including proposed revenue requirement and rates for each year of the MYRP or method for calculating such); and (3) PIMs (including but not limited to targeted areas of energy efficiency, peak demand reduction, and renewable energy and DERs). It may also include proposed tracking metrics with or without targets or benchmarks to measure utility achievement, and other PBR mechanisms to support the clean energy transition. The following additional requirements apply:

(1) MYRP may include annual rate adjustments based on projected investments, formulas, indexes, or a combination thereof. If the MYRP includes rate increases based on forecasted planned investments, the Commission shall require the electric utility to include in its PBR Application major planned investments over the plan period, the schedule for completion of those investments, and an explanation as to why the investments are in the public

interest. If projected investments are not included in the MYRP rate adjustments until after the investments are in service, then the utility may request Commission approval to defer to a regulatory asset the incremental costs from the time the investment is placed in service until the costs are reflected in the MYRP rates.

(2) PIMs should be clearly defined, measurable with a defined performance metric, and reasonably within the utility's control. The incremental costs required to achieve a PIM shall, upon approval by the Commission, either be included in rates under a MYRP or deferred to a regulatory asset until such time as the costs can be incorporated into the utility's rates.

(f) When reviewing a PBR application, the Commission may approve PIMs proposed by the electric utility as part of a PBR application including the following:

(1) Rewards based on the sharing of savings achieved by meeting or exceeding a specific performance target;

(2) Rewards or penalties based on differentiated authorized rates of return on common equity to encourage utility investments or operational changes to meet specific performance targets;

(3) Fixed financial rewards to encourage achievement of specific performance targets, or fixed financial penalties for failure to achieve such targets; and

(4) Any other incentives or financial penalties that the Commission determines to be appropriate.

(g) The Commission shall approve the PBR Application by an electric utility only upon a finding by the Commission that such mechanisms are just and reasonable, and are in the public interest pursuant to G.S. 62-2(a). In reviewing any such Application under this section, the Commission may consider whether the Application, as proposed: (i) assures that no customer or class of customers is unreasonably harmed and that the rates are fair both to the electric utility and to the customer, (ii) reasonably assures the continuation of safe and reliable electric service, (iii) will not unreasonably prejudice any class of electric customers and result in sudden substantial rate increases or "rate shock," to customers, (iv) is otherwise consistent with the public interest, (v) encourages peak load reduction or efficient use of the system, (v) encourages utility-scale renewable energy and storage, (vi) encourages DERs, (vii) reduces low-income energy burdens, (viii) encourages energy efficiency, (ix) encourages carbon reductions, (x) encourages beneficial electrification, including electric vehicles, (xi) supports equity in contracting, (xii) promotes resilience and security, and (ix) maintains adequate levels of reliability and customer service.

(h) Decision. - Upon receiving a PBR Application by an electric utility that incorporates PBR mechanisms as listed in (e), the Commission, after notice and an opportunity for interested parties to be heard, is authorized to issue an order within the time frames set forth in G.S. 62-134, approving or rejecting the utility's PBR Application; in addition to its order ruling on the electric utility's request to adjust base rates under G.S. 62-133. If the Commission rejects the PBR Application, it must provide an explanation of the deficiency and an opportunity for the utility to refile or for the utility and the stakeholders to collaborate to cure the identified deficiency and refile.

(i) Plan Period. - Any PBR Application approved pursuant to this section shall remain in effect for a plan period of not more than 60 months. Prior to the end of the PBR plan period, if the utility has not filed a petition for a subsequent PBR plan, the Commission shall initiate a proceeding to examine options for renewing or revising the PBR mechanisms.

(j) Review. - At any time prior to conclusion of a PBR plan period, the Commission, with good cause and upon its own motion, has the discretion to examine the reasonableness of the electric utility's rates under the plan, conduct periodic reviews with opportunities for public hearings and comments from interested parties, and initiate a proceeding to adjust rates or PIMs as necessary. In addition, nothing in a PBR proposal shall inhibit or take away from the Commission's authority to grant deferrals for extraordinary costs in between rate cases.

(k) Utility Reporting. - For purposes of measuring an electric utility's earnings under a PBR Application approved under this section, the electric utility shall make an annual filing that sets forth the electric utility's earned return on equity, the electric utility's revenue requirement trued up with the actual electric utility revenue, the amount of revenue adjustment in terms of customer refund or surcharge, and the adjustments reflecting rewards or penalties provided for in performance-based plans approved by the Commission.

(l) Nothing in this section shall be construed to (i) limit or abrogate the existing rate-making authority of the Commission or (ii) invalidate or void any rates approved by the Commission prior to the effective date of this section. In all respects, the alternative ratemaking mechanisms, designs, plans or settlements shall operate independently, and be considered separately, from riders or other cost recovery mechanisms otherwise allowed by law, unless otherwise incorporated into such plan.

(m) Commission Report. - No later than April 1 of each year, the Commission shall submit a report on the activities taken by the Commission to implement, and by electric power suppliers to comply with, the requirements of this section to the Governor, the Environmental Review Commission, and the Joint Legislative Oversight Committee on Agriculture and Natural and Economic Resources, the chairs of the Senate Appropriations Committee on Agriculture, Natural, and Economic Resources, and the chairs of the House of Representatives Appropriations Committee on Agriculture and Natural and Economic Resources. The report shall include any public comments received regarding environmental impacts (including but not limited to air, water and waste emission levels) of the implementation of the requirements of this section. In developing the report, the Commission shall consult with the Department of Environmental Quality.

SECTION 2.(b) The Commission shall adopt rules as required by G.S. 62-133A(g), as enacted by Section 2(b) of this act.

PART II. EFFECTIVE DATE

SECTION 1. Part I of this act is effective when it becomes law and applies to any rate-making mechanisms filed by an electric utility on or after the date that rules adopted pursuant to G.S. 62-133A(g), as enacted by Section 2(a) of this act, become effective.

NERP CASE STUDY

NATURAL GAS DECOUPLING IN NORTH CAROLINA

The 2020 North Carolina Energy Regulatory Process (NERP) prioritized energy reforms that would drive affordability, carbon-reduction, and align regulatory incentives with policy goals.

BACKGROUND AND JUSTIFICATION FOR NATURAL GAS DECOUPLING IN NORTH CAROLINA

Historically, there have been large fluctuations in the cost of natural gas. During a rate case in 2002, natural gas had a benchmark cost[1] of $2.75 per dekatherm. When the natural gas distribution companies (Piedmont Natural Gas Company, Inc., North Carolina Natural Gas, and Eastern North Carolina Natural Gas Company, ["Company"]), filed their joint rate case[2] in 2005, their benchmark cost was $7.00 per dekatherm. Subsequently, the benchmark increased to $11.00 per dekatherm by the time that the Notice of Decision from the North Carolina Utilities Commission (NCUC) was made. The higher prices caused customers to decrease use, insulate homes, and purchase efficient appliances. Both the increase in gas cost and decreases in customer use resulted in the natural gas companies not recovering their approved cost margin. All these practices adversely impacted the Company's recovery of its approved margin.

The Company's weather-normalized usage per residential customer declined an average of 2% per year and was expected to continue in future years. Usage was declining due to customer adoption of more efficient appliances to lower natural gas bills.

The Company's volumetric rate structure created a disincentive for the Company to implement energy efficiency and conservation initiatives for its customers (i.e. was not environmentally or economically sustainable).

The historical ratemaking process did not ensure that the Company fully recovered the cost of gas delivered to its customers. Gas costs (meeting the definition of North Carolina General Statute (NCGS) 62-133.4) were trued-up based on the amount billed to customers, instead of the amount "actually" collected. Therefore, the cost of the gas delivered to customers' who did *not* pay their bills (referred to as the uncollectables[3] expense) could not be recovered by the Company.

IMPLEMENTATION TIMELINE AND HISTORY

- On February 28, 2005, the Company gave notice of their intent to file a rate case.

[1] The benchmark reflects the price that market participants use to write contracts and achieve full transparency around transactions. The benchmark is the variable cost in rate design.
[2] See dockets G-9, Sub 499; G-21, Sub 461; and G-44, Sub 15
[3] Accounts that have virtually no chance of being paid.

- On April 1, 2005, the Company filed a petition for: 1) consolidation of their revenues, rate bases, schedules and expenses; 2) a general increase in their rates and charges; and 3) approval of depreciation rates. This facilitated the transition from a three-company operation into a single integrated Company.
- On August 31, 2005, the Company, the NCUC Public Staff, Carolina Utilities Customers Association (CUCA), and the federal Department of Defense (DOD) filed a Stipulation to further request the merger. In addition, the Stipulation requested the implementation of a test program for decoupling termed the "Customer Utilization Tracker" (CUT) in conjunction with an energy conservation program.
- On September 2, 2005, the Office of the Attorney General filed its Statement of Position regarding the Stipulation objecting to the implementation of: (1) the CUT; and (2) the recovery mechanism for the gas cost portion of uncollectable expenses. The Attorney General recommended the CUT be implemented for only a trial period.
- On September 28, 2005, the NCUC approved the Joint Proposed Order of Stipulating Parties. This document contained the proposed program details and rate design (which is described in more detail later in this case study).
- On November 3, 2005, the NCUC issued the final order to approve a pilot decoupling mechanism (the CUT) for a period of no more than three years.
- The NCUC specified that there was statutory authority to authorize true-up mechanisms for:
- natural gas (NCGS 62-133.4); and
- electricity (NCGS 62-133.2).[4]
- Despite their determination that statutory authority existed to authorize decoupling mechanisms, the NCUC asked the legislature to enact a law that allowed NCUC to adopt a natural gas decoupling rate mechanism to avoid future lawsuits associated with rate cases.
- On July 18, 2007, Session Law 2007-227 House Bill 1086 authorized customer usage tracking rate adjustment mechanisms for natural gas local distribution company rates.[5] This bill formally codified the CUT rate adjustment mechanism for natural gas local distribution company rates in NCGS 62-133.7.[6]
- On March 31, 2008, the Company filed for approval to permanently extend the decoupling mechanism in its general rate case[7]. The decoupling mechanism's name was proposed to be changed from the CUT to the Margin Decoupling Tracker (MDT). In this general rate case, the Company also asked for a rate increase for a fair rate of return on invested capital. This was due to: 1) significant new investments to grow and maintain the gas distribution systems to benefit current and future customers; 2) significant changes in the Company's costs and capital structure; and 3) significant declines in average per-customer usage from the assumed usage levels in existing base rates.
- On August 25, 2008, the Company, Public Staff, CUCA, DOD, and Texican filed a Stipulation of agreement.[8] The Stipulation contained the proposed rate changes and request for permanently extending the decoupling mechanism's pilot program into the MDT.
- On October 24, 2008, NCUC issued an order that allowed the Company to permanently incorporate the MDT and increase rates by a total of $15.7 million (1.5% of the Company's total operating revenues). The NCUC specified that increases to the Company's revenues during the pilot program did not indicate any flaw in the decoupling mechanism. However, it indicated that the Company was continuing to experience system growth (53,000 new customers since 2005) which produced additional revenues. One advantage of the MDT is that any growth that adds revenues at a rate higher than that approved by the NCUC actually lowers rates for existing customers.
- The NCUC relied on NCGS 62-133.7 for authority to permanently implement the MDT in 2008. The MDT's foundational design elements remained consistent with the CUT. A couple notable revisions in 2008 were: (1) an increase in the rates (1.5% of the Company's total operating revenues) so the Company could earn a fair rate of return; and (2) an increased annual expenditure of $1.275 million on conservation and energy efficiency programs.

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[4] North Carolina case law for historical precedents included the following:
State ex rel. Utilities Comm. v. CF Industries, Inc., 299 NC 504 (1980);
- CF Industries, 299 NC at 505-6 and 508;
- CF Industries, 299 NC at 507-9; and

State ex rel. Utilities Comm. v. Public Service Company, 35 NCApp 156 (1978);
- Public Service Company, 35 NCApp at 156-7;

State ex rel. Utilities Comm. v. Edmisten, 291 NC 327 (1976); and
State ex rel. Utilities Comm. v. N.C. Natural Gas Corp., 323 NC 630, 631 (1989)

[5] House Bill 1086 (Session Law 2007-227): https://www.ncleg.gov/EnactedLegislation/SessionLaws/PDF/2007-2008/SL2007-227.pdf

[6] The Session Law's text states: *§ 62-133.7. Customer usage tracking rate adjustment mechanisms for natural gas local distribution company rates. In setting rates for a natural gas local distribution company in a general rate case proceeding under G.S. 62-133, the Commission may adopt, implement, modify, or eliminate a rate adjustment mechanism for one or more of the company's rate schedules, excluding industrial rate schedules, to track and true-up variations in average per customer usage from levels approved in the general rate case proceeding. The Commission may adopt a rate adjustment mechanism only upon a finding by the Commission that the mechanism is appropriate to track and true-up variations in average per customer usage by rate schedule from levels adopted in the general rate case proceeding and that the mechanism is in the public interest.*

[7] See Docket G-9, Sub 550 for material related to adopting a permanent extension of the decoupling mechanism.

[8] See the Stipulation for details on the rate design for the MDT, including Net operating income, Rate Base and Overall Return "Exhibit A"; Rate design "Exhibit B"; Fixed gas cost allocations "Exhibit C"; Margin decoupling mechanism factors "Exhibit D"; Tariffs "Exhibit E"; Service regulations "Exhibit F"; Cost of gas "Exhibit G"; Impact of stipulated rate increase by customer class "Exhibit H"

DESIGN ELEMENTS OF THE 2005 DECOUPLING PILOT

The mechanism decouples recovery of the approved margin from customer usage. The piloted decoupling mechanism ensured that the Company collects 100% of its gas costs, prospectively. The residential and commercial sectors were included in the mechanism. The industrial sector was not included since its usage patterns and tariffs are vastly different than the residential and commercial sectors.[9]

The CUT rate adjustments were made semi-annually. These adjustments were not made in dollar amounts (like the Weather Normalization Adjustment that had been in effect prior to the adoption of the decoupling pilot). Rather, the CUT adjustments were to rates (prices) paid by customers.

The decoupling mechanism promoted conservation efforts by the Company and customers. In addition, it allowed customers to realize savings in their total gas bill associated with lower gas consumption. In the order authorizing the CUT mechanism, the NCUC ordered the Company to contribute $500,000 per year toward conservation programs and work with the Attorney General and Public Staff to develop appropriate and effective conservation programs. Such programs were to be submitted for approval by the NCUC within 45 days of the final order's issuance and were subject to an annual effectiveness review.

The decoupling mechanism used a straight fixed variable rate structure where the fixed costs would be recovered through a fixed monthly charge to customers.

Multiple compliance reports were required, including:

- annual conservation reports;
- conservation effectiveness reports;
- semi-annual true ups; and
- monthly account adjustment reports.

SOME ARGUMENTS FOR AND AGAINST THE 2005 DECOUPLING PILOT

Opponents argued that decoupling expanded the definition of "gas cost" beyond what was allowed by NCGS 62-133.4. Specifically, that the Company's write offs for nonpayment of bills were not *"occasioned by changes in the cost of natural gas supply and transportation"* in accordance with NCGS 62-133.4(a). They also stated that the affected portion of uncollectible accounts expense was not a cost *"related to the purchase and transportation of natural gas to the Company's system"* consistent with NCGS 62-133.4(e) or Rule R1-17(k).

The counterargument, which was ultimately persuasive to the Commission, is that the Company must pay suppliers for all the gas sold to customers, regardless of the number of customers who fail to pay their bills. The gas cost portion of uncollectables represents *"costs related to the purchase and transportation of natural gas"* which are under NCGS 62-133.4. Prior to decoupling, customers were at risk that the pro forma[10] uncollectible accounts expense could be higher than the actual expense of the Company. The CUT mechanism eliminates this risk and ensures that the Company will collect 100 percent of gas costs compared to a "proxy amount."

Opponents argued that rate adjustment mechanisms or "true up procedures" such as the CUT were traditionally prohibited in the State since it constitutes a retroactive ratemaking.[11] The Commission disagreed, stating that the prohibition is based upon the theory of ratemaking contained in G.S. 62-133, and it therefore does not apply to true up mechanisms specifically authorized by statute. The Commission stated that the prohibition on retroactive ratemaking applies to "fixed general" rates but not "formula rates" such as the CUT.

[9] See the Stipulation of the Parties for details on the pilot program's rate design, including: Net operating income, Rate Base and Overall Return "Exhibit A"; Depreciation rates "Exhibit B"; Rate design "Exhibit C"; Fixed gas cost allocations "Exhibit D"; Customer utilization tracker factors "Exhibit E"; Tariffs "Exhibit F"; Service regulations "Exhibit G"; Cost of gas "Exhibit H"; Temporary rate increments/decrements "Exhibit I"

[10] A report of the company's earnings that excludes unusual or nonrecurring transactions.

[11] The Attorney General cited case law. But the NCUC did not agree that the case law and stated, *"The prohibition against retroactive ratemaking was discussed in State ex rel. Utilities Comm. v. Edmisten, 291 NC 451, at 468-470 (1977). The prohibition is based upon the theory of ratemaking contained in G.S. 62-133, and it therefore does not apply to true up mechanisms specifically authorized by statute such as G.S 62-133.2 or G.S. 62-133.4. The prohibition applies to "fixed general" rates and is not violated when a formula that has been approved as part of a utility's rate structure is used to true-up an estimated rate. 156 (1978). The Commission believed that the CUT is not a "fixed general" rate but rather should be approved as a formula rate*

Opponents argued that decoupling shifts the risk of fluctuations in gas costs from the Company to the ratepayer,[12] and that decoupling penalizes customer conservation by eventually causing rate increases to allow the companies to recover costs.[13] The Commission strongly disagreed with both of these arguments.

This fact sheet represents the work of stakeholders as of 12/18/2020.

About the North Carolina Energy Regulatory Process

Governor Cooper's Executive Order 80 mandated the development of a clean energy plan for the state of North Carolina. The Clean Energy Plan recommended the launch of a stakeholder process to design policies that align regulatory incentives with 21st century public policy goals, customer expectations, utility needs, and technology innovation. The stakeholder process was launched in February 2020 and has led to policy proposals on energy reform.

LEARN MORE

Contact NERP PBR Study Group Leads:
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Access the NERP summary report and other NERP documents at:
https://deq.nc.gov/CEP-NERP

[12] NCUC Order Granting Partial Rate Increase and Requiring Conservation Initiative (p. 17). https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=0ab8a646-9837-4c85-b650-77638a534073

[13] NCUC Order Granting Partial Rate Increase and Requiring Conservation Initiative (p. 21 and 23). https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=0ab8a646-9837-4c85-b650-77638a534073

NERP CASE STUDY

MINNESOTA ELECTRICITY PERFORMANCE BASED RATES

The 2020 North Carolina Energy Regulatory Process (NERP) prioritized energy reforms that would drive affordability, carbon-reduction, and align regulatory incentives with policy goals.

INTRODUCTION

Due to the complexity of Minnesota's lengthy performance-based regulation (PBR) process, this case study summarizes the basic aspects of PBR in the state. It then focuses on data that may indicate some of the outcomes from the implementation of these efforts over the last few years.

BACKGROUND

In 2007, Minnesota passed the Next Generation Energy Act (NGEA).[1] This law requires investor-owned utilities (IOUs) to do the following;

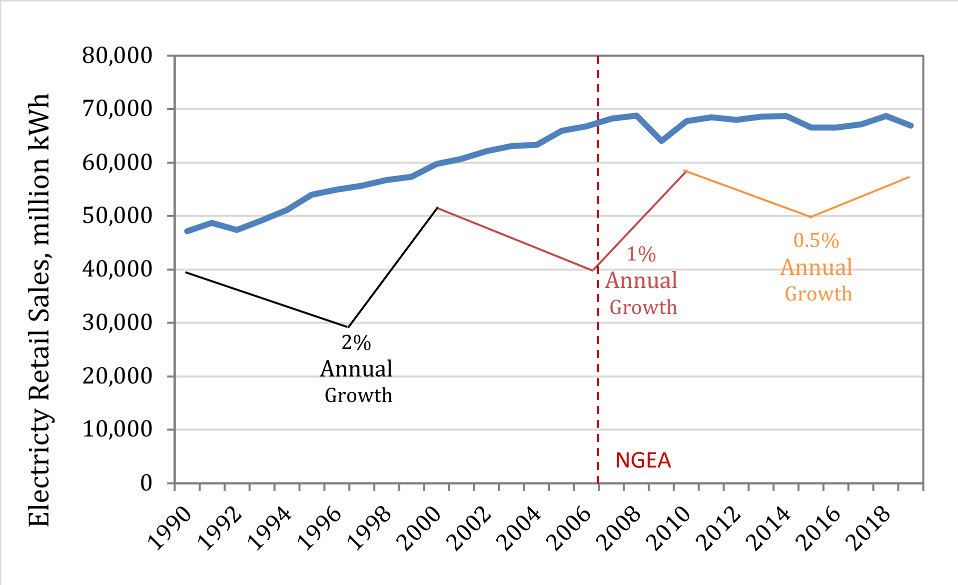
1. Reduce energy sales,
2. Spend a minimum percentage of annual operating revenues on energy efficiency, demand-side management and renewable energy starting in 2010, and
3. Incorporate a **shared savings financial incentive** model for energy efficiency.

It also required the Minnesota Public Utilities Commission (MPUC) to establish criteria and standards for **decoupling energy sales from revenues** to mitigate the impact of these energy savings goals on public utilities.

There were other factors driving electricity rate reform in the state including declining sales growth, minimal increases in customer base, and the need for infrastructure investments. The decline in sales growth, from 2% annual growth rate in the 1990s to the current annual growth rate of 0.5%, is shown in Figure 1.

[1] Minnesota Statutes, Section 216B.2412, Next Generation Energy Act, 2007.

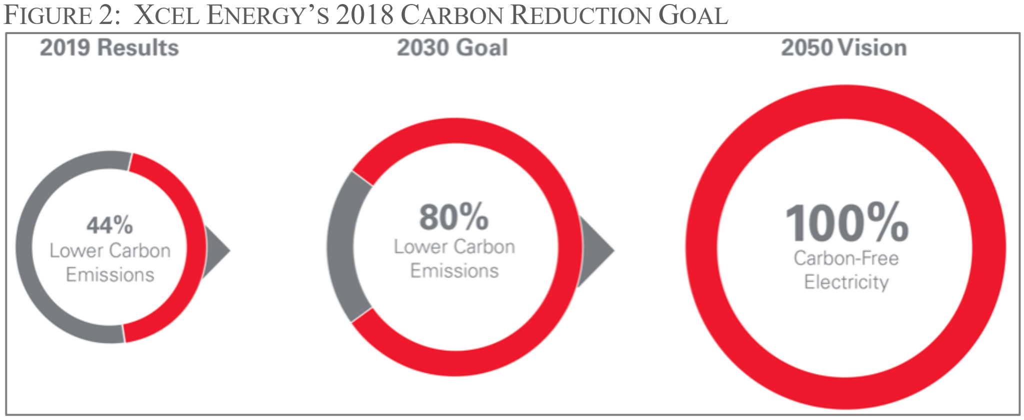
FIGURE 1: MINNESOTA RETAIL SALES OF ELECTRICITY SINCE 1990



SOURCE: ENERGY INFORMATION ADMINISTRATION (EIA) AND NC DEPARTMENT OF ENVIRONMENTAL QUALITY (NC DEQ)

Another factor in Minnesota's PBR history is Xcel Energy initiating an enterprise-wide carbon reduction plan in December of 2018.[2] Xcel was one of the first utilities in the country to develop such a plan, with a goal of 80% reduction by 2030 and 100% carbon free by 2050. As of 2019, Xcel Energy reduced its enterprise-wide carbon by 44% from 2005 levels. During 2019, Xcel Energy generated 35% of all electricity in Minnesota with fossil fuel, with 21% of that generation coming from coal and the remainder coming from natural gas.

FIGURE 2: XCEL ENERGY'S 2018 CARBON REDUCTION GOAL



SOURCE: XCEL ENERGY

While Minnesota began its path toward performance-based rates through the NGEA in 2007, it is still being developed and implemented today. This ongoing effort consists of the following components;

- Multiyear rate plan (MRP),
- Revenue decoupling mechanism ("decoupling"),
- Performance incentive mechanisms, including metrics and incentives, and
- Shared savings mechanism ("shared savings").

AUTHORITY AND ENABLING STRUCTURES FOR PBR IN MINNESOTA

Multiyear Rate Plans

[2] Xcel Energy Clean Energy Transition, https://www.xcelenergy.com/environment/carbon_reduction_plan

In 2011, the Minnesota Legislature enacted Minn. Stat. § 216B.16, subd. 19 Multiyear Rate Plan, authorizing the MPUC to approve multiyear rate plans (MRP) up to 3 years in length for regulated utilities and to establish the terms, conditions, and procedures for plans.[3] On June 17, 2013, the MPUC issued a final order on the terms and conditions for MRPs.[4] This order specified that rates charged under any MRP should be based on the utility's reasonable and prudent costs of service. It also specified that a MRP could be designed to recover costs for "specific, clearly identified capital projects and, as appropriate, non-capital costs". It also declined the use of formula rates and required a fixed rate for the plan period; however, rate adjustments pertaining to the cost of energy, emissions controls, conservation improvement, and specific tariffs were allowed. Lastly, the PUC decided that the authorized rate for return on equity would be fixed during the plan period based on the rate used in the general rate case. While the MPUC did not include an "off ramp" for the MRP, it did specify that the MPUC could adjust rates while a plan was in effect to ensure that the rates remain reasonable.

In June 13, 2015, the Minnesota Legislature modified the statute to allow a MRP to extend up to 5 years. The legislation also gave the MPUC the authority to require utilities proposing MRPs "to provide a set of reasonable performance measures and incentives that are quantifiable, verifiable, and consistent with state energy policies."

The components of the MRP, as established in the MPUC's 2013 decision, are presented in Figure 3.

FIGURE 3: COMPONENTS OF MINNESOTA MULTIYEAR RATE PLANS BASED ON MPUC 2013 ORDER

Allows for recovery of both
1) capital costs or
2) other costs
in a "reasonable manner".

"Other costs" include capital-related costs, O&M costs, conservation programs, and certain tariffs.

MPUC can adjust rates to ensure thev remain

Requires the use of a
1) fixed multiyear rate
2) fixed return on equity
during the plan period.

Riders that are "continuous and predictable" included in base rate.

Allows for adjustment of approved rate for changes that MPUC determines to be just and reasonable.

Includes changes in operating costs, nuclear plants, conservation, or significant investments.

Decoupling Rate Mechanisms

In 2007, the Minnesota Legislature enacted Minn. Stat. § 216B.2412 as part of the NEGA requiring the MPUC to establish criteria and standards for decoupling of energy sales from revenues. The legislation specified that decoupling include the following;

- Ensure the criteria and standards do not adversely affect utility ratepayers,
- Consider energy efficiency, weather, cost of capital, and other factors,
- Assess the merits of decoupling to promote energy efficiency and conservation, and
- Implement a voluntary pilot program to determine if decoupling achieves energy savings.

On June 19, 2009, the Commission issued its Order Establishing Criteria and Standards to be Utilized in Pilot Proposals for Revenue Decoupling in Docket E, G-999/CI-08-132. The details of the decoupling mechanism not included in this case study in lieu of the detailed discussion of decoupling as implemented by Xcel Energy in Section 3 below.

Performance Incentive Mechanisms

[3] Minnesota Statutes, Section 216B.16, subd. 19 Multiyear rate plan
[4] Order Establishing Terms, Conditions, and Procedures for Multiyear Rate Plans, Issued June 17, 2013, Docket No. E,G-999/M-12-587

As discussed above, performance incentive mechanisms (PIMs) were authorized by the MRP Legislation in 2015. This legislation gives the MPUC authority to require IOUs to submit PIMs with MRP and to establish the PIMs. The statute also authorized the Commission "to initiate a proceeding to determine a set of performance measures that can be used to assess a utility operating under a multiyear rate plan."

An important first step in the development of PIMs began with a multi-year stakeholder process called the "e21 Initiative". This process began in 2014 and was facilitated by Great Plains Institute and Center for Energy and Environment. The goal was to advance a decarbonized, customer-centric, and technologically modern electric system in Minnesota. The reports issued by the e21 Initiative documents the stakeholder findings and results.[5]

The e21 Initiative developed the foundation for PIMs. Over 100 performance metric topics were discussed by stakeholders. Key aspects included:

- Specifying goals for PIMs,
- Determining data points to measure in order to evaluate utility performance,
- Limiting the specific number of metrics and prioritizing implementation of certain metrics,
- Developing concrete procedures for calculating, verifying, and reporting metrics, and
- Specifying metrics should measure outcomes, not deployment of technologies or programs.

The MPUC opened a docket to identify and develop performance metrics and, potentially, incentives in 2017 in response to Xcel Energy submitting a set of performance metrics in their general rate case filed in 2015. On January 8, 2019, the MPUC issued the Order Establishing Performance-Incentive Mechanism Process.[6] The order initiated a PIM development process, which included discussions and workshops with stakeholders over a 9-month period. The order established a "goals-outcomes-metrics process" as an effective method to gather stakeholder input and develop performance metrics. Figure 4, presented on the following page, summarizes the 7-step process laid out by the MPU. The MPUC completed Steps 1 and 2 via the January 8, 2019 order.

On September 18, 2019, the MPUC issued an order establishing performance metrics.[7] In this order, Xcel Energy was directed to work with stakeholders to develop 1) methods to calculate, verify, and report metrics, and 2) a reporting schedule, which are Steps 3 and Step 4 of the PIMs process.

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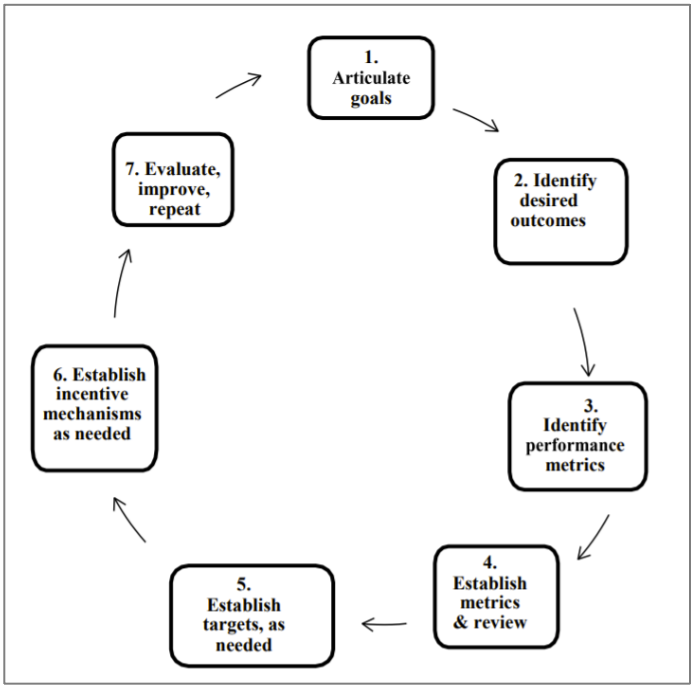
[5] See https://e21initiative.org/ for a full description of the e21 Initiative including its work products and reports.
[6] MPUC Order Establishing Performance-Incentive Mechanism Process, Issued January 8, 2019, Docket No. E-002/CI-17-401.
[7] MPUC Order Establishing Performance Metrics, Issued September 18, 2019, Docket No. E-002/Ci-17-401.

FIGURE 4: MINNESOTA PUBLIC UTILITIES COMMISSION PROCESS TO ESTABLISH PIMS

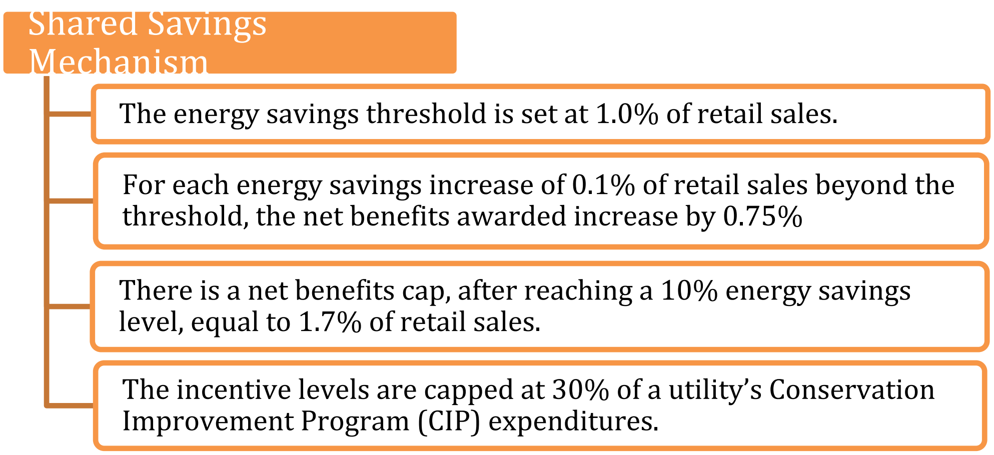


SOURCE: MPUC

Shared Savings Mechanism

Minnesota has had a shared benefit incentive for energy efficiency in place since 1999 called Conservation Improvement Program (CIP). For gas and electric utilities, the percent of net benefits awarded increases as a utility achieves a higher level of energy savings measured as a percentage of retail sales. The current Shared Savings goals for the electricity sector are listed in Figure 5.[8]

FIGURE 5: SHARED SAVINGS MECHANISM FOR ELECTRICITY SECTOR INVESTOR OWNED UTILITIES



XCEL ENERGY IMPLEMENTATION OF PBR

The only electric utility currently pursuing PBR in Minnesota is Xcel Energy. For Xcel Energy, this process started with filing for a MRP in a general rate case in March of 2015. This filing set off a series of events for Xcel Energy to implement the PBR framework laid out by both legislation and MPUC orders. The events are summarized in Figure 6.

[8] See Minn. Stat.§ 216B.241, subd. l (c) and MPUC Docket No. E,G-999/CI-08-133

FIGURE 6. SUMMARY OF XCEL ENERGY'S PBR PROCESS

An initial four-year MRP was approved by the MPUC in 2017.

A decoupling pilot program began in 2017 and continues through 2020.

Performance metrics have been developed through a stakeholder process starting in 2019. MPUC approved Xcel's proposal for metric calculation, verification, and reporting in 2020.

In 2021, Xcel is directed to 1) develop options for an online utility performance dashboard, 2) begin developing evaluation criteria and benchmarks for the metrics, and 3) consider a financial incentive for demand side management

Xcel Energy MRP

Xcel Energy filed a petition on November 2, 2015 requesting a 3-year MRP that allowed revenue increases supporting the utility's proposed cost of service.[9] The parties could not come to an agreement and the matter was referred to the Office of Administrative Hearings for contested case proceedings. On August 16, 2016, the majority of the parties to the rate case submitted a "Stipulation of Settlement" regarding the utility's MRP. The settlement set out the following design details for the MRP: [10]

- The revenue requirement, which entailed annual revenue increases over four years with a cumulative increase of 6.1%.
- The use of weather normalized sales data to set the base rates, and
- A one-year extension of the MRP to 2019.

Not all parties agreed to the settlement, therefore interim rates were set while additional proceedings were conducted to resolve the remaining issues. One of the issues was the return on equity (ROE) of 9.2%, which the Office of the Attorney General argued should be lower, on the order of 7% to 8%. On June 12, 2017, the MPUC issued an order documenting the decisions on Xcel's 2017 MRP based on both the settlement and the additional proceedings.[11] The MPUC kept the ROE from the settlement, adjusted Xcel's annual revenue requirements downward substantially, which resulted in rate increases that were less than inflation and significantly less than what Xcel proposed. Additional requirements on Xcel included;

- Prohibiting the filing of another rate case or seeking new riders during the MRP,
- Adopting a **one-way, aggregate, capital-spending true-up** where Xcel can refund money if its spending is under the budget but cannot increase rates if over the budget, and
- Requiring an annual capital projects true-up compliance report providing **granular project data and spending** for approximately 1,800 projects.

The MPUC found that a capital-projects true-up would provide ratepayers with significant protection against over budgeting of capital-spending. In addition, it would be beneficial for regulatory-review purposes to have Xcel Energy file project-level information on capital spending rather than overall spending in a given year. Figure 7 presents the basic structure of Xcel Energy's MRP for 2017 through 2019 stipulated in the MPUC Order.

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[9] Xcel Energy, Application for Authority to Increase Electric Rates, Filed November 2, 2015, Docket No. E002/GR-15-826.

[10] Xcel Energy Filing, Stipulation of Settlement Authority to Increase Electric Rates Northern States Power Company, Filed August 16, 2016, OAH Docket No. 19-2500-33074 and MPUC Docket No. E002/GR-15-826.

[11] MPUC, Findings of Fact, Conclusions, and Order, June 12, 2017, Docket No. E-002/GR-15-826

FIGURE 7: STRUCTURE OF XCEL'S MRP

Weather normalized actual sales used to set base rates.

Rates include capital costs, operations and maintenance (O&M) expenses, specific riders, and taxes.

Excludes fuel costs.

Stated return on equity of 9.20%

No increase in fixed customer charges.

Monthly service charge for residential/small commercial.

True-up mechanisms subject to caps including:

1) sales true-up for non-decoupled classes;
2) capital true-up; and
3) property tax true-up.

Adjustments are also allowed for customer classes under full decoupling. See below.

With the ending of the initial MRP in 2019, Xcel Energy filed a new MRP rate case with a request for a 3-year rate increase totaling 15.2% with the MPUC on November 1, 2019. This rate increase included an interim rate increase of 4% for all customer classes, $466 million in new revenue, and an increase in return on equity to 10.3%. Given the decoupling pilot was expected to end in 2019, the rate plan also proposed a new decoupling mechanism that would apply to all customer classes.

On the same date, Xcel Energy filed a petition to extend the current MRP plan through 2020 using three true-up mechanisms for sales revenues, capital costs, and property taxes, explaining that if the MPUC approved the petition they would withdraw its rate case filing and not file another one until November 2020.

On Dec. 12, 2019 the MPUC approved Xcel Energy's Petition for Approval of True-Up Mechanism and Xcel withdrew its 2020 rate proposal.[12] As a result, electric base rates remained unchanged in 2020. In addition, the sales true-up mechanism (which was functionally equivalent to decoupling for customer classes not included in the 2017 pilot) was extended to all customer classes at that time.

Similar to 2019, Xcel Energy has recently requested Commission approval for 2021 true-ups that would allow the utility to leave base rates for 2021 unchanged.[13] In the event this petition is not approved, Xcel also has filed a three-year MRP starting in 2021 that would increase revenues a total of 19.7%.[14] Xcel has justified this rate increase on increased investments in renewable energy resources, investments in other core and supporting infrastructure, and declining sales. The utility also has proposed interim rate increases for 2021 and 2022 as the MPUC considers the MRP request.

Xcel Energy Decoupling Pilot

Xcel Energy filed its proposal for a decoupling pilot project in 2015 with its MRP discussed above. On May 8, 2015, the MPUC issued its Findings of Fact, Conclusions of Law, and Order authorizing the pilot.[15] However, the "Stipulation of Settlement" submitted on August 16, 2016 modified the decoupling pilot program by 1) extending the program by one year and 2) requiring the use of partial decoupling (i.e., sales true-up based on weather-normalized data) for commercial and industrial customers. Xcel Energy began the four-year decoupling pilot program starting in 2017.

Xcel Energy's revenue adjustment mechanism is revenue per customer. This means that as the revenue requirement is adjusted according to the pre-agreed schedule in the multi-year rate plan, the decoupling mechanism also adjusts required revenue to reflect the increase or decrease in the number of customers within Xcel's service territory. The decoupling mechanism also has incentives for energy conservation.

Figure 8 presents the decoupling design elements of Xcel Energy's decoupling pilot. It focuses on the customer classes, for which the largest share of fixed costs is recovered through volumetric rates – residential (space heating and non-space heating), and small commercial and industrial (non-demand). It also includes partial decoupling that was added via the Stipulation of

12 MPUC Order Approving Xcel Energy's Petition for Approval of True-Up Mechanism, Issued March. 13, 2020, Docket E002/M-19-688.
13 MPUC Docket No. E-002/M-20-743
14 MPUC, Application for a Proposed Increase in Electric Rates, November 2, 2020, Docket No.E-002/GR-20-723
15 MPUC Order Findings of Fact, Conclusions, And Order, Issued May 8, 2015, Docket E-002/GR-13-868.

Settlement in 2016 order discussed above that began in 2019. Xcel Energy filed decoupling annual reports to the MPUC, which will be discussed in the Outcomes section of this study.

FIGURE 8: DESIGN OF XCEL ENERGY'S REVENUE DECOUPLING PILOT PROJECT

Revenues and Customers

a) Decoupled using Revenue per Customer
b) Full Decoupling (omits weather normalization)
   - Residential,
   - Residential *with* Space Heating, and
   - Small Commercial/Industrial (non-demand customers)
c) Partial Decoupling (includes weather normalization)
   - All other classes
   - Proposed – electric vehicles & lighting
d) Excludes non-fuel revenue and fixed customer charges

Adjustments

a) Calculated once a year
b) Rates adjusted up/down in the following year to "true-up" difference
c) Adjustments presented as either a surcharge or a credit on customer bills
d) Limitations on any upward rate adjustment:
   - Upward rate adjustments are capped at 3% of the customer group's revenues, excluding the fuel clause or other riders;
   - Costs over the cap are recovered via the following year's adjustment, assuming declining sales were triggered by DSM or similar programs;
   - If Xcel fails to achieve 1.2% in energy savings, it forgoes its rate increase in following year.

Xcel Energy Performance Mechanisms

When the Commission approved Xcel's MRP in 2017, a docket was opened to focus on PIM development. On September 18, 2019, the MPUC issued an order establishing performance metrics.[16] The order also directed Xcel to work with stakeholders to develop methods to calculate, verify, and report metrics, and a reporting schedule by October 31, 2019.

On October 31, 2019, Xcel Energy submitted its report on performance metrics and proposed both outcomes and metrics to track starting in 2020, with reporting starting in 2021.[17] Over 30 performance metrics were proposed measuring the outcomes listed below. The specific metrics are listed in Appendix A of this report.

- affordability
- reliability
- customer service quality
- environmental performance
- cost effective alignment of generation and load
- workforce and community development impact

The MPUC took comments on the proposal and on April 16, 2020 issued an order accepting Xcel's proposed methodology and reporting schedules, with several modifications.[18] Annual reporting of performance metrics is required and Xcel was directed to "explore and develop" an online utility performance dashboard.[19] Xcel Energy was directed to continue to work on Steps 3 and 4 of the PIMs process—metric identification and review—and begin work on Steps 4 through 6, which includes the following processes;

- developing a demand response financial incentive via a stakeholder process,

16 MPUC Order Establishing Performance Metrics, Issued September 18, 2019, Docket No. E-002/CI-17-401

17 Xcel Energy Filing, Proposed Metric Methodology and Process Schedule on Performance Metrics and Incentives, Docket No. E002/CI-17-401

18 MPUC Order Establishing Methodologies and Reporting Schedules, Issued April 16, 2020, Docket No. E-002/CI-17-401

19 Annual reporting is required by April 30 of each year.

- developing evaluation criteria and benchmarks, and
- using a standardized method to ensure consistency with other utility reporting.

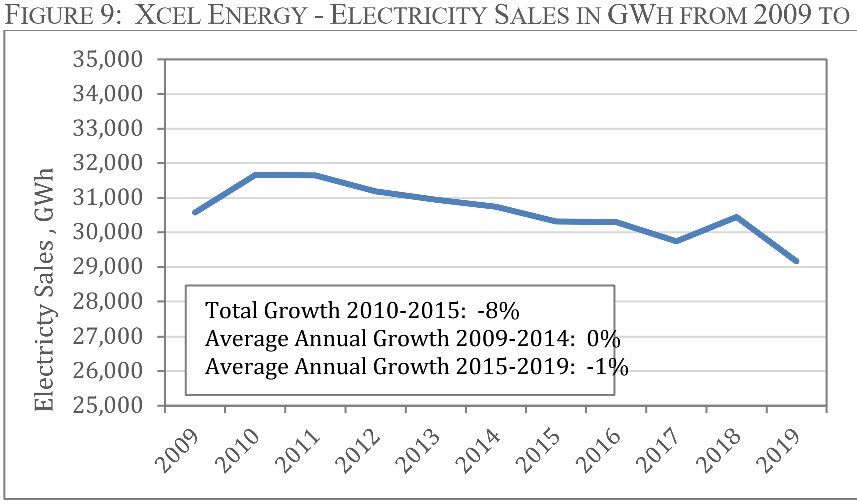
OUTCOMES FROM PBR FOR MINNESOTA AND XCEL ENERGY

Minnesota is still in the early stages of implementing PBR. Xcel Energy's MRP and the revenue decoupling mechanism pilot program have run over the last 4 years are ending in 2020. Xcel will begin measuring and reporting on performance metrics in 2021.

The following three graphs show how some key data for Xcel Energy has changed in the last 10 years.[20] The graphs have imbedded tables with the data broken down to show the 1) total growth over the 10-year period from 2009 to 2019 and 2) and the average annual growth broken into two 5-year periods to show the potential impact of Xcel Energy's implementation of PBR.

Figure 9 presents electricity sales data in GWh. This graph indicates Xcel Energy's sales have dropped by 8% over the last 10 years. Note there was an increase in 2018 due to more extreme weather in that year. The average annual growth rate in the first half was 0% while it was -1% in the second period, indicating that sales are decreasing slightly more rapidly in the second half of the period. This could be influenced by a number of things, including decoupling and the ongoing Shared Savings program for energy efficiency. Nonetheless, it indicates that these programs appear to be effective in Minnesota.

FIGURE 9: XCEL ENERGY - ELECTRICITY SALES IN GWH FROM 2009 TO 2019



Despite the decrease in sales, Xcel Energy's customer base is growing by 7% over the same 10-year period as shown in Figure 10. This amounts to a 1% average annual growth rate over both 5-years periods. Declining load growth creates a problem for traditional ratemaking approaches where increasing sales lead to increasing revenues. Xcel Energy needed to break that relationship to allow the company to recover sufficient revenues to meet its costs associated with additional customers while promoting higher levels of energy efficiency.

[20] Energy Information Administration, Form EIA-861M Monthly Electric Power Industry Report, 2019 Final Data, https://www.eia.gov/electricity/data/eia861m/

FIGURE 10: XCEL ENERGY – NUMBER OF CUSTOMERS IN THOUSANDS FROM 2009 TO 2019

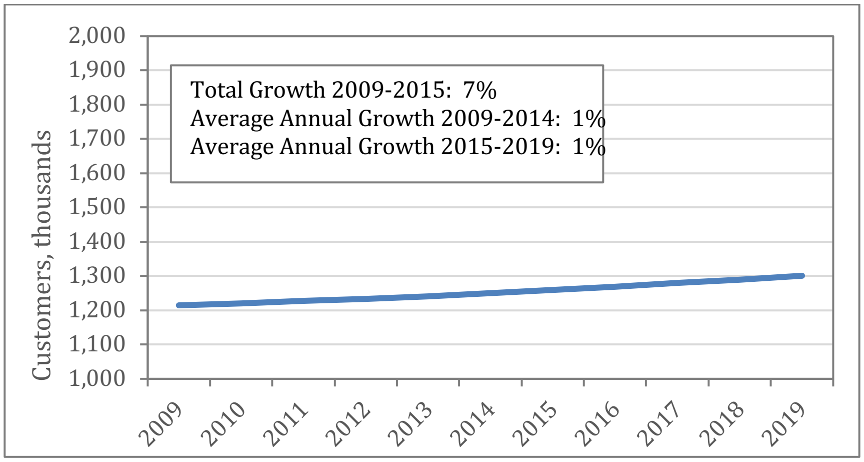
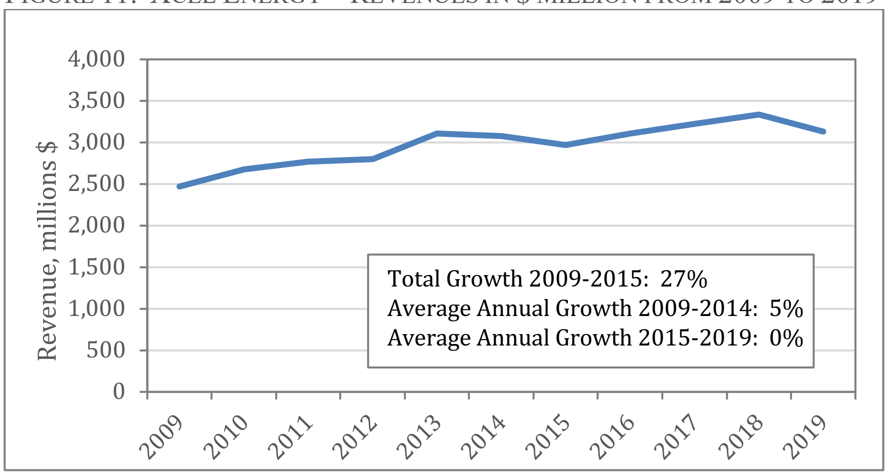


Figure 11 presents Xcel Energy's revenues over the past 10 years. Revenues have increased by 27% since 2009. However, the average annual growth in the first 5-year period was 5% while the average annual growth was 0% in the last five years. This indicates revenues are stable and increasing at a slower rate under the multiyear rate plan.

FIGURE 11: XCEL ENERGY – REVENUES IN $ MILLION FROM 2009 TO 2019



One of the benefits of a MRP is improvements in the utility's credit rating due to more stable revenues. Xcel Energy's Minnesota utility earned an "A" for its **Long-Term Issuer Default Rating (IDR)** by Fitch Ratings in October of 2020.[21] Fitch Ratings cited stable revenues for the utility due to the following:

- a constructive regulatory environment in Minnesota,
- its operation under a four-year rate plan, and
- the use of various cost-recovery riders.

This is in contrast to Xcel Energy's Southwestern Public Service Company (SPS) located in a more "challenging" regulatory environment, which earned it a rating of "BBB".

Metrics show that Xcel Energy has been financially stable over the last few years, even during the time of the pandemic. In a recent presentation to investors, Xcel showed that is has a return on equity (ROE) of 10.97% at the holding-company level and

[21] Source: Fitch Affirms Ratings on Xcel Energy & Subs; Outlook Stable, Issued October 1, 2020, accessed at https://www.fitchratings.com/research/corporate-finance/fitch-affirms-ratings-on-xcel-energy-subs-outlook-table-01-10-2020.

9.53% for its Minnesota operating company. Xcel Energy also reported that earnings per share for their Minnesota operating company were up 10% in the first nine months of 2020 compared to the same period in 2019.[22]

As stated previously, Xcel Energy submitted a report to the MPUC on its decoupling pilot program starting in 2017 for the 2016 calendar year. A summary of the calculations and the data contained in the reports for 2016 through 2019 is presented below and in Table 1.[23, 24, 25, 26]

For Xcel's Minnesota customers, a cooler than normal summer results in less electricity sales and a warmer summer results in higher sales. Therefore, over-collection of revenues is associated with summers that are warmer the baseline year and generally results in a refund to customers under decoupling. Under-collection of revenues is associated with cooler summers and generally results in a surcharge to customers.

During 2016, a warmer than normal winter resulted in an over collection of revenues for residential and small commercial and industrial customers, however, it also resulted in an under-collection of revenue for the residential space heating class as a result of the higher electricity intensity of this class, causing a surcharge. In total, the amount refunded to customers was $1.80 million.

The years 2017 and 2019 had cooler than normal summers compared to the baseline year, resulting in total revenue shortfalls and surcharges of $27.50 million and $31.20 million. In both years, the revenue surcharge was capped at 3%, thereby reducing the surcharge by $0.4 million in 2017 and $4.20 million in 2019. These amounts are carried over into the next year. This leaves a surcharge of $27.10 million for 2017 and $27.00 million for 2019 that was added to customer bills. For 2019, Xcel Energy attributes its large decrease in sales in part to energy efficiency realized from the Conservation Improvement Program (CIP).

The year 2018 was cooler than normal and resulted in an under-collection of revenue and a total refund of $13.80 million. It is noted that surcharges for 2017 and 2019 were significantly higher (+65% difference) than the refund in 2018.

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22 Comments of the Office of Attorney General, In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota, filed November 12, 2020, Docket No. E-002/GR-20-723.

23 Decoupling and Decoupling Pilot Programs: Report to the Legislature, Minnesota Public Utilities Commission February 2, 2018, https://www.leg.mn.gov/docs/2018/mandated/180155.pdf

24 Decoupling and Decoupling Pilot Programs: Report to the Legislature, Minnesota Public Utilities Commission February 2019, https://www.leg.mn.gov/docs/2019/mandated/190367.pdf

25 Decoupling and Decoupling Pilot Programs: Report to the Legislature, Minnesota Public Utilities Commission January 15, 2020, https://www.leg.mn.gov/docs/2020/mandated/200074.pdf

26 Xcel Energy, 2019 Annual Report: Electric Revenue Decoupling Pilot Program, filed January 31, 2020, Docket No. E002/M-20-

TABLE 1: XCEL ESTIMATED REVENUE DECOUPLING ADJUSTMENT, BY CLASS

	Class	Total Decoupling Surcharge/(Refund) $ millions	Carry Over Balance[2]	Estimated Surcharge Cap $ millions	Class Impact,[3] in $ millions	Average Monthly Customer Surcharge/ (Refund)	Decoupling Rate ($/kWh) April-March	Year
2016[1]	Residential	($2.60)		$0.00	($2.60)			Credit
	Residential w/Space Heat	$1.10		$0.90	$0.90			Surcharge
	Small C&I (Non-Demand)	($0.10)		$0.00	($0.10)			Credit
	Total	($1.60)		$0.90	**($1.80)**			
2017	Residential	$25.00		$26.20	$25.00	$1.87	$0.0031	Surcharge
	Residential w/Space Heat	$1.30		$0.90	$0.90	$2.19	$0.0024	Surcharge
	Small C&I (Non-Demand)	$1.10		$2.50	$1.10	$1.06	$0.0012	Surcharge
	Total	$27.50			**$27.10**			
2018	Residential	($12.50)	($0.70)	$26.20	($13.20)	($0.98)	($0.0016)	Credit
	Residential w/Space Heat	($0.30)	($0.10)	$0.90	($0.40)	($0.99)	($0.0011)	Credit
	Small C&I (Non-Demand)	($0.20)	0	$2.50	($0.20)	($0.18)	($0.0002)	Credit
	Total	($13.00)			**($13.80)**			
2019	Residential	$28.20	($1.20)	$25.60	$24.40	$1.79	$0.0031	Surcharge
	Residential w/Space Heat	$0.30	($0.10)	$0.90	$0.20	$0.45	$0.0005	Surcharge
	Small C&I (Non-Demand)	$2.80	($0.10)	$2.50	$2.40	$2.31	$0.0028	Surcharge
	Total	$31.20			**$27.00**			

1 In 2016, adjustments were not applied to monthly bills
2 Carry-over (over/under-collection) balance from decoupling deferrals.
3 Includes the total decoupling credit and carry-over balance.

The main purpose of the decoupling pilot program was to determine if decoupling created incentives for higher energy conservation and energy efficiency than the traditional system. Table 2 presents Xcel Energy's savings due to Minnesota's Conservation Improvement Program (CIP) both before and after decoupling.[27] Based on the table, the average first-year energy savings under decoupling was 113 GWh, or 23% higher than without decoupling. This indicates that Xcel Energy's decoupling pilot program was largely successful at significantly reducing electricity sales beyond what CIP required while earning revenue.

TABLE 2. XCEL ENERGY CIP ELECTRIC SAVINGS (2013-2019)

	Year	First-year Energy Savings (GWh)	Retail Sales (GWh)28	Energy Savings Percent of Retail Sales (GWh)
Without Decoupling	2013	495	28,987	1.71%
	2014	481	28,987	1.66%
	2015	497	28,987	1.72%
	Average	**491**	**28,987**	**1.69%**
With Decoupling	2016	547	28,987	1.89%
	2017	658	28,948	2.27%
	2018	680	28,948	2.35%
	2019	530	28,948	1.83%
	Average	**604**	**28,957**	**2.09%**

[27] Xcel Energy, 2019 Annual Report: Electric Revenue Decoupling Pilot Program, filed January 31, 2020, Docket No. E002/M-20-

APPENDIX A

List of PIMs Proposed in 2020 by Xcel Energy for Tracking

Outcome	Metric
Affordability	Rates based on total revenue y customer class and aggregate
	Average monthly bills
	Total residential disconnets for non-payment
Reliability	System Average Interruption Duration Index (SAIDI)
	System Average Interruption Frequency Index (SAIFI)
	Customer Average Interruption Duration Index (CAIDI)
	Customers Experiencing Long Interruption Duration (CELID)
	Customers Experiencing Multiple Interruptions (CEMI)
	Average Service Availability Index (ASAI)
	Momentary Average Interruption Frequency Index (MAIFI)
	Momentary Average Interruption Frequency Index (MAIFI)
	Power Quality
	Equity – Reliability by geography, income, or other benchmarks
Customer Service Quality	Initial customer satisfaction metrics
	Commission-approved utility-specific survey
	Subscription to third-party customer satisfaction metrics
	Call center response time
	Billing invoice accuracy
	Number of customer complaints
	Equity metric – customer service quality by geography, income or other relevant benchmarks
Environmental Performance	Total carbon emissions by utility-owned facilities/PPAs and all sources
	Carbon intensity (ton/MWh) by utility-owned facilities/PPAs and all sources
	Total criteria pollutant emissions
	Criteria pollutant emission intensity
	CO_2 emissions avoided by electrification of transportation
	CO_2 emissions avoided by electrification of buildings, agriculture, and other sectors
Cost Effective Alignment of Generation and Load	Demand response, including capacity available and amount called
	Amount of demand response that SHAPES customer load profiles through price response, time varying rates, or behavior campaigns
	Amount of demand response that SHIFTS energy consumptions from times of high demand to times when there is a surplus of renewable generation
	Amount of demand response that SHEDS loads that can be curtailed to provide peak capacity and supports the system in contingency events
	Metrics that measure the effectiveness and success of above items individually and in aggregate

SOURCE: XCEL ENERGY FILING, PROPOSED METRIC METHODOLOGY AND PROCESS SCHEDULE ON PERFORMANCE METRICS AND INCENTIVES, DOCKET NO. E002/CI-17-401

This fact sheet represents the work of stakeholders as of 12/18/2020.

About the North Carolina Energy Regulatory Process

Governor Cooper's Executive Order 80 mandated the development of a clean energy plan for the state of North Carolina. The Clean Energy Plan recommended the launch of a stakeholder process to design policies that align regulatory incentives with 21st century public policy goals, customer expectations, utility needs, and technology innovation. The stakeholder process was launched in February 2020 and has led to policy proposals on energy reform.

LEARN MORE

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Access the NERP summary report and other NERP documents at:
https://deq.nc.gov/CEP-NERP