COLORADO
Department of Regulatory Agencies
Public Utilities Commission

Jeffrey P. Ackermann, Chairman
John C. Gavan, Commissioner
Megan M. Gilman, Commissioner
Doug Dean, Director

Patty Salazar, Executive Director
Jared S. Polis, Governor

November 30, 2020

President of the Senate Leroy Garcia
Speaker of the House K.C. Becker
State Capitol Building
200 East Colfax
Denver, CO 80203

Dear President Garcia and Speaker Becker,

We are pleased to submit the Colorado Public Utilities Commission's (Commission) report in response to Senate Bill 19-236 and § 40-3-117, C.R.S., which directed the PUC to investigate "performance-based regulation" to better respond to today's energy transition, performance by investor-owned utilities and the impacts to consumers and communities.

As required by § 40-3-117, C.R.S., this report includes:

1. A general determination as to whether a transition to performance-based metrics regulation of a regulated utility would be net beneficial to the State, in terms of meeting stated objectives of the Commission and other related statutory requirements;
2. Actions that the Commission may pursue to guide the change to performance-based metrics regulation;
3. Directives to be given to utilities;
4. A list of types of future litigated proceedings within which the report could be implemented;
5. A proposed timeline for transition to performance-based regulation.

The recommendations included in the report are based on extensive stakeholder engagement completed over the past year. The Commission hosted two separate stakeholder meetings and an all-day Commissioners' Information Meeting (CIM) to discuss the issues laid out in SB19-236. Each of the stakeholder meetings was attended by approximately 40-50 stakeholders. The educational CIM was attended by 96 viewers/participants including the general public and legislators. In addition, we received over 100 written comment submissions.

The Commission appreciates the opportunity to engage with stakeholders to explore performance-based regulation and, now, to communicate our findings to the General Assembly. The attached report responds to the thoughtful input and innovative ideas raised during this process.

Sincerely,

Jeffrey P. Ackermann Chair	John C. Gavan Commissioner	Megan M. Gilman Commissioner

cc: Colorado Senate Transportation & Energy Committee members
Colorado House Energy & Environment Committee members

INVESTIGATION INTO PERFORMANCE BASED REGULATION IN COLORADO § 40-3-117, C.R.S.

Colorado Public Utilities Commission November 30, 2020

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1. EXECUTIVE SUMMARY

On September 4, 1882, the world changed forever.

On that date, the world's first central station electric power plant went online in New York City, starting what was to be the largest industrial transition that the world had seen up until that time. Electrifying the United States was an enormous undertaking that required massive amounts of capital and labor. Notable industrialists such as Samuel Insull advocated for electric utilities to be treated as "natural monopolies" with defined and exclusive franchise territories. Under this model, the utilities would build the vast amounts of needed new infrastructure and would in return, be authorized to recover their costs through a "cost of service" recovery model, or COSR. Important parameters such as reliability, safety, and just and reasonable rates were embodied as key foundational parts of this new utility model.

For the next 130 years, this COSR utility model served its purpose well. The United States was fully electrified, vast economic growth followed, and a host of new industries were born. During this period, the COSR driven utility model largely aligned with the societal goal of providing affordable and reliable electric service to every citizen. Under the COSR, utilities were incentivized to seek growth in both sales (load) and in capital expenditures that became part of the "rate base".

But, in the past decade, things have changed. Today we find ourselves in situations where societal goals, and increasingly customer demands, do not always align with utility goals under the COSR model. Some examples are:

- **Energy Efficiency** – Efforts to improve the efficient use of electricity naturally imply a reduction in sales. For this reason, utilities are dis-incentivized to support energy efficiency programs even though they advance an important societal goal.

- **Distributed Energy** – In a similar vein, distributed renewable energy generation, especially when located behind the customer meter, also implies a reduction in sales. Thus the utility is not incentivized to embrace such programs, even when those programs align with societal goals and state policy objectives.

Herein lies the growing interest in Performance Based Regulation or PBR as an alternative or adjunct to the traditional cost of service utility model. PBR methods strive to address the shortcomings of the COSR model through several mechanisms. The most prominent are the following:

- **Multiyear Rate Plans (MYPs)** – In an MYP, a set of rate structures are defined that will apply over a period of years. The advantage of an MYP is that it reduces regulatory burden by spreading rate cases out over an extended period in the anticipation that the MYP incentive will encourage utilities to cut costs and improve efficiency. As of 2019, 17 states have implemented some form of MYP. Colorado is one, having established an MYP with Xcel Energy in 2011.

- **Performance Incentive Mechanisms (PIMs)** – PIMs involve the creation of incentives designed to drive utility behavior and performance in a specific direction. PIMs can include positive as well as negative incentives. Colorado also has a history in the use of PIMs in the regulatory process.

In recent years, as the electric utility industry has begun a transformation driven by environmental, technological and market driven forces, the potential role of PBR has gained newfound currency. It's interesting to note that over the past 20 years, many European countries as well as many states, have implemented various PBR mechanisms, albeit with varying results. In most cases, these PBR efforts have focused on rewards or penalties for utility performance as well as to incentivize societal or customer driven goals. PBR efforts have largely been focused on electric utilities but the same opportunities exist in the gas utility space.

This report dives into the history of PBR initiatives in Colorado, including the use of MYPs and PIMs. It is very important as a result, to look at recent history as we explore options for the future. It is generally recognized that the implementation of effective PBR mechanisms is difficult and can be fraught with risks. If improperly done, rate-payers can be negatively impacted or the utility can be financially damaged. For this reason, many customer advocates strongly encourage a "go slow, go carefully" approach to implementing PBR mechanisms. Luckily, the Colorado PUC has acquired some good experience with these mechanisms over the years.

Two workshops and one Commissioner Information Meeting were held on this subject in the course of this investigation. Sixty-five comments from a multitude of stakeholders were collected during this investigation, which enriched the depth and breadth of the discussion. The commenters largely supported the implementation of PBR mechanisms but a number of cautions were raised.

Section 40-3-117, C.R.S., based on Senate Bill (SB) 19-236(I), directs the Colorado Public Utilities Commission (Commission or PUC) to include "[a] general determination as to whether a transition to Performance-Based metrics regulation of a regulated utility would be net beneficial to the state, in terms of meeting stated objectives of the Commission..." SB19-236 did not define "net beneficial." This report interprets "net beneficial" at face value whereby net benefits outweigh net costs. This report includes an examination of several states that now use the "National Standards Policy Manual" methodology to weigh quantitative and qualitative metrics to determine "net beneficial" unique to their states. Colorado would have its own unique criteria.

Historically, the Commission has implemented PIMs to address a specific issue. Going forward, several commenters recommended that the Commission take more of a "portfolio" approach and explore the implementation of PIMs in a more expansive framework based on desired outcomes. We feel that this type of approach has significant merit. Several commenters emphasized that PBR should be used to augment COSR and not to replace it. The general consensus is that COSR works fairly well in delivering fair and reasonable rates and we should be careful to not upset what is working. These commenters suggested that PBR be employed in the areas where COSR had not delivered satisfactory results.

Other commenters raised concerns about the potential for PBR to be detrimental to rate-payers. Some of the risks that were raised related to the issue of "information asymmetry", where the utility has the advantage of having all the data and thus an unfair advantage in setting goals. A good example of this issue is in the forecasting requirements required by MYPs. The performance of the MYP is only as good as the forecasts that the utility provides, hence the concern about the integrity of the data upon which the MYP is built. Another concern revolves around the unplanned impact of external factors such as business conditions, upon which the utility has no control.

On the plus side, commenters frequently called out the need for more focus on the issue of desired outcomes, especially as the PUC completes several large and important rule makings and as the State of Colorado implements aggressive greenhouse gas (GHG) emission reduction targets. The issue of including PIMs in the ensuing utility initiatives was a natural suggestion. It was encouraging to see some PIMs included in the recent utility Transportation Electrification Plans (TEPs) that have been filed at the Commission by the utilities. We anticipate that this too will be the case with the upcoming Distribution System Planning (DSP) rules, which have many natural tie-ins with PIMs.

On the subject of implementation strategies for PBR, several critical success factors were identified by workshop participants who had experience in the subject. The first success factor that was emphasized by several participants was the rigorous focus on desired "outputs" as compared to a less disciplined attempt at addressing a more nebulous, loosely defined set of goals. Precision is important. Several experts emphasized that the most successful PBR implementations result from collaborative negotiations with utilities versus through regulatory mandates. Productive engagement in the formulation of incentive mechanisms was called out frequently as a fundamental success factor.

One theme that came up several times was the realization among some that the Colorado PUC had some significant prior experience in the implementation of MYPs and PIMs. With many new faces both at the utilities and in the advocacy organizations, this probably should not have been a surprise. In this report we find it is important to take a look back at the PBR programs that have previously been implemented as an important way to surface lessons learned.

Going forward, the Commission clearly sees value in the use of PBR as another key "tool in the toolbox" of the regulatory process. The rapidly changing utility and regulatory landscape will certainly provide ample opportunity for the use of well-designed and effective PBR programs. We are also happy to see that the utilities are to a limited degree, seeing similar opportunities. It will be our intent to aggressively explore these opportunities in future proceedings.

2. SUMMARY OF RECOMMENDATIONS

After a review of PBR in Colorado, the Commission recommends that it is appropriate to continue to build on existing performance-based mechanisms in Colorado, with the immediate

focus being on areas that encourage reductions in GHGs. Specifically, the Clean Energy Plans (CEPs) and Transportation Electrification Plans offer appropriate proceedings in which to incorporate specific PIMs such as:

- Decarbonization: focus on performance that exceeds statutory mandates at a cost to customers below a pre-established baseline
- Energy Efficiency: reward for increased energy savings and load flexibility
- Transmission: dynamic load ratings, power flow controls, topology optimization
- Distribution System Planning: implementation of NWAs
- Customer Service: rewards for improvements and reduced impact of increased costs
- Equitable Access to Programs: implementation of programming to provide improved access to energy savings, renewable energy, transportation electrification or other benefits

The Commission also recommends continuing to engage consumer groups, environmental groups, and utilities to establish appropriate outcomes that will build on the established foundation of PBR and performance-based mechanisms in Colorado.

3. INTRODUCTION AND BACKGROUND

Section 40-3-117(1), C.R.S., directs the Commission to conduct an investigation of "financial performance-based incentives and performance-based metric tracking to identify mechanisms that may serve to align regulated utility operations, expenditures, and investments with public benefit goals including safety, reliability, cost efficiency, emissions reductions, and expansion of distributed energy resources." The review is to include existing and potential metrics as well as future test years (FTYs).

The statute directs the Commission to report its findings to the Colorado Senate Transportation and Energy Committee and the Colorado House of Representatives Energy and Environment Committee, within 18 months of the effective date of the statute, or November 30, 2020. Section 40-3-117, C.R.S., sets out requirements for the report, including:

1. A general determination as to whether a transition to performance-based metrics regulation of a regulated utility would be net beneficial to the State, in terms of meeting stated objectives of the Commission and other related statutory requirements;
2. Actions that the Commission may pursue to guide the change to performance-based metrics regulation;
3. Directives to be given to utilities;
4. A list of types of future litigated proceedings within which the report could be implemented; and
5. A proposed timeline for transition to performance-based regulation.

The statute further allows the report to include recommended legislative changes necessary to realize the benefits of PBR.

The Commission's regulatory powers and obligations and other related statutory requirements defining the public interest form the backdrop against which an evaluation of PBR must be considered.

Since its creation more than a hundred years ago, the public interest,[1] just and reasonable rates,[2] and the protection of investor and consumer interests[3] have continued to evolve to reflect the nature of the industries that the Commission oversees.

The 2019 legislative session yielded several statutes reflecting Colorado's efforts to slow climate change and reduce GHG emissions with a primary focus on the state's electric utilities: Section 25-7-102(2)(g), C.R.S. states that Colorado will strive to increase renewable energy generation to help the state achieve the statutory requirement of a 26 percent reduction in GHG pollution by 2025 from a 2005 level and a 50 percent reduction by 2030, and § 40-3.2-106(6)(a), C.R.S., beneficial electrification.

Additionally, in May 2019, Governor Polis issued a Roadmap to 100% Renewable Energy by 2040 and Bold Climate Action directing the PUC to: 1) ensure that electric utility generation and investments fully consider the social cost of carbon pollution; 2) promote distributed energy resources (DERs) and customer choice with regard to the electric distribution grid; and 3) ensure that all communities in Colorado can realize the benefits of a transition to renewable energy.

Throughout this investigation, we have examined PBR and performance-based mechanisms against this backdrop.

Additionally, the Commission has implemented PBR mechanisms to both electric and gas utilities, described below. However, the focus of most of the stakeholders and of the Commission's evaluation of PBR has centered on electric utilities.

4. RECOMMENDATIONS

a. Determination as to Transition to Performance-Based Metrics and Timeline for Transition

The investigation directed by § 40-3-117, C.R.S., and described in this report demonstrates that the Commission has implemented a number of performance-based metrics over the past two decades. These have generally been introduced to address specific utility investments and state policy goals, including targeted financial awards for meeting specific public benefit targets, quality of service plans (QSPs), MYPs, earnings sharing, and revenue decoupling. None of these performance-based metrics are unique to Colorado, and, as in all other regulatory jurisdictions, such metrics have emerged from the same

[1] *Consolidated Freightways Corp. v. Public Util. Comm'n*, 158 Colo. 239, 406 P.2d 83 (1965)

[2] *Cottrell v. City and County of Denver*, 636 P.2d 703 (Colo. 1981) and *Consumers' League of Colorado v. Colorado and S.R. Co*., 53 Colo.54, 125 P.577 (1912)

[3] *Pub. Serv. Co. v. Public Util. Comm'n*, 644 P.2d 933 (Colo. 1982)

well-established regulatory practices that underlie oversight of new utility investments and cost-of-service ratemaking. Notably, these performance metrics were introduced as innovations and improvements to the way various utility regulatory commissions addressed monopoly market structures, particular market failures, and the achievement of a number of public policies. The performance metrics have been intended to achieve efficiencies, improve customer service, maintain reliability, and secure both environmental and economic benefits. Nevertheless, these metrics were not implemented as steps toward an entire replacement of more traditional forms of regulation. Instead, in Colorado and elsewhere, the introduction of more competition and more consumer choice into the utility marketplace, within the existing paradigm of cost-of-service regulation, has been the primary approach for driving change in utility business models for the common good. Such change is evident, for example, in the growing importance of DERs and consumer investments in energy efficiency. This investigation reveals that interest in a full transition to any entirely new form of regulation for regulated utilities is a much more nascent objective.

A full transition from cost-of-service regulation to regulation based on performance-based metrics has not been achieved by any state, largely because competition and consumer choice have been so successful in driving change in the utility industry. Such a transition would require deliberative action based on specific goals that PBR is intended to meet, as well as a full understanding of where traditional cost of service regulation has failed. In the dynamic world of expanding renewable energy and distribution resources, a comprehensive view is imperative.

Other states, notably Hawaii and Minnesota, have started down the path of PBR and the Commission is actively observing those processes. One of the primary steps in such a process is establishing goals for PBR, followed by an in-depth review of how traditional cost of service regulation can be augmented or replaced to meet those goals. This is not a short-term undertaking because the consequences of misdirected measures are profound: electric and natural gas services are fundamental to all aspects of our society.

This report provides an overview of utility regulation and examples of what the Colorado PUC has done since the mid-1990s to address changes in utilities and their regulation in response to technological and policy evolution. Colorado has a strong and laudable history of responding to proposed regulatory changes, while protecting ratepayers. According to the U.S. EIA, as of 2018, Colorado's average retail electric rate was $0.1206 per kilowatt hour, cheaper than more than half of the states in the nation. The table below, from U.S. Energy Information Administration data, shows the five most expensive rates in the nation in 2018 and how Colorado compares:

Rank	State	Cost/kilowatt hour
1	Hawaii	$0.3094
2	Connecticut	0.2396
3	Alaska	0.2317
4	Massachusetts	0.2227
5	Rhode Island	0.2120
31	Colorado	0.1206

b. Actions the Commission Might Pursue

Most of the parties to this proceeding, as well as the literature on PBR advocate problem identification as the first step in any change to the form of regulation the Commission might implement because the risk is great for unintended consequences on a massive scale, given the breadth of service and importance of electric and gas utility service. After identifying a specific problem, appropriate steps can be taken to address the issue. Section 40-3-117, C.R.S., identifies safety, reliability, cost efficiency, emission reductions, and expansion of DERs as "public benefit goals" that the Commission might advance via PBR. An approach that prioritizes problem identification would attempt to pinpoint the specific problems that thwart these goals by identifying ways in which the existing regulatory environment produces utility operations that are unsafe, unreliable, or cost-inefficient, or that impede emission reductions or the expansion of DERs.

The Commission is also aware that representatives of consumer groups, including AARP, the Colorado Office of Consumer Counsel, and the Colorado Energy Consumers have voiced concern over any changes that might be implemented in utility regulation; advocates for the solar industry and environmental issues, including Western Resource Advocates, Colorado Solar and Storage Association, and Solar Energy Industries Association along with consulting firms Rocky Mountain Institute and AAEI encourage change on a broader level.

After reviewing the numerous PBR activities that the Commission has implemented for Public Service Company of Colorado (Public Service) and Black Hills Energy (Black Hills), and the actions that other commissions around the U.S. have undertaken, an appropriate course of immediate action to pursue is to evaluate PIMs that will assist Colorado in meeting its environmental goals of reduced carbon emissions and expansion of distributed renewable energy resources, including an evaluation of potential PIMs in Colorado Energy Plans and TEPs filed by Colorado IOUs, along with PIMs associated with transmission. Monitoring the PBR proceedings underway in Hawaii, Minnesota, New York, and Rhode Island will provide important insight.

The Commission could facilitate this approach by establishing clear policy goals related to utility performance in areas related to carbon emissions reductions and expansion of DERs. At present, the State of Colorado's statutory emission reduction goals provide one benchmark against which to evaluate progress, but the Commission could go further in articulating more granular targets and benchmarks for utility performance in pursuit of the larger goals established in statute. Such an approach would align well with the emphasis on problem identification described above, as a failure to hit Commission-established targets could itself constitute a problem to address with PIMs.

Additionally, it may be useful to evaluate the specific rate adjustments employed to address specific utility programs, such as Demand Side Management (DSM), against the merits of a multi-year rate plan, such as was implemented in 2011 for Public Service.

c. Toward a Determination of "Net Beneficial"

Although § 40-3-117, C.R.S., requires the Commission to make a determination as to whether a transition to PBR would be net beneficial, the statute does not define "net beneficial." The concept in the statute is taken at face value to mean that overall net benefits outweigh the net costs.

The recently published *"National Standard Practice Manual (NSPM)"* was created by the National Energy Screening Project (NESP) as a costs-benefits test document for DERs. The concept is similar to energy efficiency tests, which have experienced many nuances over the years, but provide a solid base from which to start. The NSPM test is named "jurisdiction-specific test" (JST).

Such a test serves the role of a cost-benefit analysis in utility regulation with three tests:

1. Utility;
2. Utility + customer;
3. To all of society.

All states have their own unique ways of determining costs and benefits, but commonly look at: DERs; demand response; distributed generation; electric vehicles (EVs); beneficial electrification; and battery storage. Only four states use societal cost tests even though many states have climate goals.

The JST allows for flexibility so it can be different in each state. Commissions are often challenged with moving targets and policies. The NSPM to date by states:

- Rhode Island began using a cost-benefit framework in 2016 that also included values important to their state. Rhode Island used a 12-month stakeholder process to set up their cost-benefits framework to better understand the relative values of programs to reach their state's energy goals. The Rhode Island PUC now uses the framework to evaluate any proposal, investment, or rate design and hopes to extend it to the gas sector. Commissioner Anthony reported on a NARUC call that the primary point of confusion or misunderstandings is: what is the role of cost-benefit in decisions? What is considered? How will both utility and non-utility stakeholders be using this framework?
- In New Hampshire, the Commission directed a working group (formal stakeholder process) to look at NSPM.
- In Alaska, there was an evaluator, who participated in a similar exercise.
- While Washington doesn't have relevant legislation, the UTC used it to investigate "What impacts are to be accounted for?" However, that question does not lend itself to a specific timeframe that most commissions use.
- The Connecticut PUC has also become a real world example of how the NSPM is being used.

The NESP formally published the NSMP this past August 2020. It offers guidance on developing the BCA framework that jurisdictions can use to develop primary tests and consider secondary costs as they analyze decisions about investing in different resources. It is policy-neutral. It sets foundational principles as it relates to DERs and guidance to certain symmetry to benefits and alignment with jurisdiction policy goals.

Ultimately, Commissions consider dockets/proceedings to look at and identify the impacts against other value streams, which are incorporated into the overall utility regulatory process. It is the conclusion of this report that a definitive determination of whether a transition to

performance metrics would be “net beneficial” cannot be made in the abstract. Rather, it is case-specific, and should be approached as such.

5. POSSIBLE FUTURE PERFORMANCE-BASED MECHANISMS

Category: Decarbonization

Title: Encouraging the Utility to Accelerate Decarbonization Efforts

Problem Description: Though some of Colorado’s utilities are under mandate to decarbonize on a defined path, a very important societal goal revolves around accelerating the decarbonization process. We have reached a point where the adoption of high renewable generation portfolios also offer cost reduction opportunities that can be passed on to rate-payers.

PIM Approach: Create PIMs that incentivize the utility to “go deep and go fast” in the adoption of high renewable generation portfolios, at a pace that may exceed what is required by law. A set of carefully crafted PIMs could provide the impetus and support to more boldly embark on these programs.

Category: Energy Efficiency

Title: Encouraging Utility Adoption of Energy Efficiency Programs

Problem Description: Utilities are naturally incentivized to grow sales and thus load. But, a worthy societal goal revolves around the issue of increasing the efficiency of the consumption of resources. Utilities are thus dis-incentivized to support and promote programs that reduce their kWh sales.

PIM Approach: Create PIMs that reduce or eliminate the impact of a decrease in kWh sales through a new set of incentives that instead reward energy savings and help make the utility whole while addressing an important societal goal.

Category: Transmission

Title: Transmission Capacity Expansion Alternatives

Problem Description: With the CAPEX bias associated with COSR, utilities are heavily incentivized to propose new transmission projects that involve capital expenditures that contribute to rate base.

PIM Approach: Constructing new transmission may not be the only solution to a capacity constraint on a transmission line. New technologies and approaches can offer less capital intensive methods for addressing constraints. Methods and technologies such as dynamic load

ratings, power flow controls and topology optimization now offer other alternatives that may be less capital intensive. Crafting PIMs that encourage the exploration of these new approaches can address this issue.

Category: Distribution System Planning

Title: Distribution System Capacity and Power Quality Alternatives

Problem Description: Again, with the CAPEX bias issue in mind, options now exist to overcome distribution system challenges in the capacity and power quality space through lower cost approaches.

PIM Approach: In recent years, new technologies have emerged and matured to the point where they can offer options for improving the operation of the distribution system without necessitating expensive capital intensive construction and overbuilding. Collectively called "Non-Wires Alternatives" (NWAs), some of these approaches are:

- DERs integration at the distribution level
- Energy storage integration at the distribution level
- Implementation of power quality assurance technologies such as IEEE 1547 compliant smart inverters and integrated volt-var optimization (IVVO) technologies.

These approaches and technologies can potentially provide more cost effective and rapidly deployable solutions to distribution system constraints. Again, crafting PIMs to specifically encourage the use of these technologies as a first option in distribution system upgrade programs would have value.

Category: Customer Service

Title: Encouraging Improvement of Utility Customer Service Performance

Problem Description: Customer Service is an expense for utilities and through their long history of operating as natural monopolies, utilities have never put the focus on customer service that a product based company would. Now, increased competition and a broader set of customer options is changing the traditional utility landscape and driving the need for better customer relations.

PIM Approach: Create PIMs that reward improvements in Customer Service performance and customer satisfaction, and reduce the impact of increased costs in the customer service function.

Category: Beneficial Electrification

Title: Encouraging Greater Beneficial Electrification

Problem Description: While some utilities are following greater electrification trends, incentives could be created to incentivize more proactive innovation to drive decarbonization, while providing customer cost savings and benefits to the grid.

PIM Approach: Create PIM(s) that incentivize the utility to support state policy goals related to beneficial electrification.

a. Directives to Utilities

The Commission has actively engaged in evaluating performance-based regulation and mechanisms in Colorado over the past 30 years, including the performance-based mechanisms that are currently under review for transportation electrification, distributed energy and distribution planning. The proceeding that culminated in this report comprised a process that was rich and reflects the input of a broad spectrum of stakeholders. Yet, the Commission has a practice of communicating directives to utilities through final Commission orders, based upon a fully adjudicated proceeding. The Commission anticipates that this process will continue, that it will include participation by consumer groups, environmental groups, and utilities and will result in directives that will further Colorado's drive to a zero-emissions landscape.

Working within appropriate constraints upon how the Commission issues directives to utilities, while concurrently honoring the intent of the above-referenced statutory language, the Commission communicates the following:

- Based upon the experiences of other states, performance incentives need to be specific, measurable, achievable, relevant and time-bound;
- There are several meritorious objectives that can be pursued using performance incentives; and
- The implementation of performance incentives/metrics is best conducted incrementally, versus a comprehensive overhaul of regulatory cost recovery practices.

In response to the statutory instructions to the Commission, found at § 40-3-116(2)(a)(III), C.R.S., that this Report include "Directives to be given to utilities" we note that the previous section identifies several topic areas that are likely to appear in future proceedings and are appropriate forums for their consideration. More specifically and based on the observations reached through this Miscellaneous proceeding, particularly the relative urgency to address GHG mitigation, we observe that the forthcoming filing of a Clean Energy Plan (CEP) by Public Service Company of Colorado (Public Service) offers an opportunity for the Commission explore the use of Performance Incentives. In particular, we note the following:

- Current statutory language addressing carbon dioxide reduction goals, including § 25-7-102, C.R.S and § 40-2-125.5, C.R.S., provides Public Service a specific, measurable, achievable relevant and time-bound performance goal.
- The use of a performance incentive metric that focuses on exceeding the goal, meaning reaching reduction goals prior to the statutory timelines and reaching those reduction goals at a cost to customers below a pre-approved revenue requirement, would be an appropriate incremental next step into the use of performance incentives.

- The Commission therefore signals in this report that it desires that Public Service explore in its CEP filing a performance incentive mechanism to address CO2 reduction goal attainment, as discussed above.

b. Future Litigated Proceedings within which a Report Could be Implemented

Commission rules provide for the types of proceedings that the Commission can open and issue decisions through, including litigated rate cases and applications, as well as rulemakings and administrative proceedings, which are not litigated. As the Commission continues on its course of implementing performance-based mechanisms, any one of these types of proceedings could be determined to be appropriate. It is important to note, however, that litigated proceedings carry a high financial burden for all parties, so the Commission will seek to minimize that burden to the extent possible.

The review of PBR and PIMs presented in this report demonstrates that this Commission has historically considered the introduction of performance-based mechanisms (and the modification of existing performance-based mechanisms) in a wide range of proceedings. The appropriate proceeding for the Commission to consider a given performance-based mechanism will likely depend on the specific mechanism in question and the goal it is designed to achieve. A performance incentive mechanism designed to accelerate emissions reductions ahead of statutory goals, for example, might be considered in an electric resource plan (ERP) or a CEP. Performance incentives related to expanding DERs may be most appropriate in the future rulemaking on DSP required by § 40-2-132, C.R.S. Other performance-based mechanisms might be included in rate review Advice Letters or other types of applications, as appropriate.

c. Possible Statutory Changes

Existing statutes, such as those that specify carbon emission reductions goals by specific dates, provide helpful direction for the Commission's consideration of PBR mechanisms. Utilities should not require incentives to comply with existing statutes, but performance-based mechanisms may help to encourage progress toward such statutory goals ahead of schedule and/or under cost.

At this time, additional statutory changes are not clear, but as the Commission continues on its review of its regulatory practices, if legislative changes become necessary, the Commission will provide that information through the Executive Director of the Department of Regulatory Agencies.

6. UTILITY REGULATION

The fundamental purpose of utility regulation is to ensure that ratepayers receive reliable service at reasonable rates through a safe system provided by a financially viable utility. While historically the doctrine of natural monopoly has dictated the regulation of utilities' technological advancements in recent decades and has led to changes in traditional regulatory models. For example, in telecommunications the introduction of interconnected competitive

landline providers in the 1990s and the nearly universal adoption of commercial cellular service since the early 2000s have upended the traditional landline business model and the manner in which telecommunications is regulated.

The regulatory landscape for electric utilities has begun to change as energy efficiency, the plummeting costs of renewable energy resources and environmental concerns have led to distributed generation options and DSM programs that have shifted utility load profiles. Additionally, environmental concerns and high costs have led to fossil-fuel plant closures. With these changes, traditional rate-of-return regulatory methods have evolved to include PBR methods in which the societal goals of carbon reduction and customer participation are included as goals, along with safe and reliable service at reasonable rates.

The utility's revenue requirement is at the core of traditional COSR. The revenue requirement is the total revenue that a utility must generate in order to continue to provide service to its customers and comprises rate base[4] plus operating and maintenance costs, depreciation, return on investment, and taxes. One result is that the utility has a strong incentive to increase its rate base through capital expenditures.

In COSR, a utility files a rate case when it determines that current rates are not sufficient to cover the revenue requirement or when directed by the regulatory commission to do so. Filing a rate case is expensive, generally requiring an adjudicated hearing in which written and oral testimony is provided by the utility, Commission Staff, and other intervenors. Rate cases can take months to adjudicate and all parties, including the Commission, incur expenses related to witness testimony and other filings, hearings, and post-hearing filings. Additionally, the revenue requirement is historically based on costs incurred in a previous year, a so called historic test year or HTY, meaning that by the time the Commission issues a decision, the costs might be several years outdated.[5] The time between when the rate case is filed and rates go into effect is referred to as "regulatory lag."

The benefits of COSR are that customer rates are stable between rate cases and the utility has incentive to manage its costs. However, rate cases are expensive and do not necessarily provide an incentive to the utility to pursue long-term innovative technologies, particularly with regard to energy efficiency and carbon reduction goals.

Riders, or cost adjustment mechanisms, are one method through which the utility can recover costs or pass on savings outside of a rate case. The Commission has authorized a number of cost adjustment mechanisms that will be addressed later in this report, including the energy commodity adjustment (ECA), transmission commodity adjustment, demand-side management cost adjustment (DSMCA), renewable energy standard adjustment (RESA), and Clean Air Clean Jobs Act adjustment (CACJA).

[4] Rate base is the utility's plant and facilities used in the generation and distribution of electric or gas service. In calculating a revenue requirement, the rate base is multiplied by the utility's authorized rate-of-return, which authorizes but does not guarantee the utility's profit.

[5] This problem can be addressed through FTYs, but FTYs have drawbacks also, as described later in this report.

Additional potential modifications to COSR include revenue decoupling, straight fixed-variable rates, formula rate plans, multi-year rate plans, and performance-based incentive mechanisms. As will be discussed later in this report, the Commission has implemented a number of these measures over the past decade, with varying degrees of success.

As the name implies, PBR shifts the focus from utility cost recovery to utility performance incentives. This type of regulation reduced—but does not necessarily eliminate—the utility's incentive to acquire plant and facilities, and increases its incentive to focus on efficiency and public policy goals. However, the mechanics of PBR require the determination of goals and metrics, a task that should not be underestimated in its difficulty. While metrics should not be set for goals that are beyond the utility's control, neither should the utility be rewarded for doing what it already does, or should do. Unintended consequences of a PBR mechanism are another concern as regulators move away from COSR.

PBR in some form has been a part of utility regulation since the 1990s. The Commission implemented alternative regulation for telecommunications in the late 1990s, which allowed the state's largest local exchange carrier to move from rate-of-return regulation to a rate cap structure. (Proceeding No. 99A-557T)

Public Service has also been subject to performance-based mechanisms beginning in the mid-1990s as conditions of approval of several mergers. The intent was to ensure that customer service and system reliability did not suffer as the new company sought efficiencies. The initial performance-based mechanism was a QSP, which has been modified and extended over 25 years. In the past two decades, additional performance-based mechanisms have been implemented as described below.

With technological changes that have led to changes in the way that electricity is generated and distributed, such as rooftop solar installations and smart meters, customers have become more involved in energy production, energy consumption, and interactions with the companies supplying their electricity and gas. This has led to a new era of PBR and performance-based mechanisms.

Additionally, growing environmental concerns have led to widespread energy efficiency measures, leading to a regulatory response that ensures the benefits and downsides of these measures are shared by the utility and ratepayers. DSM, DER, declining utility sales, and peak load reduction through demand response have been addressed by this Commission and those in other states through performance-based incentive mechanisms.

For network reliability, incentive mechanisms, such as System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) are still important, but need to be enhanced with mechanisms to ensure system availability, along with investment in undergrounding lines, vegetation management, and wildfire mitigation.

Utility regulation has been shifting to more performance-based mechanisms, as is demonstrated by the number of initiatives undertaken by others states and nations in recent years. However, while regulators should implement changes to reflect available technologies and environmental

necessities, the experience of the Colorado Commission and regulators in other jurisdictions shows that regulatory changes need to be implemented thoughtfully and with a careful eye to the impacts on ratepayers and utilities alike.

7. PERFORMANCE-BASED REGULATION ANALYSIS

There are many resources on the topic of PBR. The following were specifically referenced in the course of this investigation:

Colorado PUC Performance-Based Regulation "Commissioners' Information Meeting (CIM)" held on August 28, 2020

> **Introduction/Overview/History/Future of "Performance-Based Regulation"**
> ***John Shenot, Senior Advisor to the Regulatory Assistance Project (RAP)***
> **Service Quality: Safety, Reliability, Customer Satisfaction**
> ***Bill Steele, President, Steele & Associates***
> ***Ken Costello, former Associate Director and Senior Researcher, National Regulatory Research Institute***
> **Incentivizing and Measuring Cost Efficiency**
> ***Mark Lowry, PhD, President, Pacific Economics Group Research, LLC***
> **Emissions Reductions and Expansion of DERs (Distributed Energy Resources)**
> ***Dan Cross-Call, Principal, Electricity Practice, Rocky Mountain Institute (RMI)***

Although he did not provide a formal presentation that can be referenced here, at the CIM the Brattle Group's Ahmad Faruqui expressed a belief that as an economist "it is all about the incentives" and that "all regulation is incentive regulation." Faruqui stated, "when utilities are presented with clear goals and incentives, utilities get the job done."

Faruqui elaborated that PBR comes in many shapes and sizes. COSR can also include targets, goals, and penalties, which, in a sense, is PBR. Faruqui emphasized the role of the people at the utility, and whether they are innovative and smart. Success depends on establishing clear goals and right incentives, and getting utility executives and regulatory commissioners on the same page.

"PIMs for Progress: Using Performance Incentive Mechanisms to Accelerate Progress on Energy Policy Goals." **Rocky Mountain Institute with contributors Cara Goldenberg, Dan Cross-Call, Sherri Billimoria, Oliver Tully, 2020:**

PIMs are receiving increased attention for their ability to better align utility incentives with new social and environmental policy goals. By transitioning to business models where an increasing share of revenues relies on efforts to build a clean, reliable, and affordable energy economy, utilities have the opportunity to better meet evolving customer, policy, and technological demands.

PIMs can motivate utilities with financial rewards and penalties to deploy and utilize DERs, improve resilience, better engage customers, and deliver GHG emission reductions. However,

the ability of PIMs to change the way the utility does business depends on their development, design, and implementation.

"PIMs for Progress" reviews a selection of historical PIM examples and provides a simple taxonomy of the results to identify important lessons for future PIM development. By exploring why some PIM proposals are rejected by regulators and others are accepted, as well as what happens to PIMs after acceptance, we can learn how these regulatory tools can best be leveraged in a shifting electricity landscape.

***"Next-Generation Performance-Based Regulation."* Regulatory Assistance Program (RAP), 2018:**
Volume 1
Volume 2
Volume 3

This report, the first of three volumes of Next-Generation Performance-Based Regulation: Emphasizing Utility Performance to Unleash Power Sector Innovation, examines the concept PBR and how it can provide a framework to connect goals, targets, and measures to utility performance or executive compensation. It examines leading examples of PBR from around the world, including the United Kingdom's Revenue = Incentives + Innovation + Outputs (RIIO) program, New York's Reforming the Energy Vision (REV), and other successful initiatives in Denmark, Mexico, and South Africa. It also examines what regulators have learned from experience with early forms of PBR, finding that incentive measures need to be simply designed, predictable, clearly measurable, and sized in alignment with desired results. Rewards or penalties may be set too high or low initially, so a successful PBR program also needs to be adjustable.

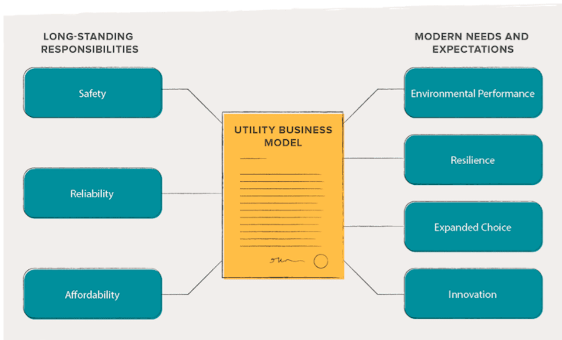
The Next-Generation Performance-Based Regulation full report was published in 2017 as a collaboration between the National Renewable Energy Laboratory and RAP, part of the 21st Century Power Partnership initiative.

***"Navigating Utility Business Model Reform."* Rocky Mountain Institute and AAE Institute, 2018:**

Advancing efficient and equitable approaches to update the utility business model—motivated by emerging technological, policy, and market conditions in the electric power sector—is crucial to the grid's transition to a more secure, clean, affordable, customer-centric system.

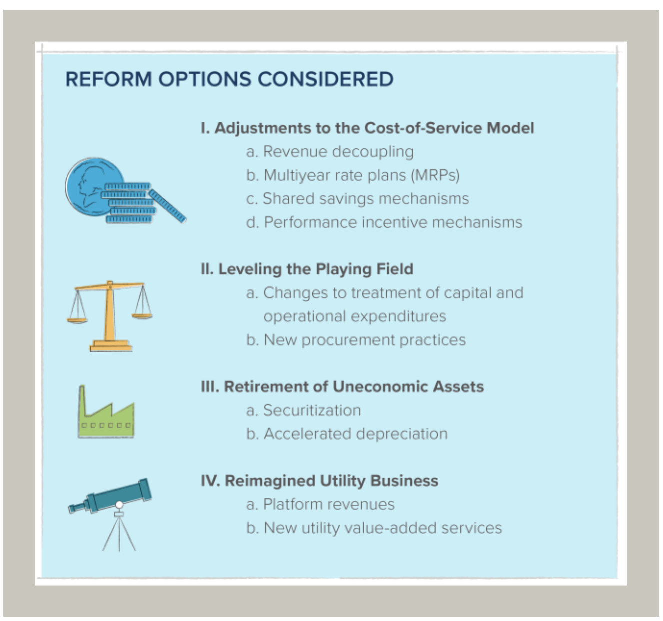
Powerful trends are impacting the contours of the electric system, including growing policy demands for improved environmental performance, the increasingly widespread availability of DERs like rooftop solar and storage, more customer demand for energy choice, and the need for strengthened resilience in the face of more extreme weather across the country.

In identifying, evaluating, and encouraging innovation in business models, the report offers a menu of regulatory options for policymakers, utilities, and electric customers to best support and manage the maturation of a 21st century grid.



Navigating Utility Business Model Reform seeks to establish foundational elements of different reform options, poses key questions to explore their applicability, identifies illustrative experiences for ideas and concepts, and explores policy implementation options to help spur action.

Navigating Utility Business Model Reform is being released alongside a set of case studies focused on experiences with business model reform options to help industry actors craft innovative approaches that are tailored to local context and circumstances. The report was produced in a joint collaboration between Rocky Mountain Institute, America's Power Plan, and Advanced Energy Economy Institute.



"Compensating Risk in Evolving Utility Business Models." **The Brattle Group, 2017:**

Utility cost of capital estimation for regulated industries is likely to face increased need for innovation in both the short- and long-term. This is being driven by accelerating trends in the business models of regulated electric utilities.

Specifically, utilities are being affected both by slowing electricity demand and cost increases or cost transfers by the sometimes inefficient bypassing of their systems by DERs and kindred technologies (due to outdated rates that do not reflect costs or sufficient differences in customer characteristics). Risk is likely to increase as a general matter due to the regulatory process uncertainty, as the terms of the utility "compact" with its customers is being rewritten gradually. Risk changes will not occur uniformly across the industry, instead arising on a more fragmented basis in terms of geographic regions and customer classes. It will take a while for the evidence to stabilize about what the risk conditions have become and for experiments in compensation to be tested for efficacy.

> *Regulators are actively developing responses that range from focused revenue supports to comprehensive industry reorganization. The new risks need to be compensated or mitigated so that utility costs can be recovered and investors can continue to have an unbiased opportunity to earn their cost of capital.*

Cost of capital measures will have to evolve in parallel with innovations in service design, pricing, and utility infrastructure, recognizing that it often may be easier to mitigate a risk directly rather than to measure its marginal effects on the cost of capital. Such adjustments will be critical for utilities to have the financial strength and incentives to support the many changes the Utility of the Future environment will require.

***"Performance-Based Regulation in a High Distributed Energy Resources Future."* Lawrence Berkeley National Laboratory (LBNL), 2016:**

Lawrence Berkeley National Laboratory hosted a webinar on January 27, 2016, titled "Performance-Based Regulation in a High Distributed Energy Resources Future." To view a recording of the webinar, click here.

The report explores key elements and variations of such regulation and its advantages and disadvantages from the perspectives of utilities and customers. A unique feature of the report is its treatment of comprehensive, performance-based approaches to regulation in the context of a potential future with a high reliance on energy efficiency, peak load management, distributed generation and storage. It is the third report in Berkeley Lab's "Future Electric Utility Regulation" series.

PBR of utilities has been an important ratemaking option in numerous jurisdictions across the United States and other advanced industrialized countries. PBR aims to strengthen performance incentives, streamline regulation, and provide utilities with greater operating flexibility. Ideally, the utility and its customers share the benefits of better performance.

PBR is an alternative to traditional COSR, where utility revenues are based on investment and operating costs. This traditional approach can conflict with certain policy goals, since it provides strong incentives to increase electricity sales and utility rate base. COSR also may not provide utilities with appropriate financial incentives to address evolving electric industry challenges such as changing customer demands for electricity services, growth of distributed energy resources, and changing federal and state policies.

***"Utility Performance Incentive Mechanisms."* Synapse Energy Economics, 2015:**

This report describes how regulators can guide utility performance through the use of performance incentive mechanisms. Regulators have used these mechanisms for many years to address traditional performance areas such as reliability, safety, and energy efficiency. In recent years, these mechanisms have also received increased attention due to regulatory concerns over resilience, utilities' ability to respond to technological change, and the expanding opportunities for DERs.

Whether performance incentive mechanisms are added onto traditional ratemaking practices, included as part of PBR plans, or considered as a central element of new regulatory and utility business models, they can be used to help improve utility performance. As with all regulatory mechanisms, they should be designed thoughtfully and they should build off of lessons learned from past practices.

8. PUBLIC INTEREST GOALS AND THE COMMISSION'S MANDATE

As noted above, for more than a century the Commission has been charged with the public interest in overseeing public utility activities. Although there is no statutory definition of the public interest, decades of case law and practice have led to a general acceptance that the public interest includes safe, reliable, and reasonably-priced services consistent with Colorado's economic, environmental, and social values. Section 40-3-117, C.R.S., adds additional "public goals" that the Commission must consider when evaluating PBR: safety, reliability, cost efficiency, distributed resource generation, and carbon emissions. For this report, customer service was added as an additional public goal.

Before looking at the performance-based mechanisms that the Commission has authorized, a brief discussion of the public goals will aid in the understanding of how the performance-based mechanisms meet those goals.

a. Safety

A fundamental charge for the Commission is to ensure that utility service is provided safely, as is demonstrated by statute: § 40-3-101(2), C.R.S. requires that "[e]very public utility shall furnish, provide, and maintain such service, instrumentalities, equipment, and facilities as shall promote the safety, health, comfort, and convenience of its patrons, employees, and the public, and as shall in all respects be adequate, efficient, just, and reasonable." For gas distribution, § 40-2-115, C.R.S., authorizes the Commission to adopt rules for natural gas pipeline safety, consistent with 49 U.S.C. § 60101 *et seq*. Grid safety and reliability are included as benefits of energy storage systems in §§ 40-2-201(1)(a)(III), and § 40-2-203(2)(a), C.R.S.

The Commission does not set minimum safety standards but does adopt certain safety standards such as the National Electric Safety Code, which applies specifically to electric utilities. The Commission is primarily responsible for ensuring that each utility has the financial means to

provide service safely and that the utility acts prudently when incurring safety-related costs primarily for the purpose of setting rates.

The Commission's authority for public safety is to ensure public safety with respect to utility services. This can include metrics of the number of incidents, injuries, and fatalities resulting from members of the public contacting the electric or gas system; and the utility's speed of response to emergency situations involving the electric or gas system; number of incidents, injuries, and fatalities resulting from members of the public contacting the gas system. The Commission does not regulate utility work safety, as this is beyond the authority provided by statute.

b. Reliability

Reliability is a central concern for utilities and is addressed through QSPs, described below. Reliability metrics focus on utility detection of outages and time to restore service, as well as outage severity and the number of customers who experience repeated service interruptions. Additionally, capacity availability to meet load at generation plants is an important aspect of reliability. As renewable energy has become increasingly more available, both at utility scale and as a distributed resource, the Commission has implemented measures to address overall generation resources, adjusting as State environmental goals have evolved.

Authorized rates allow the utility to make necessary investments to ensure reliable service and Colorado utilities have provided high levels of reliability over the past decades. This means that it has been unnecessary to define minimum acceptable levels of reliable service; the performance measures that have been implemented are calibrated under the assumption that past performance can be used to ensure no degradation in reliability.

c. Customer Service

Customer satisfaction has traditionally been measured by call center answering times, customer complaint rates, surveys conducted after a customer contacts the utility, response times for service requests and outage resolution, on-time, and missed appointments at the customer's premises. However, customer service can also include affordable rates, which are part of the Commission's mandate. Additional measures of customer service are avoided shut offs and reconnections, particularly with regard to low-income customers, which have become especially important in this time of the COVID-19 pandemic.

d. Cost Efficiency

For purposes of this report, and given the context of the other public benefit goals provided in § 40-2-117, C.R.S., the Commission takes cost efficiency to mean generally a consideration of costs and benefits to both ratepayers and utilities in financial terms. A regulatory challenge with cost efficiency is establishing the costs and balancing them with other public goals such as emission reductions and DERs.

As the Commission considers PBR for DERs, it will be helpful to review the National Standard Practice Manual (NSPM) for Benefit Cost Analysis of Distributed Energy Resources published in August 2020 by the NESP. NESP comprises a range of individuals and organizations working to

update cost-effective screening practices in DERs. The NSPM provides guidance for conducting benefit-cost analyses of various types of DERs, including energy efficiency, demand response, distributed generation, distributed storage, EVs, and building electrification.

e. Distributed Energy Resources (DER) Cost Efficiency

DERs are as defined in 4 *Code of Colorado Regulations* (CCR) 725-3-3652 of the Commission's Rules Regulating Electric Utilities, as retail renewable distributed generation, including community solar gardens (CSGs) and onsite solar, as well as wholesale renewable distributed generation. The latter are renewable energy resources with a nameplate rating of 30 MW or less that does not qualify as retail renewable distributed generation. The Commission currently has a rulemaking that considers elements of DER and how those are integrated into the electric grid.

In Proceeding No. 19M-0670E, the Commission collected comments and other information relating to developing rules governing the filing of DSPs by Colorado electric utilities. The ensuing rulemaking on DSP may provide a platform for the Commission to consider the use of PBR mechanisms to encourage the expansion of DER.

f. Emission Reductions

In considering emission reductions, the Commission is mindful of the statutory goals set out in § 40-2-125.5 and § 25-7-102(2)(g), C.R.S. The former requires regulated electric utilities with more than 500,000 customers to reduce carbon dioxide emissions by 80 percent by 2030 and 100 percent by 2050, as compared to 2005 levels. The latter sets goals of statewide GHG emission reductions of 26 percent by 2025, 50 percent by 2030, and 90 percent by 2050, as compared to 2005 levels.

9. PBR AND PIMS IN COLORADO

The Commission first implemented an alternative form of regulation for an industry in the late 1990s with the introduction of rate cap regulation for telecommunications. At about the same time, the Commission ordered initial performance-based mechanisms for the predecessor of Xcel Energy through QSPs. Over the past two decades, the Commission has ordered a number of PIMs in the electric and gas industries.

In every decision that the Commission makes, it is charged with the public interest. Although there is no statutory definition of the public interest, decades of case law and practice have led to a general acceptance that the public interest includes safe, reliable, and reasonably-priced services consistent with the economic, environmental, and social values of Colorado. These have guided the implementation and evaluation of PIMs. In 2019, § 40-3-117, C.R.S., added additional "public goals" that the Commission must consider when evaluating PBR: safety, reliability, cost efficiency, distributed resource generation, and carbon emissions. The Commission augmented the "public goals" with customer service as a consideration for PIMs discussed in this report. As is shown in these examples of PIMs in Colorado, the public interest

and public goals are woven into the mechanisms and are primary considerations when evaluating the efficacy of the mechanisms.

a. Quality of Service Plans (QSPs)

The Commission's early implementation of performance-based mechanisms were part of the approval of mergers: the Public Service/SPS merger in 1995[6] and the merger of Public Service's then parent company New Century Energies, Inc. with Northern States Power Company in 1999.[7] PBR was cast as "a central pillar of the Commission's approval of the Public Service/SPS merger."[8] These performance-based mechanisms were included so that the merged companies would not seek cost savings at the expense of quality of service, providing for bill credits if quality of service metrics were not met. An earnings sharing mechanism (ESM) was included in both mergers, extending through 2006. QSPs address safety, reliability, and customer service and carry financial penalties if threshold goals are not met.

b. Public Service Electric

Public Service's current electric QSP, effective through 2021,[9] allows for $11 million in bill credits, should Public Service fail to achieve performance goals associated with: 1) number of customer complaints, 2) telephone response times, 3) individual customers experiencing greater than five electric service interruptions of five minutes or more; and 4) individual customers experiencing service interruptions of 24 hours or more. Each of these measures carries a potential penalty of $1 million in bill credits per year. A "regional system reliability" metric of just over $7 million that spans Public Service's nine operating regions and is pro-rated based on the number of customers in each operating region.

The primary measure of system reliability under the electric QSP is the SAIDI associated with Ordinary Distribution Interruptions (ODI) for each of the Company's nine operating regions. ODI is defined in the electric QSP tariff as sustained (> than 300 seconds) interruptions that originate on the Company's primary or secondary electric distribution system, excluding interruptions that commence on Major Event Days and certain other classes of interruptions defined as Extraordinary Distribution Interruptions.

A set of industry measures are employed to measure Public Service's performance: Customer Average Interruption Duration Index, the average time to restore electric service; SAIDI, the average interruption duration for all customers; and SAIFI, the average number of interruptions per customer served.

Customer complaints are based on complaints obtained from the Commission's External Affairs Consumer Complaint System, and Telephone Response Time is calculated as the percent of calls answered within 45 seconds.

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[6] Proceeding No. 95A-531EG

[7] Proceeding No. 99A-337EG, C00-0393 issued April 24, 2000.

[8] Decision No. C00-0393 at p. 9.

[9] Decision No. C20-0096, Proceeding No. 19AL-0268E issued February 11, 2020.

c. Public Service Gas

Public Service's Gas QSP comprises three measures totaling up to $750,000 per year. Each of the measures carries an annual penalty of $750,000 if Public Service exceeds the baseline: Damage Prevention, with a baseline of 2.02 damages/1,000 locates; Emergency Response, with a performance baseline of 76.1 percent response rate within 60 minutes; and Grade 2 Leak Repair Time, intended to reduce methane released, with a performance baseline of 63.3 days to repair.

d. Black Hills Electric

Black Hills Colorado Electric LLC's Colorado tariff indicates that it implemented a QSP for five years, beginning July 1, 2005, then extended compliance reporting through June 30, 2013. Benchmarks were established for customer complaints received by the Commission; telephone response time in the Black Hills customer call center; and electric service unavailability. Bill credits were to be issued in the event that QSP metrics were not met, to a maximum of $281,250 in the initial five-year QSP term.

e. Black Hills Gas

Black Hills Colorado Gas, Inc. has a QSP effective through December 31, 2025, which includes five metrics: Damage Prevention and Emergency Response Time (Safety), Outage Frequency (Reliability), Average Time to Answer Customer Calls, and On-Time Rate for Non-Emergency Calls (Adequacy of Service). Each metric includes a threshold level and a maximum penalty (negative financial incentive) of $135,000 annually. Annual reports are filed in May of each year.

f. Rocky Mountain Natural Gas

Rocky Mountain Natural Gas LLC (RMNG) is an intrastate natural gas pipeline and does not engage in local distribution service, so it has two metrics: Safety: Damage Prevention, and the Reliability: Outage Frequency. The annual maximum negative financial incentive for RMNG is $10,000.

g. Colorado Natural Gas

Colorado Natural, Inc. (CNG) has a Damage Prevention Metric, Grade 2 Leak Repair Time, Customer-Owned Yard Line (COYL) metric which requires CNG over a period of 24 months ending December 31, 2021 to determine the location of each COYL on its system and to provide information to each customer regarding customer responsibilities for operating and maintaining COYLs. CNG is also required to file an application for a System Safety and Integrity Rider (SSIR) by the second quarter of 2020 to recover the costs of system safety improvements. Each of the metrics has a $9,500 annual penalty if CNG does not meet threshold requirements.

h. Demand Side Management (DSM)

In 2007, DSM was codified at §§ 40-1-102, 40-3.2-101, 103, and 104, C.R.S. Specifically, the Legislative Declaration of § 40-3.2-101, C.R.S. states:

> …cost-effective natural gas and electricity demand-side management programs will save money for consumers and utilities and protect Colorado's environment. The general assembly further finds, determines, and declares that providing funding mechanisms to encourage Colorado's public utilities to reduce emissions or air pollutants and to increase energy efficiency are matters of statewide concern and that that public interest is served by providing such funding mechanisms.

Section 40-3.2-104(5), C.R.S., directs the Commission to allow for an "opportunity for a utility's investments in cost-effective DSM programs to be more profitable to the utility than any other utility investment that is not already subject to special incentives." Under this subsection, the Commission is to consider incentive mechanisms that include:

(a) a rate of return on DSM investments that is higher than the utility's rate of return on other investments;
(b) accelerated depreciation or amortization period for DSM incentives;
(c) retention of a portion of the net economic benefits associated with a DSM program for its shareholders; and
(d) collection of the costs of DSM programs through a cost adjustment clause.

Public Service's 2019 to 2020 DSM plan[10] provided for annual energy savings of more than 500 GWh and annual demand reduction of more than 90 MW, with demand response savings of about 470 MW per year. The budget for each year is $78 million, with a 20 percent presumption of prudence for expenditures of up to $93.6 million.

Three performance incentives, capped at $15 million annually, are available to Public Service - Electric:

- Performance Incentive: equal to a percentage of the estimated present value of net economic benefits generated over the lives of the energy efficiency measures installed during that year;
- Energy Disincentive Offset: $1.5 million when Public Service achieves 160 GWh of energy efficiency savings, with an additional $1.5 million when it achieves 280 GWh of energy efficiency savings.
- Demand Response Incentive of 15 percent of the benefits of Public Service's Demand Response products each year, capped at $2.5 million annually.

Public Service is also allowed to apply a 50 percent non-energy benefits adder to low-income measures and projects, and a 20 percent adder to all other measures and products. This is intended to allow evaluation of cost effectiveness.

[10] Proceeding No. 18A-0606EG

The costs of DSM programs are recovered through a DSMCA that is applied to customer bills. The costs included in the DSMCA are reviewed each year by the Commission for prudency.

i. Revenue Decoupling Adjustment (RDA)

Utility rates have several components, including a charge for the cost of the amount of electricity used, the volumetric charge, and a charge for the cost of the infrastructure that delivers the electricity to the premises, the fixed charge. The two are not completely separate, however, so if volumetric sales decrease, as is encouraged in programs such as DSM, the utility might not recover its fixed costs. The incentive for a utility to maximize sales to augment revenues and to recover the fixed charges that are embedded in volumetric rates is known as a "throughput incentive," and is counter to programs such as DSM, which encourage energy conservation. Revenue decoupling addresses this issue by allowing comparison of a pre-established target level; if the utility's revenues are greater than the target, customers are refunded, if revenues are less than the target, customers are assessed a surcharge.

Programs such as integrated volt-var optimization (IVVO), discussed below, also benefit from decoupling as the utility is less likely to make investments in IVVO because the efficiencies gained through IVVO are lost electric sales.

The Commission has authorized a pilot revenue decoupling adjustment mechanism (RDA), for Public Service electric, in effect until 2023 for residential and small commercial customers.[11]

j. Advance Grid Infrastructure System (AGIS) and Integrated Volt-Var Optimization (IVVO) (C17-0556)

In 2017, the Commission authorized the deployment of IVVO, along with an automatic metering infrastructure (AMI) within Public Service's Advanced Grid Intelligence and Security (AGIS) initiative.[12] AGIS is intended to enhance the security, efficiency, and reliability of Public Service's distribution system, as well as help to safely integrate more distributed resources, and enable improved customer products and services. Through AGIS, Public Service will install advanced meters (Advance Meter Infrastructure or AMI) across its service territory. AMI installations are slated to begin in the second quarter of 2021 and will extend through the end of 2024. Additionally, intelligent field devices will be deployed to nearly 70 percent of Public Service's customers by implementing IVVO on feeders within the Denver metro area.

IVVO works with AMI and other devices on the distribution systems to automate and optimize distribution voltage regulating and control devices, saving energy by reducing line losses and reducing end user demand. It also allows for deferral of distribution system upgrades. In approving investment for IVVO, the Commission determined IVVO would reduce load and increase energy savings, making it an acceptable use of ratepayer funds, as described in § 40-2-123(1)(c), C.R.S. Recovery of revenue reductions resulting from reduced sales is authorized through the ECA.

[11] Decision No. C20-0096, Proceeding No. 19AL-0268E issued February 11, 2020

[12] Decision No. C17-0556, Proceeding No. 16A-0558E issued July 25, 2017.

Two deferred accounting mechanisms would be established for each project (IVVO and AMI): one for deferred capital investment and one for operations and maintenance (O&M) expenditures. In the event the sum of the two capital investment deferrals totals $50 million or more, the Company would begin to assess an interest rate equal to the Company's after-tax weighted average cost of capital. Because the AMI meters will be utilized for more than measurement of a customer's consumption for billing purposes, some portion of these meter costs will not be classified as a specific customer cost for recovery through the fixed monthly Service and Facilities charge.

k. Utility-Owned Resources

Through § 40-2-123, C.R.S., the General Assembly provided guidance for the development of increasing amounts of solar energy, allowing the Commission to consider utility-scale[13] solar resources and determining the appropriate amount of these resources that should be acquired by the utility. In making that determination, the Commission was directed to consider energy storage and consequent reductions in performance and financial risk for the utility, potential decreases in water consumption for electric generation, cost stabilization through mitigation of the impact of varying fossil fuel prices, and potential reduction of long-term costs and risks related to carbon regulation or taxation. Section 40-2-123(1)(a), C.R.S., directs the Commission to consider utility investments in energy efficiency to be an acceptable use of ratepayer moneys.

Several incentive mechanisms are associated with these statutes, including an allowance in Public Service's most recent Renewable Energy Standard (RES) Plan[14] for 8 MW of utility-owned CSG for low-income subscribers. Public Service is allowed to receive an upfront renewable energy credit (REC) incentive of up to $0.05 per kWh for the project.

l. Equivalent Availability Factor Performance Mechanism (EAFPM) and Base Load Energy Benefit (BLEB)

The Base Load Energy Benefit (BLEB), ordered in 2006, created an incentive for Public Service to improve the efficiency of its coal-burning plants.[15] The BLEB was based on a benchmark energy production target, with monetary savings from coal production over the benchmark shared between customers (80 percent of savings) and Public Service (20 percent of savings). The BLEB was discontinued in 2009 when it was determined to be incompatible with Colorado's regulatory and environmental goals. [16]

The EAFPM was a benchmarking plan for some of Public Service's fossil-fuel generation plants, intended to provide an incentive for Public Service to maintain its generation plants for

[13] Utility scale is defined as projects with nameplate ratings greater than two megawatts

[14] Proceeding No. 19A-0369E

[15] Proceeding No. 06S-234EG, Decision No. C06-1379 issued December 1, 2006

[16] Proceeding No. 09AL-299E, Decision No. C09-1446 issued December 24, 2009

optimum availability and cost effectiveness. The EAFPM was first approved in 2015, tying a monetary bonus or penalty to generation plant production. In 2016 and 2017 Public Service received no bonus or penalty under the EAFPM, but in 2018, Public Service received a $3 million bonus under the mechanism.[17]

In 2019, the Commission eliminated the EAFPM,[18] agreeing with Public Service's request in a rate case that because of the changing nature of the generation fleet, an EAFPM could cause it to make additional investments in fossil-fuel facilities in order to meet the minimum threshold and avoid penalties. The Commission agreed, noting that the EAFPM was adopted prior to more formal state policies on carbon emissions.

m. Distributed Energy Generation Equivalent Availability Factor Performance Mechanism (EAFPM) and Base Load Energy Benefit (BLEB)

DERs comprise a broad spectrum of generation and storage technologies that includes distributed renewable energy generation, such as rooftop solar and utility-scale renewable energy; CSGs; energy storage systems; microgrids, and DSM measures, including energy efficiency and demand response.[19] In 2019, the Commission undertook rulemakings for CSGs [20]and interconnection.[21]

The RES, at § 40-2-124, C.R.S., provides a definition of renewable energy resources which includes, among other sources, solar, wind, and geothermal. "Retail distributed generation" is defined as a renewable energy resource that is located on the site of a customer's facilities, is interconnected on the customer's side of the utility meter, and supplies no more than 120 percent of the customer's average annual electricity consumption. In 2020 and beyond, 30 percent of each qualifying retail utility's generation must be from eligible energy resources, with distributed generation equaling at least 3 percent of its retail electricity sales. At least one-half of the distributed generation must be from retail distributed generation.

CSGs, which expand the opportunity for households to participate in solar generation beyond rooftop solar and allow renters, low-income utility customers, and agricultural producers to own interests in solar generation facilities, are the subject of § 40-2-127, C.R.S. CSG participants and the prices they pay for subscriptions are not subject to Commission regulation.

Distributed generation is addressed at § 40-2-109.5, C.R.S., and is defined at § 40-2-109.5(2), C.R.S., as means a system by which a consumer generates heat or electricity using renewable energy resources for his or her own needs and may also send surplus electrical power back into

17 Proceeding No. 18A-0206E, Decision No. C18-0385 issued May 29, 2018, recovered through the ECA

18 Proceeding No. 19AL-0286E, Decision No. C20-0096

19 Beneficial electrification can also be considered to be part of DER. However, a discussion of beneficial electrification is included below under emissions reductions.

20 Proceeding No. 19R-0608E

21 Proceeding No. 19R-0654E

the power grid. The Commission currently has an ongoing rulemaking (Proceeding No. 19R-0096E) which addresses changes to net metering rules.

Energy storage systems are defined at § 40-2-130(2)(a), C.R.S., and again at § 40-2-202(b), C.R.S. Through § 40-2-202(b), C.R.S., the energy storage is to be integrated into the planning process for electric utilities; the Commission implemented rules for energy storage systems in 4 CCR 723-2-3602 through 3617. In 2019 Public Service proposed construction of up to 15 MW of Company-owned storage, for which it requests presumption of prudence for cost recovery in rate base or through a cost-recovery mechanism.[22] A unanimous settlement on the proposal was filed in May 2020 and is awaiting an order from the assigned Administrative Law Judge.

n. Clean Air – Clean Jobs Act

In 2009, the CACJA[23] was implemented at § 40-3.2-201, C.R.S., requiring reduction of emissions from regulated utilities' coal-fired generation plants through retirement of 900 MW of coal-fired generation plant capacity or 50 percent of the utility's capacity, whichever was less.

The statute provided a financial incentive to the utilities for replacement generation sources and early retirement of those coal-fired plants. Specifically, Public Service and Black Hills were authorized to own replacement generation and to recover a return on certain accounting mechanisms incurred as the replacement facilities were constructed. As an additional financial mechanism, each utility was allowed to implement a rate adjustment on customer bills to compensate for the retirement of coal-fired plants and the conversion to natural gas or renewable energy sources.

o. Beneficial Electrification

Additional statutes from the 2019 Legislative session direct the Commission to consider the cost of pollution in utility planning and electrification. Section 40-3.2-106, C.R.S., contains a definition of "beneficial electrification," the shifting from a nonelectric source to an electric source for powering end uses, such as transportation, water heating, space heating, or industrial process, and § 40-5-107, C.R.S., directs electric utilities to file an application with the Commission every three years, beginning in 2020, for activities that will support widespread transportation electrification. The electrification of the transportation sector is the most prominent current example of beneficial electrification, but other efforts to advance beneficial electrification in water and space heating, and in a new planning process for natural gas investments, are also underway.

The Bill that established the statutory requirement for regulated electric utilities to file TEPs, SB19-077, contemplated TEPs as a means of facilitating the "widespread adoption of electric vehicles." Accordingly, the Bill included provisions to allow the Commission, at its discretion, to approve various activities related to utility investments to support transportation electrification development. The Bill specifies that the Commission may allow utilities to own

[22] Proceeding No. C19-0225E
[23] Proceeding Nos. 10M-0245E and 10M-0254E

EV charging infrastructure,[24] it may authorize a return on TEP investments at the utility's weighted average cost of capital,[25] it may approve rate recovery mechanisms that allow early recovery of TEP costs,[26] and it may approve "performance-based incentive returns or similar investment incentives".[27] By authorizing the Commission to approve these regulated activities, the legislation provided options for the Commission to consider in its determination of whether TEP proposals are in the public interest.

Both Public Service and Black Hills have filed TEPs in Proceeding Nos. 20A-0204E and 20A-0195E, respectively, which are currently in litigation as of the time of this writing. Consistent with statutory language, both utilities include proposals for PIMs related to the utilities' efforts to reduce barriers to the adoption of EVs consistent with state goals. Although these proposed PIMs have not been approved by the Commission as of the publication date of this report, we describe them briefly below as examples of PIMs proposed within Colorado's existing regulatory environment.

Public Service notes in its TEP proposal that "any PIM should first fall within the broad categories of 'public benefit goals' that Senate Bill 19-236 and the Commission have outlined." [28] Accordingly, Public Service proposes two PIMs focusing on "high quality customer experience" and "cost efficiency". Both PIMs are incentive-only PIMs (with positive incentives for good performance, no negative incentives for poor performance), ranging from $0 to $1.5 million each.

Public Service's proposed Customer Experience PIM would measure the quality of customer service based on the Customer Effort Score (CES) of residential customers participating in TEP programs. The CES ranges from 0 percent to 100 percent, and is designed to measure the ease with which customers report being able to navigate a program or receive a service. The Customer Experience PIM would begin to reward Public Service for CES scores above 70 percent, awarding $50,000 for each percentage point increase in CES up to the maximum ($1.5 million) reward available at a CES of 100 percent.

Public Service's proposed Cost Efficiency PIM would assess cost efficiency based on the percentage of light duty EVs in the Company's service territory participating in some form of managed charging or receiving service via a time-varying rate. The Cost Efficiency PIM would begin to reward the Company when the enrollment level exceeds 10 percent and would award $50,000 for each percentage point increase up to the maximum ($1.5 million) reward available at an enrollment level of 40 percent.

Black Hills' TEP proposes a single PIM using estimates of the value of CO_2 emission reductions associated with the adoption of EVs in its service territory. The PIM is tied to the number of rebates awarded and calculated based on the social cost of carbon benefit achieved through

[24] § 40-5-107 (1)(b)(I), C.R.S.

[25] § 40-3-116 (1)(a), C.R.S.

[26] § 40-3-116 (1)(b), C.R.S.

[27] § 40-3-116 (1)(c), C.R.S.

[28] Referring to SB 19-236 and Commission Decision No. C19-0969 in Proceeding No. 19M-0661EG issued December 5, 2019, Public Service lists those goals as including safety, reliability, cost efficiency, emissions reductions, expansion of distributed energy resources, and customer service.

the TEP. The Company would be awarded the value of avoided emissions up to an amount representing 15 percent of the total cost of its TEP.

The 2021 through 2023 TEP proposals are the most high-profile beneficial electrification efforts currently before the Commission, but they are not the only ones. Public Service has included two new beneficial electrification proposals in its 2021 through 2022 DSM plan, Proceeding No. 20A-0287EG. These proposals provide incentives for customers to convert natural gas water heaters to electric heat pump water heaters and to offset natural gas furnace usage with electric heat pumps. The combined budget for these proposals is about $500,000 per year.

Finally, in Public Service's recent gas rate review, Proceeding No. 20AL-0049G, parties reached a settlement that establishes new processes for planning and reporting to the Commission regarding Colorado gas utilities' natural gas infrastructure. The stated purpose for the new processes is to allow parties to collaborate on a rulemaking related to, among other things, "the appropriate consideration of enacted beneficial electrification laws, rules, and regulations" as they relate to certain transmission and distribution capacity and infrastructure projects.

p. Earnings Sharing

The Commission authorized earnings sharing for Public Service in 2000, with the ECA and the incentive cost adjustment (ICA), which allowed for a 50-50 sharing of economy sales with customers. In 2012, as part of an MYP, an ESM established 10 percent as the authorized return on equity (ROE) for Public Service, with customers sharing a percentage of earnings at any point that the return exceeded 10 percent. In 2014 and 2015 the result was a negative sharing and the mechanism expired in 2017.

Capital cost sharing was part of Public Service's Rush Creek Wind Project, with a sharing of capital cost savings between customers and the company if the capital costs to build the Rush Creek Wind Project were less than $1.0958 billion. Additionally, a performance metric was established to access the generation performance of Rush Creek for years 13 to25 of the project.

q. Rate Adjustments and Multi-Year Plans (MYPs)

MYPs set a defined schedule of discrete changes in a utility's base rates over time. MYPs can serve as a form of PBR depending on their features, such as the inclusion of earning sharing mechanisms, quality of service PIMs, and other metrics tracking as discussed in this report. Even without PBR features, MYPs are intended to diminish the frequency, and hence reduce the costs, of fully-litigated utility rate cases, to provide rate stability for ratepayers, and to offer revenue certainty for utilities.

MYPs rely on utility forecasts which inject a degree of uncertainty into rate setting, because although MYPs incentivize cost containment and potentially lower rate case costs, there is also the risk that utility revenues will be greater than costs over time. The forecasted cost of service could fail to incorporate the utility's unreported strategic plans for cost efficiency improvements (*e.g.*, workforce reductions to capture O&M savings), such that the calculated MYP revenue requirements reviewed and approved by regulators simply provide the utility a

baseline level of profits captured simply by the utility implementing its business plans—plans that are not necessarily disclosed to parties and regulators during the course of a rate proceeding. Accordingly, the expected savings in rate case expenses from conducting a single MYP proceeding instead of a series of rate cases might be overshadowed by greater regulatory expenses, as the costs and forecasts underlying the MYP must be more closely scrutinized by intervening parties. A further concern with MYPs is that ratepayers might not benefit if cost evaluation is not reviewed regularly in rate case.

Great Britain's RIIO is an example of how MYPs can be implemented; it contains strong cost control incentives and focuses on long-term investments. RIIO has been successful, although it is highly complex and expensive to administer. It is based on eight-year business plans in which regulators rely on third-party engineering analysis and statistical benchmarking to establish the reasonableness of costs. Additionally, capital and operating expenses are combined into a "totex," a portion of which is subject to a rate-of-return. This is intended to encourage the utility to be agnostic in terms of capital and non-capital investments. PIMs also play an important part of RIIO, guiding utilities to achieve public policy goals.

In the U.S. several states, including Maryland, Minnesota, Hawaii, and New York, have implemented or are in the process of implementing MYPs. The experience of these states is discussed in Section 9.

r. MYPs in Colorado

The Commission has considered MYPs in a number of electric and gas rate case proceedings and, after has twice approved a version of an MYP. In reviewing MYP requests, the Commission has consistently applied regulatory standards of whether the utility is suffering from adverse situations outside its control, such as high inflation, high interest rates, or rapid expansion of utility facilities, along with the paramount consideration as to whether it would serve the public interest and benefit ratepayers.

The Colorado PUC did approve an MYP for Public Service in 2012, after the Colorado Legislature (Legislature) passed the Clean Air Clean Jobs Act. Parties to this rate case, Proceeding No. 11AL-947E, arrived at a settlement that was based on a forecasted test year, also known as an FTY, and allowed for revenue requirement increases in each of the three years of the MYP. Public Service agreed to a three-year "stay out" provision for rate cases and deferred property tax expense and depreciation related to the CACJA, although the statute allowed recovery of those expenses. The MYP allowed for a 2.5 percent rate increase for residential rates in 2012, 1.9 percent increase in 2013, and a 1.0 percent increase for 2014, for a total of a 5.53 percent increase over the three years.

The MYP also included an earnings test to protect ratepayers in the event sales volumes or other factors would result in an ROE greater than the authorized 10 percent. Public Service realized over-earnings throughout the MYP, stemming from decreased O&M costs and increased revenue, underscoring the challenges of forecasting underlying MYP cost of service determinations.

Public Service filed its next electric rate case, Proceeding No. 14AL-0660E in 2014. Parties to that rate case also reached a settlement that the Commission approved. The settlement included a reduction in rates from those approved through the earlier MYP, establishing base rates for each year 2015 through 2017, along with an extension of the earnings test and QSP,

and Public Service's agreement that it would not file a rate case before 2017. Additionally, a new CACJA rider was implemented, offsetting some of the reduction in base rates.

On the whole, MYPs go beyond specific public policy statutes and riders and cover the whole of the utility's business plan. MYPs are broad stroke, addressing large capital outlays over years, including O&M, labor, and variable costs, tied to productivity. In contrast, public policy goals have led to riders or PIMs, which are specific to those goals and allow review of specific costs and expected outcomes. That is, MYPs provide guidance for operational efficiency and reduced costs, whereas PIMs allow regulators to guide utilities toward specific outcomes and goal

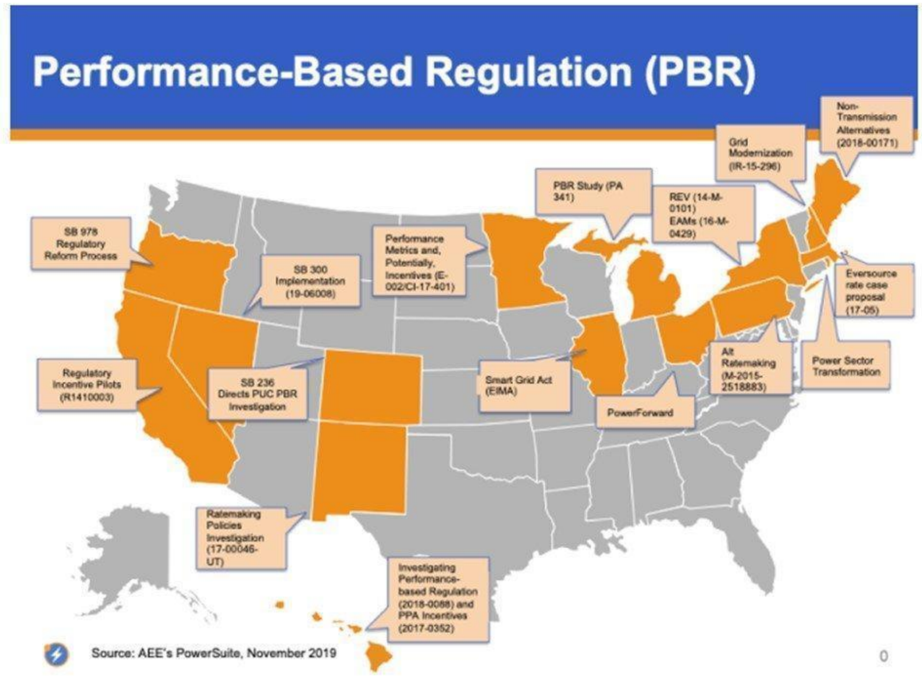
s. Test Years

In order to determine what a utility's revenue requirement is, the Commission must understand what costs the utility has to recover and what revenues will be necessary for that recovery. The period of time from which the utility's costs are calculated is called a test year. Historically, the Commission has employed a historic test year (HTY), which, as the name implies is a period of 12 months already passed. Using an HTY allows the Commission to evaluate "known and measurable" costs associated with investments in utility plant necessary to provide service "used and useful."

A future, or forecasted, test year (FTY) requires an estimate of what costs the utility has yet to incur. Forecasting is an inexact science and therefore carries risk that costs will be greater or less than revenues over the forecast period, as was the case in Public Service's 2011 through 2014 MYP. For this reason, FTYs are more challenging than HTYs.

Some recent rate cases filed with the Commission have been based on a hybrid of historical and future periods, proposing to use historical costs but adjusted to reflect known and measurable changes through a future period. This is intended to limit reliance on forecasted information while maintaining the regulatory principle of matching revenues, investments, and expenses over the same time period.

10. PBR IN OTHER STATES



a. California

The California Public Utilities Commission (CPUC) arguably has North America's most experience with PBR for retail electric utilities. A California regulator is said to be the first to use the term "PBR." The CPUC's jurisdiction is second in size only to that under the jurisdiction of the Federal Energy Regulatory Commission. Six investor-owned electric utilities (two of which are very large) are regulated, along with natural gas, telecommunications, water, railroad, and rail transit companies. MYPs are used in California by the CPUC's routine use of forward test years. California's power market was restructured in the 1990s. Today, two of three large, jurisdictional electric utilities continue to have sizable generation operations.

The CPUC has limited the frequency of general rate cases using "rate case plans." Rate cases are staggered to reduce the chance that the Commission has to consider cases for multiple large utilities simultaneously.

California initiated a regulatory incentive mechanism pilot ("California's Pilot PIM") in 2016 that specifically targeted DERs. The pilot PIM was implemented, which modified COSR by allowing utilities profit margin on certain expenses, if those expenses defer or displace capital expenditures. This mechanism aims to make a utility indifferent to whether it meets customer and grid needs through rate-based traditional infrastructure, or through third-party owned DER.

The CPUC also has been a national leader in revenue decoupling and PIMs for DSM.

b. Connecticut

The Connecticut Public Utilities Regulatory Authority (Authority) has opened an array of new grid modernization proceedings. It issued an interim order in its grid modernization investigatory proceeding in October 2019, deciding to open new dockets on 11 specific topics. The Authority opened six of these proceedings in Q4 2019, which focus on energy affordability, advanced metering infrastructure, electric storage, zero-emission vehicles, innovation pilots, and interconnection.

c. Hawaii

In April of 2018, the Hawaii Public Utilities Commission (Hawaii PUC) opened a proceeding to investigate performance-based regulation. The Commission established an approach that would proceed in two phases. In Phase 1, which took place from April of 2008 to May of 2019, the Commission comprehensively evaluated the existing regulatory framework in Hawaii and identified specific areas for further PBR development. In Phase 2, which formally began in June of 2019 and is ongoing as of this writing, the Commission is working collaboratively with stakeholders to refine and/or modify the existing regulatory framework according to the areas identified for improvement in Phase 1.

In its decision concluding Phase 1 of its PBR investigation, the Hawaii PUC adopted a set of guiding principles, goals, and regulatory outcomes to guide the development of PBR mechanisms in Phase 2. The three guiding principles are: (1) a customer-centric approach; (2) administrative efficiency; and (3) utility financial integrity. The decision identifies 12 specific outcomes, organized around the 3 regulatory goals of enhancing customer experience, improving utility performance, and advancing societal outcomes.

Hawaii's interest in and experience with PBR grows out of a particular regulatory context. The Commission notes that the "convergence of factors driving fundamental change in the electric power industry are further amplified in Hawaii." Hawaii has the highest electricity prices in the nation and the penetration rates of DERs in the Hawaiian Electric Companies' (HECO Companies) service territories are among the highest in the world. In launching its PBR investigation, the Hawaii PUC noted that the reality of high rates and increasing dependence on DER "stands somewhat in conflict with the incentives inherent in the State's existing regulatory framework."

The Hawaii PUC recognizes the current PBR investigation as a "continuation of significant efforts" dating back to the 1990s to implement some aspect of PBR. The HECO Companies proposed specific PBR frameworks in 1996 and 1999. The Commission approved decoupling mechanisms for the HECO Companies in 2010, which were amended and supplemented in later proceedings so as to include many of the elements the HECO Companies had proposed in the late 1990s. These elements include: (1) fixed, multi-year intervals between general rate cases; (2) index-based price caps based on an annual gross domestic product price index adjusted by a productivity factor; (3) ESMs; and (4) service quality PIMs with performance targets, "deadbands," and specified maximum rewards and penalties.

The ongoing Phase 2 portion of Hawaii's PBR process began with a series of technical workshops and group meetings, then transitioned to a more traditional Commission proceeding, with formal briefings from interveners and an evidentiary hearing in September, 2020. The Hawaii PUC anticipates issuing a Decision in this proceeding in December, 2020.

d. Illinois

Illinois implemented a version of PBR in 2011 after the passage of the state's Energy Infrastructure Modernization Act (EIMA).[29] The EIMA allowed utilities to employ formula rates if the utility agreed to certain investments in the electric grid over ten years. Illinois Public Utility Law requires that utility rates be cost-based but the EIMA allows the utility to use a formula to estimate its costs and revenue requirements, then reconcile them when actual costs are known.

The formula rates are set based upon a forecast of the expected capital investments and operating expenses in the coming year. After actual costs are known, there is a subsequent true up to prevent over- or under-recovery of costs. A requirement of EIMA was that residential customer rates could not increase more than 2.5 percent compounded annually.

Consolidated Edison Company (ComEd) was required to invest $1.3 billion in electric system upgrades, $10 million in training facilities, and $200 million in infrastructure upgrades to lessen potential weather damage over a five-year period, and an additional $1.3 billion in transmission, distribution, and Smart Grid upgrades over a ten-year period. Ameren was required to invest $265 million in system upgrades and training facilities and $360 million in transmission, distribution, and Smart Grid upgrades over a ten-year period. Both utilities have remained within the bounds of the customer rate changes.

In 2015 the Illinois Commission considered allowing cloud computing to be treated as a capital expense and issued a notice of inquiry. In 2017 Staff submitted a report recommending that the Commission revise its regulatory accounting rules, allowing cloud computing to be treated in the same manner as on-premises computing, which is considered a capital expense. Staff of the Illinois Commission proposed a rule that would allow 80 percent of costs to be capitalized as a regulatory asset and 20 percent to be included in operating expenses. In July 2020, the Commission rejected the proposed rule, stating that the 80/20 split was arbitrary and not grounded in evidence. The Commission noted that the Financial Accounting Standards Board has accounting standards that will allow appropriate recovery of cloud-based computing expenses. Additionally, the Commission stated that the rulemaking is untimely, given the uncertainty on rates of uncollectibles resulting from the current COVID-19 pandemic and stated that the data used to establish the proposed rule dates to 2017 and is therefore likely outdated.

[29] The EIMA came under scrutiny in 2020 after ComEd was accused of bribing legislators in order to have certain legislation passed.

e. Maryland

Maryland began an examination of PBR in August of 2019, specifically an MYP based on an HTY with up to three FTYs for gas and electric utilities. At that time, the Maryland Commission also found that although aligning state policy goals and utility rate adjustments through PBR is important, further investigation as to how to accomplish this would be necessary. The Commission therefore established a working group to develop a detailed MYP implementation report. The Commission used that report to establish a Pilot MYP program in February 2020. Participation in the MYP Pilot was optional and not all utilities in Maryland opted into the program, citing concerns about complexity, cost, and procedural burdens of an MYP.

Maryland Commission Staff proposed a process of an initial MYP test case filed by one utility, which would run for three years and allow for a "lessons learned" process. At the conclusion of the pilot, utilities could begin filing MYPs at five-month intervals. Although the Commission found that it does not have the authority to require utilities to file according to a five-month timeline, it does have the authority to reject or modify a proposed MYP if the application is not consistent with the public interest.

With regard to FTYs, the Commission agreed with the Working Group that the Pilot Utility should bear the risk of forecasting errors.

Maryland declined a formula rate in Order No. 89226 because formula rates do not address regulatory lag and shift financial risks to customers and reduce incentives for utilities to control costs.

f. Massachusetts

In a rate case filed in November of 2018, National Grid, an electric utility serving over 1.3 million customers in Massachusetts, proposed a PBR plan with three main components: a PBR mechanism to adjust rates annually, PIMs and scorecard metrics, and a climate mitigation and adaptation plan. The proposed PBR mechanism replaced an existing mechanism designed to allow the utility to recover an annual revenue requirement on incremental capital investments, called the capital investment recovery mechanism.

National Grid argued that the PBR plan was necessary to address declining sales revenues and increasing operating and capital costs, claiming that it could no longer operate effectively under cost of service regulation.

The Massachusetts Department of Public Utilities Approved National Grid's PBR proposal with several modifications. The approved plan covers five years and imposes a revenue cap formula to adjust base distribution rates annually through an adjustment to the Company's revenue decoupling mechanism. The PBR mechanism includes a "customer dividend" to share efficiency gains with ratepayers, and an earnings sharing mechanism according to which the company returns revenues to ratepayers when its realized ROE exceeds the commission-approved ROE by 200 basis points.

g. Minnesota

Minnesota has been ahead of many other states in the movement away from traditional cost-of-service ratemaking and towards PBR. In a September 18, 2019, order, the PUC established a series of metrics for outcomes related to:

1. Affordability;
2. Reliability;
3. Customer Service;
4. Environmental Performance;
5. Demand Response; and
6. Cost-Effective Alignment of Generation and Load.

On October 31, 2019, Northern States Power, or NSP, filed proposed final metrics with a description of the corresponding methodology underlying each of the metrics outlined above, and a proposed process schedule for reporting the metrics.

NSP intends to track the metrics beginning January 1, 2020, which comprises 24 of the 33 metrics, 17 of which the utility is currently providing in some other context. The metrics are scheduled to be reported to the PUC by April 30, 2021. NSP is a unit of Xcel Energy Inc.

This docket was opened in September 2017 following NSP's MYP that was filed in November 2015.

The Minnesota Public Utilities Commission, on February 20, 2020, voted to accept a series of performance-based metric calculations and reporting schedules for Northern States Power Co., Minnesota's electrical operations to help align regulatory incentives the utility seeks with performance outcomes. Minnesota state law established MYPs for regulated utilities, which was enacted in 2011, provides that the PUC has authority 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.”

Affordability will be measured by rates per kilowatt-hour, average monthly bills, total arrearages, and total disconnections for nonpayment for residential customers. Reliability is to be measured by system average interruption duration and frequency, customers experiencing long interruption duration and experiencing multiple interruptions and average service availability. Customer service will be measured by customer satisfaction metrics, using existing multi-sector metrics including J.D. Power, as well as utility performance metrics such as call center response time.

With respect to environmental performance, the utility will be graded on total carbon emissions and carbon intensity from utility-owned facilities, power purchase agreements and all sources, among other things. And cost-effective alignment of generation and load will be measured through demand response, including megawatt-hour capacity available and amount called per year.

The performance-based metrics would apply only to NSP, Minnesota's largest investor-owned utility, when it files its next rate case. The state's other investor-owned utilities have not filed MYPs.[30]

h. New York

New York implemented performance-based measures in the 1990s, but in 2014 the New York Public Service Commission (NYPSC) implemented the REV, intended to better align utility interests with state energy policy objectives of 40 percent reduction in GHGs by 2030 and an 80 percent reduction by 2050. A primary goal of the REV proceeding is to place distributed energy resources on the same level as traditional investments. The NYPSC noted that its goals were ambitious but stated that attaining those goals would be possible over a period of years, in concert with industry, customers, non-governmental advocates, and regulatory when possible.

REV is designed to encourage third-parties, such as distributed energy developers and technology companies to partner with utilities with the following objectives: increased system reliability and resilience, fostering of markets that utilize DERs, and optimize grid assets to create value and deliver energy more efficiently, enhance customer knowledge and capabilities, ensure fuel and resource diversity, improve system-wide efficiency, and reduce carbon emissions.

The NYPSC established two tracks: Track One focused on DER markets and Track Two focused on utility ratemaking reform. The NYPSC directed its staff to work with the New York State Energy Research and Development Authority to develop proposals for DSP, energy efficiency measures, and large-scale renewables.

In February 2015, the NYPSC adopted an order establishing a framework for a reformed retail electric industry. The order envisioned an electric system driven by consumers and non-utility providers, enabled by utilities acting as Distribution System Platform providers. The utilities would work with third-party aggregators to develop products and services that would enable full customer engagement, providing uniform market access to customers and DER providers. At the same time, the utilities would provide an interface between aggregated customers and the NYISO.

The NYPSC stated that its statutory responsibility to maintain universal, affordable service is a critical driver of the REV initiative and noted that it had opened a proceeding to examine energy affordability programs. Utility plans for DER were to identify, measure, to engage and enable participation by low and moderate income customers, including basic service plans, bill relief options, and incentive programs, with affordability a priority in any rate design. (Synapse, Utility Performance Incentive Mechanisms)

With regard to benefit-cost analysis (BCA) of REV, NYPSC staff proposed a BCA framework that was widely supported by parties to the proceeding. However, there was significant

[30] Dan Lowrey, Performance-based utility regulation taking shape in Minnesota, S&P Global Market Intelligence, Friday, February 21, 2020

disagreement as to the framework components. The NYPSC determined that the BCA framework should focus on: (i) utility investments to build DSP capabilities; (ii) procurements of DER via selective processes; (iii) procurement of DER via tariffs; and (iv) energy efficiency programs, with allowances within each of these areas for modification based on circumstances.

In 2016, the NYPSC issued a REV Track 2 Order, which expanded on earnings adjustment mechanisms. The NYPSC noted that it was building on the Demand Management (BQDM) program approved in 2014, which addressed load growth in Brooklyn and Queens. ConEd proposed a portfolio of DER for forecasted summer load in lieu of constructing a substation, switching station, and subtransmission feeders. The NYPSC approved several incentives for the project, including a regulated return on the alternative investments, a ten-year amortization period, and a 100-point ROE adder on BQDM program costs tied to specific outcomes. The REV Track 2 Order incentivized annual energy savings and incremental annual system peak demand reductions.

i. Nevada

Nevada's PBR stems from SB300, which passed the Nevada Legislature in 2019. The legislation authorized the PUCN to consider alternative ratemaking mechanisms as part of an application from an electric utility. The PUCN opened a rulemaking in July 2019 and held three workshops.

In addition to SB300, Nevada has previous experience with various alternative ratemaking mechanisms:

1. infrastructure replacement mechanisms/riders;
2. incentives for EVs;
3. incentives for NWAs or demand response;
4. incentives for vegetation management as part of our disaster planning;
5. earnings sharing;
6. decoupling;
7. riders/adders for energy costs; and
8. other incentives (construction in aid of contribution in rate base, annual tracker for variable interest debt expense, both currently unused by the electric utilities).

While SB300 applies only to electric utilities, other utilities, including gas and water utilities, have some of the other listed incentives/mechanisms available to them. For example, gas and large water utilities in Nevada have both decoupling and infrastructure replacement mechanisms available to them. Gas utilities also have the interest rate tracker mechanism available for variable interest on debt, and a tracker mechanism available for uncollectible bad debt (from ratepayers) on gas energy costs.

The PUCN released its first concept paper in April 2020 regarding goals and outcomes in conjunction with Rocky Mountain Institute (RMI) and the Regulatory Assistance Project (RAP) in mid-April. The PUCN plans:

- Concept Paper 1 on goals and outcomes;

- Concept Paper 2 regarding the existing regulatory structure in Nevada and what is and is not working with that existing regulatory structure;
- Concept Paper 3 regarding the alternative ratemaking mechanisms listed in SB300 and which mechanisms might be appropriate for Nevada;
- Concept Paper 4 regarding metrics, minimum filing requirements for a plan for alternative ratemaking filed by an electric utility and the evaluation criteria the PUCN will use in evaluating an alternative ratemaking plan;
- At the conclusion of this stakeholder engagement process with RMI and RAP, a straw proposal will be drafted to test the PUCN's chosen goals and outcomes, alternative ratemaking mechanisms to accomplish those goals and outcomes, metrics, filing requirements, and evaluation criteria. After the straw proposal, a more formal regulatory review will be conducted in order to adopt regulations.

More information on Alternative or Performance-Based Ratemaking in Nevada: http://puc.nv.gov/Utilities/Electric/AlternativeRateMaking/

j. New Mexico

In 2017, the New Mexico Public Regulation Commission opened an investigation to study the potential for implementing PBR in utility rate design.

In March 2019, New Mexico authorized the use of decoupling, which reduces the utility disincentive to investing in energy efficiency by eliminating the link between sales and revenues.

k. Rhode Island

Commissioner Abigail Anthony is leading an effort to investigate how electric utilities can move away from traditional cost of service regulation. Anthony is aiming to shape the discussion with a proceeding in Rhode Island looking at performance incentive mechanisms for utilities that involve both awards and penalties for achieving certain goals.

"I am trying to dig into and come up with a standard of review for performance incentive mechanisms specifically that can help utilities make an evidentiary case before regulators," Anthony said in a June 2019 E&E News interview. "Can we show with evidence how customers will benefit if we allow this incentive or this penalty for utility shareholders?" Utilities "stand to gain money and new business by regulating based on performance," Anthony said. "By offering shareholders profit for the utility to advance carbon goals or peak demand reduction, we are allowing them to move into a market that could otherwise be served by competitive companies."

Originally Governor Gina Raimondo initiated the state's "Power Sector Transformation" in March 2017 by writing to the Rhode Island Public Utilities Commission, the Office of Energy Resources, and the Division of Public Utilities and Carriers, asking the three agencies to collaborate in the development of more dynamic regulatory framework that would enable the state and its utilities to advance a cleaner, more affordable and reliable energy system.

The agencies submitted their Phase One "Power Sector Transformation" report in November 2017. The report was divided into four discrete categories on which principles and recommendations were developed:

1. utility business model;
2. grid connectivity and functionality;
3. distribution system planning; and
4. beneficial electrification.

The Rhode Island Commission drafted a guidance document to provide direction on how it would apply its general and specific authority to set rates, tariffs, tolls, and charges to proposals for performance incentives for jurisdictional public utilities. The draft Guidance Document proposes five principles:

1. A PIM can be considered when the utility lacks an incentive (or has a disincentive) to better align utility performance with the public interest and there is evidence of underperformance or evidence that improved performance will deliver incremental benefits.
2. Incentives should be designed to enable a comparison of the cost of achieving the target to the potential quantifiable and cash benefits.
3. Incentives should be designed to maximize customers' share of total quantifiable, verifiable net benefits. Consideration will be given to the inherent risks and fairness of allocation of both cash and non-cash system, customer, and societal benefits.
4. An incentive should offer the utility no more than necessary to align utility performance with the public interest.
5. The utility should be offered the same incentive for the same benefit. No action should be rewarded more than an alternative action that produces the same benefit.

The guidance document is contained in Docket No. 4943 and is ongoing. It can be found at: http://www.ripuc.ri.gov/eventsactions/docket/4943page.html

11. STAKEHOLDER COMMENTS

Stakeholder participation was encouraged throughout the development of this report. Written comments and responses were requested, questions posed regarding PBR and the public interest goals that are the focus of this report.[31]

Several workshops were planned to generate discussion on a variety of PBR topics and allow for exchange of ideas. Two workshops were held, on February 21, 2020 and September 14, 2020; two additional workshops were planned but not held because of challenges in scheduling remote workshops during the spring and summer due to the COVID-19 pandemic.

A number of parties representing a broad spectrum of constituencies provided comments, which are summarized below. A summary of responses to the questions posed regarding public

[31] Decision Nos. R19-1002-I issued December 16, 2019, R20-0127-I issued February 26, 2020, and R20-0343-I issued May 6, 2020 in Proceeding No. 19M-0661EG.

interest goals follows. Filed comments can be found at the Commission's e-filings site: https://www.dora.state.co.us/pls/efi/EFI_Search_UI.search Proceeding No. 19M-0661EG.

a. AARP

AARP represents more than 670,000 members in Colorado, many of whom have low- or fixed-incomes and may struggle to make ends meet. AARP states that although it supports sustainable energy policies where cost-effective, has concerns about new policies or mechanisms that could result in higher utility rates; the organization advocates exploring PBR if measures can be shown to promote improvements in safety, reliability, or customer service.

Asserting that it is unclear what problem PBR in Colorado would solve and that, except for the consultants to the states looking at PBR, there is no groundswell of support for PBR, AARP supports a narrow focus for this proceeding, encouraging a focus on safety, reliability, and customer service. AARP cautions that this proceeding not be hijacked so special interests can promote their agenda. The organization suggests that if the Commission wishes to pursue PBR, it should start with a pilot and a few simple metrics.

AARP states that PBR dates to the 1980s, but the reason that some regulatory bodies investigate, adopt, and then abandon PBR concepts is because of the complexity of designing and measuring alternative mechanisms and there is great risk that current incentives for cost effectiveness can be lost. A practical concern is that access to data is largely asymmetrical because it is maintained by the utility. AARP opposes MYPs because they are based on speculative forecasts of costs.

AARP expresses concern that performance-based mechanisms will be designed with metrics that are easily met and that ratepayers end up rewarding the utility for doing what it was already obligated to do. Furthermore, AARP states that ratepayer funds could subsidize services that do not benefit most customers, citing EV charging stations as an example. Specific to DER, AARP questions rewarding Public Service for promptly completing distributed generation interconnection for 50,000 customers when Public Service has a duty to serve 1.4 million electric and gas customers. Furthermore, AARP states that the process for designing and measuring PBR is more difficult than the current cost of service system.

AARP states that few lessons can be learned from other states because few states have actually implemented PBR: the Maryland Commission rejected the use of formula rates, while Minnesota and Hawaii are still in the process of developing PBR. AARP participated in a recent rate case in Washington, D.C., questioning the benefits of PBR and pointing out the risks to affordability.

b. Advanced Energy Economy Institute (AEE Institute)

AEE Institute is a charitable organization with a mission to raise awareness of the public benefits and opportunities of advanced energy; it is affiliated with Advanced Energy Economy, a business association whose purpose is to advance and promote the common business interests of its members, which comprise more than 100 companies across the technology spectrum, as well as purchasers of advanced energy technologies and services.

AEE Institute encourages the Commission to enhance the existing regulatory model through PBR so that utilities are rewarded for providing the most valuable and cost-effective solutions for customers and are afforded opportunities to achieve sustainable and long-term business health. AEE Institute states that PBR offers an opportunity to introduce flexibility in utility regulation so that the utility can better adjust to changing conditions. Furthermore, if PBR is properly implemented, the utility will be rewarded for taking action consistent with state policy rather than having cost recovery wholly dependent on fixed costs and a revenue requirement that is subject to outside pressures, such as COVID-19. AEE Institute recommends that the Commission focus not on problems within the current system, but instead look to create a regulatory structure designed to achieve future regulatory objectives.

AEE Institute suggests that the Commission take a holistic approach to the investigation of PBR and apply a four-step process: 1) adoption of definitions of PBR, including goals, outcomes, and metrics; 2) agreement on the goals and objectives for PBR; 3) agreement on outcomes and measurement for those outcomes; 4) identification of financial incentives attached to outcomes and other mechanisms to encourage achievement of prioritized outcomes and offset lost revenues. AEE Institute provides a detailed explanation of how this proposed process can be implemented and encourages the Commission to do so in a follow-on to the present investigation.

AEE Institute suggests that properly constructed PBR will decrease customer costs in the long run and that the benefits of moving to PBR generally outweigh the costs. Furthermore, the organization advocates MYPs, stating that these have been successfully implemented in other jurisdictions and encouraging the Commission to consider implementing MYPs in Colorado, using PIMs to offset any unintended consequences. For customer service, AEE Institute encourages inclusion of DER interconnection and DSM participation; equitable access through reduced barriers to clean energy options.

AEE Institute notes that the COVID-19 pandemic has shifted energy use from commercial to residential and has caused widespread employment losses, highlighting issues of utility cost recovery, particularly fixed cost recovery, through traditional COSR. AEE Institute states that PBR allows flexibility for utilities to react to situations such as the current pandemic.

AEE Institute agrees with Public Service that peak shaving is a prime candidate for PIMs to incentivize cost efficiency and agrees with Black Hills that the treatment of utility expenditures on information technology and software should be further evaluated.

With regard to DER, AEE Institute states that the current regulatory system acts as a disincentive to utility investment because DER represents foregone earnings opportunities. Furthermore, utility stranded assets resulting from DER deployment and technology obsolescence will increase under COSR, but can be mitigated through PBR. AEE Institute agrees with other stakeholders who call for coordination of DSP, renewable energy standard planning, and ERP planning processes, as well as securitization, accelerated depreciation, and other methodologies that would encourage early retirement of stranded assets.

c. Atmos Energy

Atmos Energy (Atmos) is a natural gas distribution utility serving approximately 120,000 customers in Colorado.

Atmos states that policy goals are the best starting place rather than PIMs or PBRs, especially for smaller utilities. Atmos cautions that PIMS should not measure factors beyond a utility's control and that PBR and PIMs should be combined with COSR. As a small gas distribution company, Atmos encourages the Commission to avoid a "one-size-fits-all" approach to any PBR and notes that electric and gas utilities have some fundamental differences that dictate different approaches when considering performance-based metrics.

Atmos suggests that "net beneficial" should be considered in the context of customer bill impact, comparing costs under COSR and the effectiveness of current regulatory ratemaking. With regard to MYPs, Atmos recommends adoption of a comprehensive annual rate mechanism (ARM), such as is used in Tennessee. The ARM requires an annual true-up of actual revenues and expenses to ensure that there has not been over- or under-recovery of authorized rate-of-return.

d. Black Hills Energy

Black Hills Energy comprises Black Hills Colorado Electric, LLC; Black Hills Colorado Gas, Inc.; and Rocky Mountain Natural Gas LLC.

With regard to safety, reliability, and customer service, Black Hills notes that no commenters identified specific problems that PBR could address. However, Black Hills notes that with clear objectives, PBR offers an opportunity for innovation through price signals sent to utilities to meet public policy goals and improve operational performance. Black Hills states that COSR has been successful for more than a century and that movement away from COSR should be undertaken carefully, deliberatively, and incrementally.

Black Hills states that a PBR process must identify desired outputs that could be achieved through metrics and that the outputs should be analyzed to determine whether incentive, penalty, or both are appropriate. Additionally, the creation of metrics should include: clarity, use of reasonably available data, avoidance of unnecessary administrative costs, items that are within the utility's control, focus on long-term results of the policy goal, and focus on averages, not individual instances.

Black Hills recommends that metrics be specific to utilities, not applied universally, with recognition of utility size, resource, geographic, and customer demographic differences.

e. Colorado Energy Consumers (CEC)

CEC's membership comprises industrial and commercial customers of Public Service. For this proceeding, CEC's membership includes: Airgas USA, LLC; Denver Metro Building Owners and

Managers Association; Lockheed Martin Corporation; MillerCoors; Suncor Energy (U.S.A.) Inc.; and Western Metals Recycling.

CEC states that currently, nothing suggests that COSR is insufficient or is producing unsatisfactory results, noting that statutes require utilities to provide safe, reliable service at just and reasonable rates without additional PBR mechanisms and incentives. CEC states that its members, who are among the largest economic engines in the state, depend on this.

Therefore, CEC holds that wholesale restructuring of the current regulatory construct in Colorado is unnecessary; CEC expresses concern that a sweeping movement away from the COSR model would erode the foundational core of public utility regulation. CEC states that the protection and furtherance of this core must be prioritized. CEC commends the Commission for keeping Colorado at the forefront of energy transition, including promoting a transition to a lower-emitting resource mix and development of advanced technologies, while ensuring reliable service at just and reasonable rates. CEC states that any PBR mechanisms should be considered on a limited and targeted basis, with demonstrable net measurable and tangible benefit to all ratepayers. CEC recommends a holistic approach to implementing PIMs and suggests that PIMs transfer funds from ratepayers to shareholders.

Noting that the utilities and consumer groups participating in this proceeding agree that COSR is sufficient, CEC questions recommendations to move to a comprehensive PBR regulatory structure. CEC takes particular exception with the suggestion that the Commission should move from the "used and useful" requirement for regulatory cost recovery. When considering "net beneficial," CEC encourages the Commission to consider not only the potential improvements in specific metrics but also be cognizant of the risk of harming Colorado's regulatory success. Furthermore, CEC holds that the Commission should not look to other states that are pursuing PBR to help define net beneficial, but should focus on Colorado's specific regulatory environment. CEC also states that while MYPs and FTYs have the potential to reduce costs, they are also complicated mechanisms that could increase regulatory burden and shift risk and costs to ratepayers.

With regard to DER, CEC acknowledges the potential to improve utility service and reduce generation, transmission, and distribution infrastructure investment, but states that since improved service and reduced infrastructure costs are public utility objectives, utilities should not be rewarded with incentives that encourage what they already should be doing. CEC states that DERS should not be incentivized unless they are proven to be more cost-effective than other options. Furthermore, CEC states that the Commission must consider the impact on ratepayers of both the return on investments and that on new investments and proposes cost-mitigating measures such as securitization.

Finally, with regard to the concept of allowing a return on operations expenditures or using a totex accounting approach to address capital bias, CEC states that because this would be such a departure from COSR it would warrant extensive investigation and analysis.

f. Colorado Energy Office (CEO)

CEO is a state agency with the mission of reducing GHG pollution and consumer energy costs by advancing clean energy, energy efficiency, and zero-emission vehicles to benefit all Coloradans. CEO is statutorily charged with sustaining Colorado's energy economy and promoting all Colorado energy, as well as promoting energy efficiency, increasing energy security, lowering long-term consumer costs, and protecting the environment.

CEO notes the PIMs that have been implemented by the Commission and states that these have shown how PBR can be used to align utility financial interests with public policy. CEO further suggests that the Commission build on the PIMs that it has implemented individually and move toward a full implementation of PBR, including setting performance metrics that align with the State's goals for GHG emission reductions, encouraging the growth of DERs, and ensuring that customers have an opportunity to participate in and benefit from the energy transition.

CEO recommends the Commission review state policy goals or outcomes for which COSR does not create an incentive, then establish metrics for each outcome, including the level of desired performance. CEO suggests that as the Commission revises its Electric Rules and considers DSP and utility TEPs, it is the appropriate time to determine the desired outcomes for utilities and to develop baselines from which future performance can be assessed.

CEO recommends that emissions reduction be a specifically identified output in this investigation and also recommends that customers be the focus of at least one performance-based output. With regard to customers, CEO offers potential metrics associated with customer satisfaction, such as disconnections and delinquencies, customer call response rates, complaints, appointments, and outage responses. In addition, CEO proposes that customer access to and benefits from the energy transition are important considerations. CEO further recommends affordability as an explicit component to this output that includes income-eligible programs and services, retail customer rates and charges, and direct utility bill impacts for customers from DSM, distributed generation, and other DERs. For this output, metrics could be developed associated with utility bill stabilization or reductions through savings passed through by utilities or through direct DER access.

While stating that it does not see COSR structure as irreparably broken, CEO notes that it is inherently retroactive, considering capital or operations expenditures after they have been incurred and deemed used and useful. This leads to regulatory lag, which challenges innovative policies or forward-looking technology changes. In addition, the requirement that facilities be "used and useful" can create a barrier to utilities' willingness to commit capital spending to innovative projects. COSR also does not permit prospective financial planning for new plans and processes, such as transportation electrification and DSP, through its use of an HTY. Consequently, COSR emphasizes large capital spending, while policies that seek to manage revenue or encourage prospective planning would better thrive under a performance-based model. CEO suggests the parties' and Commission's analyses focus on how the current hybrid structure can change and evolve in response to a rapid energy transition that does not necessarily align with new technology and State policies.

CEO notes that net beneficial is not defined in statute, but CEO suggests that it requires a qualitative assessment, not a quantitative analysis. CEO proposes the following questions: (1) Does the current cost of service framework provide the best support for evolving State policy? (2) Would a performance-based framework better allow the Commission to align utility cost-recovery with State policy? and (3) Does a performance-based regulatory framework help preserve the goals of the regulatory compact in an ever-changing policy and technology landscape?

To answer these questions, CEO believes the Commission should define its objectives, then consider statutory requirements and policy goals including the RES.

CSG requirements, the requirement to establish energy savings and peak demand reduction goals, transportation electrification, and GHG pollution reduction goals.

In considering goals for regulation, CEO suggests that the Commission should consider its own rules: Rule 3601 addressing minimization of net present value of revenue requirement and cost-effective implementation of new clean energy and energy-efficient technologies in ERP; Rule 3611, addressing cost effective acquisition of resources; and Rule 3651 encouraging local ownership of renewable energy generation facilities.

g. Karey Christ-Janer

Karey Christ-Janer is an independent advocate in Colorado and California with a focus on renewable energy programs and utility business model reform.

Christ-Janer sees optimal deployment of DERs as tied to safety, reliability, and customer service. As such, she maintains that PBR is appropriate to address disincentives to the deployment of non-traditional technologies. She notes that the California Commission has opened an Integrated Distributed Energy Resources Proceeding through which the investor-owned utilities implement DER deployment with regulatory incentive, and encourages Colorado to do the same. (She provides the California Commission's 2016 filings that address this proposal.)

Additionally, Christ-Janer encourages the Commission to consider energy storage, which can provide grid resiliency, referencing Public Service's recent Community Resiliency Initiative Application (Proceeding No. 19A-0225E). She suggests that a variety of performance-based incentives could be explored for deployment of DERs.

With regard to cost-effectiveness, Christ-Janer states that PBR measures should include an exploration of avoided costs for DERs. Furthermore, she states that any PBR rulemaking principles would feature a provision that the definition of cost-effectiveness would include premium or incentive costs such that DER+incentive measures generally would meet the cost of traditional infrastructure, or beat that cost, including the incentive.

h. Colorado Natural Gas (CNG)

CNG is a natural gas distribution company serving communities in South and Central Colorado.

CNG states that COSR supplemented by certain PBR mechanisms is working well for utilities and for their customers. CNG also states that advocates for a change in the current regulatory construct are seeking to accelerate DER deployment for electric utilities and recommends that if PBR is to be implemented it should be done for electric utilities while keeping gas distribution utilities under COSR.

With regard to MYPs and FTYs, CNG suggests that these mechanisms are less about PBR and more about streamlining the rate-making process to reduce regulatory lag. CNG states that because it does not have frequent rate cases, MYPs and FTYs are not a great concern, although it would consider them, and that the cost of ratemaking for CNG is a non-issue.

CNG further points out that because parties can advocate for their individual interests in a litigated proceeding, utilities have a strong incentive to manage expectations of revenue recovery and rate-of-return.

CNG states that COSR has been sufficient for the current ERP and RES processes. CNG suggests that an appropriate initial step in encouraging DER deployment could be to consider DER in the RES review context rather than by modifying the entire regulatory construct.

CNG states that considerations of cost/benefit are important if the Commission is considering PBR. Specifically, CNG questions if the cost of a regulatory structure change can be justified; how the benefits of a regulatory structure can be measured; and how customers can measure if they are better off.

CNG points out that jurisdictions that have undertaken more extensive PBR methods do not have long track records from which to determine that the change is worth the cost of doing so or makes a difference. CNG concludes that while the switch to PBR may be aspirational in some jurisdictions, it is not yet necessarily measurable.

i. Colorado Solar and Storage Association (COSSA), Solar Energy Industries Association (SEIA), and Vote Solar

Note: Some rounds of comments were submitted by COSSA and SEIA only, while some were provided by all three parties as the Joint Solar Parties

COSSA is a Colorado nonprofit association whose mission is to expand solar markets and generate jobs in Colorado. SEIA is a national trade association working for policies that promote competition and growth of reliable, low-cost solar power. Vote Solar is a national organization dedicated to making solar power more accessible and affordable.

COSSA/SEIA encourage the Commission to recognize this proceeding as an opportunity to investigate how the regulatory paradigm can evolve to align utility operations and financial incentives with public interest goals. COSSA/SEIA state that the current regulatory compact

has provided utilities with a significant competitive advantage that should be evaluated as part of this investigation. Furthermore, COSR creates inherent financial biases and incentives for utility capital expenditures that exclude non-utility owned assets and services that could otherwise provide customers service at lower cost. COSSA/SEIA state that PBR provides an opportunity to restructure utility incentives and profit motives.

COSSA/SEIA state that information and communication technologies, solar and other renewable generation, storage, financing, and energy service models can all be provided by third-party service providers at competitive cost and performance measures, but are dependent on a market environment that offers them a fair opportunity to compete with utilities. However, utility capital bias insulates some traditional utility functions from competitive market providers, hindering innovation and third parties' abilities to drive down costs.

COSSA/SEIA envision a fully-functioning PBR framework that could manifest through the evolution of the utility business model. COSSA/SEIA describe a "platform service model" under which the utility would be responsible for providing network services and value to the overall power system, while supporting provision of services from third parties to customers. Utility earning opportunities would include investments in distribution and other infrastructure, core utility functions in operating the grid, and revenues from services it provides to third parties. Examples of utility platform services include interconnection, hosting capacity analyses, billing services, facilitating data collection, and providing data to customers and certified third parties. Third-party services and providers include generation services, information and data technology, and DER developers and aggregators.

COSSA/SEIA see DER expansion as an unparalleled opportunity to leverage the capabilities of DERS to achieve other public goals. Thus, designing PBR mechanisms to align utility financial incentives with achieving public benefit goals should consider how these mechanisms can be employed to foster sustainable DER markets.

The Joint Solar Parties filed comments stating that the Commission should broadly investigate PBR in this proceeding, including a full assessment of PBR's role in the evolving public utility regulatory environment. They further state that the report must consider benefits of a shift in the regulatory model and should solicit stakeholder feedback to define the desired outcomes, examine performance-based mechanisms that can better align utility operations, expenditures, and investments with achieving those goals, and provide recommendations for implementing the findings. The Joint Solar Parties go on to state that the regulatory mechanisms deployed to incentivize the utility to achieve public interest goals are in fact incentives aimed at changing the utility business and regulatory model to align with public benefit goals. They state that one example is to incent the utility to achieve more cost-effective operations and investment decisions and operational changes, to facilitate the expansion of DERs and hold that the role of PBR therefore cannot be separated from the issues implicated by the evolving utility business model and public utility regulatory environment.

Furthermore, the Joint Solar Parties state that the Commission's legislative report should find that a shift to PBR will provide net benefits to Colorado and state that PIMs are insufficient to achieve public interest goals. The Joint Solar Parties offer four reasons for fundamental changes to Colorado's regulatory structure: 1. Utilities are not currently rewarded for achieving

societal outcomes such as GHG reductions; 2. Traditional regulation biases utilities toward capex, when opex might be lower cost; 3. Utilities are not well motivated to become more efficient, due to the relatively short revenue control period and the “cost-plus” aspect of COSR; and 4. Utilities need new regulatory flexibility to develop a new business model and transform themselves in response to changing customer demands.

The Joint Solar Parties encourage the Commission to move from the traditional methodology of determining revenue requirement, which involves evaluation of investments, expenses, and cost of capital, which the Joint Solar Parties state cannot adequately determine the utility’s efficiency in decision making. Instead, the Joint Solar Parties advocate a method more closely aligned with competitive markets in which firms are pushed to minimize cost and provide maximum service. Toward this end, the Joint Solar Parties recommend a revenue or price caps, which will remove investment bias and allow the utility to select a least-cost approach. The result is favorable to non-wire alternatives. Furthermore, the Joint Solar Parties state that revenue cap regulation will address a utility’s concerns about losing earnings opportunities.

The Joint Solar Parties acknowledge that “there are many details to be worked out before a regulator can implement revenue cap regulation,” but hold up Hawaii as an example of a state that is moving from rate-of-return regulation.

j. City and County of Denver (Denver)

Denver supports a move away from COSR and encourages an evaluation of utilities’ capex bias against DER expansion. Denver further states that it is necessary to align utilities’ earning opportunities with achieving public interest goals, with PBR to incentivize the most cost-effective solutions for the electric system.

Denver states that under a well-designed PBR system, utilities will be provided the opportunity to earn fair compensation based on a business model aligned with the public interest. Denver encourages exploration of revenue adjustment mechanisms (RAMs) and PIMs for DER asset effectiveness in Colorado. With the adoption of an appropriate set of RAMs and PIMs, utilities can be rewarded for delivering outputs, such as achieving public benefit goals, rather than delivering inputs, such as capex. Denver states that this regulatory framework shift is necessary to create value for utility shareholders and cost savings for customers.

Denver disagrees with the notion that DERs have limited ability to reduce overall system costs and recommends that PBR metrics should include a holistic accounting of the costs and benefits of DERs.

Denver states that its aggressive decarbonization objectives require utility planning, resource procurement, and grid operations that offer viable market participation by DERs. Therefore, appropriate incentives and compensation will encourage customer participation in and utility management of NWAs and DER aggregation programs, particularly if beneficial electrification is to benefit the grid.

Denver requests that the report the Commission submits to the General Assembly on PBR include a recommendation that future proceedings to implement a comprehensive PBR framework consider the inclusion of "Clean Energy Peak Standard" under which a utility would have a clear financial incentive to choose the lowest cost solution to meet a certain percentage of retail utility seasonal peak electricity demand with qualified clean peak resources.

k. Delta-Montrose Electric Association (DMEA)

DMEA is a nonprofit electric distribution cooperative that serves communities in Delta County, Montrose County, and portions of Gunnison County. DMEA is a public utility under § 40-1-103(2)(a), C.R.S., but through a vote of its member-owners it has exempted itself from Commission regulation. Although DMEA is a non-jurisdictional electric cooperative for purposes of Commission regulation, it notes that any framework created for regulated utilities could, directly or indirectly, have consequences for electric cooperatives like DMEA.

DMEA recommends that an incremental, multi-year trial period would be advisable for exploring PBR in Colorado. DMEA further provides detail as to how it has addressed the public interest goal of reliability, and the risk posed by wildfires in its service territory. Additionally, DMEA provides comment on dispatch and reliability standards to improve safety and system reliability, and the importance of planning metrics to forecast future system needs. DMEA notes that these metrics are beneficial to DMEA's operations and may be helpful as the Commission continues its data-driven investigation. DMEA also implements specific safety metrics and protocols that could be explored in this PBR docket.

L. Senator Chris Hansen

Senator Hansen provided comments emphasizing the need to consider policy goals to decarbonize the electric power sector, stating that the larger question is, If de-carbonization is to be achieved, what investments need to be made and who should make those investments? Senator Hansen states that other jurisdictions have seen rapid de-carbonization through partnership between all market players. Senator Hansen states that Colorado has only one chance at de-carbonization and encourages the Commission to look broadly at the utility business model and ensure that it is designed to meet Colorado's climate change policy goals.

m. Institute for Policy and Integrity at New York University School of Law (Policy Integrity)

Policy Integrity is a nonpartisan think tank dedicated to improving the quality of government decision making through advocacy and scholarship in the fields of administrative law, economics, and environmental policy. Policy Integrity notes that its comments do not necessarily represent the views of New York University.

Policy Integrity states that the value of a given DER is the net benefit it provides relative to the costs that would otherwise be incurred to perform comparable functions. Measuring that value requires specifying an analytical perspective; identifying, quantifying, and comparing benefits and costs; and ensuring that the evaluation of benefits and costs accurately reflects how the DER performs in its particular circumstances. Policy Integrity provides a description of these

key components of value measurement and suggests steps to translate the concepts into quantified and monetized values.

Policy Integrity encourages the Commission to consider metrics and analytical steps as it considers DER valuation. Policy Integrity provides examples of metrics from states including New York, Minnesota, and California, but cautions that these metrics would likely require adjustment to Colorado's unique circumstances. They do, however, provide examples of the approaches taken by other jurisdictions. Metrics include transmission system costs that DERs can potentially defer or wholly avoid such as congestion, line losses, and upgrades or capacity additions; estimates of the transmission capital and operational costs; costs avoided by community-scale, and rooftop solar installations.

Policy Integrity states that properly valuing DERs includes consideration of the material quantities of GHG emissions and local air pollutants that they avoid, and recommends that the Commission encourage the appropriate monetization of pollution costs and benefits and calculate the marginal emissions rate for each generation source.

n. Laborers' International Union of North America Local 720 (LIUNA)

Laborers Local 720 has approximately 1,800 members in Colorado. Local 720 is an affiliate of the Laborers' International Union of North America, the eighth largest labor organization in the United States. LIUNA members work in multiple sectors of the construction industry, including building, gas distribution, highway, water/sewer, asbestos abatement, and power.

LIUNA's members work for major utility contractors and are on the front lines of building Colorado infrastructure and modernizing Colorado's energy facilities.

LIUNA states that PBR should be guided by seven principles: 1) Rates should be aligned with Colorado's social, environmental, and economic justice goals, and while supporting the State's energy agenda and strong labor policies; 2) Rates should spur responsible capital investment to modernize the grid, while creating family-supporting jobs with tracking to measure wage and benefit quality in the renewable energy sector; 3) Wage and benefit levels on solar and wind farms should equal or exceed jobs in the fossil fuel sector, with an emphasis on hiring Colorado residents; 4) Ratemaking should provide for transparency of a utility's labor practices (*i.e.*, safety metrics) for its in-house and contracted workers, to assure compliance with state and federal employment laws, and worker safety and health regulations; 5) Rate methods such as ESMs that incent utilities to cut costs should not be approved without strong labor protections; 6) Rates should be designed in a deliberate and transparent manner that includes community stakeholders, labor unions, consumer advocates, utilities, local governments, and legislators; and 7) Performance based rates that move Colorado more aggressively to the clean energy economy must not leave workers behind. Incentives that create union jobs in this sector should be rewarded. Utilities should be penalized for creating low wage jobs in this sector through their supply chains.

o. Mission:data

Mission:Data is a national coalition of approximately 30 technology companies that represent over $1 billion per year in advanced energy management services, providing consumer-focused energy services.

Mission:data states that its services, such as DER aggregation, smartphone applications for home energy management, and advanced demand response systems are generally created by third-party entities, not utilities, thus the Commission must provide non-utility entities opportunities to work with utilities if Colorado is to achieve its emissions reduction goals.

Furthermore, Mission:data states that the siting and operation of DERs such as energy efficiency, rooftop solar, battery storage, and demand response all require digital access to customer-authorized energy data such as usage and historic bills, so customers must be able to allow third-party access to this information.

Mission:data notes that Public Service agreed to implement Green Button Connect (GBC) in 2020 in a settlement agreement in Proceeding No. 16A-0588E, but has moved that date to 2021. Mission:data states that without an electronic method for accessing energy data, most DERs must manually transcribe paper bills. Mission:data holds that if automation is correctly done, cost-effective DERs can thrive. Therefore, Mission:data proposes that a portion of utility earnings should be tied to data portability performance. To this end, Mission:data proposes metrics related to customer application timing, data delivery time, system availability, data accuracy, issue resolution, and complaints that apply to Public Service's GBC platform. Mission:data also proposes that an annual report be required. Mission:data cites California, New York, and Texas as states that have appropriate technical standards for GBC.

p. Colorado Office of Consumer Counsel (OCC)

OCC is a state agency statutorily charged with representing the public interest, as well as the specific interests of residential, agricultural, and small business consumers in matters before the Commission.

OCC notes that Hawaii and New York have undertaken regulatory reform and have begun shifting toward PBR. OCC notes that Colorado has also implemented PIMs to supplement COSR, in order to keep prices close to or below the national average, while achieving significant reductions in GHGs, significant growth in renewable generation, an uptick in residential self-generation, growth in EV adoption, and maintaining highly reliable, adequate, and safe services for its energy providers.

OCC states, however, that Colorado differs significantly from Hawaii and New York, as Colorado's environmental policy is nation-leading. This has been done within a COSR/PBR hybrid regulatory structure. It is this hybrid, OCC contends, that has given the Commission a broad range of tools to meet the public interest, achieve policy goals, drive utilities to voluntarily adopt nation leading carbon reduction goals, and keep prices affordable.

OCC encourages the Commission in this investigation to evaluate the presuppositions of COSR and PBR, evaluating the strengths and weaknesses of each, and to determine what problems inherent in COSR could be resolved by PBR. This evaluation would allow the Commission and stakeholders to understand the net costs and benefits of PBR.

OCC reviews COSR and notes that it is a balance between monopoly power to provide safe, reliable, and affordable service to all ratepayers in exchange for the opportunity to recover prudently incurred costs and a return on assets. This relationship has largely eliminated redundancies within power systems, delivered reliable service to its customers, and avoided discriminatory rates. While COSR limits the actions of the utility, it also creates opportunities for the utility to maximize its own interest within that structure through earnings. Furthermore, because regulated utilities are profit seeking entities, they will always adjust activities to maximize their return. This is inherent in any regulatory structure in which they are engaged, whether it is COSR or PBR.

OCC contends that although COSR might seem slow to react to changing policy landscapes, it has continued to provide safe, reliable, and affordable service in Colorado and is able to adapt to significant shifts in policy while being responsive to the public interest.

OCC does not disagree that the rate-of-return formula of COSR creates an inherent bias toward inefficient utility activities and rewards capital investment, but suggests that this criticism is an oversimplification of the challenges within COSR. OCC states that it is difficult to address the inefficiencies created when compounded with a policy environment focused on decarbonization. And while a new regulatory paradigm is attractive it remains unclear if mechanisms, like PBR, would not suffer from the same or new challenges that COSR has seen.

OCC observes that COSR integrates PBR approaches to maximize efficiencies and produce outcomes that are in the public interest, as has been happening since the 1980s. OCC suggests that the question of whether the state, and by extension the Commission, should transition to PBR should be reframed as How can the Commission examine failures in COSR regulation and apply PBR principles to align regulated utility operations, expenditures, and investments with public benefit goals. OCC notes that in Minnesota, the Minnesota Commission determined that a discussion of incentives and penalties was premature and that the primary tasks to be completed were problem identification and information gathering.

q. Public Service Company of Colorado (Public Service)

Public Service recommends that financial performance-based incentives and performance-based metric tracking be considered in the context of broader utility revenue and the regulated business model, and asserts that PBR does not replace the regulatory compact's requirement that utility rates be just, reasonable, and designed to recover the utility's cost to serve and provide an opportunity to earn a fair return on prudent utility investments. Public Service contrasts PBR with COSR in terms of how the opportunity to earn a rate-of-return can be realized, noting that performance-based ratemaking should encourage innovation and flexibility while balancing reward with risk.

Public Service states that there is no need for an overhaul of utility regulation in Colorado and states that legislation does not call for such an overhaul. Public Service states that COSR in Colorado has resulted in safe, reliable, affordable energy from a system that continues to be carbon free on a grid that continues to modernize. Public Service states, that along with the Commission, it continues to move Colorado toward achieving energy policy goals.

Public Service recommends that any PIMs implemented should vary by utility because there is no one-size-fits-all solution in utility regulation. Public Service also recommends specific actions that the Commission undertake: 1) review COSR in context of achieving the public interest goals of this Proceeding; 2) establish nomenclature for PBR discussions, including a definition of PBR and PIMs; 3) establish key design principles as a foundation for PBR evaluation; 4) acknowledge and consider potential pitfalls of performance metrics; and 5) reaffirm that the purpose of this Proceeding is to review ratemaking with regard to regulated utility services, and not to reevaluate the larger regulatory construct.

Design criteria should include clear policy goals and metrics that are clearly defined, quantifiable based on available data, free from external influences, easily interpreted, easily verified, and complement and inform evaluation of utility performance. Public Service identifies pitfalls associated with performance metrics as unintended consequences, regulatory burden, uncertainty, and disproportionality (*i.e.,* rewards or penalties that are too high relative to customer benefits or utility costs).

Public Service asserts that it has been shaping its generation fleet for more than a decade, anticipating evolving customer requirements and transitioning to cleaner energy sources. Public Service cites the CACJA in 2010, the Our Energy Future initiative in 2015, and the Colorado Energy Plan in 2017. Public Service also notes that the Rush Creek Wind Project, a 600 MW wind project in eastern Colorado, brought more than $1 billion of capital investment to Colorado, and state that its AGIS initiative will enhance security, efficiency, and reliability.

Public Service also notes that it is already required to report on its performance including QSPs, electric DSM programs, electric trading margins, and construction cost savings sharing.

With respect to customer service, Public Service states that it is in JD Power’s top nation quartile of large utilities in residential customer satisfaction on “actions to take care of the environment,” and in the second quartile for customer service and corporate citizenship. Public Service cites is 2016 Renewable*Connect offering that responded to customer interest in clean energy and carbon reduction options. Renewable*Connect complements the WindSource and Solar*Rewards programs. Further, in January 2020, Public Service implemented a rate for large, non-residential customers for EV charging.

Public Service acknowledges that there continues to be opportunities for it to improve, but advocates a cautious approach in order to avoid jeopardizing progress that has already been made in terms of grid modernization, clean energy transition, carbon reductions, and beneficial electrification.

Addressing cost efficiency, Public Service contends that riders or MYPs should not automatically result in lower authorized returns, citing the legal precedents for fairness and reasonableness of authorized returns established in *Hope* and *Bluefield*. Furthermore, the utility's need for capital investment to fulfill its obligation to serve and the opportunity to earn a fair return are the underlying reasons for investigation of PIMs and performance-based metrics within the context of the broader utility revenue and regulated business model.

Public Service states that 9 percent of its total electric retail customers participate in some form of renewable customer choice program, many of which are DERs. Public Service asserts that the expansion of on-site solar systems and CSGs could expand both equitably and rapidly if policies supporting these programs are realigned to incorporate cost neutrality and equity across all parties, and cost effectiveness relative to other forms of generation.

Public Service states that momentum behind the adoption and siting of DERs will not only support personal customer choices but lead to a more robust electrical grid that expands the benefits more broadly to participants and non-participants alike. There are two pathways with respect to the application of PBR to DERs. PBR could be applied to the current policy structure in an attempt to "bandage" its flaws, or it can be applied to a more solid policy foundation where past policies are revamped in an effort to drive the adoption of DERs where disincentives are eliminated and customers benefit. Public Service suggests that the latter is necessary to establish improved policies with the aim of delivering more value to all.

R. R Street Institute

R Street is a nonprofit, nonpartisan, public policy research organization whose mission is to engage in policy research and outreach to promote free markets and limited, effective government.

R Street states that as the electricity system becomes cleaner and more distributed, one implication is that customers will take more control over their electricity usage by using equipment and resources from entities other than the regulated monopoly utility. This has an impact on COSR, which R Street states is no longer sustainable. R Street suggests that an appropriate question for the Commission is "What comes after COSR?"

R Street sees growing DER as evidence of competition in the electric utility environment, which calls into question the fundamental tenet of COSR, monopoly power of the utility. R Street recognizes the important role the distribution system will and must play in the evolution occurring across the industry, and states that the existing monopoly structure is not best suited to realize these benefits once the evolution occurs. By focusing on the growth of DER and how to best extract the value of DER, there is a need to change the COSR model to one based on true performance that puts the monopoly in a position that does not favor its own resources over those of others.

R Street is an active party in that PBR proceeding in Minnesota and states that the proceeding lacks certainty as to whether the collected metrics will be used to implement a PBR mechanism. Furthermore, the Minnesota Commission has given no sense of whether it will truly implement or consider a PBR mechanism. R Street states that it is not opposed to a metric collection

effort on a standalone basis and recommends that the Commission be clear on the purpose of the metric collection effort. However, as the Minnesota process shows, there are many existing and potential metrics of interest to stakeholders but it is unclear to what extent those metrics can or should be leveraged to develop the detailed metrics necessary for a PBR mechanism or the adoption of PIMs. R Street encourages the Commission to consider as few metrics linked to PIMs as possible.

Based on R Street's participation in the Minnesota proceeding, R Street recommends that the Commission include in this investigation the gathering of additional input on the feasibility of the current COSR model for Colorado, including a determination as to whether the current monopoly structure will meet the goals of the state.

R Street also notes that this proceeding is one of several the Commission has opened in response to legislation passed in 2019 looking at future-oriented electricity topics, which include GHG emissions reduction, beneficial electrification, and growth of DER. R Street recommends that the Commission consider developing some guidance or a report on how these proceedings are being organized and aligned. Goals from this proceeding should align with any goals or principles adopted by the related proceedings. Development of goals and outcomes, with a recognition that this proceeding is not operating inside a vacuum, will greatly assist stakeholders and help align the process here with processes in other proceedings.

S. Rocky Mountain Institute (RMI)

RMI is an independent, nonpartisan nonprofit organization that engages businesses, communities, institutions, and entrepreneurs to accelerate the adoption of market-based solutions that cost-effectively shift from fossil fuels to efficiency and renewables.

RMI states that PBR, along with other reforms the Commission is implementing in other proceedings, offers an important tool for aligning Colorado policy goals with electric and gas utility business incentives. RMI has worked on PBR efforts in other states and has found that stakeholder engagement and collaboration is necessary in the process of considering PBR reforms and in process design. RMI calls on the Commission to produce timely and clear guidance in order to maintain focus on key objectives, particularly related to the public policy benefit goals of safety, reliability, cost efficiency, emission reductions, and expansion of DER.

RMI states that while PBR can be used to address traditional facets of the utility business, additional outcomes, such as clean energy deployment, resilience, and public health should also be considered; traditional regulation might not adequately address these outcomes and RMI suggests that the Commission should ensure that appropriate attention is given to these new outcomes as well.

RMI notes that PBR implementation will be more successful if it is developed and evaluated through a holistic, system-oriented approach. Furthermore, it is important to consider PBR in the context of existing regulatory and other policy or business incentives, in order to design and implement changes that are compatible with other utility regulations and policy, such as DSP, ERP, and regional power market participation. RMI suggests scenario planning and analysis to augment the process.

RMI suggests that a combination of various types of metrics, including outcome-based metrics, could be appropriate for tracking, but asserts that metrics alone are likely insufficient to motivate a significant positive change in utility performance toward outcomes. Therefore, metric should be linked to targets and be accompanied by financial rewards or penalties. RMI further states that aligning on priority outcomes for utility regulation is an important initial step that can enable constructive stakeholder input and provide a foundation for the Commission's general determination of whether a transition to PBR is net beneficial.

As a point for discussion in this proceeding, RMI provides an illustrative framework showing how example outcomes and metrics can address the public interest goals articulated in § 40-3-117, C.R.S. RMI notes, however, that a more complete review of applicable regulatory mechanisms for achieving each outcome will be necessary, not just a focus on metrics and PIMs. RMI also recognizes that priority outcomes may vary between electric and gas,

RMI suggests that the Commission, in developing its report, identify priority outcomes, compare available approaches to address each priority outcome, consider PBR approaches that might be used to achieve each priority outcome, and assess how the regulatory approaches might interact if implemented together.

RMI states that PBR provides an opportunity to consider the type of utility and regulation that are necessary in light of evolving public policy goals and technological capabilities, with consideration of appropriate cost control and risk sharing between the utility, customers, and stakeholders. The fundamental purpose of PBR is to better align utility incentives with customer and societal interests in order to improve outcomes, and a well-designed PBR framework can substantially reduce customer costs, among other benefits.

T. Sierra Club

Sierra Club expresses concern about Colorado's uneconomic generating assets and states that COSR creates disincentives for utilities to review and modify the use of their existing power plant fleet to ensure all plants remain cost-effective throughout their operation. Sierra Club warns that there is an urgent need for the Commission to update its regulation of electric utilities. Specifically, Sierra Club states that because the continued operation of uneconomic plants is inconsistent with a cost-effective resource plan, this leads to higher than necessary revenue requirements and customer costs. This is inconsistent with the State's energy policy goals. Sierra Club urges the Commission to pursue PBR mechanisms that ensure the cost-effectiveness of utilities' existing generating units, and suggests that a well-designed PBR framework could motivate utilities to reassess the cost-effectiveness of plants on a timelier basis.

Sierra Club proposes several issues for stakeholder discussion, including using PBR mechanisms to deliver net benefits to customers in service quality, cost efficiency, fair risk allocation, and achievement of energy policy goals; MYPs that include revenue caps and are modified by ARMs; and PIMs for uneconomic generating resources, utility exposure to fuel costs, shared savings mechanisms for NWAs, penalties for failure to meet interconnection standards, and rewards for exceeding energy efficiency and DSM goals.

Additionally, Sierra Club suggests that the Commission require tracking of cost of generating resources, total generation costs, capacity factor, and heat rate.

U. Walmart

Walmart states that its interest in this proceeding stems from its role as a large energy customer in Colorado, and from its company-wide renewable energy goals to be supplied 50 percent by renewable energy by 2025, and, ultimately, to be supplied 100 percent by renewable energy.

Walmart states that it does not generally support an overhaul of the current regulatory structure without compelling reasons to do so, especially because regulated utilities are already providing safe and reliable service to their customers while meeting the State's renewable energy goals.

V. Western Resource Advocates (WRA)

WRA's mission is to protect the West's land, air, and water to ensure that vibrant communities exist in balance with nature.

WRA states that in this proceeding it intends to contribute examples, research, discussion, and recommendations of regulatory mechanisms that encourage utilities to make operational and investment decisions that will result in environmental benefit and reduce environmental harm, with particular emphasis on the reduction of GHG emissions.

While policy goals related to safety, reliability, and customer service might be realized through narrowly defined incentives and penalties tied to specific metrics reporting, WRA states that achieving broader policy goals such as CO_2 emission reductions can involve multiple, complex utility investment and operational decisions. WRA suggests that the Commission consider a performance-based mechanism that links significant utility incentives, such as an ROE, to quantifiable metrics that correspond to achievement of these larger policy goals.

WRA recommends development of streamlined PBR mechanisms and tracking whenever possible. Developing an extensive list of metrics and dividing a large incentive pool into smaller parts across too many metrics may dilute the intended impact of the performance incentive.

12. STAKEHOLDER RESPONSES TO QUESTIONS POSED IN PROCEEDING DECISIONS

In each of the three decisions issued by the Hearing Commissioner requesting comments in this proceeding, parties were invited to respond to specific questions. The following is a summary of those responses; note that not all parties provided answers to the questions.

a. Reliability, Safety, Customer Service (Decision No. R19-1002-I)

Are there specific problems related to utility safety, reliability, or customer service in the State of Colorado that PBR is well suited address?

AARP is unaware of any problems that need to be addressed by PBR or PIMs.

AEE Institute recommends financial incentives only become available to utilities above some established baseline of performance and suggests measures beyond traditional metrics such as call-center wait times to also look at DER-related metrics such as timeliness of processing interconnection request or customer participation rates in utility DSM programs. AEE Institute also strongly encourages the Commission to use PBR to drive outcomes related to system-wide metrics such as peak demand reduction, increased energy efficiency, and GHG reduction. When PBR is used to unlock efficiencies in utility operations that would not otherwise be discovered in the regulatory process, PBR delivers its greatest potential to customers.

Atmos Energy Corporation believes that the issues of safety, reliability, and customer service can and have been successfully addressed using existing regulatory tools, including: the Commission's review of utility expenditures in rate cases; Commission review of customer protections in tariffs; Commission adjudication of customer complaints, both formal and informal; and Commission oversight and active monitoring of safety. Atmos also states that there must be a continual balancing of any benefits achieved with the costs incurred.

Black Hills agrees with other commenters that have identified traditional cost of service ratemaking as effective for over 100 years in ensuring safe and reliable services with just and reasonable rates, and therefore any movement away from that approach should be undertaken in a careful, deliberate, and incremental manner. Black Hills asserts that no specific problems have been identified but suggests utility resilience related to wildfire mitigation and vegetation management programs, as well as promoting cybersecurity defense and customer transparency into the usage data should be addressed through PBR/PIMs.

Colorado Energy Consumers (CEC) notes that its members are all electric customers of Public Service and are among the largest economic engines in the state and that while PBR mechanisms may be useful and appropriate to achieve certain targeted policy goals, at this point there is nothing to suggest that the Commission's traditional use of cost-based regulation is insufficient or producing unsatisfactory results. CEC encourages the Commission to ensure that any implemented PBR mechanism is necessary for a defined purpose and results in a net measurable and tangible benefit to ratepayers.

Colorado Energy Office (CEO) lists four areas for PBR investigation: 1) GHG reductions; 2) DERs and competition; 3) affordability and customer benefits, noting that expanding to a broader metric will be responsive to efficient interconnectivity for DER affordability; and 4) reliability and safety. CEO states that achieving high

standards of reliability and safety should be understood as standard, rather than a behavior to be incentivized.

Colorado Office of Consumer Counsel (OCC) notes that the state's utilities are high performers in safety and reliability. OCC recommends the Commission develop uniform and comparable data sets across utilities to create historic trackers of data related to these topics.

Colorado Solar and Storage Association (COSSA) focuses on expanding customer access to DERs, providing transparent and usable energy data to customers and encourage the Commission to engage a third-party to study and make recommendations for integrating billing and other information systems used by utilities to gather, store and process customer data. COSSA states that utility investments in cybersecurity are critical to ensuring the reliability of the grid and should be viewed as critical infrastructure investments for which the utility may earn a rate-of-return.

Delta-Montrose Electric Association (DMEA) believes it would be beneficial for the state to collaborate with all utilities, including cooperatives like DMEA, in an effort to mitigate the risk of fire, limit liability, and improve access to vegetation management.

Laborers' International Union of North America states that utilities currently tend to address safety metrics related to their own employees but PBR could expand efforts to cover the quality of training offered to a contractor's employees.

Public Service Company of Colorado points out that measuring interruptions especially from an end-user standpoint is necessary to assess reliability. Public Service states that customer service quality metrics should seek to identify what customers want and need from their utility and then adequately measure customer satisfaction and performance on behalf of the utility. Public Service also recommends that the Commission consider proposed PIMs related to customer service in the context of comparison of utility results in comparison to national industry peers among other potential reasonable customer service measures.

Rocky Mountain Institute (RMI) states that cost-of-service regulation does not incentivize utility efforts to address modern societal expectations and needs, including exemplary customer service and innovation. RMI holds that growing concerns around risk of service interruptions or other reliability issues due to increasing severity and frequency of wildfires have prompted multiple electric utilities across the Western states to submit wildfire mitigation plans. Additionally, there are public health concerns due to air quality – particularly from ozone and health impacts from indoor natural gas combustion for heating and cooking that could be particularly acute in smaller, older residences.

Western Resource Advocate (WRA) suggests the need for NWAs for electric distribution grid reliability and resilience, DER for community resilience, and a

public safety policy concern relevant for PBR mechanisms in wildfire mitigation.

A) **Are there specific policy goals for the State of Colorado related to safety, reliability, or customer service whose achievement PBR is well suited to improve or accelerate**?

AARP urges the Commission or Legislature to survey what other states have done, stating, however, few states are actually using PBR so the data set is limited. AARP suggests that since utilities are already required to pursue safety, reliability and customer service goals, any new goals should be geared towards incremental improvements.

AEE Institute suggests Safety: cybersecurity, is increasingly as important as physical security and worker safety; Reliability: proactive outage identification and mitigation, and how the impacts of outages may disproportionately impact vulnerable communities; Customer service: regulatory framework in which customers have equitable access to services and that reduces barriers to customers participating in clean energy options.

Atmos Energy Corporation believes that maintaining or improving the metrics listed in the decision are sufficient, also referencing their experience with the SSIR program that has proven that achievement of safety and reliability policy goals can be accelerated on a cost-effective basis using constructive rate mechanisms.

Colorado Energy Consumers (CEC) states that if the Commission determines that additional PBR mechanisms are necessary or appropriate to achieve certain policy goals, such mechanisms should be narrowly tailored to achieve the policy goals and must result in ratepayer benefits that are demonstrably greater than what would have resulted from COSR.

Public Service Company of Colorado (Public Service) states that it is committed to customer satisfaction and enhancing the customer experience, and details its previous and existing PBR mechanisms, which include QSPs for gas and electric, earnings tests, trading margins, construction cost savings sharing, FTYs and MYPs, DSM incentives and equivalent availability factor performance mechanism.

Public Service also references its JD Power customer service, noting that its customer experience satisfaction program measures customer satisfaction across key customer moments such as new construction, service outage, billing and payment as well as several customer channels such as phone agents, website, mobile application, email correspondence, and new construction.

B) For any problems or policy goals identified, what regulatory options should the Commission consider in order to improve utility performance?

AARP urges the PUC to recommend goals that reduce rates and keep the utility from requesting increases.

AEE Institute offers an extensive recommendation:

Generally, the Commission could consider changes to the treatment of capital and operational expenditures, where the traditional regulatory paradigm discourages utilities from taking advantage of services that are treated as operating expenses, such as cloud computing or NWAs. AEE Institute also encourages examination of new procurement practices, moving to a process where cost-effective energy efficiency and demand response can compete with power supply options.

For safety, utilities should be measured on the safety and security of their system and ROE should be tied to safety certifications and protocols. In addition, requiring utilities to incorporate weather forecasting into their plans could also provide benefit and improve restoration efforts.

For reliability, SAIDI and SAIFI are established metrics used by utilities to measure the reliability and resiliency of the electric system, but customer average interruption duration of the number of customers experiencing multiple interruptions could prove to be a better metric. Another good metric would be to measure the speed of the restoration following an outage. AEE Institute also provided an example of Xcel Energy's proposal to the Minnesota PUC to develop an equity-reliability metric that maps reliability performance by zip code, which would help visualize whether there is geographic disparity in impact.

For customer service, many utilities gauge customer satisfaction by using JD Power surveys, however, these do not reflect the range of customer experiences hence and are not sufficient. Metrics like Net Promoter Score are beginning to be tracked and adopted within the utility industry as a more precise gauge of customer experience.

Atmos Energy Corporation (Atmos) states that if the Commission believes a utility is failing in an area, it can initiate a complaint or show cause proceeding to determine if a utility is prudently providing service. The Commission could also address these issues in rate filings or other appropriate filings made on a regular basis. However, if those proceedings prove that a utility is imprudently spending money in an area, a disallowance could be determined. Atmos holds that if a utility is simply not performing well in an area, it could be ordered to improve that metric. Furthermore, Atmos suggests that the Commission could require utilities to describe their approach to meeting specific policy goals in Phase I rate proceeding testimony, presumably the time at which the costs associated with meeting policy goals would be reviewed.

Black Hills Energy (Black Hills) did not identify problems, but recommends that the Commission focus on metrics that tie to industry-accepted standards to quantify and measure performance, including SAIDI and SAIFI. Black Hills states that it assesses risks and rewards ensuring that its actions best align in a prudent course to provide safe and reliable services. Black Hills strongly advises the Commission to avoid future PBR mechanisms that fail to fully align utility interests with chosen outcomes.

Colorado Energy Consumers (CEC) recommends that if the Commission determines that additional PBR mechanisms are necessary, such mechanisms should be narrowly tailored to achieve the policy goals and must result in ratepayer benefit.

Colorado Energy Office (CEO) envisions that each output would have one or more metrics associated with measuring a utility's performance associated with this output. CEO suggests that reliability and safety may be more appropriate for a penalty rather than an incentive.

Colorado Solar and Storage Association (COSSA) encourages strengthening requirements for utilities to track and report certain interconnection related metrics with PIMs that tie financial rewards and penalties to utility performance, offering targets and metrics, including total DERS, Customer DERS, New DERS, Capacity Constrained Interconnection, Pending Interconnection Requests, Days to Interconnect, Average Cost of Interconnection, and DER Hosting Capacity. With regard to data access and quality, COSSA recommends requiring utilities to track and report specific data requests and data response related metrics could be implemented to improve the quality of customer service and provide greater transparency. Additionally, COSSA notes that cybersecurity is a critical aspect of grid reliability and PBR could encourage utilities to advance cybersecurity protocols and technologies to protect the grid against cybersecurity risks.

Laborers' International Union of North America states that it does not support any PBR that would decrease the needed gas pipeline safety investment, maintaining that cost cutting in construction budgets could cause the utilities to find savings by lower wages for construction workers.

Rocky Mountain Institute suggests that the Commission consider shared savings mechanisms, treatment of capital and operating expenses, and accelerated retirement of uneconomic or high-emitting generation assets.

Western Resources Advocates (WRA) notes the Commission has opposed a full Lost Revenue Adjustment Mechanism for recovery of lost revenue due to utility DSM programs and that alleviating the lost revenue financial disincentive is likely to be insufficient to encourage the optimal level of energy efficiency that will benefit customers with lower bills and reduced emissions. Revenue recovery mechanisms that place operational and third-party expenditures on a more even standing with utility capital investment

b. Cost Efficiency (Decision No. R20-0127-I)

A) The statute references safety, reliability, cost efficiency, emissions reductions, and expansion of DERs as public benefit goals. Are there other specific public goals that should be considered in the discussion of PBR and PIMs?

AEE Institute believes the five statutorily public benefit goals coupled with customer service represent a solid foundation. AEE Institute also notes that the Commission does not necessarily need to map outcomes one-to-one under each policy goal, and suggests system-wide metrics may drive achievement of multiple public benefit goals, such as peak demand.

Black Hills suggests two additional public benefit goals: 1) local public policy goals of the communities served by utilities, including economic development; and 2) customer satisfaction goals, including issues related to online customer interfaces, disconnects, reconnects, and customer communication campaigns.

Karey Christ-Janer states that cost effective measures should include a comprehensive exploration of avoided costs for DERs. In addition, any PBR rulemaking principles should include a provision for definition of "cost effectiveness" as any premium or incentive cost such that such DER+incentive measures meet the cost of traditional infrastructure or beat that cost, including the "incentive".

Colorado Energy Consumers (CEC) states safety, reliability, and cost efficiency are the primary benefit goals that the Commission should consider. Goals such as emission reductions and expansion of distributed energy resources should only be pursued if they will not interfere with the primary public benefits of safe, reliable service at just and reasonable rates.

Colorado Energy Office (CEO) recommends a new metric of "reasonable rates and customer benefits" that incorporates the Commission's quality of customer service goal. This goal would include disconnections, delinquencies, customer call response rates, complaints, appointments and outage responses; customer access to DER and other clean energy resources; and affordability and utility bill stabilization.

Colorado Natural Gas (CNG) has no recommendations for additional goals but states that this investigation is useful for confirming that COSR supplemented with PBR mechanisms has adequately addressed issues regarding customer generation, safety, reliability, cost efficiency, emission reductions, and the expansion of DERs.

Colorado Office of Consumer Counsel (OCC) notes that cost efficiency is not a defined term in the statute but is similar to cost effective. OCC states that § 40-1-102(5), C.R.S., defines "cost effective" to mean having a benefit-cost ratio greater than one. OCC further states that Commission Rules 3601 and 3602 with regard to "cost-effective resource plan" as a designated combination of new resources acquired at a reasonable cost and rate impact should serve as a guide in discussing of PBR and PIMs.

Joint Solar Parties: Colorado Solar and Storage Association (COSSA), Solar Energy Industries Association (SEIA), and Vote Solar do not provide additional public interest goals, but state that changes in energy and telecommunications regulation in the U.S. have resulted from changes in industry-specific economics and changes in society's expectations for utilities and their market structure.

Public Service Company of Colorado does not propose additional goals but suggests that the Commission's objectives with regard to the public goals could be captured in specific metrics.

Rocky Mountain Institute (RMI) does not propose additional public benefit goals, stating that those already articulated are useful and appropriately inclusive to guide the investigation.

Walmart states that utilities currently tend to address safety metrics related to their own employees but PBR could expand efforts to cover the quality of training offered to a contractor's employees.

B) The statute references "net beneficial" as a metric against which a transition to performance-based metrics regulation would be appropriate. What specific component must be a part of an evaluation of "net beneficial"?

AEE Institute sees two definitions of net beneficial: 1) Whether moving into a PBR system as a whole is net beneficial compared to COSR; and 2) Whether a particular PIM tied to achieving a specific outcome is net beneficial. AEE Institute encourages the Commission to use a regulator perspective test instead of a single traditional cost-benefit test. In evaluating a PIM, AEE Institute states that a PIM is beneficial if the resulting gross benefits to customers are greater than the cost of the incentive, including costs charged to customers. The incentive must also outweigh the utility's opportunity cost.

Black Hills finds that COSR has been successful and that in considering PBR, the Commission should determine what missing gaps in current regulation could be addressed or improved with a transition to performance-based metrics and consider increased cost versus the benefits associated with the transition to performance-based metrics. If the Commission determines that the benefits outweigh the cost, the transition will necessarily have net beneficial results.

Colorado Energy Consumers (CEC) suggests the Commission should consider quantitative factors and examine qualitative impacts such as customer service and service reliability. Also, the Commission should monitor PBR to ensure ratepayers receive measurable value for any incentive contemplated. CEC states traditional COSR has produced relatively low utility rates and PBR must not put these results at risk.

Colorado Energy Office (CEO) believes other states such as Hawaii, Nevada, Rhode Island, Minnesota, and Oregon can provide examples. CEO also states that Hawaii may provide the most comparable instance of a net beneficial assessment, referencing Hawaii's whitepaper in 2014, and legislative studies in 2016 and 2019. CEO suggests following models used in other states to assess the merits of PBR and recommends that the Commission state its desired goals or outcomes of regulation; engage stakeholders to determine a clear list of desired regulatory outcomes; and assess how COSR and PBR regulatory structures reach those goals. CEO believes the Commission needs to reach a determination of which set of regulatory tools better aligns "utility operations, expenditures, and investments." CEO acknowledges that

the existing tests utilized by the Commission, such as the societal cost test, do not examine the broader regulatory context thus, CEO maintains that the analysis should be qualitative. CEO recommends a holistic evaluation of PBR and PIM net benefits, rejecting the notion that increased PIMs will mean increased costs to ratepayers. However, CEO is not assuming that PBR will result in lower costs. CEO advocates a comprehensive, multi-year assessment of the impacts to a utility's revenue requirement and cost allocation methodology.

Colorado Natural Gas (CNG) responds that "specific" should include: 1) whether there is a financial benefit to utilities from implementation of PBR versus the cost to do so; 2) whether there are customer benefits from PBR which would not otherwise be available under COSR regulation; and 3) whether there is regulatory efficiency in the administration of the Commission's oversight of regulated utilities that is enabled or enhanced by PBR versus the current COS system.

Colorado Office of Consumer Counsel (OCC) references § 40-1-102(5)(b), C.R.S., and Subsection (c) of § 40-1-102(5) C.R.S., as a guidance calculating the benefit-cost ratio. OCC expresses DSM serving as a guide in discussing what specific component evaluating net beneficial but that also it mentions raises issues defining and quantifying "nonenergy benefits".

Public Service Company of Colorado suggests that in evaluating whether a shift to PBR is net beneficial, the Commission should assess whether potential improvements in utility performance can be achieved in a cost efficient manner, whether regulatory burden is increased or decreased, and what impact PBR would have on Public Service's current activities in advancing Colorado's energy policy. Specific components of the assessment would be quantifiable monetary benefits, quantifiable monetary costs, and other benefits that are not easily monetized, such as improved safety, reliability, or customer service. An additional evaluation would be whether regulatory burden could be decreased with the same or higher level of performance.

Rocky Mountain Institute (RMI) states that net beneficial should be evaluated by comparing the costs, risks, and rewards of COSR with PBR. RMI states this could be done through quantitative modeling, but would also need to include qualitative assessment. Net beneficial evaluation should consider: 1) the perspectives of ratepayers and utilities, as well as the residents of Colorado as a whole, possibly extending to a global lens of emission reductions; 2) the scope of interests that includes customer bill impacts, utility earnings and cash flow, public health, and enhanced capability to integrate renewable energy sources; and 3) a long-term timeframe horizon.

Sierra Club proposes that performance be compared under COSR and PBR within four areas: 1) service quality; 2) cost efficiency; 3) risk; and 4) achievement of energy policy goals. Cost efficiency could be evaluated using total factor productivity or whether the utility is actively procuring lower-cost alternatives even if those alternatives are not utility-owned. Risk can be evaluated by determining whether risks are shifted to ratepayers, and who bears risk of cost overruns, forecast error, and stranded costs.

C) What are the specific benefits and drawbacks of an MYP?

AEE Institute references its white paper *Navigating Utility Business Model Reform: A practical guide to regulatory design* jointly released with RMI in September 2018, which focuses on ten options for utility business model reform, and which addresses MYPs. AEE Institute states that a rate case moratorium and an attrition relief mechanism are two key elements that differentiate MYPs from traditional ratemaking. MYPs can support cost containment and realignment of profit- making incentives. AEE Institute also believes that an MYP has the potential to deliver savings to customers. AEE Institute suggests that the Commission should combine any MYPs with additional tools such as shared savings mechanism to avoid potential utility over- or under-earnings resulting from MYPs.

Black Hills identifies MYP benefits as lower administrative costs associated with frequent rate reviews, reduction of regulatory lag, and better alignment of current utility costs with current rates. The drawbacks Black Hills finds are difficulties in forecasting utility costs over the course of multiple years and a lack of Commission guidance on expectations and minimum filing requirements the Commission deems necessary to support an MYP, which increase the risks of unsuccessful rate review proposals.

Colorado Energy Consumers (CEC) states the Commission should not experiment with both MYPs and FTYs unless there are demonstrated ratepayer benefits. CEC states that MYPs and FTYs are counter to the “used and useful” principle of regulation; FTYs must adhere to the matching principle within or unreasonable rate increases might result. CEC notes that FTYs and MYPs require a heavy reliance on utility projection of future cost and revenues and states that FTYs and MYPs can reduce utility incentive to control costs. Finally, MYPs decrease shareholders’ risk and should therefore result in lower authorized ROEs.

Colorado Energy Office (CEO) recommends that the Commission consider reduced administrative costs and increased procedural efficiency when contemplating MYPs. CEO identifies several benefits of MYPs, including customer savings, rate stability, reduced regulatory lag, and predictability. Conversely, utilities may over earn if cost adjustments and projected revenue growth are inaccurate. CEO suggests that success depends on accurate calculations and analyses when establishing MYP design.

Colorado Natural Gas (CNG) states that the benefits and drawbacks of MYPs and FTYs are the same and that the underlying issue is that both rely on forecasts going out several years. Because that forecast, by definition, will ultimately be incorrect, it is therefore an inappropriate basis for setting rates.

Colorado Office of Consumer Counsel (OCC) states that an MYP offers an alternative option to COSR ratemaking approaches, encouraging utility performance and reducing regulatory burden. OCC points out that regulatory lag can be effective in leveraging regulatory outcomes and passing on meaningful savings to customers. Some of the benefits of MYPs are the potential for regulatory efficiency. Focus on cost containment should be the primary driver for implementing an MYP. Challenges with MYPs include: 1) designing an MYP that provides sufficient incentives for utility without adding risk to customers; and

2) both PBR and COSR require extensive regulatory oversight, stakeholder engagement, and may generate associated costs. OCC states that the use of riders also presents challenges in MYP context because riders conceal costs that would normally be included in a representative rate base, and are thus inconsistent with the concept of MYPs.

Public Service states that MYPs and FTYs are the best way to set rates that reflect the utility's costs at the time the rates are effective. MYPs can provide rate predictability and provide the utility incentive to be efficient; MYPs also reduce rate case filings and therefore reduce financial and resource burdens for the utility and intervening parties. Public Service notes that the Commission approved an MYP in 2012 and references a 2017 Lawrence Berkeley National Laboratory study's findings that MYP ratemaking can provide stronger incentives for utility innovation with attendant reduced costs to customers.

Rocky Mountain Institute (RMI) acknowledges that MYPs are not a panacea to align utility incentives with customer and societal goals, but states that MYPs are an important part of PBR. While MYPs encourage cost containment and can reduce regulatory lag, they can add complexity to rate cases and can be challenging when dealing with large increases in capital spending.

D) What are the specific benefits and drawbacks of a future test year?

Black Hills states that the benefits and drawbacks of an FTY are similar to those of MYPs, but sees an FTY as the middle ground rate design, falling between HTYs and MYPs. FTYs better align utility costs with rates and reduce regulatory lag, but also carry difficulty in forecasting utility costs and litigation risks to the utility because the Commission has generally not favored FTYs.

Colorado Energy Office (CEO) states that FTYs can reduce regulatory lag by incorporating forward-looking forecasts of costs and that FTYs should be considered because utilities will be making substantial new investments in transportation electrification and DSP in the coming years. However, as with MYPs, efficacies of FTYs depend on the accuracy of analysis underpinning assumptions and calculations.

Colorado Office of Consumer Counsel (OCC) states that the move to FTY from an HTY is a substantive shift in approach, effort, costs, oversight, and practices. OCC notes that the experience of other states does not provide sufficient evidence that adoption of FTYs reduces regulatory cost.

OCC references an empirical study of the use of FTY conducted by the National Regulatory Research Institute and found that FTYs shift risk considerably to ratepayers. Some of the FTYs that challenges OCC notes are evaluation of cost and sales forecasts, utility incentive to bias its forecasts in support of a larger rate increase, the "ratchet effect" causing distortive utility behavior, added complexity in rate cases, additional staff requirements; and the need for assurance of prudent utility management and cost efficiency.

Rocky Mountain Institute (RMI) lists the advantages of FTYs as having the potential to more accurately reflect costs and sales during the time in which rates will be in

effect and being more flexible for large-scale changes, such as widespread DER adoption, transportation electrification, and adoption of third-party services in place of capital spending. However, FTYs offer incentive for utilities to overestimate future costs, requiring greater scrutiny by all parties in a rate case. RMI notes that decoupling can help to mitigate forecasting errors by requiring a true up of actual and forecast revenues.

E) Are there specific policy goals for the State of Colorado related to cost efficiency whose achievement PBR or PIMs are well suited to improve or accelerate?

AEE Institute suggests that with new regulatory approaches such as PIMs, a holistic view of capital expenditures and operating expenditures should be strongly considered.

Black Hills states that narrowly tailored PBR/PIM mechanisms will encourage utilities to innovate and continuously improve in a cost-effective manner. Black Hills specifically notes that software solutions are recognized as expenses, rather than as capital investment hence, there is the need to consider how to ensure utilities have better incentives to make the most cost-effective decisions to address customer needs. Black Hills cites the National Association of Regulatory Utility Commissioner resolution passed in 2016 that encourages utility commissions to consider permitting utilities to rate base investment in a cloud-based software.

Colorado Energy Consumers (CEC) notes that traditional COSR regulation has produced favorable utility rates but that PBR may lead to rate increases as ratepayers are forced to pay additional incentives to utilities. Furthermore, CEC questions whether a transition from COSR to PBR would achieve cost efficiency.

Colorado Energy Office (CEO) believes that cost efficiency could be implied to mean cost effective, a term the Commission uses in its electric rules and most frequently in the ERP. In other words, a cost effective resource plan then is defined as having "a reasonable cost and rate impact." CEO recommends a qualitative approach when approving a cost effective resource plan. In its assessment of utility operations, expenditures, and investment, CEO also states that the Commission should consider, but not limit itself to reasonable costs and rate impacts. CEO does not recommend a specific metric be adopted on cost efficiency nor that it develop one or multiple metrics designed to measure cost efficiency.

Colorado Natural Gas (CNG) states that cost efficiencies are gained with usual energy efficient gas appliances such as furnaces, boilers, and hot water heaters that are already the subject of PIMs through the DSM Programs and DSM Bonus Program as required by Commission Rules 4750 and 4760, of the Rules Regulating Gas Utilities and Pipeline Operators, 4 CCR 723-4.

Colorado Office of Consumer Counsel (OCC) points to the Commission's Electric Rules 3601 and 3618 as well as to Proceeding No. 19R-0096E, the ERP rulemaking, which all address cost effectiveness and the issues of generation resources that are included in this investigation. Additionally, OCC suggests that it would be beneficial to review prior rate cases in which MYPs were rejected.

Public Service states that EV implementation and Public Service's TEP align with the State's policy goals. Public Service also finds DSP should be examined further in terms of whether benefits will outweigh costs.

Rocky Mountain Institute (RMI) suggests MYPs, efficiency carryover mechanisms, capitalization of certain operating expense categories, and totex accounting. Additionally, revenue decoupling, incentivized fuel-cost trackers, shared savings mechanisms, and securitization are potential measures to employ.

Sierra Club proposes general operating cost efficiency, cost efficiency of generation fleet and fuel costs, minimization of stranded costs, cost effective implementation of NWAs, distributed renewable generation as areas that are well-suited to PBR and PIMs.

F) What existing electric and gas utility PIMs addressing cost efficiency in Colorado are working well? Which are not working well?

Black Hills notes that one set of PIMs not working well is DSM because, although the Financial Disincentive Offset is intended to make up for revenue losses and the Performance Incentive is intended to reward the utility for achieving DSM targets, the utility is ultimately not adequately compensated. Additionally, Black Hills suggests that PIMs that intend to boost utility performance should stay revenue neutral and should reward the utility for achieving certain targets.

Colorado Energy Consumers (CEC) states the PBR mechanism should be simple and transparent. CEC states that Public Service's earnings test and ESM that expired in 2017 worked well because it was clear and transparent. Similarly, Public Service's QSP worked for customers, although there is room improvement. CEC states it is not in favor of rewarding behavior already mandated by the Legislature.

Colorado Energy Office (CEO) states DSM PIMs have worked, and that the utility earns incentives based on the variety of the DSM related achievements. The incentives give utilities increasing opportunities to earn larger incentives through greater DSM investments and encourages cost efficiency. The EAFPM is another PIM that encourages cost efficiency and improved performance.

Public Service Company of Colorado states that generally its PIMs are not directly aimed at incenting cost efficiency measures, but notes that its Rush Creek Wind Project resulted in significant construction budget savings and customer savings over the life of the contract.

Sierra Club states that the operation of generation plants, and more specifically, the decision to retire plants is adversely affected by capital bias and pass-through costs, which reduce efficient operations incentive. Without a comprehensive PBR framework, utilities will not comprehensively evaluate the economics of their existing generating units in ERPs. However, Sierra Club finds that energy efficiency and DSM incentives are working well. Sierra Club also offers areas that short-term off-system sales margin and EAFPM have had "mixed results."

G) What PIMs addressing cost efficiency in other jurisdictions should be considered in Colorado?

AEE Institute notes that Illinois, New York, and Massachusetts have significant PBR track records. Specifically, AEE Institute cites Brooklyn Queens Demand Management, which includes an opportunity to earn a return on program cost as well as a shared savings mechanism; Oklahoma's shared-savings based PIM, which has been in effect since 2008; and the UK's RIIO system.

Colorado Office of Consumer Counsel (OCC) suggests that the Commission look at Minnesota's PIMs for measuring cost-efficiency of PBR activities.

Public Service cites Hawaii, Maryland, New York, Ohio, Oklahoma, Pennsylvania, and Rhode Island as states to observe. Additionally, Public Service suggests that peak shaving, as proposed in Michigan, is an effective way to increase cost efficiency by reducing customer usage during system peak.

Rocky Mountain Institute (RMI) suggests Rhode Island, New York, and Hawaii as states to observe.

Sierra Club suggests that the Commission consider cost efficiency of generating resources, as is done in Hawaii, Oregon, and Vermont, and provides a discussion of various tracking metrics; interconnection of DERS, as is being done in Hawaii; and NWAs, such as in New York.

c. Distributed Energy and Carbon Emissions (Recommended Decision No. R20-0343-I)

A) What incentives and disincentives do Colorado investor-owned utilities currently have to expand DERs?

Black Hills states that its commitment to customer service provides incentives to assist customers who choose to install and interconnect DER, and currently offers a Performance-Based Incentive Program to incentivize on-site solar installations. Black Hills also notes that it is statutorily bound to the RES requirements, which it has exceeded. Black Hills states, however, that non-DER customers are negatively impacted by DER expansion. Black Hills' fixed costs are largely recovered through volumetric rates. As customers install DERs, cost responsibility is shifted to non-DER customers. Furthermore, although utility-scale solar resources are more cost effective than some DERs, such as rooftop solar, Black Hills has been discouraged from expanding DERs when it can provide other renewable resources to customers in a manner that results in greater bill savings.

Colorado Energy Consumers (CEC) states that because Colorado statutes, the Commission's regulatory authority, and the regulatory compact already require public utilities to provide safe and reliable service at just and reasonable rates in return for the exclusive right to serve within certificated service territories and the opportunity to earn a return on their investments, it is a slippery slope to begin supplementing incentives for increasing grid efficiency, improving reliability, and reducing costs, as these endeavors should already be a primary focus of providing utility service. With regard to DER, utilities are already afforded opportunities to earn ratepayer-funded incentives for energy efficiency and demand response investments through their DSM plans and activities. The Commission should not layer on additional, and potentially pancaked, incentives for achieving energy efficiency and demand response goals. Specific to Public Service's DER expansion, CEC states that DERs will lead to qualitative benefits, such as increased customer satisfaction and goodwill in the community and among shareholders, so Public Service does not need, further financial incentive for pursuing the goals it has already established internally and publicly advertised. Additional ratepayer-funded financial incentives may add unnecessary cost, and thus potentially conflict with or erode Public Service's goal of keeping bills low.

Colorado Energy Office (CEO) notes that utilities have been granted the opportunity to earn performance incentives for DER investments in transportation electrification, DSM, and to earn a return on certain investments, such as rebates that support transportation electrification. The CACJA created an incentive for replacement of generation sources and early retirement of existing resources. With regard to the RES, CEO notes that while utilities must file RES Compliance Plans, there is no associated incentive. Additionally, RES Compliance Plans require investments in customer-sited distributed generation, which may exceed RES compliance obligations, in support of other policies that encourage the expansion of retail renewable distributed generation. CEO points out that Proceeding No. 19M-0670E on DSP addresses the broader role that DERs have on the distribution grid.

CEO summarizes the diverse treatment of DERs in state:

DER	Statutory citation	Financial incentive permitted or
Beneficial electrification	Defined in § 40-3.2- 106(6)(a), C.R.S.	No
Community solar gardens	§ 40-2-127, C.R.S.	No
Demand-side management	§ 40-3.2-103, C.R.S.; § 40-3.2-104, C.R.S.	Yes
Distributed generation (customer-sited)	§ 40-2-124, C.R.S.	No

City and County of Denver notes that DER expansion has historically been driven by legislative mandate. Stating that Public Service has demonstrated a preference for large-scale renewable energy procurements, Denver suggests that Colorado will be most successful at achieving an affordable and reliable expansion of DERs by positioning and compensating qualifying retail utilities as distribution service providers and allowing for appropriate utility compensation using performance-based metrics. This will encourage innovation and collaboration between qualifying utilities, utility customers, and third-party DER providers to expand DERs.

Joint Solar Parties: Colorado Solar and Storage Association (COSSA), Solar Energy Industries Association (SEIA), and Vote Solar state that COSR offers only negative incentives for utilities: statutory and regulatory mandates such as distributed energy requirements under the Colorado RES, net metering requirements, and interconnection obligations for DERs all carry a penalty for non-compliance. Furthermore, these statutory mandates do not offer a solution for utilities' capex bias against DER expansion. Therefore, COSR encourages utilities to only pursue minimum required for DER expansion. However, with a well-designed PBR system, earning opportunities for utilities can be aligned with public interest goals. The Joint Solar Parties urge the Commission to include in the report to the General Assembly, recommendations for future PBR proceedings to develop comprehensive PBR frameworks that create a regulatory environment under which utilities can adapt their business models to align operations, expenditures, and investments with DER expansion and other public interest goals.

Public Service states that there are possible instances where DER deployment could defer traditional grid investment or provide additional functionality leading to a more robust and integrated grid. These concepts are currently being examined as part of the Commission's DSP docket within Proceeding No. 19M-0670E. Additionally, Public Service states that customer satisfaction is its primary incentive to provide and continuously improve its private customer choice options, whether through EV ownership, low-income assistance, energy efficiency options, or participation in higher levels of renewables.

With regard to utility ownership of DERs and the inclusion of these assets in rate base or being afforded a return or incentive on the ownership, Public Service states that this was contemplated in House Bill 18-1270 which provided the Company the opportunity to own up to 15 MW of battery storage. Public Service cites its Community Resiliency Initiative (Proceeding No. 19A-0225E) for storage deployment that benefits to communities and the system and allows an opportunity to continue to gain experience in the application of battery storage technologies. Finally, Public Service notes that it is in the midst of constructing three company-owned CSGs dedicated to low-income customers.

Noting that this proceeding is not the venue for discussion of net metering policies, Public Service notes that these policies should be revised. Public Service recommends that the Commission address the inequity and intra-class subsidy that results from net metering before further encouraging Colorado utilities to support expansion of DERs through PBR.

Rocky Mountain Institute (RMI) notes that incentives can be explicit (*i.e.,* rewards or penalties intentionally designed to influence utility behavior) or as implicit (*i.e.,*

rewards or penalties that arise unintentionally or as a side product of achieving other objectives) and that it is important to identify implicit incentives as they can play important roles in shaping utility decision making. Two specific areas that RMI addresses are capital bias and throughput incentive: Capital bias exists because utilities earn a return on capital investments but not on operating expenses. When the rate-of-return on equity is higher than the cost of equity, utilities can increase shareholder value through capital investment, creating an implicit incentive to prioritize capital expenditures. Capital bias can provide an incentive for utility-owned DER expansion or serve as a disincentive if DERs are procured through operating expenses, as when they are provided by a third party.

Throughput incentive results from the utility's recovery of fixed costs through volumetric charges, so the utility has incentive to increase customer usage. The throughput incentive may encourage DER expansion in cases where this will result in increased energy sales, such as with beneficial electrification. However, there will be a disincentive to expand DERs: The throughput incentive can discourage utilities' DER expansion in behind-the-meter generation, such as rooftop solar.

Western Resource Advocates (WRA) finds that utilities currently lack sufficient incentive to expand DERs. With regard to PBR, the strongest existing incentives are for DSM programs, although the Commission did recently introduce revenue decoupling, which preserves the utility's approved revenue recovery with an annual adjustment mechanism. Utility expansion of DERs is mainly in response to requirements to follow Commission rules, statutes, and State policies. WRA expresses concern about three existing incentive structures relating to distributed generation: 1) The utility's ability to recover lost revenue from CSG subscriptions through collection of CSG bill credit offsets from all customers via the ECA and RESA riders rather than through the Revenue Decoupling Adjustment rider; 2) Utility profit-sharing from REC sales; and 3) the emergence of negative REC pricing. WRA notes that DSM and IVVO both have performance incentives and that the TEPs submitted by Public Service and Black Hills are statutorily allowed incentives. Finally, WRA states that no incentive mechanism currently exists to specifically encourage utility investment in NWA projects.

B) Will the expansion of DERs create any stranded assets?

AEE Institute notes that there will always be a risk of stranded assets and that the Commission plays a role in dealing with these. Under traditional regulation there was a low risk of stranded assets, but as technology such as DERS have decreased in cost and improved in efficiency, the risk of stranded assets will grow under COSR. This is a result of the conflict of interest between customer-owned DER expansion and the utility's infrastructure investments. AEE Institute states, however, that the benefits of DERs can outweigh the potential risks of stranded assets. Additionally, if under PBR the utility has the opportunity for earnings related to DER deployment, the risk of stranded assets will be reduced.
AEE Institute notes that there is interaction with DSP and states that the Commission's DSP investigation (Proceeding No. 19M-0670E) and future rules are

especially important. AEE Institute also suggest that the Commission update depreciation schedules for the new kind of utility investments, particularly in communications technology. Finally, AEE Institute notes that EVs are a form of DER that, as they will eventually feed power back into the grid and contribute to load growth, will not increase the risk of stranded assets.

Black Hills does not identify specific stranded costs, but states that it would need to undertake an analysis of potential stranded costs based upon specific net-metering expansion forecasts that consider policy or legislative changes requiring changed assumptions for DERs' adoption rates.

Colorado Energy Consumers (CEC) stresses caution in considering the potential for stranded assets before providing utilities incentives to expand DERs. Cost recovery of stranded assets should continue to be examined on a case-by-case basis considering the unique facts and circumstances of each particular asset. Providing utilities with unchecked or streamlined avenues to retire assets and rate base, new resources have the potential for misuse, even if the utility is undertaking such actions to achieve state policy goals. To address stranded assets, the Commission should consider, among other options, securitization or the use of the RESA funds.

Colorado Energy Office (CEO) does not offer an opinion as to whether DER expansion will result in stranded assets, but states that PBR could address the potential for any stranded assets or changes in State policies. CEO states that the answer also depends on how DERs are utilized and which attributes are encouraged. CEO further notes that seeking prudency prior to commencing investments could increase the risk of stranded assets, and that certain DERs, such as water heaters, might create new sources of flexible, electrified load that was previously fueled by natural gas, so the Commission should be attentive to these implications.

City and County of Denver states that the answer depends on the level of coordination across utility ERP activities. Denver suggests following examples in other states, particularly Rhode Island. Denver states that, at a minimum, Colorado should synchronize and combine the DSP, RES planning, and ERP processes.

Joint Solar Parties state that "stranded assets" is unclear, but assume that it refers to the undepreciated balance associated with electric or gas facilities that are taken out of service before the capital investment is fully depreciated. They state that the term does not imply that the utility is denied recovery of the investment, and in fact under most circumstances, utilities can recover the costs of stranded assets by converting the undepreciated balance into a regulatory asset. The Joint Solar Parties state that coal plants across the U.S. are being retired early and replaced with renewables that leave customers better off than if the coal plant had continued running. Therefore, although the coal assets may be stranded, the public interest favors closing the plants and retiring the remaining balance. Securitization and accelerated depreciation are appropriate strategies to address the issue. The Joint Solar Parties also note that the discussion of stranded assets also occurs in the context of discussions regarding possible changes to the electric utility market structure in Colorado, including the possibility of Colorado joining an organized

wholesale market in a Regional Transmission Organization and utility restructuring. The Joint Solar Parties encourage the Commission to note this restructuring in the report to the General Assembly as a broader conversation might be warranted as Colorado transitions to a renewable energy economy.

Public Service states that it is not likely that the expansion of DERs will result in power plants, transmission lines, or distribution assets that are no longer used and useful. At the distribution level, it is possible that DERs could lead to the deferral or replacement of more traditional solutions. However, DERs could also lead to the need for additional grid enhancements. Public Service recommends that this topic be addressed within the ongoing DSP Proceeding.

Rocky Mountain Institute (RMI) defines stranded assets as those that become obsolete (or lose significant value) before the end of their anticipated useful lives. A well-designed PBR framework (coupled with robust planning and procurement practices) can encourage DER expansion in ways that minimize the risk and cost of stranded assets. RMI suggests that the question is not how to avoid stranded assets, but rather how to manage the transition to minimize their negative effects on utility finances, customer bills, and equitable outcomes. RMI distinguishes between efficient stranded assets, that is when a solution to a particular problem maximizes net benefits, it can be considered economically efficient, and inefficient stranded assets, such as an asset that becomes stranded even though the optimal solution involves its continued use, it can be considered an "inefficient" stranded asset. RMI suggests strategies that include: 1. Incent DER expansion in ways that reduce overall costs; 2. Reduce the costs of retiring efficiently stranded assets; 3. Avoid investing in new high-risk assets; 4. Consider the electric and gas systems jointly during planning; and 5. Ensure impacts are distributed equitably

Western Resource Advocates (WRA) states that a robust planning process can help to avoid electric generation stranded assets due to expansion of DERs. WRA acknowledges that it is possible that a combination of utility incentives encouraging emissions reductions and acquisitions of DERs, along with an ERP process evaluating the costs and benefits of emission reductions for existing as well as future resources, could result in the early retirement of an existing generation resource. In that case, WRA holds, such a stranded asset should not be considered a negative outcome because it is the result of State policy goals, planning processes, and technological advances. In fact, continuing to operate a thermal generation unit when a better alternative exists would itself be a negative outcome. WRA concludes that stranded costs resulting from DER adoption may be a result of technology advancement and an unintended outcome of State policy goals, unless the Commission determines it is due to poor planning or an imprudent acquisition or action. WRA looks to video technology for comparison, asking whether it would have been reasonable to require Netflix to pay Blockbuster Video for the sunk costs that remained for the DVD rental business after technology moved on to online streaming.

C) Does expansion of DERs provide greater opportunities for investor-owned utilities to create value for their current investors?

AEE Institute states that since DER expansion sits on the edge of the grid and is not regulated, utilities can create shareholder value by taking advantage of DER

opportunities, but cautions that these opportunities are diminished under COSR because DER expansion does not align well with investment decisions. Under PBR, however, that alignment can be adjusted so that utilities are rewarded for DER investments.

AEE Institute encourages the Commission to conduct a net benefits analysis when it moves to PBR, considering not just a single traditional cost-benefit test but incorporating a regulatory perspective test that includes the State's regulatory goals. An appropriate test would evaluate whether PIMs or COSR will more cost-effectively promote emission reductions or DER expansion; AEE Institute references Synapse Energy Economics' *Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments*.

Black Hills has not identified investor opportunities associated with DER expansion and states that the current net-metering structure is problematic for it to recover embedded fixed costs. Black Hills states that if it were allowed to engage in behind-the-meter solutions as a regulated option, it would be able to increase opportunities for investors and provide cost-effective solutions to meet customer demands. Black Hills suggests that the Commission should address the issue of cross-subsidies associated with rooftop solar.

Colorado Energy Consumers (CEC) states that there are already many opportunities for utilities to increase value for their investors through traditional COSR. CEC suggests that the Commission should also consider whether the increased value for investors comes at ratepayer expense. CEC states that the primary argument for the expansion of DERs is reduced utility investment in generation, transmission, and distribution infrastructure, resulting in a lower cost to serve and lower utility rates. Coupling investment in DERs with ratepayer-funded incentives for investors' benefit will erode the cost efficiencies intended to flow from DERs for ratepayers. Expansion of DERs should be focused on whether and to what extent there is resulting value for ratepayers, not the value created for investors.

Colorado Energy Office (CEO) states that the value created would depend on the State's policy frameworks, citing DSM and transportation electrification statutes which illustrate that the PIMs are not coordinated across DER investments or broad utility financial interests. Each incentive mechanism addresses an individual technology, resulting in different outcomes for retail renewable distributed generation, energy storage, DSM, beneficial electrification, and EV infrastructure. CEO calls for a more comprehensive PBR approach that aligns utility investments with State policy outcomes that will provide greater opportunities for utilities and shareholders.

City and County of Denver states DERs can and should provide opportunities for shareholder value. Specifically, Denver states that opportunities include: 1) load growth through beneficial electrification and functionalizing and leveraging those assets as distributed resources; 2) utility ownership of DERs and deployment of NWA in DSP; and 3) utility positioning and compensation for acting as a distribution service

provider. Denver states that it is pursuing aggressive de-carbonization objectives that are likely to increase load in buildings and transportation and is working collaboratively with Public Service to better understand how building and transportation loads can be functionalized into grid assets. Further, Denver states that it supports the need for a diversity of distributed and utility-scale systems to maximize value for ratepayers while ensuring reliability and affordability. There must be appropriate mechanisms to accurately determine and compare the cost and value of different renewable resources available to the utility and its customers; a process must include: 1) the additional value streams associated with DERs and their subsequent utilization in NWA solutions; 2) the avoided costs that on-site DER systems provide; and 3) the non-energy costs associated with building transmission infrastructure and interconnecting new utility-scale resources to the Company's system. Ultimately, aligning the utility financial incentive with public benefits is critical to ensuring ratepayer benefits and cooperative behavior for all parties involved in the expansion of DERs.

Joint Solar Parties state that under COSR, the utility has a financial disincentive to expand DERs on its system because the expansion will erode earnings opportunities. However, PBR changes the financial incentive structure so that utility decision making results in outcomes that advance the public interest and maintain the financial health of the utility. A well-designed PBR framework, which includes revenue adjustment mechanisms and performance mechanisms, establishes an earning environment under which utilities are rewarded for their performance in delivering "outputs" (*i.e.,* achieving public benefit goals) as opposed to inputs (*i.e.,* capex). Therefore, under PBR, the opportunity for the utility to create value for investors is tied to how well the utility performs in delivering those outputs. Citing Moody's revision of its outlook for HECO Companies, the Joint Solar Parties also state that a comprehensive PBR framework can be beneficial for utility credit ratings. The Joint Solar Parties urge the Commission to include recommendations in its report to the General Assembly that future Commission actions on PBR must include the adoption of a comprehensive PBR system in order to fully realize the benefits of PBR.

Public Service states that the current net metering rules result in short-term revenue losses which directly and negatively impact utility revenues and utility investors. Revenue decoupling can address these issues but the currently approved revenue decoupling adjustment is fundamentally flawed and is not expected to compensate Public Service for lost revenues associated with DERs. Lost revenues from DERs are eventually socialized to all customers through rate cases which leads to the cost-shift that is experienced by non-participating customers.

Rocky Mountain Institute (RMI) states that DER expansion has the potential to provide multiple opportunities to create shareholder value, but the extent to which this potential is realized depends on the regulatory incentive structure. RMI provides the example of electric utilities earning a return on the construction of EV charging infrastructure and profit from demand growth due to building electrification. Revenue decoupling is more complex, but a comprehensive approach to PBR aimed at more fully aligning utility incentives with customer and societal interests can further enhance the earnings opportunities associated with cost-efficient DERs. RMI notes that an MYP with a revenue cap can encourage a utility to employ DERs to reduce costs if it is able to retain a share of those savings.

RMI provides a concept paper, *Identifying the Least Cost Regulatory Framework for Colorado's Energy Transition*.

Western Resource Advocates (WRA) states that Utilities and their shareholders can benefit from the incentive mechanisms but under the current revenue model, the utility likely has more opportunity to benefit from other types of grid investments that support DER expansion, such as investment in flexible grid operations and make-ready infrastructure for vehicle electrification. Without the utility's complementary investments that support DER technology advancement, such innovation and non-traditional investment would not be feasible. In this way, the utility and third-party DER providers can benefit in a symbiotic relationship. Additionally, utilities operate in a regulated environment that is fundamental to their business model. The regulatory system creates the foundation for the utility business model and its shareholders' opportunity to benefit from their investment. When that regulatory system establishes requirements on the utility, its earnings depend on the utility's effective compliance with those requirements. As the State of Colorado has various policies encouraging DERs, renewable energy, emission reductions and innovative clean energy, the utility and its shareholders benefit by effectively implementing those policies.

D) What metrics can be used to measure the ability of DERs to reduce overall system costs by avoiding or deferring transmission and distribution system upgrades?

AEE Institute encourages the Commission to consider outcomes-based metrics because they provide flexibility for innovation and alleviate the regulatory burden of extensive program planning and oversight. AEE Institute notes that it is not necessary to map outcomes and metrics one-to-one under each policy goal. AEE Institute recommends collecting at least one-year's data and then developing appropriate incentives associated with financial incentives or penalties, then going back another two or three years to establish a performance baseline. AEE Institute provides several specific recommendations including metrics for: 1) GHG reductions mapped to increased non-fossil fuel technologies; 2) DER integration measured by locations of new DERs and by measuring the volume and process speed of interconnection requests; and 3) peak demand reduction that results in avoided capital investments. To address the six public interest goals identified for this investigation, AEE Institute recommends establishing a stakeholder working group.

Black Hills does not employ metrics to measure a DER's ability to avoid or defer transmission/distribution system upgrades, and notes that this issue is currently being discussed in the DSP miscellaneous proceeding, Proceeding No. 19M-0670E.

Colorado Energy Consumers (CEC) notes that establishing metrics to measure and evaluate utility performance is an inherent difficulty in any PBR mechanism and does not propose specific metrics for measuring the ability of DERs to reduce system costs. CEC does offer general principles applicable to all PBR metrics that should be followed for any metrics related to DER: metrics should be quantifiable, transparent, and easy to understand; set a reasonably high bar for incentives; and clearly

demonstrate that ratepayers are receiving benefits in excess of the incentives they are funding.

Colorado Energy Office (CEO) supports NWAs as a means to avoid or defer transmission and distribution upgrades and notes that Proceeding No. 19M-0670E is currently exploring the role of NWAs in DSP and may address cost-effectiveness, metrics, or models for analyzing NWAs. CEO also encourages the Commission to consider metrics for peak demand reduction; minimization of the net present value revenue requirement; and cost comparisons on a dollar per megawatt basis between traditional and alternative investments.

City and County of Denver recommends that the Commission develop and adopt a methodology to quantify: 1) the locational and temporal costs and benefits of DERs; and 2) the avoided costs of traditional utility distribution investments. Denver cites a 2016 report from the Smart Electric Power Alliance and Nexant that proposes the use of a metric called the load carrying capacity factor for DER. It incorporates each DER's unique operating characteristics and quantifies its ability to address a specific distribution system need at a specific location at a specific time. Denver also recommends following the examples of metrics established by Hawaii and Minnesota.

Joint Solar Parties state that DERs will lower system costs and provide other ratepayer benefits in numerous ways, not simply by postponing investment in transmission and distribution system upgrades. The ability for DERs to reduce system costs is a function of both the technological capability of DERs and the market participation pathways available for DERs to provide the services they are capable of providing. In addition to deferring transmission and distribution system infrastructure, DER expansion can also provide including peak demand reduction, carbon emissions reduction, and ratepayer risk mitigation. The Joint Solar Parties urge the Commission to include in its report to the General Assembly recommendations that future proceedings to implement a comprehensive PBR framework must consider the ability of DERs to defer distribution and transmission infrastructure as well as other use-cases for which DERs can be deployed to reduce system costs and contribute to the achievement of other public benefit goals.

Public Service maintains that a foundational point on this issue is that in no instance will a DER eliminate the need for existing transmission or distribution infrastructure. On the other hand, NWAs, a topic central to the DSP Proceeding, does have the potential to defer future traditional utility distribution and transmission assets, although these opportunities may be limited. Currently, the evaluation of deferral of traditional transmission and distribution infrastructure or upgrades is best and most clearly completed on a project-level basis. If a general set of metrics were developed, numerous underlying assumptions would be required that may or may not apply to the specific situation that arises, thus yielding a more subjective rather than quantitative set of metrics. Additionally, the geographic nature of distribution planning, as well as transmission, should be taken into account, along with flexibility.

Rocky Mountain Institute (RMI) states that multiple metrics could be used to measure the ability of DERs to produce cost savings by avoiding or deferring electricity transmission and distribution system upgrades, NWAs. RMI suggests that

possible metrics include avoided transmission and distribution upgrade costs, avoided carbon dioxide emissions, and peak-demand reduction. RMI further states that while metrics are essential for tracking utility performance in relation to desired outcomes, they may be insufficient on their own to encourage DER expansion, particularly where existing utility incentives are poorly aligned with the desired changes. Therefore, consideration should be given not only to which metrics should be adopted, but also to the role these play in structures that align utility incentives with customer and societal interests.

Western Resource Advocates (WRA) states that the appropriate proceeding for establishing metrics, incentives, and cost-benefit analysis parameters for deployment of DERs, or NWAs is the DSP proceeding (Proceeding No. 19M-0670E). WRA has provided extensive comments in that proceeding. WRA includes as metrics of successful NWA implementation: project and implementation cost, avoided or deferred cost, reliability and power quality, avoided capacity or capacity benefit, GHG reductions valued at the Social Cost of Carbon, reduced energy, and peak demand.

WRA also suggest that the Commission should have included the question What performance metrics and incentives can be used to encourage utility emissions reduction? WRA states that this is important because this question encompasses DER expansion and utilization, as well as a broader array of utility actions that can reduce emissions. While cost efficiency may itself result in reduced emissions, additional PBR mechanisms for cost reductions would be useful to achieve the State's carbon dioxide reduction goals and to encourage greater emission reductions.