BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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IN THE MATTER OF THE APPLICATION	**)**
OF PUBLIC SERVICE COMPANY OF	**)**
COLORADO FOR APPROVAL OF ITS	**) PROCEEDING NO. 21A-________E**
2021 ELECTRIC RESOURCE PLAN AND	**)**
CLEAN ENERGY PLAN	**)**

DIRECT TESTIMONY OF BROOKE A. TRAMMELL

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

March 31, 2021

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

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IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2021 ELECTRIC RESOURCE PLAN AND CLEAN ENERGY PLAN	**) PROCEEDING NO. 21A-______E**

DIRECT TESTIMONY OF BROOKE A. TRAMMELL

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	**Meaning**
2021 ERP & CEP	Public Service Company of Colorado's 2021 Electric Resource Plan and Clean Energy Plan
AFUDC	Allowance for Funds Used During Construction
ASC 842	Accounting Standards Codification 842
BHE	Black Hills Energy
BOT	Build-Own Transfer
CCPG	Colorado Coordinated Planning Group
CEC	Colorado Energy Consumers
CEO	Colorado Energy Office
CEP	Clean Energy Plan
CEPA	Colorado Energy Plan Adjustment
CEPR	Clean Energy Plan Rider
CIEA	Colorado Independent Energy Association
Commission	Colorado Public Utilities Commission
COSSA/ SEIA	Colorado Solar and Storage Association/Solar Energy Industries Association
CPCN	Certificate of Public Convenience and Necessity
CWIP	Construction Work in Progress
DER	Distributed Energy Resources
DSM	Demand-Side Management
ECA	Electric Commodity Adjustment
ERP	Electric Resource Plan
ERZ	Energy Resource Zone

Acronym/Defined Term	**Meaning**
FERC	Federal Energy Regulatory Commission
GDA	Generation Development Areas
Interwest	Interwest Energy Alliance
ITC	Investment Tax Credit
kV	Kilovolt
LGIP	Large Generator Interconnection Process
NEPA	National Environmental Policy Act
NREL	National Renewable Energy Laboratory
OATT	Open Access Transmission Tariff
Pathway Project	Colorado's Power Pathway Project
PBR	Performance-Based Regulation
PIM	Performance Incentive Mechanism
PPA	Purchased Power Agreement
Public Service or Company	Public Service Company of Colorado
RE Plan	Renewable Energy Plan
RESA	Renewable Energy Standard Adjustment
RES	Renewable Energy Standard
ROE	Return on Equity
RFP	Request for Proposal
RSG	Responsibly Sourced Gas
SB 07-100	Senate Bill 07-100
SB 19-236	Senate Bill 19-236
SEC	Securities and Exchange Commission
SPE	Special Purpose Entity

Acronym/Defined Term	**Meaning**
TCA	Transmission Cost Adjustment
WBK	Wilkinson Barker Knauer LLP
WRA	Western Resource Advocates
XES	Xcel Energy Services Inc.
Xcel Energy	Xcel Energy Inc.

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

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IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2021 ELECTRIC RESOURCE PLAN AND CLEAN ENERGY PLAN	**) PROCEEDING NO. 21A-_______E**

DIRECT TESTIMONY OF BROOKE A. TRAMMELL

I. INTRODUCTION, QUALIFICATIONS, PURPOSE OF TESTIMONY, AND RECOMMENDATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Brooke A. Trammell. My business address is 1800 Larimer Street, Denver, Colorado 80202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am employed by Xcel Energy Services Inc. ("XES") as Regional Vice President, Rates and Regulatory Affairs. XES is a wholly owned subsidiary of Xcel Energy Inc. ("Xcel Energy") and provides an array of support services to Public Service Company of Colorado ("Public Service" or the "Company") and the other utility operating company subsidiaries of Xcel Energy on a coordinated basis.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THE PROCEEDING?

A. I am testifying on behalf of Public Service.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. As Regional Vice President, Rates and Regulatory Affairs, I am responsible for providing leadership, direction, and technical expertise related to regulatory processes and functions for Public Service. My duties include the design and implementation of Public Service's regulatory strategy and programs, as well as the direction and supervision of Public Service's regulatory activities, including oversight of rate filings, administration of regulatory tariffs, rules and forms, regulatory case direction and administration, compliance reporting, and complaint responses. I have previously testified as a policy witness on behalf of Public Service in several proceedings before the Colorado Public Utilities Commission ("Commission"). A description of my qualifications, duties, and responsibilities is set forth in my Statement of Qualifications at the conclusion of my Direct Testimony.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to address a number of technical policy aspects of the Company's 2021 Electric Resource Plan and Clean Energy Plan ("2021 ERP & CEP"). These topics relate to transmission considerations relevant to this 2021 ERP & CEP, cost recovery methodologies associated with early retirement of generation resources,[1] the cost recovery mechanisms and framework established by the General Assembly for this 2021 ERP & CEP, and

[1] In particular, I provide an overview of securitization and explain how decisions made by the Commission in this proceeding may initiate a series of regulatory events and ratemaking policy considerations over the next two decades should the Commission determine the early retirement of Comanche Unit 3 is reasonable and approve the Company's request to pursue financing through securitization.

other regulatory and ratemaking implications related to various Electric Resource Plan ("ERP") topics.

Among those other ERP topics, I discuss stand-alone battery storage technologies that we expect to see bid into the competitive solicitation and how our request for proposals ("RFP") for dispatchable resources has incorporated important considerations to prevent negative financial impacts for contracts that trigger capital lease, or what is now referred to as finance lease, accounting. I also discuss how these considerations are consistent with how the Company and the Commission has historically mitigated these financial impacts in prior Public Service ERPs.

In addition, given Senate Bill 19-236's ("SB 19-236") requirement that Public Service—in this 2021 ERP & CEP—work to achieve carbon emission reductions beyond 2030, I discuss the need for Public Service to investigate the feasibility of resource technologies such as pumped storage hydropower that the Company believes will be required to achieve 100 percent carbon reductions by 2050. I discuss the long lead time required to develop such resources and the Company's request that the Commission find it reasonable for Public Service to conduct investigatory work into the feasibility of these resources. I also discuss the Company's request that the Commission authorize certain ratemaking treatment to provide a pathway to recovering the costs of this investigatory work.

In response to the Commission's report to the Colorado General Assembly related to performance-based regulation, I discuss how the Company has incorporated recommendations and directives from the Commission related to performance incentive mechanisms into this 2021 ERP & CEP. Specifically, I present the Company's proposed emissions reduction performance incentive mechanism ("PIM"). I also discuss the future consideration of performance standards for new, Company-owned generation acquired in this 2021 ERP & CEP in follow-on Certificate of Public Convenience and Necessity ("CPCN") proceedings and the Company's willingness to evaluate project management performance incentives related to new generation resources to be constructed by the Company.

Finally, I present and support the costs Public Service has incurred and anticipates it will incur to process this 2021 ERP & CEP with the Company's proposal to defer those costs in a non-interest-bearing regulatory asset for review in a future rate proceeding.

Q. ARE YOU SPONSORING ANY ATTACHMENTS AS PART OF YOUR DIRECT TESTIMONY?

A. No.

Q. WHAT RECOMMENDATIONS ARE YOU MAKING IN YOUR DIRECT TESTIMONY?

A. Consistent with the discussion in my Direct Testimony, I support the recommendation of Company witness Ms. Alice K. Jackson that the Commission approve Public Service's Phase I 2021 ERP & CEP. In addition, I recommend the Commission issue several findings and approvals as part of its Phase I decision in this proceeding, as follows:

- A finding that the Company's plan to securitize the costs associated with the accelerated retirement of Comanche 3 is reasonable and in the public interest to enable the Company to begin a series of actions over the next two decades to effectuate the securitized refinancing, which will involve subsequent regulatory filings and Commission approvals;

- Approval to initiate the Clean Energy Plan Rider ("CEPR") after the issuance of the Phase II decision in this Proceeding;

- A finding that the Commission recognizes the financial implications of adding stand-alone battery storage resources in this 2021 ERP & CEP and accordingly approves the Company's request to accept and negotiate contract terms for these types of resources that do not result in finance lease accounting treatment;

- A finding that the Commission encourages the Company to investigate the feasibility of certain long-lead time generation resources to achieve carbon reductions beyond 2030 and authorize a certain ratemaking treatment for associated costs;

- Approval of the proposed Emissions Reduction PIM; and

- Approval to track and defer costs incurred in association with preparing and litigating this proceeding into a non-interest-bearing regulatory asset to be reviewed for recovery purposes in a future rate proceeding.

II. TRANSMISSION POLICY CONSIDERATIONS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. The purpose of this section of my Direct Testimony is to provide background on the Company's Transmission Planning efforts involved and leading up to this ERP filing. In doing so, I discuss the transmission facility proposed in Proceeding No. 21A-0096E, which is a 560-mile, 345 kilovolt ("kV") double circuit transmission facility called Colorado's Power Pathway project (the "Pathway Project"). The Pathway Project provides a high voltage networked transmission facility that interconnects the Eastern Plains and Southern Colorado to Public Service's load centers, providing developers the ability to develop and bid cost-effective projects into renewable-rich Energy Resource Zones ("ERZ") 1, 2, 3, and 5. I discuss the Joint Transmission Proposal presented in Proceeding No. 19R-0096E, and explain how we have incorporated the overall spirit and intent of that proposal into our ERP filing. I then discuss the categories of additional transmission investment the Company anticipates will be needed to support the 2021 ERP & CEP and how we plan to bring it forward to the Commission for review.

Q. PLEASE EXPLAIN HOW PUBLIC SERVICE APPROACHED ITS TRANSMISSION PLANNING EFFORTS FOR THIS 2021 ERP & CEP.

A. Colorado's energy transition is not limited to generation resources and will likewise require a shift in how transmission planners have historically developed and analyzed transmission needs. This fundamental shift in how, where, and when electricity is generated—especially as generation moves to more remote areas—

is driving new challenges that our transmission planners are tasked with solving. Historically, the State's and the Company's transmission planning processes have been driven by the need to integrate known generation additions to each provider's system. This process, however, was established when the principal goal of resource and transmission planning was ensuring reliability surrounding a fleet of predominantly centralized fossil fuel units.

Following the Company's 2016 ERP, Public Service's Transmission Planning and Resource Planning groups have been actively collaborating on how to better align their respective processes for future ERPs. This includes earlier consideration of the size and location of potential resources needed to meet public policy initiatives, so that Public Service can better plan the transmission necessary to accommodate these new resources. The Pathway Project CPCN filing I discuss below is a tangible example of this increased coordination from both a technical perspective and a procedural perspective. Company witness Mr. Hari Singh addresses the Company's Transmission Planning efforts in more detail in his Direct Testimony.

Q. WHAT IS THE PATHWAY PROJECT?

A. The Pathway Project involves constructing an approximately 560-mile, 345 kV double circuit network transmission system between four existing substations and three new substations.[2] The Project will connect the Front Range load center(s)

[2] The three new substations will be switching stations. A switching station is a type of substation that operates at a single voltage level.

to areas of northeastern, eastern, and southeastern Colorado that are rich with renewable energy resource development potential, but do not currently have a backbone[3] network transmission system that can integrate new clean energy resources needed to meet the State's clean energy goals. As detailed in Proceeding No. 21A-0096E, initiated by the Company on March 2, 2021, the Pathway Project is comprised of five Project segments, and will be constructed in three phases with certain segments planned to be in-service by the end of 2025, and subsequent segments planned to be in-service by 2026 and 2027.

Company witness Mr. Hari Singh describes the location and technical benefits of the Pathway Project in more detail in his Direct Testimony.

Q. WHY DID PUBLIC SERVICE PROPOSE THE PATHWAY PROJECT IN ADVANCE OF ITS ERP FILING?

A. The Company proposed the Pathway Project separately and in advance of this proceeding to provide a strategic backbone transmission resource in eastern Colorado that bidders may propose to interconnect to in the Phase II competitive solicitation. The presence of this high-voltage network transmission infrastructure will allow bidders in our Phase II competitive solicitation to unlock renewable energy resources in ERZs 1, 2, 3, and 5.

[3] A "backbone" system generally refers to bulk transmission lines networked together that can move large amounts of energy from a distant location to load areas. Backbone transmission systems support the reliability of the transmission system because of they are networked systems, and thus offer more than one route to move power to load. A grid supported by backbone transmission is better positioned to withstand outages without losing generation resource or load.

Q. DID PUBLIC SERVICE PROPOSE ANY ADDITIONAL FACILITIES IN ITS PATHWAY PROJECT CPCN FILING?

A. Yes. Public Service presented for Commission consideration a 90-mile, 345 kV extension called the May Valley-Longhorn Extension. The May Valley-Longhorn Extension would involve constructing approximately 90 miles of new 345 kV double circuit transmission line from the new May Valley Substation, at the southeastern corner of the Pathway Project near Lamar,[4] south to a new Longhorn Substation located near Vilas, Colorado. This optional extension to the Pathway Project would establish additional transmission interconnection opportunities for potential clean energy resource developers in the wind-rich southeastern area of the state. The Company anticipates that having a well-planned transmission line to this area will not only facilitate clean energy resource development, but also minimize the potential likelihood of clean energy project developers needing to construct multiple generation tie lines in this region to interconnect to the Pathway Project, at potentially high costs to individual generation projects bid into this and future ERPs.

Q. HOW IS THE COMPANY'S APPROACH TO TRANSMISSION AS IT RELATES TO THIS ERP CONSISTENT WITH STATE POLICY OBJECTIVES?

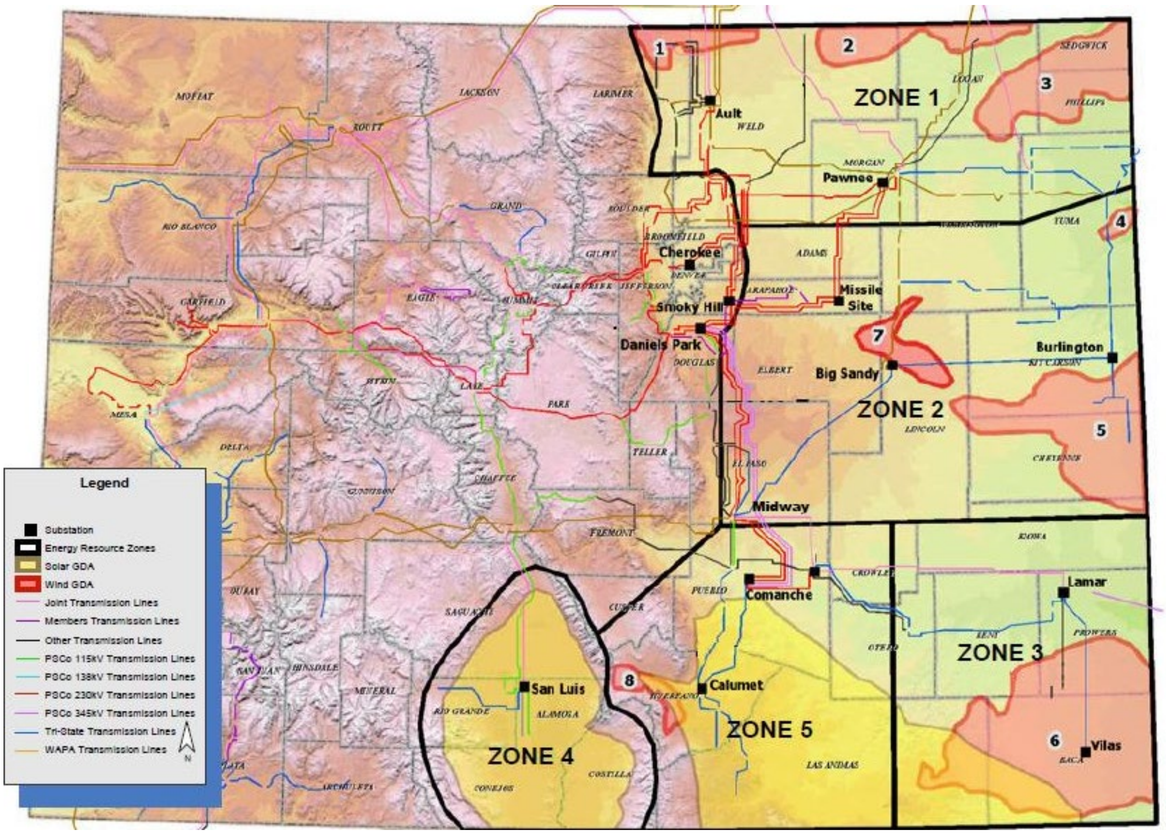
A. Colorado's Senate Bill 07-100 ("SB 07-100") established the concept of ERZs, or "geographic area[s] in which transmission constraints hinder the delivery of

[4] Note the May Valley Substation will be constructed as part of the Pathway Project even if the May Valley-Longhorn Extension is not approved.

electricity to Colorado customers, the development of new electric generation facilities to serve Colorado consumers, or both."[5] Electric utilities are required to designate these ERZs in advance of transmission planning, develop plans to ensure sufficient transmission facilities "to deliver electric power consistent with the timing of the development of beneficial energy resources located in or near such zones," and "[c]onsider how transmission can be provided to encourage local ownership of renewable energy facilities."[6] In accordance with § 40-2-126, C.R.S., the Company designated five ERZs, which have been identified in the Company's reports submitted to the Commission pursuant to SB 07-100. These SB 07-100 reports were historically filed in each odd-numbered year beginning in 2007, but since 2018 have been incorporated into the Rule 3627 Reports filed each even-numbered year. These ERZs are largely located in eastern and southern Colorado, where the Pathway Project will be constructed. Figure BAT-D-1 below shows a map of Colorado's five designated ERZs as well as the State's wind and solar generation development areas ("GDAs").[7]

[5] *Id.* at § 2(1).
[6] *Id.* at § 2(2)(b) and (c).
[7] The wind and solar GDAs were identified by the Task Force on Renewable Resource Generation Development Areas, created by Senate Bill 07-091. The Task Force was given the charge to map the renewable resources throughout the State of Colorado and identify GDAs where resources can be developed with competition among developers for utility-scale wind and solar projects.

Figure BAT-D-1: Colorado ERZs and GDAs



Q. HOW WILL THE COMPANY'S TRANSMISSION INITIATIVES HELP UNLOCK CLEAN ENERGY RESOURCES IN THESE ZONES AS PART OF THIS ERP?

A. Currently, transmission constraints in southern and eastern Colorado hinder the development of cost-effective clean energy resources. Without a nearby transmission backbone, developers must connect to the existing transmission network through lengthy and potentially expensive interconnection facilities. The available transmission in the region is insufficient to reliably accommodate the new generation needed to meet the State's renewable and clean energy goals. Bidders will need to be able to cost-effectively tap into these clean-energy rich zones in order for the Company to achieve its and the State's aggressive climate goals in 2030 and beyond. The Pathway Project will create a transmission backbone for

Phase II project developers to practically and cost-effectively develop the beneficial energy resources located in eastern Colorado's ERZs in a manner that ensures the continued reliability of the grid.

Q. DOES POTENTIAL PARTNERSHIP ON THE PATHWAY PROJECT AFFECT THE INTERCONNECTION PROCEDURES FOR GENERATION DEVELOPERS?

A. No. Public Service expects to construct and operate the entire Pathway Project, therefore, Public Service's Federal Energy Regulatory Commission ("FERC")-approved Large Generator Interconnection Process ("LGIP") under its Open Access Transmission Tariff ("OATT") would govern interconnection of resources selected in this ERP to Public Service's transmission network.

Q. WHAT IS THE STATUS OF THE COMMISSION'S RULEMAKING PROCEEDING NO. 19R-0096E AS IT PERTAINS TO THE ERP RULES?

A. At the Commissioners' Weekly Meeting on March 24, 2021, the Commission discussed the rulemaking at length and decided to not adopt new rules as a result of the proceeding.[8] However, one of the items the Commission focused on in those deliberations was what is referred to as "the Joint Transmission Proposal." By Decision No. C20-0661-I, the Commission had initiated another round of comments specifically related to transmission considerations relevant to the Company's Clean Energy Plan filing. Through this last segment of this rulemaking

[8] As of the writing of this Direct Testimony, the Commission's written Decision is pending.

process, the Company worked with a diverse coalition of stakeholders to advance a consensus proposal to better align transmission planning and resource planning.

Q. PLEASE EXPLAIN.

A. In Decision No. C20-0661-I, the Commission requested more information on "whether applications for approval of a CPCN for new transmission facilities should be filed concurrently with the initial ERP filing that launches Phase I of an ERP proceeding, particularly when the new transmission facility is necessary for the utility to achieve . . . the emission reductions required for a Clean Energy Plan pursuant to § 40-2-125.5(3)(a)(I), C.R.S."[9]

Consistent with that directive, several parties—including Public Service—filed comments addressing how transmission planning should or could be made more cohesive with the ERP process.

Q. PLEASE DISCUSS THE CONSENSUS PROPOSAL THAT EMERGED IN PROCEEDING NO. 19R-0096E.

A. In Public Service's initial comments filed on September 30, 2020, Public Service supported Commission consideration of transmission project CPCNs filed before or concurrently with a Phase I ERP and designating transmission projects for bidding as part of a Phase I ERP.[10] Over the course of this phase of the rulemaking, though, Public Service worked with Black Hills Energy ("BHE"), Colorado Energy Consumers ("CEC"), the Colorado Energy Office ("CEO"), the Colorado Independent Energy Association ("CIEA"), the Colorado Solar and

[9] Proceeding No. 19R-0096E, Decision No. C20-0661-I (mailed Sept. 15, 2020), at ¶ 29.
[10] Comments of Public Service Company of Colorado in Response to Decision No. C20-0661-I (filed Sept. 30, 2020), at 13.

Storage Association/Solar Energy Industries Association ("COSSA/SEIA"), Interwest Energy Alliance ("Interwest"), and Western Resource Advocates ("WRA") on the transmission aspects of the rulemaking and collectively introduced the Joint Transmission Proposal.[11] The Joint Transmission Proposal aims to better align transmission planning and resource planning by allowing for bidding into bid-eligible planned transmission projects in the Phase II competitive solicitation without burdening developers with costs from the transmission project. The Joint Transmission Proposal aims to do so by, among other things, having the Commission approve a "menu" of bid-eligible planned transmission projects as part of the Phase I decision.[12] However, the Joint Transmission Proposal did not preclude the filing of CPCNs for new transmission ahead of an ERP, as we have done here.

Q. IS THE COMPANY ADVANCING THE PATHWAY PROJECT UNDER THE JOINT TRANSMISSION PROPOSAL?

A. No. In the Commission's deliberations of Proceeding No. 19R-0096E, the Commission lauded the work which yielded the Joint Transmission Proposal and encouraged the use of the process, outside of new Rules, to the extent necessary. I say to the extent necessary because the Commission also acknowledged the filing of the Colorado Power Pathway Project after the creation of the Joint Transmission Proposal may likely influence the need for the proposal's use. The

[11] *See* Proceeding No. 19R-0096E, Updated Joint Transmission Proposal and Joint Final Comments to Decision No. C20-0661-I (filed Oct. 30, 2020), at 1 & Attachment A – Updated Joint Transmission Proposal Redline Rule Changes.

[12] Proceeding No. 19R-0096E, Updated Joint Transmission Proposal and Joint Final Comments to Decision No. C20-0661-I (filed Oct. 30, 2020), at 9-10.

Commission was correct. While the Pathway Project is conceptually consistent with the Joint Transmission Proposal's objective of providing bidders with greater certainty around transmission assets, it does not meet the definition *per se* of a bid-eligible transmission resource under the Joint Transmission Proposal. Notably, the Joint Transmission Proposal contemplates the designation of planned transmission as bid-eligible in the Phase I process, with the Phase II process ultimately determining if we should move forward with CPCNs for the designated planned transmission projects. We do not expect an ERP Phase II decision until late 2022 or early 2023, which will not allow time to develop the Pathway Project and have certain segments in service by 2025.[13] Given these timing issues, the Company filed its CPCN for the Pathway Project ahead of this ERP.

I also want to reinforce that, while the Pathway Project is not "designated" as a planned transmission project such that it would go through the process contemplated under the Joint Transmission Proposal, the Pathway Project has been studied by the Colorado Coordinated Planning Group ("CCPG") and has its roots in the Lamar-Front Range project that has been a long considered transmission solution in Colorado. Accordingly, I think the Pathway Project is consistent with the spirit of the Joint Transmission Proposal and goes towards the same ends—identifying strategic transmission investment that can unlock cost-

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[13] In Direct Testimony filed in support of the Pathway Project in Proceeding No. 21A-0096E, Company witness Mr. Brian J. Richter discusses the Company's planned sequencing of the Pathway Project to maximize the opportunity to capture Federal tax credits. The sequencing would allow bidders to bid into segments as they are placed in-service, which will position the Company to capture the benefits of the Production Tax Credit ("PTC") and Investment Tax Credit ("ITC") extension.

effective clean energy *ahead* of the Phase II competitive solicitation as opposed to waiting to see where the generation resources in the final portfolio are located.

Q. DO YOU HAVE ANY OTHER COMMENTS ON THE JOINT TRANSMISSION PROPOSAL?

A. The Joint Transmission Proposal was the product of significant stakeholder engagement by the Company and represented a policy proposal that was supported by a diverse set of parties. The Company therefore is moving forward consistent with the general direction of the proposal, which allows for the consideration of bid-eligible planned transmission projects as part of the Phase I process. We are not providing every component of the proposal as part of our Phase I filing, but we are meeting the central component of the proposal, which provided for the Phase I process as a venue to consider bid-eligible planned transmission projects.

Q. IS THE COMPANY PROPOSING ANY BID-ELIGIBLE PLANNED TRANSMISSION UNDER THE JOINT TRANSMISSION PROPOSAL?

A. No. The Company has considered other transmission projects such as the Weld County Expansion Project and San Luis Valley Project, but ultimately determined that these projects were not sufficiently developed to designate them as bid-eligible at this time. As Mr. Singh discusses in his Direct Testimony, these projects remain conceptual at this time and each pose unique challenges that do not render them appropriate for designation as bid-eligible planned transmission at this time.

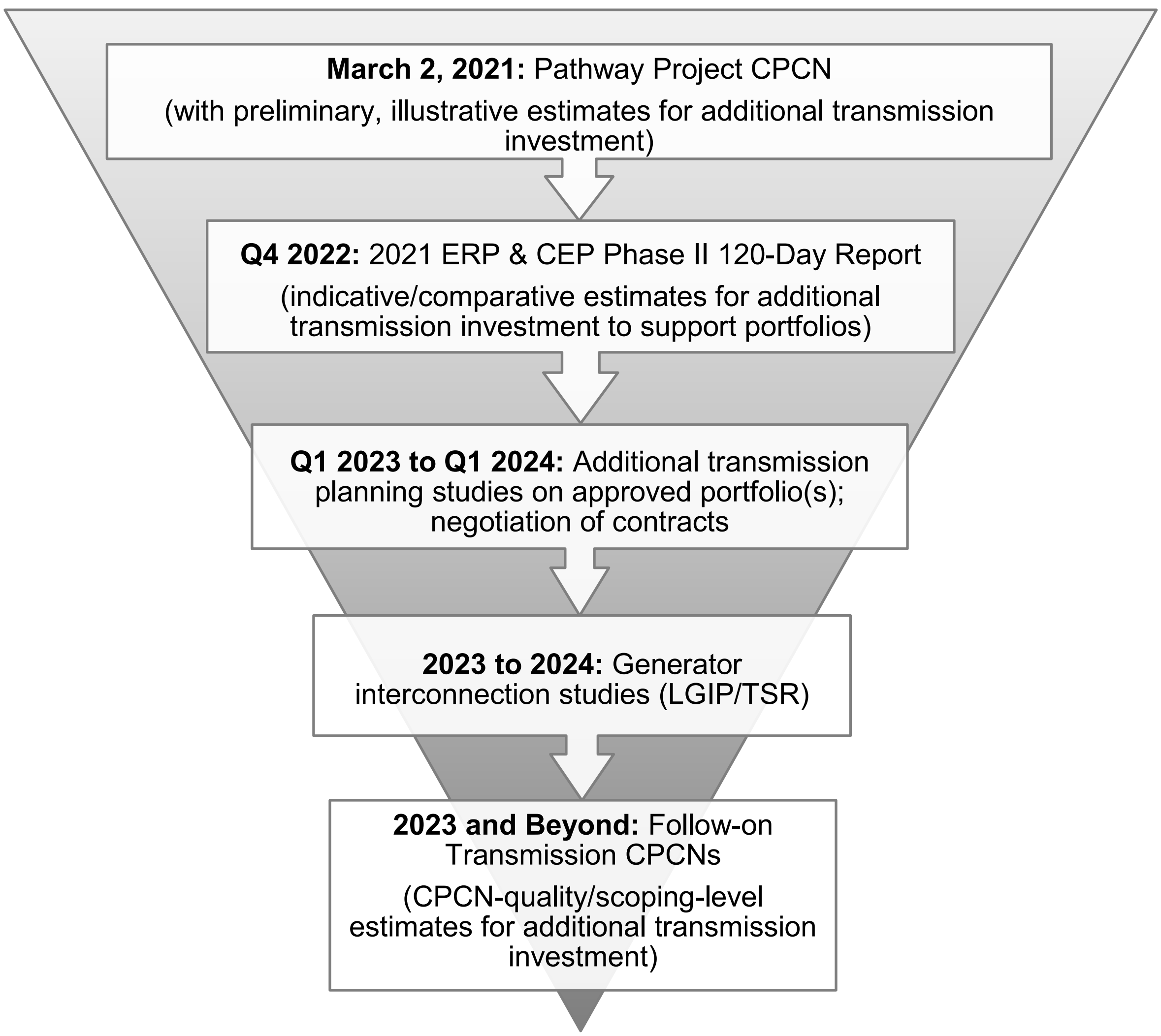
Q. DO THESE PROJECTS REMAIN CONCEPTUAL PROJECTS THAT WILL CONTINUE TO BE STUDIED IN THE COLORADO COORDINATED PLANNING GROUP?

A. Yes. Public Service will continue to evaluate the viability of these and other projects on its own and through the CCPG process.

Q. DOES PUBLIC SERVICE ANTICIPATE ADDITIONAL TRANSMISSION INVESTMENT WILL BE NEEDED TO RELIABLY IMPLEMENT THE 2021 ERP & CEP, BEYOND WHAT IS INCLUDED IN THE PATHWAY PROJECT CPCN?

A. Yes. The Pathway Project reflects a significant component of the transmission investment necessary to accommodate the 2021 ERP & CEP. However, as Public Service looks to unlock new generation resources in more remote areas of the State, we expect additional transmission investments will be needed to support the portfolio ultimately approved as part of our 2021 ERP & CEP beyond what is included in the Pathway Project CPCN filing. Additional anticipated costs generally fall into four categories: (1) Denver Metro area network upgrades; (2) grid (strength) reinforcement; (3) reactive/voltage support; and (4) generation interconnection facilities. Similar to our 2016 ERP, we will not be able to advance additional transmission cost estimates associated with our ERP until we have received and evaluated bids, and built resource portfolios, through the 120-Day Report process. Once final resources are approved through the Commission's Phase II decision, the Transmission Planning team will conduct additional, more specific studies on the approved portfolio(s) as needed. The Company will then further refine its transmission cost estimates to CPCN-quality levels for any follow-on transmission investment following the necessary studies. Company witness Mr. Singh discusses these cost categories and studies more fully in his Direct Testimony. Figure BAT-D-2 below provides a high-level visual representation of the timeline for additional transmission investments. Note that the timeline shown in Figure BAT-D-2 is a rough projection for illustrative purposes only and is subject to change based on future developments.

Figure BAT-D-2: Estimated Timeline for Additional 2021 ERP & CEP Transmission Investment



Q. ON WHAT TIMELINE DOES THE COMPANY ANTICIPATE IT WILL BE ABLE TO BRING FORWARD MORE REFINED ESTIMATES FOR THE OTHER TRANSMISSION INVESTMENT NECESSARY TO IMPLEMENT THE 2021 ERP & CEP?

A. As reflected in Figure BAT-D-2 above, Public Service Company anticipates its Phase II 120-Day Report will be filed late next year. The 120-Day Report will provide the Commission with indicative/comparative estimates of the transmission investment associated with the various Phase II portfolios evaluated. The Company will then perform more detailed planning studies and begin generator interconnection studies after a Phase II decision issues that approves the final resource plan portfolio. Following these studies, Public Service will file follow-on transmission CPCN applications with CPCN-quality cost estimates for these additional transmission investments needed to interconnect and deliver the chosen generation resources. This is the same process that the Company followed in the 2016 ERP and CEPP. Company witness Mr. Singh discusses this process in his Direct Testimony and explains the specific studies the Company will perform.

Q. ARE THERE WAYS THE COMPANY WILL KEEP THE COMMISSION AND STAKEHOLDERS UPDATED ON THE PROGRESS AND STATUS OF ITS STUDY RESULTS AND COST ESTIMATES?

A. Yes. The Company will continue to keep stakeholders informed through regularly-scheduled CCPG and FERC Order No. 890 meetings. Additionally, studies conducted pursuant to the Company's LGIP in its OATT will be published on its OASIS website. From a procedural perspective, the Company will provide more refined transmission cost estimates for these four categories of costs as part of its 120-Day Report and then follow-on transmission CPCN applications with supporting cost estimates for these additional transmission investments.

Q. ARE YOU SEEKING ANY APPROVALS OF THE COMMISSION IN THIS PROCEEDING REGARDING THE PATHWAY PROJECT?

A. No. The Commission will evaluate the necessity of the Pathway Project in the separate CPCN proceeding, and the Company has requested that the Commission issue a decision prior to the issuance of the Phase I decision in this proceeding. Given the interaction here with the Phase II process, I thought it was important to reiterate the background of the Pathway Project here.

Q. WHY IS IT IMPORTANT TO OBTAIN A DECISION ON THE PATHWAY PROJECT PRIOR TO THE PHASE I DECISION IN THIS ERP PROCEEDING?

A. First, from a bid evaluation perspective, the bids provided in Phase II of this 2021 ERP & CEP that interconnect to the Pathway Project will not be burdened with additional transmission costs under our proposed bid evaluation approach, which is consistent with the spirit of the Joint Transmission Proposal and will help advance cost-effective clean energy bids in our Phase II process. Second, the grant of a CPCN *prior* to commencement of the Phase II competitive solicitation will allow the Company to begin to make progress towards building the project and maximize certainty for bidders that the project will be developed.

III. SECURITIZATION POLICY CONSIDERATIONS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I describe securitization, its historical uses, and provide background information related to Colorado statute that enabled the voluntary option for utilities to utilize securitization as a method to recover the remaining net book value and expected decommissioning costs of Company-owned generation assets that are retired before the end of their previously presumed useful life. I also describe how the legislation also provides a potential pathway to aid communities impacted by a generation plant closure. After reviewing this background, I summarize the Company's securitization proposal in this ERP, which is specifically related to the early retirement of Comanche 3 and discuss the timeline of events that would occur to effectuate the use of securitization for Comanche 3 early retirement between this ERP and the plant's proposed retirement date of 2040. I also explain why the Company is not proposing securitization to recover the costs associated with early retirement of other Company-owned coal generation assets. I preview the important ratemaking considerations that the Commission will need to consider in future rate cases by authorizing the Company's securitization proposal. Company witness Mr. Scott A. Watson discusses the analysis the Company has performed to evaluate the three options for recovery of stranded assets due to early retirement: accelerated depreciation, regulatory asset treatment, and securitization. Finally, before going into more detail, I want to emphasize that the Company has not filed a financing order application as part of this Phase I ERP. Rather, the actual financial transaction to refinance the Comanche 3 retirement-related costs through securitization—to the extent the Commission finds in this proceeding that it is appropriate for the Company to move forward—would not occur until closer to the actual retirement date.

Q. WHAT IS SECURITIZATION?

A. Securitization is a form of refinancing that involves the creation of a financial security, typically a bond, that is backed by an authorized revenue stream pledged to repay the principal and interest of the security, as well as administrative and other costs associated with issuing and servicing the securities. These securities rely solely on the cash flow stream generated by the underlying asset or pool of assets, and not on the credit of the originating company. In Colorado, as I explain in this section of my Direct Testimony, it is a voluntary tool that the utility may use for purposes of asset recovery. There are other asset recovery methods more commonly used by this Commission—namely the regulatory asset approach—discussed in more detail by Company witness Mr. Scott A. Watson.

In the context of utility regulation, examples of the use of securitization include reducing stranded costs in electric restructuring, recovering extraordinary costs incurred as a result of storm damages and natural disasters, and financing early retirement of generation assets. In the latter scenario, assets are not stranded as result of deregulation of energy markets or storm damage. Rather, the assets "stranded" are the remaining value of generation facilities that are retired and decommissioned before the end of their presumed useful lives. When this occurs for assets that have been placed in service and included in base rates, utility ratemaking must account for recovery of the value of those assets remaining on the utility's books but not recovered in utility base rates.

Q. IS SECURITIZATION COMMON?

A. In the power industry, securitization has not been used frequently — and it is a complex refinancing option. Historically, accelerated depreciation or the creation of a regulatory asset have been common ways to recover the costs of early retirement of generation facilities. Accelerated depreciation speeds up the recovery of costs on a timeframe that matches the remaining period until earlier retirement dates. With this methodology, savings from early retirements can be offset by short-term increases in customer rates. Establishment of a regulatory asset to recover costs associated with early retirements after the retirement date can have a much lower impact to customers because the amortization period can be extended beyond the earlier retirement date, lowering the annual cost to customers compared to the accelerated depreciation method. The Commission has used this regulatory asset approach extensively in transitioning the Company's generation system.

Q. WHY DO YOU SAY SECURITIZATION IS A MORE COMPLEX FINANCING TRANSACTION?

A. Securitization requires a specific financing order, the presence of a legislatively-mandated revenue stream, creation of a special purpose entity ("SPE") to facilitate the transaction, and the issuance and servicing of specially packaged bonds. Therefore, executing a securitization requires more time and additional administrative expenses. Compared to accelerating depreciation in rates and/or recovering the amortization of a regulatory asset, these external financing requirements make securitization far more involved than the other two options. The accelerated depreciation and regulatory asset approaches can be effectuated completely within a ratemaking framework, unlike the securitization approach.

Q. HOW WOULD ONE OPTIMIZE THE AMOUNT OF AN EXECUTION OF A SECURITIZATION TO BRING THE LOWEST COST TO THE CUSTOMER?

A. Optimal execution in current markets could be achieved if securitization amounts exceed $300 million. The reason for this is that there is an index eligibility threshold that attracts investment grade investors. If the bonds are in an amount equal to $300 million or more, the bonds will be viewed as more liquid and may have more potential buyers. More investor interest tends to generate better pricing. The expected pricing for the future securitization of the undepreciated balance and other accelerated retirement costs of Comanche 3 in future markets will be driven at that time.

Q. IS SECURITIZATION AN OPTION IN COLORADO?

A. Yes, on a voluntary basis. In the 2019 legislative session, the Colorado General Assembly enacted § 40-41-101, the Colorado Energy Impact Bond Act, in SB 19-236 The purpose of the Colorado Energy Impact Bond Act was to create the voluntary option for electric utilities, in their sole discretion, to issue specific state-backed bonds in order to finance costs that the electric utility has incurred or will incur that are caused by, associated with, or remain as a result of the retirement of an electric generating facility located in the State.[14] The legislation provided that an electric utility may file an application with the Commission for approval to issue Colorado Energy Impact Bonds in one or more series, charge and collect nonbypassable charges authorized under a Commission financing order, and create Colorado Energy Impact property related to the retirement of a Colorado generation facility in the favor of the utility and that will be used to pay, and secure the payment of, the bonds and financing costs authorized in the financing order.

Q. WHAT KIND OF COSTS CAN BE SECURITIZED?

A. Examples of costs that could be securitized include the remaining book value and associated projected demolition/decommissioning costs associated with a plant, as well as upfront and ongoing costs associated with the securitization financing. The upfront and ongoing costs of the financing can be substantial and include underwriting fees, structuring fees, legal counsel fees, rating agency fees, trustee fees and expenses, accounting and auditing fees, Securities and Exchange Commission ("SEC") registration fees, printing and filing expenses, SPE organizational costs, servicer costs, marketing and other expenses.

Q. ARE OTHER COSTS INCLUDED IN A SECURITIZATION PROPOSAL?

A. Yes. Utilities may securitize amounts to affected workers and communities if approved by the Commission. I would note that another provision of SB 19-236 contemplates recovery of community assistance plan costs through a standalone cost recovery mechanism as well for accelerated retirements included as part of a

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[14] *See* § 40-41-103(1), C.R.S. ("An electric utility, in its sole discretion, may apply to the commission for a financing order as authorized by this section.")

Clean Energy Plan ("CEP"). Given the runway to the retirement of Comanche 3, and as explained in more detail by Company witness Ms. Hollie Velasquez Horvath, we are in the early stages of assembling a comprehensive community assistance plan approach for Pueblo. The proposed use of securitization factors into where we are in the planning process, as we will need to determine whether to securitize these costs or seek recovery through a post-ERP filing (i.e., a non-financing order application). For now, we are focused on how to build on the community assistance efforts undertaken with the Colorado Energy Plan and continuing to work with Pueblo stakeholders on a community assistance approach. A securitization here dovetails with that, and if the Commission approves a 2040 retirement date for Comanche 3, we will advance our community assistance plan efforts and securitization efforts in parallel to ensure they are complementary of one another.

Q. HOW DOES A SECURITIZATION WORK?

A. There are three components to securitization. First, state legislation must authorize securitization. Second, state regulatory commissions must authorize dedicated revenue streams, or nonbypassable charges, to recover the cost of the securitized bond from customers. This is accomplished through a separate financing application and financing order from the Commission. And finally, securitization requires the establishment of a SPE to facilitate the transaction.

In the first step, state legislation allows electric utilities to finance recovery of costs through issuance of bonds and establishes that the nonbypassable charge associated with the securitized bond is irrevocable. Next, the regulatory commission issues a financing order to establish the nonbypassable charge on utility customer bills. The financing order that is issued from the state regulatory commission is irrevocable, meaning it cannot be cancelled or annulled. The final step consists of creating a SPE to handle finance related to the securitization. The utility deposits charges collected from customers into the SPE and bondholders collect them from the account. Public Service would also perform other bond administration using these funds.

Q. WHAT ARE THE BENEFITS OF SECURITIZATION?

A. Refinancing the cost of early retirements through securitization has the benefits of lowering financing costs for customers and, depending upon the amounts securitized, supporting impacted communities. The credit quality and ratings for securitization reflect the predictability of that associated cash flow, and therefore the securitization is often able to achieve high credit ratings and attractive financing costs. Financing costs are lower for customers because the securitization is based on a debt only-cost, which is lower than the than the utility's weighted average cost of capital, the savings of which are reflected in customer rates. Impacted communities can benefit through community assistance, typically authorized as in SB 19-236.

Q. ARE THERE DRAWBACKS TO SECURITIZATION?

A. Yes. Securitization can erode the future financial health of a utility substantially by eliminating the return on, as well as the return of, the utility's invested capital in the early retired generation while, at the same time, adding debt from the securitization. This adversely impacts various metrics used by credit rating agencies to grade a utility's creditworthiness, including:

- CFO Pre-working capital + Interest / Interest
- CFO pre-working capital / Debt
- CFO Pre-working Capital minus dividends / Debt
- Debt / Capitalization

To the extent securitization is utilized for Comanche 3 in 2040, its use would need to be accounted for in determining the Company's capital structure in future rate cases. It is imperative that securitization not harm the Company's financial health, and Public Service would need to carry a higher equity ratio to account for the securitization of the plant. Company witness Mr. Watson addresses this in more detail but, given the Commission's historical support for the Company's financial health, it is an important perspective to add as we evaluate the use of this tool for Comanche 3.

Q. ARE THERE OTHER CHALLENGES WITH SECURITIZATION?

A. Yes—securitization transactions are complicated and require the creation of a SPE for the securitized assets. The right to recover the costs of the stranded assets through the nonbypassable charge must be transferred to the SPE, with the nonbypassable charge collected by Public Service and passed directly to the SPE for bond service and administration. This requires additional legal work and other costs above what the utility would pay for a standard bond issuance, for example, to set up the SPE and associated ongoing billing, reporting, and administrative burden. Other challenges and considerations include: the financing order and associated issuance process takes longer than a standard bond issuance (12-24 months), thus introducing additional market risk to the transaction; the diligence process performed by the rating agencies is much more involved, typically taking two to three months; there is a requirement of the sponsor (Public Service) to act as servicer with ongoing duties including periodically calculating and adjusting the charge to ratepayers and creating investor reports; there are significant administrative, servicing and accounting/billing systems responsibilities in the event that the issuer has not previously securitized; and finally, there are higher upfront costs associated with the set-up of the SPE, billing and accounting, systems, structuring advisor, legal fees, and other fees.

Q. ARE THERE AVENUES TO MITIGATE THE EROSION OF THE UTILITY'S FINANCIAL HEALTH DUE TO SECURITIZATION?

A. Yes. Releasing a utility's capital funds through securitization can be paired with utility reinvestment in new energy resources—including cost-effective clean energy resources—can help offset some of the negative financial impacts of securitization. Enabling redeployment of utility capital into clean energy resources not only supports the financial health of the utility but also supports the advancement of State energy policy and emission reduction objectives.

Q. DOES SB 19-236 AUTHORIZE REPLACEMENT GENERATION?

A. Not specifically, but several considerations support the proposition that the opportunity to reinvest in utility-owned replacement generation is a key policy consideration when evaluating securitization. First, securitization is a voluntary tool, which is made clear by § 40-41-103(1), C.R.S. providing that "[a]n electric utility, in its sole discretion, may apply to the commission for a financing order as authorized by this section." Second, early retirement of coal-fired generation creates a resource need as the subject generation is retired. Generally speaking, and from a public policy perspective, the resource need created by early retirement of utility-owned generation facilitated through securitization should be met with utility-owned, clean energy resources to avoid adverse impacts to the utility from the voluntary use of the securitization tool. This action mitigates the lost value to the utility from the early retirement of the generation through securitization and creates a pathway to enabling more clean generation.

In the context of this 2021 ERP & CEP, the Company has modeled and is proposing the potential use of securitization to refinance the costs of early retirement of Comanche Unit 3 in 2040 as part of its preferred plan. This securitization would include associated decommissioning costs and securitization transaction costs. Future applications made by Public Service would address the actual financing authorization, as well as replacement generation. I discuss these future activities in more detail later in this Section.

Q. WHAT ARE THE IMPACTS OF SECURITIZATION TO THE COMPANY'S FINANCIAL INTEGRITY?

A. The securitized costs of the Company's proposed early retirement of Comanche Unit 3 would represent a significant component of Company debt; therefore, a securitization could result in negative impacts to the Company's financial metrics at the time of securitization and throughout the securitization period. Financial metrics are evaluated by rating agencies in determining the bond rating of utilities.

These bond ratings directly impact a utility's access to capital at affordable rates. It is in the best interest of utility customers to ensure utility credit ratings are strong.

Q. DOES APPROVING A PATHWAY TO SECURITIZATION IN THIS PROCEEDING HAVE IMPLICATIONS FOR FUTURE RATE CASES?

A. Yes. The credit implications of securitization are credit negative in early years and credit positive in later years. This is because securitized debt amortizes like a mortgage, i.e., in the early years, most of the payment goes towards interest and in the later years, most of the payment goes to pay principal. From a utility credit perspective, financial ratios are negatively impacted in the early years of securitization when most of the revenue collected goes to pay interest. As financial ratios are stressed due to the presence of this securitized debt, it is important that the regulatory environment supports the Company's financial integrity, which enables the Company to maintain a sound financial condition. This is particularly important as the Company transitions its generation fleet to meet aggressive clean energy targets not only between now and 2030—but also beyond 2030 as the Company moves toward a carbon-free future by 2050.

As I described above, the actual financial transaction to refinance the Comanche 3 retirement related costs through securitization will not occur until closer to the actual retirement date. Recovery of the securitized costs will occur over many years and it is not until later years when most of the revenue collected will go towards paying down principal. Therefore, it will be many years down the road before the stress of securitization eases for Public Service. Prior to and during this time when financial ratios are stressed, it will become increasingly important for the Commission to take credit-supportive actions in Public Service's base rate proceedings.

Q. WHAT ARE CREDIT SUPPORTIVE ACTIONS THAT THE COMMISSION CAN TAKE WHEN PUBLIC SERVICE'S FINANCIAL METRICS ARE STRESSED?

A. The Commission has a number of tools that it can use to support the Company's financial integrity—the benefits of which are reflected in customer rates through lower long-term costs of debt and equity. One tool available to the Commission is to authorize a higher equity ratio, which the Commission has done in the past to strengthen Public Service's credit metrics. For example, in the early 2000s, the Commission supported the Company's efforts to improve its credit rating by increasing the amounts of equity in its capital structure and authorized an equity ratio of up to 60 percent. One of the main drivers of the Company's equity ratio was and continues to be the negative credit implications of off-balance sheet debt due to purchased power agreements ("PPA") because, given long-term fixed obligations under PPAs, the utility commits cash flow, which in turn affects the utility's ability to meet other financial obligations—including other debt obligations. For example, in a settlement agreement approved by the Commission, it "recognize[d] the Company's need to increase its equity ratio, as calculated for financial reporting purposes, to 56 percent in order to offset the debt equivalent value of existing purchased power agreements and to improve the Company's overall financial strength."[15] In 2006, building on this prior decision, the

[15] Decision No. C05-0049, at ¶ 95, Consolidated Proceeding No. 04A-0215E.

Commission approved an equity ratio of 60 percent.[16] The higher equity ratio, paired with the Company's actions to manage its balance sheet in a way to increase equity, helped to counteract the negative credit implications of the off-balance sheet debt, among other things. These Commission decisions and actions helped to improve Public Service's credit rating to BBB in 2008, to BBB+ in 2009, and to A- in 2010, resulting in lower coupon rates for new bond issuances and savings for customers over the lives of those bonds. These same considerations are relevant in the case of a securitization, and it is undisputed that it is in our customers' best interests to have a utility that is financially healthy.

Q. ARE THERE OTHER TOOLS BEYOND CONSTRUCTIVE TREATMENT OF THE COMPANY'S EQUITY RATIO AVAILABLE TO THE COMMISSION TO SUPPORT PUBLIC SERVICE'S FINANCIAL INTEGRITY?

A. Yes. First, the Commission can authorize a return on equity ("ROE") that is at the upper end of the range of the ROEs authorized for similarly situated utilities of comparable risk. Although recently authorized ROEs for Colorado utilities have been below the national average, the Commission had previously approved ROEs that were at or above the national average authorized ROEs. Authorizing ROEs consistent with or above the national average ROE sends a powerful message about the credit-supportiveness of the regulatory jurisdiction.

Second, the Commission has the option to increase the Company's authorized depreciation and amortization rates, which increases cash flow and

[16] Decision No. C06-1379, at ¶ 35, Proceeding No. 06S-234EG,

improves the credit metrics that the rating agencies rely on to establish ratings. For example, Public Service's sister company, Northern States Power Company – Minnesota, has a lower authorized equity ratio than Public Service but generally stronger credit metrics because the Minnesota commission has established higher depreciation rates than this Commission has approved for utility assets. I offer this not as a criticism of this Commission, but because Commission decisions have a significant impact on the Company's credit quality and this serves as an example of the interaction of the different tools and how they are viewed by rating agencies.

Third, the Commission can approve and maintain cost recovery mechanisms that eliminate or reduce the effects of regulatory lag. It is important to note that these mechanisms are not mutually exclusive. The Commission can approve a combination of mechanisms to ensure that the Company maintains access to capital markets at a reasonable cost.

Q. IF SECURITIZATION IS THE ASSET RECOVERY METHODOLOGY THE COMMISSION AUTHORIZES WITH REGARD TO COMANCHE 3'S EARLY RETIREMENT, HOW WOULD THE COMPANY EFFECTUATE THE SECURITIZATION?

A. If approved by the Commission, implementing securitization would occur through a series of events, including a subsequent application for approval of the securitization financing order closer to the 2040 retirement date. Table BAT-D-1 below outlines this estimated timeline.

Table BAT-D-1: Securitization Series of Events

2021 ERP – Clean Energy Plan	Commission authorizes: • Early retirement of Comanche Unit 3; • Public Service to file future financing application to securitize, at a minimum, the costs of unrecovered net book value, decommissioning and transaction costs associated with the early retirement of Comanche Unit 3.
Subsequent Limited-Scope Decommissioning CPCN	The Company presents decommissioning estimates for Commission approval through CPCN
Financing Application	The Company presents costs of securitization in a financing order application, including as applicable unrecovered net book value, Commission-approved decommissioning costs, potential workforce transition or community assistance costs, and transaction costs.

Q. WHAT DRIVES THE TIMING OF THE FINANCING APPLICATION?

A. The timing of the financing application is driven by the approved retirement date of the securitized asset. In general, the time needed to prepare and file the financing application, obtain rating agency approval, set up the SPE, transfer assets and complete the financing transaction is 12 to 24 months, depending on structure and complexity of the transaction. We can work with the Commission on the timing of this application if our preferred coal action plan is approved in this proceeding; however, the financing application associated with the proposed Comanche 3 early retirement would not be presented to the Commission until a later time closer to the securitization.

Q. HOW WILL SECURITIZED COSTS BE RECOVERED?

A. The securitized costs are recovered through a nonbypassable charge assessed to all retail customers. The nonbypassable nature of the charge is foundational to the securitization approach, and § 40-41-102(17), C.R.S. provides a specific definition of "nonbypassable": "[T]he payment of a CO-EI charge may not be avoided by any future or existing customer located within an electric utility service area as such service area existed as of the date of the financing order or, if the financing order so provides, as such service area may be expanded, even if the customer elects to purchase electricity from a supplier other than the electric utility. As part of a financing order application, the utility will also provide "a proposed methodology for allocating the revenue requirement for the CO-EI charge among customer classes, including special contract customers."[17]

Q. WHY HAS THE COMPANY PROPOSED TO SECURITIZE THE COSTS OF COMANCHE 3'S ACCELERATED RETIREMENT, BUT NOT PROPOSED TO SECURITIZE THE COST OF OTHER COAL ACTIONS?

A. The Company analyzed the impacts of accelerated depreciation, regulatory asset, and securitization recovery mechanisms for each of its proposed coal actions in the Company's preferred plan, as discussed in more detail by Mr. Watson. Under the Company's preferred plan, securitization results in customer savings when evaluating the accelerated retirement of Comanche 3 in 2040 as compared to the alternative accelerated depreciation or regulatory asset approaches. Our analysis

[17] § 40-41-103(3)(a)(IV), C.R.S.

of securitization for Craig and Hayden coal actions, however, does not result in projected savings to customers and our analysis is explained in more detail by Mr. Watson. Pawnee is not proposed for an accelerated retirement, as it will stay on until the end of its book life in 2041 under our preferred plan. Pawnee is, however, proposed for conversion to natural gas, and the conversion will result in the retirement of certain coal-related assets at the plant. For these costs, as explained by Mr. Watson, the Company is proposing to use the regulatory asset approach for asset recovery, which has been commonly and effectively used by this Commission for numerous accelerated retirements. Moreover, it is legally questionable—at best—whether we can securitize these assets; moreover, our analysis does not show a benefit to customers from a securitization approach when evaluated alongside the regulatory asset approach.

Q. IF THE COMMISSION APPROVES THE COMPANY'S PLAN TO SECURITIZE COMANCHE 3 IN 2040 AS PART OF ITS PHASE I DECISION, WILL THE COMMISSION DETERMINE IN PHASE II OF THIS ERP THE CLEAN GENERATION RESOURCES THAT THE COMPANY WILL REINVEST IN?

A. No. Under our preferred plan, Comanche 3 does not retire in the resource acquisition period and therefore the Commission will evaluate and determine the Company-owned generation resources to replace the capacity need associated with Comanche 3 as part of the resource acquisition period in a future ERP.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS ABOUT SECURITIZATION FROM A POLICY PERSPECTIVE AS IT RELATES TO THE COMANCHE 3 PROPOSAL?

A. Yes. Securitization is an appropriate tool to finance the costs of early retirement of Comanche Unit 3 because the associated costs (remaining net book value, decommissioning, transaction costs, and potentially community assistance costs) are of appropriate magnitude for this type of involved financing transaction. Securitization—properly deployed and under the right circumstances—can reduce costs to customers and support advancement of the clean energy transition in Colorado by enabling potential assistance to affected communities and reinvestment by the Company in future clean energy resources. Approving the Company's plan to securitize the assets stranded by the early closure of Comanche 3 is the first step in a series of securitization-related actions that would occur over the next two decades.

Q. PLEASE SUMMARIZE THE COMPANY'S REQUEST OF THE COMMISSION IN THIS PROCEEDING RELATED TO COMANCHE 3 AND THE COMPANY'S SECURITIZATION PROPOSAL.

A. In this Phase I portion of the Company's ERP, Public Service requests a specific finding from the Commission authorizing an early retirement date of 2040 for Comanche 3 as well as a specific finding that the Company's plans to securitize the costs associated with the unit's early retirement is reasonable and in the public interest. This authorization is needed in this ERP in order begin a series of involved actions as the Company approaches Comanche 3's early retirement date to determine decommissioning cost estimates and effectuate the securitized refinancing, which will involve subsequent regulatory filings and Commission approvals.

IV. SB 19-236 COST RECOVERY

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. The purpose of this section of my Direct Testimony is to address cost recovery topics associated with the 2021 ERP & CEP. SB 19-236 puts in place a specific cost recovery framework, and while cost to customers will ultimately be determined through the Phase II process and subsequent rate proceedings, it is important to outline them here for Commission review and affirmation prior to Phase II.

Q. WHAT MECHANISMS ARE AVAILABLE TO RECOVER COSTS ASSOCIATED WITH THE 2021 ERP & CEP?

A. There are new tools, traditional tools, and repurposed tools available for cost recovery for the 2021 ERP & CEP. These tools include a new mechanism, the CEPR provided by SB 19-236, as well as existing or repurposed mechanisms, e.g., the Renewable Energy Standard Adjustment ("RESA") for select incremental costs, the Electric Commodity Adjustment ("ECA") for fuel costs and other items, the Transmission Cost Adjustment ("TCA") for network transmission costs, and base rates. I am duplicating a table below from the Direct Testimony of Ms. Jackson.

Table BAT-D-2: Relevant Cost Recovery Mechanisms

Mechanism	*Scope of Recovery*
CEPR (SB 19-236)	Clean Energy Plan capital investments and operating and related expenses *exclusive* of fuel costs, transmission costs, ERP portfolio costs, eligible energy resource incremental costs, clean energy resource and directly related interconnection facilities incremental costs
RESA (SB 19-236)	Incremental costs of clean energy resources and directly related interconnection facilities (one-half of annual RESA collections plus accrued funds)
RESA (Traditional)	Incremental costs of eligible energy resources (all remaining RESA funds)
ECA	Fuel costs plus other approved items
TCA	Network transmission costs
Base rates	All other costs

Q. PLEASE PROVIDE MORE DETAIL REGARDING THE CEPR.

A. The purpose of the CEPR is to ensure "retail rate stability," and one of the stated goals articulated by the General Assembly for the ERP and CEP portion of SB 19-236 is to "allow Coloradans to enjoy the benefits of reliable clean energy at an affordable cost." The CEPR recovers the incremental costs of the CEP as compared to the ERP, exclusive of certain costs recovered through other mechanisms. These other mechanisms are transmission costs recovered through the TCA, fuel costs recovered through the ECA, incremental costs of eligible energy resources recovered through the RESA, and incremental costs of clean energy resources and their directly related interconnection facilities recovered through the "repurposed" RESA. The utility has discretion as to when to start the CEPR and what level to start the CEPR at, with the maximum amount set at 1.5 percent of the total electric bill annually. Section 40-2-125.5(5)(a)(II), C.R.S. provides that the CEPR "may be established as early as the year following approval of a clean energy plan by the commission ….". Accordingly, we are proposing to start the CEPR at an appropriate level to be established by the Phase II decision and it will continue through a final reconciliation in the first rate proceeding after 2030. The CEPR essentially recovers the costs of clean energy plan activities that are incremental to the ERP costs. To effectuate this, we have built an ERP reference case to isolate ERP costs, and the CEPR then recovers the incremental costs of the preferred plan as compared to this reference case. Company witness Mr. James F. Hill describes the "ERP portfolios" and the "CEP portfolios" in his Direct Testimony, as does Mr. Alexander G. Trowbridge.

Q. WHAT COSTS ARE ELIGIBLE FOR RECOVERY UNDER THE CEPR?

A. Section 40-2-125.5(5)(a), C.R.S. allows for recovery of "additional clean energy plan activities," and the statute broadly refers to these activities to "include retirement of existing generating facilities, changes in system operation, or any other necessary actions."[18] Accordingly, the costs of new or acquired generation, retirement costs, and any other costs necessary to advance towards the clean energy target are recoverable through this mechanism. By providing for the CEPR, the statute "afford[s] customers certainty on the maximum rate impact of the approved additional clean energy plan activities through at least calendar year 2030."[19] It also provides for annual reporting on the amount of CEPR collections, the CEPR account balance, interest expense on the CEPR balance, and any other information required by the Commission.[20]

[18] § 40-2-125(4)(a)(III), C.R.S.
[19] § 40-2-125.5(5)(a)(IV), C.R.S.
[20] § 40-2-125.5(a)(IV(A)-(E).

Q. WHAT HAPPENS WITH THE CEPR AFTER 2030?

A. The Commission will perform a reconciliation of the CEPR in the first electric rate proceeding following "the final implementation the clean energy plan," which in my view means after 2030. Any positive rider balance will be returned to customers or used to reduce rates, and any negative balance is incorporated into rates and recovered by the Company. In this way, the CEPR functions like a tracker and is either returned or recovered depending on its balance at the time of the reconciliation. Additionally, from the CEPR's commencement through the post-2030 reconciliation, the CEPR may be increased or decreased at the request of the Company and as approved by the Commission.

Q. HOW IS THE COMPANY MODELING THE CEPR IN THIS PROCEEDING AND WHAT APPROVALS ARE YOU SEEKING WITH REGARD TO THE CEPR?

A. Company witness Mr. Trowbridge provides two different alternatives of the CEPR collections, one with the full one and one-half percent starting on January 1, 2024, and one with a shaped approach where the CEPR is brought in at one percent, then stepped up to one and one-quarter percent, and ultimately brought to a full one and on-half percent. We may need to use a shaping approach or we may not—it all depends on the make-up of the bid portfolios as part of the Phase II process. Mr. Trowbridge provides these two respective analyses to show two different approaches for CEPR recovery and use of CEPR funds. We seek Commission approval to implement the CEPR following the Phase II decision in this proceeding, but its exact structure will be determined through the Phase II process once we figure out the best recovery approach for the CEPR.

Q. PLEASE PROVIDE MORE DETAIL REGARDING THE TWO RESPECTIVE USES OF THE RESA DESCRIBED ABOVE.

A. Some background on the RESA may be helpful as a starting point, and more detail is provided by Company witness Mr. Alex Trowbridge. The RESA has been in place to implement the Renewable Energy Standard ("RES") for many years, and under § 40-2-124(1)(g), C.R.S. it recovers the incremental costs of eligible energy resources. Under that structure, avoided costs are recovered through the ECA and incremental costs are recovered through the RESA. With the Company's 2016 Colorado Energy Plan, however, the Stipulation giving rise to the plan provided for use of one percent of RESA funds to recover the incremental accelerated depreciation expense associated with the accelerated retirement of Comanche 1 and Comanche 2. The Commission established the Colorado Energy Plan Adjustment ("CEPA") for this purpose in Decision No. C18-0762 in Proceeding No. 17A-0797E. In the compliance proceeding to implement the CEPA, Proceeding No. 20AL-0191E, the Commission issued Decision No. C20-0700 approving its implementation while also "conclud[ing] that there is insufficient basis for continuing a RESA surcharge after December 31, 2022."[21] The Commission further provided, however, that "Public Service may file an advice letter to continue the RESA after December 31, 2022, where such filing will trigger a holistic examination of the RESA surcharge."[22]

[21] Decision No. C20-0700, at ¶ 20.
[22] Decision No. C20-0700, at ¶ 21.

Q. WHY IS THE RESA IMPORTANT FOR PURPOSES OF THIS FILING?

A. It is important for two reasons. First, it provides a cost recovery mechanism to recover the incremental costs of eligible energy resources. Second, SB 19-236 provides an avenue to utilize RESA funds more broadly; specifically, if the minimum percentage requirements of the RES are satisfied, then the utility may "propose to use up to one-half of the funds collected annually [through the RESA], as well as any accrued funds, to recover the incremental cost of clean energy resources and their directly related interconnection facilities."[23] This extends the utilization of RESA funds to cover a broader set of resources, i.e., clean energy resources as opposed to just eligible energy resources. Eligible energy resources are a subset of clean energy resources, so this is a broader application. In sum, if the RESA were to continue, it would be available to absorb the incremental costs of eligible energy resources and clean energy resources, as provided for under the RES statute and SB 19-236.

Q. SHOULD THE RESA BE EXTENDED BEYOND ITS CURRENT EXPIRATION DATE AT THE END OF 2022?

A. As explained by Mr. Trowbridge, the Company believes the RESA remains a helpful tool to assist in recovering the cost associated with this plan and to continue to pay the incremental costs of Distributed Energy Resources ("DER"). We project a substantial amount of DER development in this plan through 2030 (1,300 MW) and we believe that between those acquisitions and the significant level of

[23] § 40-22-125.5(4)(a)(VIII), C.R.S.

renewable energy resources projected to be brought online through this plan, there may be value in extending the RESA.

Q. HAS THE COMPANY FILED AN ADVICE LETTER TO CONTINUE THE RESA AS PART OF THIS PLAN?

A. No. We believe, however, that the examination of portfolios in this Phase I proceeding can provide information helpful in evaluating whether to extend the RESA and merits further discussion in this proceeding. Mr. Trowbridge provides modeling around the RESA under a one percent collection and a one-half of a percent collection for these purposes. However, the Company will formally file to extend the RESA, if appropriate, in a future Renewable Energy Plan ("RE Plan") proceeding. The RESA and its use can also be more fully evaluated after coal actions are approved in this Phase I proceeding and actual bids are received in Phase II. The Company is, at this time, seeking approval of the lockdown approach described by Mr. Trowbridge for use in any future RESA evaluation. We would use this lockdown approach as the RESA is evaluated in a future RE Plan proceeding.

Q. WHAT COSTS WOULD FLOW THROUGH THE ECA?

A. The ECA is the mechanism that allows Public Service to generally collect its fuel and eligible energy resource costs (purchased or owned). Generation fuel costs and other approved items would be recovered through the ECA. Under the SB 19-236 construct, this mechanism would recover non-CEPR, ECA-eligible costs, including the avoided costs of eligible energy and clean energy resources and fuel costs.[24] This mechanism would work with base rate recovery, as discussed below, to recover the costs of the plan, e.g., ERP plan costs not covered by the CEPR and avoided costs traditionally recovered through this mechanism.

Q. WHAT COSTS WOULD FLOW THROUGH THE TCA?

A. Network transmission costs would be recovered through the TCA in between rate cases. This would include the costs of the Pathway Project, as well as any additional network transmission costs necessary to implement the plan.

Q. WHAT COSTS WOULD GENERALLY END UP IN BASE RATES?

A. Any costs not recovered by the mechanisms outlined above would be recovered in base rates.

Q. DO YOU HAVE ANY OTHER COMMENTS ON THESE COST RECOVERY MECHANISMS?

A. Yes. To simplify the cost recovery structure, I find it helpful to think about it as follows:

- CEPR – incremental costs above the ERP plan **FROM CLEAN ENERGY ACTIVITIES;**
- RESA – incremental costs of eligible energy resources and clean energy resources;
- ECA – traditional ECA costs**;**
- TCA – network transmission costs; and
- Base rates **– ALL OTHER COSTS.**

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[24] "Avoided costs" in the RESA context mean the costs recovered through the ECA, while incremental costs are the costs above the avoided costs and recovered through the RESA.

I should note that if and when any financing order for a Comanche 3 securitization is approved by the Commission, there would also be a nonbypassable charge on customer bills associated with the securitization. In addition, if a cost recovery mechanism is authorized in the future for community assistance and/or workforce transitions costs, this could also be included on customer bills. This determination, as explained by Company witness Ms. Jackson, will be made at a future time in another proceeding.

Q. WHAT ARE THE PROJECTED RATE IMPACTS ASSOCIATED WITH THE PREFERRED PLAN?

A. The rate impacts are addressed by Company witnesses Mr. Hill and Mr. Trowbridge.

V. OTHER REGULATORY AND COST RECOVERY CONSIDERATIONS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. The purpose of this section of my Direct Testimony is to address regulatory considerations related to stand-alone storage in our upcoming Phase II competitive solicitation. In addition, I address cost recovery related to long-lead time resources and a potential framework moving forward as we advance towards a carbon-free future by 2050.

A. Regulatory Considerations for Stand-Alone Storage

Q. PLEASE SUMMARIZE WHAT THE COMPANY IS REQUESTING RELATED TO STAND-ALONE STORAGE RESOURCES.

A. Through the Phase II competitive solicitation, Public Service anticipates receiving bids for additional cost-effective energy storage devices for the enhancement of system reliability and other benefits and potentially acquiring these resources as part of its approved portfolio. As discussed in the Dispatchable Resources RFP included in Volume 3,[25] these proposed resources could be acquired as a Company "self-build" (i.e., Company developed and owned), a "build-own transfer" ("BOT"), or through a PPA.

Q. HOW HAVE STORAGE RESOURCES BEEN BID INTO PRIOR COMPETITIVE SOLICITATIONS?

A. Historically, all battery storage resources have been paired with a solar generation resource and, through the Commission's approval of the Colorado Energy Plan,

[25] Volume 3 is provided as Attachment AKJ-3 to the Direct Testimony of Alice K. Jackson.

acquired through PPAs. Currently, federal investment tax credit ("ITC") policy allows energy storage projects to realize the ITC value when paired with solar generation, but not on a stand-alone basis. Federal tax policy could shift to grant the ITC to stand-alone storage, and/or future Phase II bid processes could yield a different result. However, to date, solar plus storage bids have been the most economic pathway to bring battery storage to the system, largely because of the higher available tax incentives.

Q. WHAT ARE THE IMPLICATIONS OF RECEIVING BIDS IN THE COMPETITIVE SOLICITATION FOR STAND-ALONE BATTERY STORAGE RESOURCES?

A. Implications related to stand-alone battery storage resources involve an operational perspective and a financial perspective. First, from an operational perspective, for stand-alone energy storage acquisitions fulfilled with PPAs, the Company will control the real-time charging and dispatch of these resources to optimize their value to the electric system. This is similar to how the Company would control the resource through a self-build or BOT option; however, with a PPA the Company would not own or otherwise take title to the resource. Given the degree of control that will be conveyed to Public Service in a PPA for a stand-alone battery storage resource, any such PPAs will qualify as leases for accounting purposes, and could potentially trigger capital lease treatment—or, to use more updated terminology—finance lease treatment.[26].

[26] Prior to the effective date of Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 842 (January 1, 2019 for Public Service), *finance leases* were called *capital leases*; however, the overall accounting treatment and financial ramifications for Public Service are still the same.

Q. WHY ARE STAND-ALONE BATTERY STORAGE PPAS EXPECTED TO RESULT IN LEASES?

A. As discussed above, in order to take full advantage of these resources, Public Service will control both charging and dispatch of the stand-alone storage facilities. Accounting Standards Codification 842 ("ASC 842") generally defines a lease as a contract conveying the rights to direct an asset's use and to receive substantially all of its economic benefit for a period of time. Based on this definition, Public Service has determined that given the Company's control over charging and dispatch (and receipt of economic benefits) of stand-alone storage facilities, PPAs for this type of resource will be recognized by the Public Service as leases from an accounting perspective.

Q. WHAT ARE FINANCE LEASES AND HOW DO THEY DIFFER FROM OPERATING LEASES?

A. Off-takers that enter into PPAs that qualify as leases are required under ASC 842 to classify these agreements as either operating leases or finance leases. As further discussed below, ASC 842 establishes criteria intended to determine whether a lease is similar economically to the purchase of an asset, conveying the right to direct its use and obtain substantially all of its remaining economic benefits. If any of these criteria are met, the arrangement will be classified as a finance lease. Following Public Service's implementation of ASC 842 in 2019, both operating leases and finance leases require an off-taker to recognize an asset for the right to use the leased asset over the lease term, as well as a corresponding liability for the obligation to make lease payments. However, from a credit rating standpoint, the credit rating agencies view finance lease obligations in a more punitive manner than operating leases.

Q. WHAT TYPES OF CONTRACT TERMS MAY RESULT IN PUBLIC SERVICE ACCOUNTING FOR A STAND-ALONE BATTERY STORAGE RESOURCE AS A FINANCE LEASE?

A. Two particular criteria are most closely evaluated when determining if a dispatchable PPA contains a finance lease:

(1) if the present value of the lease payments represents "substantially all" of the fair value of the leased asset; or

(2) if the lease term is for a "major part" of the estimated economic life of the leased property.

If either of these criteria are met, then the lease must be treated as a finance lease. In practice, if the present value of the lease payments is 90 percent or more of the fair value of the asset, this would represent substantially all fair value. And if the lease term is 75 percent or more of the estimated life of the asset, the lease term is presumed cover the "major part" of the estimated economic life. There are other lease arrangement attributes that trigger finance lease treatment, including transfer of the asset to the off-taker at the end of the contract, the existence of a bargain purchase option, and whether the leased asset is so specialized that it has no alternative use to the resource owner at the end of the lease term. However, these latter criteria are unlikely to be problematic given the terms of the Company's model contracts and the nature of the resources.

Q. WHAT ARE THE BALANCE SHEET AND CREDIT RAMIFICATIONS OF FINANCE LEASES TO THE COMPANY?

A. To summarize, when a contract contains a finance lease, the present value of the future lease payments is recognized as a lease liability. This amount, adjusted for any prepayments and lease incentives, is recognized as a lease asset. Public Service expects that the credit rating agencies will evaluate the amounts presented for finance leases in the Company's Generally Accepted Accounting Principles financial statements as 100 percent on-balance-sheet debt, negatively impacting debt-to-capitalization ratios, and putting stress on Public Service's credit ratings – placing upward pressure on borrowing rates for the Company and its customers, among other issues.

Q. DOES THE COMPANY FACE SIMILAR FINANCE LEASE ISSUES FOR OTHER PPAS?

A. As discussed above, PPAs for stand-alone battery storage have been determined to qualify as a lease, and certain of these contracts may further qualify as a finance lease based on specific terms of the arrangement, including the present value of the lease payments relative to the fair value of the asset, and the length of the PPA relative to the economic life of the asset. Public Service has reached a similar conclusion under Accounting SC 842 that dispatchable PPAs for gas-fueled generation facilities qualify as leases (given the Company's control over the assets), and the Company similarly needs to evaluate whether finance lease treatment is appropriate for such arrangements. However, for solar and wind PPAs, given the inability for the Company to directly dispatch these resources (power production and dispatch is determined by weather or solar irradiance), the arrangements do not qualify as leases under ASC 842, and as such do not create finance lease issues under this accounting guidance.[27]

Q. DOES THE COMPANY HAVE A PROPOSAL TO MITIGATE THE NEGATIVE POTENTIAL FINANCIAL IMPACT OF STAND-ALONE STORAGE PPAS?

A. Consistent with previous ERP proceedings, in order to mitigate the negative credit implications of finance leases, Public Service seeks to accept bids for stand-alone battery storage resources in the form of self-builds, BOTs, or PPAs; however, with respect to PPA bids received, the Company will negotiate contract terms that do not result in finance lease treatment. Specifically, the dispatchable RFP documents included in Volume 3 (provided as Attachment AKJ-3 to the Direct Testimony of Alice K. Jackson) expressly state that the Company is unwilling to be subject to the accounting treatment that results from the classification of a PPA as a finance lease. Public Service proposes to continue to protect the Company and its customers from the negative impacts of finance leases by again applying these guidelines to all dispatchable resources.

Q. HOW IS THIS CONSISTENT WITH PRIOR ERP PROCEEDINGS?

A. In the Company's 2007 ERP (Proceeding No. 07A-447E), the financial impacts of leasing and consolidation was addressed and the Commission permitted the Company to include language in its RFPs addressing the capital lease and

[27] There is also a second test under ASC 842 to determine if an arrangement contains a lease if neither the lessee (off-taker) nor the lessor (resource owner) directs an asset's use (for PPAs, generally dispatch of the facility). In the second test, a lessee evaluates whether it designed or operates the asset. Since Public Service neither designs nor operates the wind or solar facilities contracted under its PPAs, the Company's model wind and solar PPAs do not qualify as leases under ASC 842.

financial reporting issues. Specifically, in Decision No. C08-0929, the Commission approved use of the following language in the RFP:

> The Company is unwilling to be subject to any accounting or tax treatment that results from a PPA's capital lease or FIN 46 treatment. As a result, all bidders are required to state in their proposal(s) (i) that the bidder has reviewed and considered applicable accounting standards in regard to capital leases and variable interest entities, i.e., FASB Interpretation No. 46(R), Consolidation of Variable Interest Entities and Emerging Issues Task Force issue No. 01-08, Determining Whether an Arrangement Contains a Lease, (ii) summarize any changes that the bidder proposes to the Model PPA in order to attempt to address these issues, and (iii) to the bidder's knowledge and belief, the bidder's proposal should not result in such treatment as of the date of the proposal.

Q. HAS SIMILAR LANGUAGE BEEN INCLUDED IN RFPS SINCE THE 2007 ERP?

A. Yes.

Q. WHAT LANGUAGE HAS THE COMPANY INCLUDED IN THIS 2021 ERP & CEP RFP?

A. Section 2.5 of the Dispatchable RFP includes language that the Company's objectives with respect to term lengths are to avoid the concurrent expiration of multiple contracts, and to avoid or minimize the adverse financial impact of imputed debt, finance lease, and variable interest entity-related obligations.[28]

Section 2.7 includes further information regarding such contract accounting obligations.

> All contracts proposed to be entered into as a result of this RFP will be assessed by the Company for appropriate accounting and/or tax treatment. Respondents shall be required to supply promptly to the Company any and all information that the Company requires in order to make such assessments.

[28] Public Service also evaluates PPAs for a potential requirement to consolidate assets and liabilities (including debt) of the seller under the variable interest entity guidance of ASC 810. Based on its model PPAs and the typical nature of contracted resources, PSCo has not historically been required to consolidate any applicable entities under this guidance.

The Company has specific concerns regarding proposals received in response to this RFP that could result in either (i) a contract that must be accounted for by the Company as a finance lease or an operating lease pursuant to Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 842, or (ii) consolidation of the seller or assets owned by the seller onto the Company's balance sheet pursuant to the variable interest entity requirements of FASB ASC 810. The following shall therefore apply to any proposal submitted pursuant to this RFP:

The Company is unwilling to be subject to any accounting or tax treatment that results from a PPA's finance lease or consolidated variable interest entity classification. As a result, respondents shall state in their proposal(s) (i) that the respondent has considered applicable accounting standards in regard to finance leases and variable interest entities, (ii) summarize any changes that the respondent proposes to the Model PPA in order to attempt to address these issues, and (iii) to the respondent's knowledge and belief, the respondent's proposal should not result in such treatment as of the date of the proposal.

As applicable, the Company will not execute a PPA without confirmation from the Company's external auditors that the PPA will not be classified as a finance lease, or a consolidated variable interest entity.

By submitting a proposal, each respondent agrees to make available to the Company at any point in the bid evaluation process any financial data associated with the respondent and its proposed project so the Company may independently verify the respondent's information in the above matters. Financial data may include, but shall not be limited to, data supporting the economic life (both initial and remaining) of the facility, the fair market value of the facility, the means by which the respondent intends to meet the security and performance requirements[29] of the model PPA, and any and all other costs and financing plans (including debt specific to the asset being proposed) associated with the respondent's proposal. The Company may also use financial data contained in the respondent's financial statements (e.g. income statements, balance sheets, etc.) as may be necessary.

[29] See Article 11 of the Model PPAs.

Q. HAS THE COMPANY INCLUDED A MODEL PPA FOR STAND-ALONE STORAGE TECHNOLOGIES IN ITS RFP?

A. Yes. Company witness Ms. Tara Fowler summarizes the contractual terms of the Company's proposed model stand-alone storage PPA in her Direct Testimony. Stand-alone storage technologies are considered in the Dispatchable RFP included in Volume 3.

B. <u>Regulatory Considerations for Long-Lead Time Resources</u>

Q. HOW IS PUBLIC SERVICE POSITIONING FOR THE NEXT PHASE OF THE ENERGY TRANSITION BEYOND THE RESOURCE ACQUISITION PERIOD IN THIS 2021 ERP & CEP?

A. The transition to a carbon-free future does not end with this plan. Indeed, in some sense, this plan is just the beginning. Consistent with our ambitious 2050 emissions target and, as directed in SB 19-236, Public Service is thinking beyond 2030 in terms of the technology and resource characteristics that will be required on our system to achieve 100 percent carbon free generation. In addition to the 2030 emissions reductions, CEPs filed by utilities are to seek to achieve providing customers energy generated from one hundred percent clean energy resources by 2050. Specifically, § 40-2-125.5(3)(a)(II) states as follows:

> For the years 2050 and thereafter, or sooner if practicable, the qualifying retail utility shall seek to achieve the goal of providing its customers with energy generated from one-hundred-percent clean energy resources so long as doing so is technically and economically feasible, in the public interest, and consistent with the requirements of this section.

Q. IS PUBLIC SERVICE PROPOSING TO ACQUIRE RESOURCES BEYOND 2030 IN THE 2021 ERP & CEP?

A. No. However, consistent with the directives in SB 19-236, we are seeking policy support and direction from the Commission to investigate the technological and economic feasibility of generation resources that possess characteristics required to achieve remaining carbon emission reduction goals or maintain system reliability as more clean energy resources are added to the system. Existing regulatory processes and ratemaking authorizations do not provide regulatory clarity with respect to how utilities can pursue investigation into the viability of these resources. Accordingly, the Company requests the Commission authorize Public Service, in the Phase I decision in this proceeding, to conduct preliminary work in order to determine if such a project is feasible. The Company also requests that the Commission determine a policy framework to enable review and recovery of costs prudently incurred to investigate the feasibility of a resource technology that possesses the characteristics necessary to advance a carbon free system.

Q. WHAT TYPE OF RESOURCE CHARACTERISTICS ARE YOU REFERRING TO?

A. The Company believes that resources capable of providing longer-duration energy storage are likely to be an imperative piece of the puzzle as we move towards a carbon-free future by 2050. Energy storage resources shift power from periods of excess renewable generation to periods of low renewable generation, displacing otherwise carbon-emitting resources. Short-duration energy storage (e.g., four hours or less), typically the domain of battery energy storage systems, is useful;

however, short-duration storage is limited in its ability to replace traditional capacity and energy resources. In the future, longer duration energy storage of a variety of types will be required to cost-effectively maintain reliability and reduce emissions to zero. Only when the Company has a portfolio of carbon-free dispatchable resources will the emissions reductions currently envisioned be achievable. One such longer-duration energy storage facility is pumped storage hydropower technologies and along with even longer-duration storage, may prove both necessary and cost-effective in this effort.

Q. WHAT KIND OF TIMEFRAME IS REQUIRED TO DEVELOP RESOURCES LIKE PUMPED STORAGE HYDROPOWER?

A. Resources like pumped hydro storage can take many years to develop—potentially over a decade.

Q. WHY DOES PUMPED STORAGE HYDROPOWER TAKE SUCH A LONG TIME TO DEVELOP?

A. Pumped storage hydropower projects are significant infrastructure projects that have lengthy development times due to a variety of factors. First, it can take several years to identify a potential project and undertake the work required to validate the suitability and feasibility of that project. After a project is identified, the process to obtain a license moves forward at the FERC. At a minimum, that process could take four to five years. Design and manufacturing of turbines and site construction, running in parallel, would likely take approximately six years. So, at a minimum development of a pumped storage hydropower project would take over a decade. To expedite a project, certain activities such as turbine design and issuance of requests for proposals for contractors could run in parallel with licensing-related activities, but even running these processes in parallel would only shave a few years off the project. In addition, significant investment would be required throughout the project development horizon.

Q. WHEN WOULD DEVELOPMENT OF A PUMPED HYDROPOWER STORAGE FACILITY NEED TO BEGIN IN ORDER TO CONSIDER SUCH A RESOURCE IN A FUTURE RESOURCE ACQUISITION PROCESS?

A. We would expect that to achieve an in-service date of 2034, preliminary activities associated with performing in-depth environmental studies and geologic exploration to determine the suitability of a site would need to start in 2022 and would take roughly two years. That means that a project site location would need to be identified and evaluated before 2024.

Q. HAS THE COMMISSION PREVIOUSLY INDICATED THAT IT WOULD BE REASONABLE FOR THE COMPANY TO INVESTIGATE THE FEASIBILITY AND POTENTIALLY PURSUE LONG LEAD TIME RESOURCES LIKE PUMPED STORAGE HYDROPOWER?

A. Not directly. However, as I described above, SB 19-236 requires that a utility's CEP seek to provide customers with carbon free energy by 2050. We have modeled a carbon-free future, as explained in more detail by Company witness Mr. Jon T. Landrum but need to explore a variety of options to get us there. Given the need for long duration storage, or otherwise carbon-free, dispatchable resources beyond 2030 and the long lead time required to investigate and develop such projects, this 2021 ERP & CEP is the appropriate venue for this Commission to determine how it will enable Public Service now to pursue resources that can deliver carbon free energy to customers in the future.

Q. HOW CAN THE COMMISSION ENSURE THAT PUBLIC SERVICE IS COMPLIANT WITH THE STATUTORY REQUIREMENTS OF SB 19-236 AND ENABLE THE COMPANY TO PURSUE FUTURE RESOURCES TO ACHIEVE 100 PERCENT CARBON REDUCTIONS?

A. For a fully regulated electric utility like Public Service, establishing a clear policy position that the Commission finds that it is reasonable for Public Service to engage in such work and enabling a supportive cost recovery framework can assist the Company in investigating the feasibility of long lead time resources, like pumped storage hydropower, in Colorado. Specifically, determining a framework for evaluation of costs incurred to investigate the initial suitability and feasibility of projects along with a pathway to recover those costs is needed in order for the Company to move forward.

Q. WHAT IS THE COMPANY PROPOSING?

A. The Company requests that in its Phase I ERP decision in this proceeding, the Commission find it reasonable for Public Service to investigate the initial suitability and feasibility of a future resource like pumped storage hydropower in Colorado. The Company expects that enough investigatory work could occur in 2022 and 2023 such that the Company could report back to the Commission in 2024 regarding whether an identified pumped storage hydropower project could be feasible. I explain this proposed reporting in 2024 in more detail below. To recover costs associated with this investigatory work, the Company requests a specific ratemaking authorization to treat preliminary, investigatory costs prudently incurred as Construction Work in Progress ("CWIP") and accrue allowance for funds used during construction ("AFUDC"). If after the 2024 report, the Commission—or the Company—determines that Public Service should not continue to further develop the identified project, then the Company requests a second specific ratemaking authorization to reclassify the previously recorded costs from CWIP to a deferred regulatory asset, establish an appropriate amortization period to recover the costs, and permit recovery of the costs in base rates. For the time period between the establishment of the deferred regulatory asset and inclusion of the regulatory asset in base rates, the Company proposes to apply a carrying cost at the Company's effective AFUDC rate. This continues the application of AFUDC for the initial construction-related costs consistent with how AFUDC is accrued on CWIP.

Q. WHAT IS CWIP?

A. CWIP refers to expenditures related to utility plant in process of construction that is eligible for AFUDC. AFUDC is the existing accounting principle that allows the capitalization of the cost to finance projects that are capital in nature until the project is placed in service.

Q. HOW WOULD PRELIMINARY COSTS TO INVESTIGATE THE SUITABILITY AND FEASIBILITY OF A LONG LEAD TIME PROJECT LIKE PUMPED STORAGE HYDROPOWER OTHERWISE BE RECORDED?

A. Absent the proposed treatment, preliminary costs would otherwise be recorded to FERC Account 183 - Preliminary Survey and Investigation Charges. FERC

Account 183 is a deferred plant account so under normal FERC accounting practices the costs would be deferred on Public Service's balance sheet. No Commission ratemaking or accounting authorization is needed for Public Service to record costs to FERC Account 183. Since FERC Account 183 is a deferred plant account, it is not included in rate base and costs are only recorded to this account for a period of time until a formal capital project is established, at which time the costs are reclassified as CWIP. In the example of a pumped storage hydropower project, it could be many years before a capital project is established and construction commences and therefore many years before costs recorded to FERC Account 183 would be recorded to CWIP.

Q. WHY DOES PUBLIC SERVICE SEEK A DIFFERENT CLASSIFICATION FOR THESE COSTS AND AUTHORITY TO POTENTIALLY RECORD COSTS PRUDENTLY INCURRED INTO A REGULATORY ASSET FOR FUTURE BASE RATE RECOVERY?

A. Costs recorded to FERC Account 183 are meant to be classified in this manner during the initial stages of a potential capital project. In that respect, this is an appropriate account to record preliminary, initial investigatory costs associated with determining the suitability and initial feasibility of a pumped storage hydropower project. However, if the potential capital project does not move forward, costs recorded to FERC Account 183 are written off. If the Commission agrees that it is reasonable for the Company to take preliminary steps to investigate the potential for a pumped storage hydropower project, the costs incurred by the Company should not be subject to write off. Even if the

Commission or the Company ultimately decides that a project is not feasible, the costs incurred to arrive at that determination would still be legitimate costs for Public Service to recover and the establishment of a regulatory asset at the point of that determination would enable the Company to recover the costs of the actions the Commission had found reasonable and prudent.

Q. PLEASE DESCRIBE THE TYPES OF INITIAL COSTS PUBLIC SERVICE WOULD EXPECT TO INCUR TO INVESTIGATE THE SUITABILITY AND INITIAL FEASIBILITY OF A PUMPED STORAGE HYDROPOWER PROJECT.

A. In order to determine the initial suitability and feasibility of a potential pumped storage hydropower project, the Company expects it would need to incur costs related to performing geologic testing to validate that subsurface features are suitable for a pumped storage hydropower project and performing environmental studies required as part of the National Environmental Policy Act ("NEPA") evaluation that would be undertaken by FERC through the licensing process. This work would be conducted over roughly the period from mid-2022 (when the Phase 1 Order granting the ratemaking treatment requested herein would be expected to be issued) through mid-2024.

Q. WHAT LEVEL OF EXPENDITURES DOES PUBLIC SERVICE ESTIMATE IT COULD INCUR TO CONDUCT THESE INITIAL ACTIVITIES?

A. The Company estimates these activities could cost $5 to $15 million. The primary cost drivers are the cost of borings to validate the subsurface geology and various types of environmental studies that would ultimately be used in support of the NEPA process at FERC. We estimate the cost of borings between $2 and $10 million, with costs dependent on the nature of the rock being bored and the number of borings required. The cost of environmental studies could range from $3 to $5 million.

Q. HOW DOES THE COMPANY PROPOSE TO INFORM THE COMMISSION OF ITS FINDINGS AFTER CONDUCTING THIS PRELIMINARY WORK?

A. Public Service proposes to provide a summary of this preliminary work in a report to the Commission filed in this proceeding by June 1, 2024. Upon receipt of that report and a recommendation from Public Service on whether the project should be further evaluated, the Commission could decide whether the Company should further pursue development of a pumped hydropower project or not.

Q. YOU ALSO MENTIONED THE NEED FOR OTHER TECHNOLOGY INVESTMENTS IN THE FUTURE THAT MAY ADVANCE THE COMPANY TOWARDS ITS 2050 CARBON-FREE GOAL. PLEASE EXPLAIN.

A. Clearly there is much work to be done between now and 2050 to achieve a zero-carbon system. Our generic modeling and the lack of a good proxy for zero-emission dispatchable technologies reflects the fact that these technologies do not represent a readily available, affordable, commercial solution. In order to model a carbon-free future, we assumed transitions to hydrogen between 2040 and 2050 to close the gap. Just as this State and Commission started back in the early 2000s in the exploration of adding increasing amounts of wind and solar, even though uneconomic, we are at this juncture again to explore new technologies in the interest of achieving a long-term goal—carbon-free energy. We believe now is the time for the Commission to clearly establish a framework and provide guidance on how we should expect to be able to bring forward these technologies—purchased or owned—over the next decade plus for consideration.

We have questions that would be helpful for the Commission to address with the benefit of the record in this proceeding. These inquiries include:

(1) does the Commission prefer pilots or fully grown projects?

(2) should these future technologies be evaluated based on total project cost or by a cost per ton of carbon reduced?

(3) can we expand our Innovative Clean Technology process to incorporate these types of projects?

This is not an exhaustive list but meant to start a broader discussion. We do not believe this discussion, nor the Commission's associated policy determinations for Public Service, belong in a rulemaking but are appropriate to address in this 2021 ERP & CEP, consistent with the long-term statutory directives of SB 19-236.

Q. DO YOU HAVE ANY SUGGESTIONS OR IDEAS ON WHAT THE SOLUTION COULD BE?

A. Depending on the direction the Commission would like to take on this framework, it could range from one end of the spectrum where the Commission establishes a maximum dollar amount assumed in this 2021 ERP & CEP to be spent on these types of clean energy resources to be "cleared" through our established Innovative Clean Technology process. Alternatively, the Company would need to file a CPCN to explore the possibility. Because of the efficiency, we would prefer to move through the former versus the latter recommendation.

VI. PERFORMANCE INCENTIVE MECHANISMS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I support the Company's proposed PIM and discuss how it is consistent with the Commission's directives to Public Service in its report to the Colorado General Assembly related to performance-based regulation ("PBR"). I also discuss that the evaluation of performance standards for new, Company-owned generation acquired through this 2021 ERP & CEP is best addressed in follow-on CPCN proceedings, as well as the Company's commitment to consider project management performance metrics and PIMs in follow-on CPCN proceedings related to Company-owned generation resources Public Service would construct.

A. Background on Performance Based Regulation

Q. HAS THE COMPANY RECENTLY CONSIDERED EXPANDING PERFORMANCE BASED REGULATION?

A. Yes. The 2019, the General Assembly saw the introduction and approval of PBR legislation that was codified as § 40-3-117, C.R.S. This legislation required the Commission to investigate PIMs and PBR and provide a report to the General Assembly with the Commission's findings no more than 18 months after May 30, 2019. The Commission's report was required to:

- Determine whether PBR was net beneficial to the state;
- Identify actions the Commission may pursue in the adoption of PBR;
- Issue directives to the utilities under its purview; and

- Propose a timeline for transition to a PBR structure.

In response, the Commission opened Proceeding No. 19M-0661EG in late 2019. Twenty-two stakeholders participated in three rounds of comments which address the topics of: Public Interest Goals and the Commission's Mandate; PBR and PIMs in Colorado; and PBR in Other States. Following these three rounds of comments, the Commission held a Commissioner's Information Meeting on August 28, 2020 to receive presentations regarding PBR topics.

Q. WHAT WAS THE CONCLUSION OF PROCEEDING NO. 19M-0661EG?

A. Proceeding No. 19M-0661EG culminated in a report to the Colorado General Assembly on November 30, 2020. The report provided three recommendations regarding the future of PBR in Colorado.[30] First, the Commission found that PBR has been implemented by the Commission already, but a full transition has not been achieved, in part, because of the success of the incremental steps that have already been taken. Second, the Commission determined that a continuation of the incremental approach that it found to be successful in the past was warranted versus a full overhaul of ratemaking in order to balance the potential downside risks with the need to reform how public utilities are regulated. Finally, the Commission found that PBR ratemaking cannot be found net beneficial "in the abstract" but is instead more appropriately considered on a case by case basis where the merits can be more appropriately considered.

[30] Investigation into Performance Based Regulation in Colorado, § 40-3-117, C.R.S., at 10-12 (Nov. 30, 2020).

Q. WHAT DIRECTIVES RELATED TO THE COMPANY'S 2021 ERP & CEP WERE INCLUDED IN THAT REPORT?

A. In its PBR Report, the Commission signaled that the Company should provide performance incentives for emissions reductions as part of its next ERP. The Commission specifically stated that;

> 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*.[31]

The Commission further provided as follows:

> 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.[32]

Q. WHAT IS A PERFORMANCE INCENTIVE MECHANISM?

A. In the context of a regulated utility, a PIM is a concept that encourages or discourages a utility from a specific action or inherent bias. For example, to incentivize a utility to pursue demand-side management ("DSM") programs in order reduce sales, lower peak demand, or defer or avoid capital investment, performance incentives provide a financial return equal to or in excess of the potential capital expenditure benefits.

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[31] *Id.*, at 14 (emphasis added).
[32] *Id.*, at 15 (emphasis added).

Q. IS THERE ENABLING LEGISLATION, RULES, OR COMMISSION PRECEDENT FOR THE COMPANY'S DSM PROGRAM PIMS?

A. Yes. In 2007, the General Assembly enacted House Bill 07-1037, codified in relevant part at § 40-1-102(5) – (11), C.R.S. and §§ 40-3.2-101, 104. Section 40-3.2.104(5) specifically requires that the Commission "allow an opportunity for a utility's investments in cost-effective DSM programs be more profitable to the utility than any other utility investment that is not subject to special incentives." Decision No. C08-0560 in Proceeding No. 07A-420E was the Commission's first authorization for Public Service to utilize a performance incentive. This PIM included both a performance incentive, earned upon the achievement of certain benchmarks, and a disincentive offset, designed to offset some of the Company's disincentive to actively reduce its sales. Similarly, Rule 4754, which implements the natural gas DSM rules, allows for the utility to receive both a performance incentive and the recovery of lost revenues associated with its natural gas DSM programs.

Q. HAS THE COMMISSION APPROVED OTHER PIMS FOR PUBLIC SERVICE?

A. Yes. In Proceeding No. 19M-0661EG, the Company's initial comments submitted on January 1, 2020 that detailed various PIMs previously approved by the Commission.

Q. WHAT DESIGN CRITERIA HAS THE COMMISSION ESTABLISHED FOR ITS CONTINUED CONSIDERATION OF PIMS?

A. The PBR report states that PIMs "need to be specific, measurable, achievable, relevant and time-bound" and that PIMs are "best conducted incrementally, versus a comprehensive overhaul of regulatory cost recovery practices."[33] The Commission also outlined specific decarbonization PIM guidelines stating;

- *Decarbonization: focus on performance that exceeds statutory mandates at a cost to customers below a pre-established baseline*
- *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.*

The Company has considered these guiding principles and the Commission direction and developed a framework for the introduction, review, and approval of PIMs associated with this 2021 ERP & CEP.

Q. PLEASE DESCRIBE THE PIM FRAMEWORK THE COMPANY IS PROPOSING.

A. Consistent with the Commission's directives in the PBR Report, the Company's framework includes a proposed PIM related to emissions reductions as well as PIMs for potential consideration in follow-on CPCN proceedings for Company-owned resources acquired in this 2021 ERP & CEP. Figure BAT-3 illustrates how the Company expects to bring these PIMs forward.

[33] *Id.*, at 14.

Figure BAT-D-3: Proposed PIM Framework

Proceeding	PIM Category	PIM
2021 ERP & CEP Phase I		
	Emissions Reductions PIM	
		Greater than 80%, with Early Action Incentive
Follow-on CPCNs for Company-owned Resources		
	Performance Standards PIM(s) for new Company-owned generation acquired in the 2021 ERP & CEP	
		Resource A
		Resource B
		…
	Project Management PIMs for new Company-owned generation acquired in the 2021 ERP & CEP and constructed by Public Service	
		Resource A
		Resource B
		…
	Methane Intensity Reduction PIM (potential)	

This framework allows for the gradual and incremental introduction of PIMs that I believe is consistent with the Commission's intention regarding performance-based regulation. As part of this Phase I process, the Company introduces an emissions-based PIM that is necessary now in order to inform the direction the Company takes in designing and recommending various portfolios are part of Phase II. Follow-on CPCN proceedings would be the appropriate venue to consider PIMs related to performance standards for new, Company-owned generation resources. The Company is also willing to evaluate PIMs related to project management performance specific to new generation resources the Company might construct.

B. Emissions Reductions PIM

Q. PLEASE DESCRIBE THE PROPOSED EMISSIONS REDUCTION PIM.

A. The Company proposes a PIM designed to incentivize Public Service to both exceed the statutory 80 percent clean energy target as well as create an incentive to accomplish those emissions reductions earlier than required in statute. This framework is consistent with the Commission's goals for Public Service in the PBR Report 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." This incentive framework also adheres to the Commission's design criteria in that is it specific, measurable, achievable, relevant, and time-bound. The PIM specifically provides an incentive opportunity for the achievement of verifiable emissions reductions that exceed statutory minimum requirements by 2030. This performance metric is relevant to the emissions reductions directives of SB 19-236, this 2021 ERP & CEP, as well as the directives of the Commission in its PBR Report.

Q. HOW WOULD THE PROPOSED EMISSIONS-BASED INCENTIVE BE DETERMINED?

A. The proposed emissions-based PIM is expressed as follows:

$$(\text{carbon reduction } \%_{[\text{achieved}]} - \text{carbon reduction } \%_{[\text{required}]}) = \% \text{ exceeded}$$

Where,

- carbon reduction % $_{[\text{achieved}]}$ is the Company's 2030 achieved emission reductions compared to the 2005 baseline, verified by the Colorado Department of Public Health and Environment; and

- carbon reduction % $_{[required]}$ is the required 80 percent carbon reduction requirement from 2005 levels pursuant to SB 19-236.

Then, for every one percent of carbon emissions reductions achieved beyond the statutory minimum of 80 percent below 2005 levels, the Company would earn a financial incentive equal to a 20 basis point addition to its earned equity return for a number of years equal to the percent of emission reductions exceeded. So, for example, if the Company achieved an 83 percent carbon emissions reduction in 2030, the Company would receive a performance incentive in calendar years 2031, 2032, and 2033 equal to a 60 basis point (3 * 20 bps = 60 bps) return calculated based on the rate base in the test year approved to set rates in calendar years 2030, 2031, and 2032. Put more simply, each percentage point allows for a year of application for the PIM.

Q. WOULD THE COMPANY EARN AN ADDITIONAL INCENTIVE IF THE COMPANY ACHIEVED EARLY EMISSION REDUCTIONS PRIOR TO 2030?

A. Yes. I will refer to this as the "Early Action Incentive." If the Company were to achieve or exceed the statutory emissions reduction prior to 2030, the Company would receive the financial incentive for an additional number of years equal to the number of years the Company achieved the emissions reductions ahead of 2030. Therefore, to extend the prior example, if the Company achieved an 83 percent carbon emissions reduction in 2028, the Company would receive a performance incentive in calendar years 2029, 2030, 2031, 2032, and 2033 equal to a 60 basis point return on its calendar years 2028, 2029, 2030, 2031, and 2032 electric rate base as reported in its Appendix A filed in 2029, 2030, 2031, 2032, and 2033, respectively.

Q. WHAT IF THE COMPANY REPORTS AN EARNED RETURN ABOVE ITS COMMISSION-AUTHORIZED RETURN IN THE APPLICABLE APPENDIX A?

A. If the Company's electric retail jurisdictional earned return as reported in its Appendix A filings exceeds the Commission's authorized return on equity by 50 basis points or more, the Company proposes to share half of an incentive earned through the Emissions Reduction PIM with customers. This would be effectuated through earning only half the financial incentive in the applicable year.

Q. HOW DOES THE COMPANY PROPOSE TO COLLECT A FINANCIAL INCENTIVE EARNED THROUGH THE EMISSIONS REDUCTION PIM?

A. The Company proposes to collect a financial incentive earned through the Emissions Reduction PIM through the ECA rider or a similar adjustment mechanism.

C. PIMs Applicable to Future Proceedings

Q. PLEASE DESCRIBE THE COMPANY'S RECENT HISTORY WITH PERFORMANCE STANDARDS FOR COMPANY-OWNED GENERATION.

A. Performance standards are not new and have been approved as part of the Company's recent Rush Creek Wind Project and Cheyenne Ridge Wind Project. For example, the Rush Creek Wind Project has a construction cost cap with a sharing mechanism for construction cost savings. It also has a performance metric applicable to generation in the outer years of the project.

Additionally, with regard to the Cheyenne Ridge Wind Project, the settlement agreement approved in Proceeding No. 18A-0905E established a point cost for capital costs, a generation performance metric similar to the Rush Creek Wind Project, and a customer protection mechanism that sets up a series of evaluations based on a $/MWh benchmark.

Q. HAS THE COMPANY DEVELOPED THE PERFORMANCE STANDARDS FOR COMPANY-OWNED GENERATION THAT WILL BE ACQUIRED IN THIS 2021 ERP & CEP?

A. No. Consideration of applicable performance standards for new, Company-owned generation acquired through this 2021 ERP & CEP are best evaluated in follow-on CPCN proceedings after the Commission has approved those resources through this ERP process.

Q. PLEASE DESCRIBE THE CONCEPT OF A PROJECT MANAGEMENT PIM.

A. For new, Company-owned resources approved as part of the Phase II ERP proceeding and to be constructed by Public Service, the Company is willing to evaluate potential project management PIMs. Similar to any performance standards for new, Company-owned generation resources acquired in this 2021 ERP & CEP, potential performance management PIMs are best addressed in the follow-on CPCNs for those resources. As the Commission notes in the PBR Report, project management PIMs that incentivize the utility to reduce capital expenditures in return for a financial incentive can produce mutual benefits for both the utility and the customer.

Q. PLEASE DESCRIBE THE CONCEPT FOR A POTENTIAL METHANE INTENSITY REDUCTION PIM.

A. The Company is still evaluating potential PIM designs related to potential methane intensity reductions. Such a PIM could incentivize Company actions aimed at reducing methane emissions, which would have a positive environmental impact. The Company's conceptual goal would be to incentivize actions that reduce methane emissions from the upstream – production and transportation – supply chain for natural gas. This type of mechanism would also have the benefit of reducing a negative externality imposed by the use of natural gas to fuel non-energy limited, dispatchable resources such as combustion turbines that are critical for maintaining reliability.

Q. WHY IS THE COMPANY NOT PROPOSING THE METHANE EMISSIONS PIM SHOWN IN FIGURE BAT-D-3 IN PHASE I?

A. Company witness Mr. Jack W. Ihle discusses methane and responsibly sourced gas ("RSG") further in his Direct Testimony. As Mr. Ihle discusses, additional stakeholder discussion and Commission consideration of the potential costs and benefits is needed. However, the Company believes a potential Methane Intensity Reduction PIM could warrant further consideration in the future as RSG is considered in this 2021 ERP & CEP and in future proceedings.

Q. ARE THERE OTHER PIMS THE COMPANY MAY BRING FORWARD AS PART OF THE PHASE II OR FOLLOW ON CPCN PROCEEDINGS?

A. I believe it is possible that additional PIMs may come forward in these proceedings. The Company also remains open to stakeholder suggestions and dialogue on potential PIMs that can help better align customer and utility benefits.

VII. 2021 ERP & CEP EXPENSES

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I support the Company's request to defer expenses associated with preparing and litigating this proceeding. Specifically, the Company requests deferral of expenses related to consultant work, transcripts and hearing costs, and outside legal counsel.

Q. PLEASE LIST AND GENERALLY DESCRIBE THE MAJOR EXPENSE CATEGORIES YOU ARE PRESENTING FOR DEFERRAL.

A. The major categories of expenses for the Company's 2021 ERP & CEP are listed below with a brief description for each.

Consultants: Consultants are necessary for the preparation of an ERP for a number of reasons. Often consultants will testify or provide subject matter expertise, perform specific analyses, provide review of testimony, and respond or consult on discovery. Typically, the expertise sought from the consultant is not an expertise that is hired on a permanent basis within the organization.

Transcripts/Hearing Costs: During the course of a proceeding, a court reporter will be necessary to transcribe depositions and hearings before the Commission. There is a cost of having court reporters record and transcribe these proceedings. This fee increases or decreases based upon the timeframe by which the reporter is asked to prepare the transcript.

Legal Counsel: The Company has an in-house legal department whose regulatory team works on the matters that we have before the Commission. However, the Company has more Commission-related work than can be handled by our in-house attorneys, so we also need to retain outside attorneys for this work. Particularly since ERPs represent one of the most complex and involved regulatory filings Public Service makes and ERPs are not filed every year, the Company does not staff up its legal department in preparation for an ERP filing, but we do assign inside attorneys to our cases. Our ability to rely on our inside counsel for resource planning cases is dependent upon other pending matters. Therefore, outside legal assistance is sometimes necessary.

Q. PLEASE DISCUSS THE SPECIFIC CONSULTANT AND OUTSIDE WITNESS COSTS THAT THE COMPANY IS PROJECTING TO INCUR FOR THIS ELECTRIC RESOURCE PLAN.

A. The costs associated with securing outside consultants or witnesses with specific areas of expertise are necessary for the support and completion of the case. We estimate these costs to be $124,900 at this time for consulting services provided by Astrapé Consulting, the National Renewable Energy Laboratory ("NREL"), and Burnham Coal, LLC.

Q. PLEASE DESCRIBE THE SERVICES THAT WERE OR WILL BE PROVIDED BY ASTRAPÉ CONSULTING.

A. Company witness Mr. Kevin Carden provides Direct Testimony that introduces and summarizes the Planning Reserve Margin and Resource Adequacy Study that Astrapé Consulting conducted on behalf of Public Service. More specifically, he discusses the input assumptions, study methodology, and results of the study. His testimony also provides an overview of how the study results compare to similar planning reserve margin and resource adequacy assessments on an industry-wide basis. The Company requests deferral of $39,900 to cover written testimony, witness preparation, oral testimony, and discovery request support as part of this ERP proceeding.

Q. PLEASE DESCRIBE THE SERVICES THAT WERE OR WILL BE PROVIDED BY NREL.

A. NREL is providing support to the Company for this 2021 ERP & CEP and the Company has estimated that work to total $75,000. As explained by Company witness Mr. Welch, the Company is actively working with NREL to assess specific, historical weather events and analyze how generation resource acquisitions, transmission system additions and/or impacts, as well as other operational changes contemplated as part of this resource planning process, may respond to such events. We expect that considerations from NREL's work will help inform our analysis of resources and overall system operations when evaluating portfolios.

Q. PLEASE DESCRIBE THE SERVICES THAT WERE OR WILL BE PROVIDED BY BURNHAM COAL, LLC.

A. Burnham Coal, LLC provided the Company with a coal supply study as ordered by the Commission in Decision No. C17-0316. The coal supply study can be found in Volume II Technical Appendix of the Company's 2021 Electric Resource Plan (Attachment AKJ-2). The Company is requesting deferral of $10,000 for the cost of conducting the study.

Q. PLEASE DISCUSS THE TRANSCRIPT AND HEARING COSTS THAT THE COMPANY IS PROJECTING TO INCUR AS PART OF THE ELECTRIC RESOURCE PLAN PROCEEDING.

A. The Company anticipates incurring an approximate cost of $54,500 for the purchase of transcripts of the hearings and other hearing costs.

Q. PLEASE DISCUSS THE OUTSIDE LEGAL FEES THAT THE COMPANY IS PROJECTING TO INCUR AS PART OF THE ELECTRIC RESOURCE PLAN PROCEEDING.

A. Outside Legal costs are estimated to be $1,774,550 for the legal services provided by Wilkinson Barker Knauer LLP ("WBK") for the Phase I and Phase II process. WBK was retained for its expertise and specific knowledge of Public Service and other Xcel Energy operating companies. The firm provided, or will provide, assistance in assembling testimony and attachments, witness preparation, responding to discovery, and generally processing the case. I would also add that the Company's internal legal team works hard to ensure that duties are appropriately assigned to outside legal counsel and to ensure that work efforts are not duplicative. The internal and external legal teams work as a unit and are in constant coordination to be as efficient as possible.

VIII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. Consistent with the discussion in my Direct Testimony, I support the recommendation of Company witness Ms. Alice K. Jackson that the Commission approve Public Service's Phase I 2021 ERP & CEP. In addition, I recommend the Commission issue several findings and approvals as part of its Phase I decision in this proceeding, as follows:

- A finding that the Company's plan to securitize the costs associated with the accelerated retirement of Comanche 3 is reasonable and in the public interest to enable the Company to begin a series of actions over the next two decades to effectuate the securitized refinancing, which will involve subsequent regulatory filings and Commission approvals;
- Approval to initiate the CEPR after the Phase II decision in this Proceeding;
- A finding that the Commission recognizes the financial implications of adding stand-alone battery storage resources in this ERP and accordingly approves the Company's request to accept and negotiate contract terms for these types of resources that do not result in finance lease accounting treatment;
- A finding that the Commission encourages the Company to investigate the feasibility of certain long-lead time generation resources to achieve carbon reductions beyond 2030 and authorize a certain rate-making treatment for associated costs;
- Approval of the proposed Emissions Reduction Performance Incentive Mechanism; and
- Approval to track and defer costs incurred in association with preparing and litigating this proceeding into a non-interest-bearing regulatory asset to be reviewed for recovery purposes in a future rate proceeding.

Q. DOES THIS CONCLUDE YOU DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Brooke A. Trammell

As the Regional Vice President of Rates and Regulatory Affairs, I am responsible for providing leadership, direction, and technical expertise related to regulatory processes and functions for Public Service. My duties include the design and implementation of Public Service's regulatory strategy and programs, and directing and supervising Public Service's regulatory activities, including oversight of rate cases and other related filings. Those duties include: administration of regulatory tariffs, rules, and forms; regulatory case direction and administration; compliance reporting; complaint response; and working with regulatory staffs and agencies. Additionally, I oversee the rate implementation procedures for all of Xcel Energy's utility operating companies.[34]

I accepted the Regional Vice President position with Public Service in June 2018 after holding the Director of Customer and Community Relations position in another Xcel Energy Inc. subsidiary, Southwestern Public Service Company ("SPS"), since June 2016. From January 2014 to June 2016, I was Manager, Rate Cases and was responsible for the strategic oversight of SPS's regulatory activity in Texas after being promoted from Case Specialist, the position in which I started with Xcel Energy in September 2012. As a Case Specialist, I supported SPS's proceedings before regulatory authorities in Texas and New Mexico as well as the Federal Energy Regulatory Commission and led SPS's

[34] Xcel Energy Inc.'s operations include the activity of four wholly-owned utility subsidiaries that serve electricity and natural gas customers in eight states. These utility subsidiaries, referred to as operating companies, are Northern States Power-Minnesota serving electric and natural gas customers in Minnesota, North Dakota, and South Dakota; Northern States Power-Wisconsin serving electric and natural gas customers in Wisconsin and Michigan; Southwestern Public Service Company serving electric customers in Texas and New Mexico; and Public Service serving electric, natural gas and steam customers in Colorado.

participation and policy analysis in administrative rulemaking proceedings in all jurisdictions.

Prior to Xcel Energy, I was employed with PNMR Services Company, a wholly-owned subsidiary of PNM Resources, Inc., the parent holding company of Public Service Company of New Mexico and Texas-New Mexico Power Company. I held various roles in the Pricing and Regulatory Services department including Rates Analyst II, Senior Rates Analyst and Project Manager, Federal Regulatory Affairs. In those positions, I provided cost of service, cost allocation, pricing, and rate design analysis to support general rate cases, audited rate calculations and filing packages, and managed regulatory filings and proceedings in the company's retail jurisdictions before managing PNM's regulatory proceedings before the Federal Energy Regulatory Commission and leading strategic regulatory and transmission policy initiatives.

I hold a Master of Business Administration degree from West Texas A&M University along with a Master of Arts degree in Economics with a specialization in Public Utility Regulation and a Bachelor of Science degree in Agricultural Economics and Agricultural Business from New Mexico State University.