Xcel Energy®

PUBLIC SERVICE COMPANY
OF COLORADO

OUR ENERGY FUTURE: DESTINATION 2030

2021 ELECTRIC RESOURCE PLAN AND CLEAN ENERGY PLAN

Volume 1
Plan Overview
CPUC Proceeding No. 21A-____E
March 31, 2021

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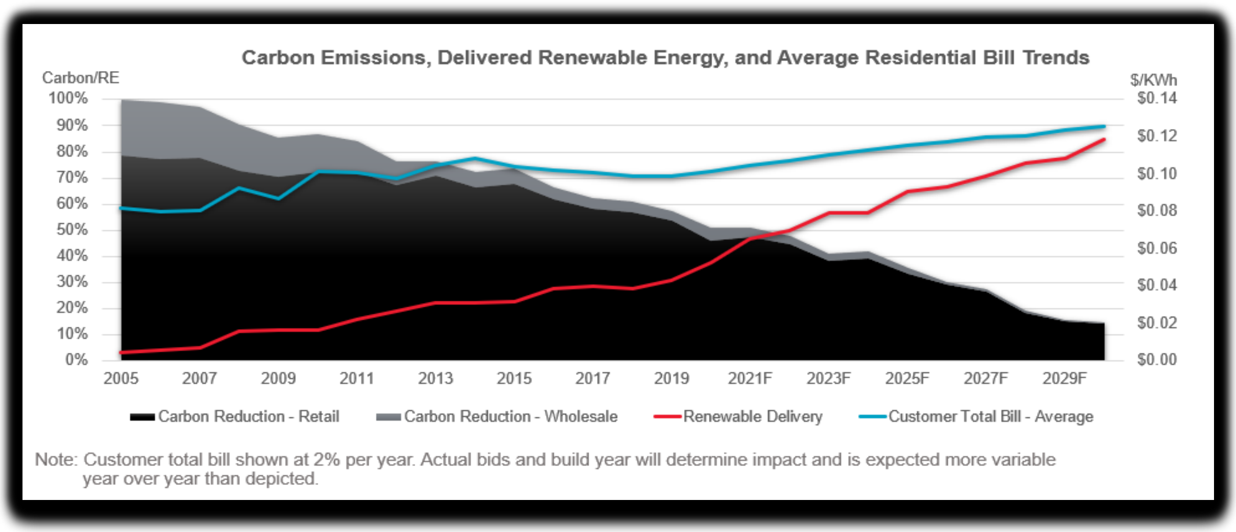
1.0 EXECUTIVE SUMMARY

Our Energy Future: Destination 2030

Public Service Company of Colorado ("Public Service" or the "Company") is excited to present its 2021 Electric Resource Plan and Clean Energy Plan ("2021 ERP & CEP"). After many years of technical and system advancements, we are able to confidently present for consideration by the Colorado Public Utilities Commission ("Commission") a plan that would achieve by 2030 an estimated **85 percent reduction in carbon dioxide emissions** from 2005 levels and deliver nearly **80 percent of our customers' consumed energy from renewable resources**. What makes this plan even more extraordinary is it accomplishes these objectives without compromising the Company's longstanding focus on reliability and affordability.

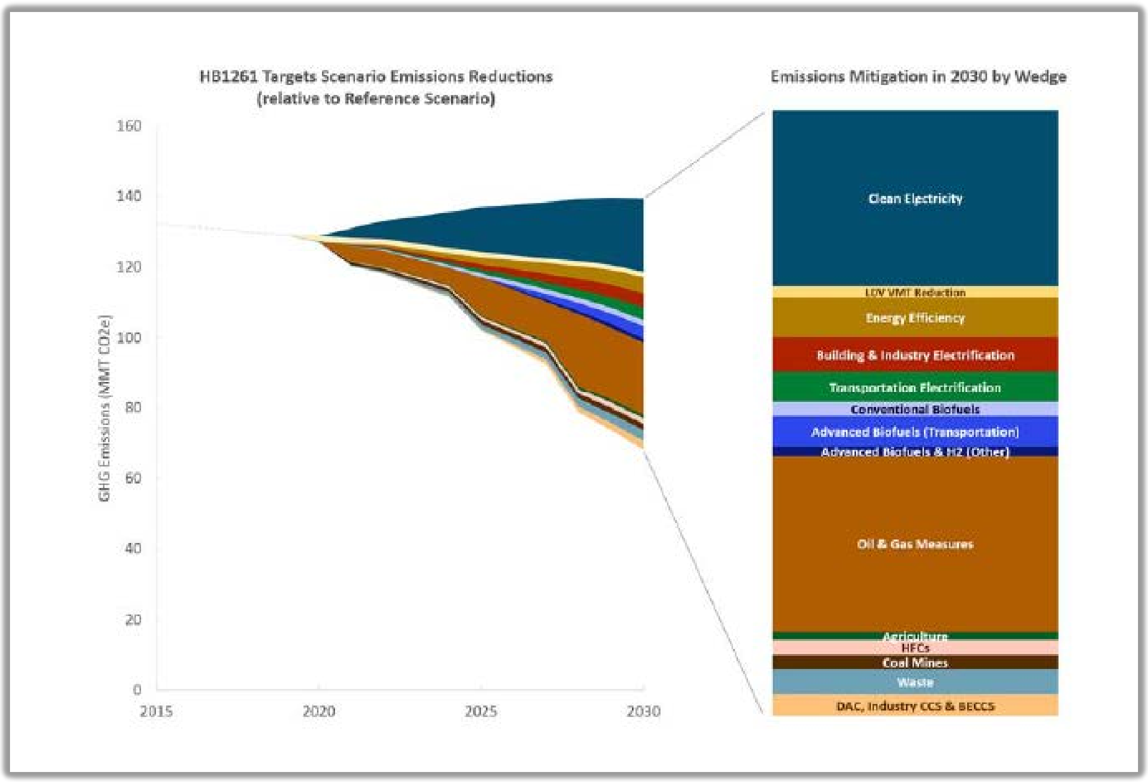
Colorado has been a leader in the clean energy transition for over two decades—with Public Service leading the way. As of 2020 we have reduced our emissions from the power sector by 46 percent since 2005 through a series of innovative initiatives while maintaining reliability and affordability for our customers. The graphic below illustrates the advancements made to date, as well as those we can achieve through this 2021 ERP & CEP.



The filing of the 2021 ERP & CEP is a landmark moment for Colorado energy policy and climate policy nationally. Indeed, it is not only the largest resource plan in the 150-plus year history of our Company, but also creates a framework and sets an example for how other commissions and utilities can advance cost-effective emission reductions as we collectively work to address the challenge of a lifetime.

The root of this plan started on December 4, 2018, when Xcel Energy announced a first-of-its-kind commitment to reduce emissions 80 percent from 2005 levels by 2030 and deliver 100 percent carbon-free electricity to customers by 2050. Our national leadership on this issue spurred similar commitments across the utility sector, with over twenty utilities having since adopted similar pledges. Shortly after Xcel Energy's announcement, the Colorado General Assembly embarked on its 2019 legislative session, which made history with two landmark bills. House Bill 19-1261 set economywide emission reduction goals, while Senate Bill 19-236 established a pathway and guidance for large regulated utilities to achieve the same goals we announced using Colorado's ERP process. These bills created Colorado's first-ever comprehensive and aggressive climate law.

The State of Colorado continued this climate leadership by developing the Colorado Greenhouse Gas Pollution Reduction Roadmap ("Roadmap") which represents the template for development of sector-specific approaches toward the achievement of the economy-wide emission reductions outlined in House Bill 19-1261. The Roadmap counts on the power sector to lead the way in the State's clean energy transition, and this 2021 ERP & CEP is foundational to achieving these broader economywide efforts. This is illustrated in the figure below, which shows clean electricity as one of the leading contributors to the state's targeted emissions reductions.



There are numerous factors to balance as we—the Company, our customers, our communities and stakeholders, the Commission, and the State—take the next, giant steps in the journey to a carbon-free future. Our direct case shows we are prepared to meet this charge—reliably and affordably. Simply put, we need to advance substantial emission reductions while maintaining reliability and affordability and advancing equitable access to clean energy. Doing so will require major changes to our distribution and transmission system, energy markets, and generation fleet, which in turn mean changes for our host communities in different parts of the State and a need to focus on a just transition. This human element—the fact that energy policy has significant and tangible impacts on communities and families—is as much a driver of our ERP as the analytics underlying it.

Against that backdrop, this ERP accelerates our transition away from coal-fired generation, adds substantial amounts of clean energy supported by flexible dispatchable generation, and ensures a planful and just transition for our host communities affected by the transition. Of course, we also need to execute this transition while maintaining system reliability, affordability, and Company health, consistent with the obligation to serve we have been entrusted with and have executed on for over 150 years.

Transitioning the Coal Fleet

The Company's plan addresses all of the remaining coal on the system in two ways: accelerating retirements and implementing conversions. First, the Company has negotiated accelerated retirement dates for Craig 2, Hayden 1, and Hayden 2 with our partners in those units. We bring those proposed retirement dates to the Commission for approval in this proceeding, and the accelerated retirement dates are all based on the regulatory and system requirements of all owners of these plants. Under this approach, Craig 2 will retire in 2028, Hayden 1 will retire in 2028, and Hayden 2 will retire in 2027.

At Comanche 3 in Pueblo, we propose to accelerate the retirement of the unit by 30 years, moving the retirement date from 2070 to 2040. In addition, we recommend that Public Service operate the unit with an annual capacity factor limitation of 33 percent beginning in 2030. This allows for lower emissions while providing cost effective reliable operations for the Colorado system. In 2040, we recommend securitizing the undepreciated balance of the unit upon its retirement. The securitization tool, combined with limited operations beginning in 2030, provides a 20-year runway for our host Pueblo community, and strikes the right balance between emission reductions, reliability, and cost for our customers and the state.

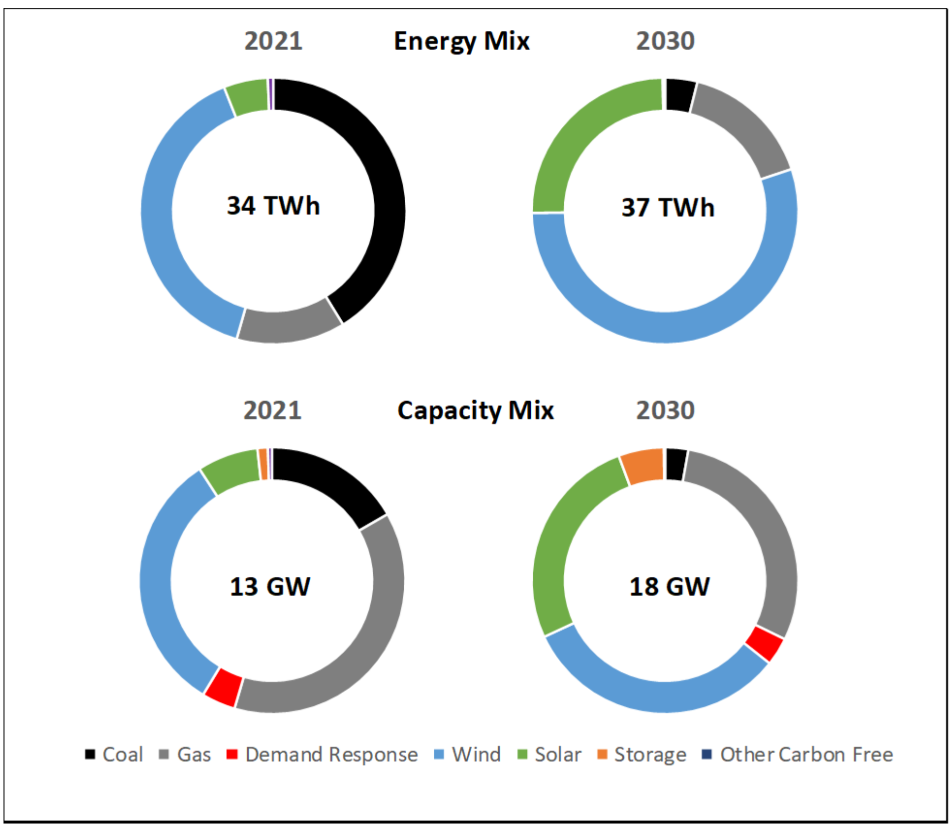
The plan also to takes advantage of a low-cost option to convert Pawnee to natural gas in 2028. This minimizes the workforce transition and community impacts of a standalone accelerated retirement in Morgan County, while also providing our system with a dispatchable generator to provide critical system reliability.

Adding Clean Energy and Flexible Resources

This resource plan is the largest and most-climate driven proposal brought forward in our Company's history. Indeed, after examining numerous portfolios and modeling options, Public Service has proposed a preferred plan featuring: **2,300 MW of wind, 1,600 MW of large-scale solar, 400 MW of battery storage, and 1,300 MW of flexible dispatchable generation.**[1] And to bring these resources forward, we will again harness the ERP all-source solicitation process and expect a robust pool of bids enabled by the transmission solution of Colorado's Power Pathway 345 kV Transmission Project (the "Pathway Project").

There are many drivers of these various resource acquisitions. One such driver is the social cost of carbon ("SCC") in our optimization. Between application of the SCC and the potential use of securitization, we are carefully but purposefully utilizing the tools provided by the General Assembly in Senate Bill 19-236 as a part of this plan.

The preferred plan will transition our system in a dramatic way from both an energy and capacity mix perspective, as shown below.



[1] In addition to these acquisitions, we have accounted for a robust distributed energy resource future as part of our plan, with 1,158 MW of resources modeled as coming online through 2030.

A Planful and Just Transition

Taking the next step in the clean energy transition requires more than crunching the emission reduction numbers and ensuring reliability and affordability. While each of those items is important, it is also critical to recognize that this transition will impact people, both within the Company's workforce and in the communities we serve. To that end, our just transition efforts consist of workforce transition and community assistance components, consistent with the directives of Senate Bill 19-236.

Public Service addresses workforce transition at Hayden 1 and 2, Pawnee, and Comanche 3 with a specific workforce transition plan provided as part of this 2021 ERP & CEP. We have deep experience with developing and implementing successful, low-impact workforce transition plans for previous plant retirements and fuel-switching actions in Colorado. In fact, during the course of numerous accelerated plant retirements over the past two decades, we have not implemented layoffs or forced workforce reduction—and we are committed to a similar outcome for our valued employees here using the approach reflected below. The following figure represents the five basic steps of our workforce transition plan:

1	2	3	4	5
Model the impacted workforce, inventory skills, identify future opportunities, and file the workforce transition plan with the state (Phase I filing)	Identify transition opportunities from future assets, potential contractor insourcing, and natural attrition across all operations business areas	Conduct transition conversations with impacted workers, map employee aspirations to opportunities, and perform skill gap analysis	Create and deploy workforce transition resources and roll out transition pathways for workers; Encourage employees to leverage resources to better prepare and qualify for their transition aspirations	Update workforce transition plan, file the workforce transition plan with the state (Phase II filing), and update all key stakeholders

The Company also has a proud history of working with our host communities affected by accelerated retirements of coal plants, and we are proposing to build on that history here. In the 2016 ERP, for example, we worked closely with the Pueblo community on the Comanche 1 and 2 accelerated retirements to build stakeholder support for these retirements and find a win for the community. A centerpiece of that effort was the siting of economic solar generation within Pueblo County, which helped to restore the tax base lost as a result of the Comanche 1 and 2 accelerated retirements. Each community and accelerated retirement is different, however, and there is no community assistance blueprint that can fit each and every situation.

Our Leadership and Next Steps

Electric Resource Planning is one of the most important undertakings of a utility in collaboration with its utility commission and other stakeholders. Decisions made in this proceeding are critical to reliability and delivery of electric services, which are a foundational responsibility of any utility. Those same decisions determine a substantial portion of the long-term costs of electric services for customers, as well as utility economics and health. And now, as an even larger focus, the Clean Energy Plan drives emission reductions from the electric system and makes environmental impact one of the most substantial considerations in the selection of resources. There will be many considerations taken into account through the duration of this proceeding, and decisions regarding pathways, trajectories, and impacts will be part science, part analytics, and part art—all while considering the real impacts on real people and communities associated with our plan.

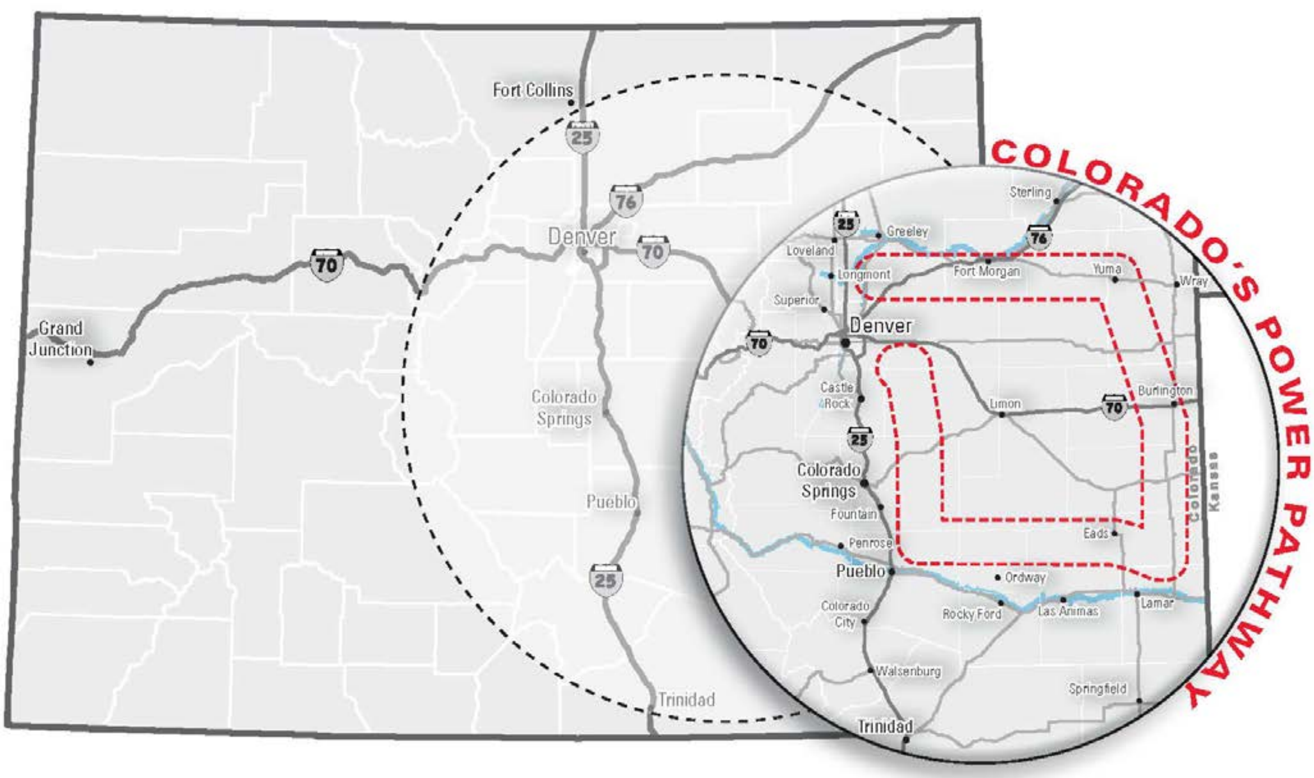
The preferred plan that we are presenting to the Commission in this 2021 ERP & CEP, along with robust data and information backup, is a balanced approach to a successful long-term future. This is truly a landmark plan that will take the next step in the energy transition, provide the State of Colorado with the emission reduction down-payment it is depending on from the power sector to advance toward economywide goals, and transition our workforce and host communities on an appropriate timetable. We need to develop a sensible and sensitive coal transition plan as part of this Phase I process and believe we have brought one forward here. Once the coal transition decisions are made in this phase of the proceeding, we will be positioned to use the well-established and high-functioning ERP competitive bidding process to build a portfolio that will not only meet but hopefully exceed the clean energy targets established for the Company by Senate Bill 19-236. We all have a lot of complicated work to do and it will take many stakeholders beyond just us to make this all come together. We are excited about the future of the Company and the State of Colorado, with this plan as the anchor of the implementation of one of the most robust climate policy agendas in the United States.

Transmission Infrastructure: Colorado’s Power Pathway

Colorado’s clean energy transition is not limited to generation resources. Achieving the State’s emission reduction goals will require increased alignment between resource planning and transmission planning. 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.

A key component of achieving the clean energy targets is the development of significant transmission infrastructure to interconnect and deliver new clean energy resources to our customers. As Public Service accelerates the clean energy transition, the Company needs to expand its transmission "backbone" to create a power pathway around the clean energy-rich areas of the State to enable the generation fleet of the future. Colorado is fortunate to have some of the best wind and solar resources in the country–particularly in the eastern and southeastern part of the State–however, the current lack of transmission infrastructure is a limiting factor in the ability to harness the potential wind and solar resources in the region.

On March 2, 2021, in Proceeding No. 21A-0096E, the Company filed an Application for a Certificate of Public Convenience and Necessity ("CPCN") to construct the Pathway Project. The Pathway Project involves construction of nearly 600 miles of new 345 kilovolt ("kV") transmission infrastructure to provide a high voltage networked transmission facility that interconnects the Eastern Plains and Southern Colorado to Public Service's load centers. The vicinity of the Pathway Project routing study area is shown in the graphic below.



The Company filed the CPCN prior to our 2021 ERP & CEP filing to seek approval of the CPCN in advance of the 2021 ERP Phase II competitive solicitation process to give bidders certainty that transmission capacity will be available across Energy Resource Zones ("ERZ") 1, 2, 3, and 5. The Pathway Project will be particularly helpful in facilitating access for projects across ERZs 1, 2, 3 and 5 and provides an opportunity to achieve further geographic diversity of wind and solar resources across the State. Moreover, it provides reliability benefits as high levels of variable energy resources are brought on the system.

The Pathway Project 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. By having certain segments and substations constructed and in-service by the end of 2025, wind and solar developers will be able to interconnect their resources prior to the expiration of the Production Tax Credits ("PTCs") and Investment Tax Credits ("ITCs"). Bids submitted by generation developers will enable significant cost savings to customers if those generating resources can be online before the end of 2025, which is when the PTC is set to expire and the ITC steps down.

1.1 INTRODUCTION AND BACKGROUND

Purpose of Filing

Public Service submits this 2021 Electric Resource Plan ("ERP") pursuant to the Electric Resource Planning Rules, 4 CCR, 723-3-3600 *et. seq.* ("ERP Rules"). This 2021 ERP contains the Company's Clean Energy Plan ("CEP") submitted pursuant to the requirements of Senate Bill 19-236 ("SB 19-236") as codified in § 40-2-125.5, C.R.S.

This 2021 ERP containing the CEP ("2021 ERP & CEP" or the "Plan") provides the framework for how the Company assesses the need for future electric supply resources over the resource acquisition period ("RAP") that extends through 2030 as prescribed by SB 19-236 and § 40-2-125.5(4)(I), C.R.S., as well as a plan for acquiring those resources. The purpose of the CEP is to set forth a plan of actions and investments by the Company projected to achieve compliance with the clean energy targets established by SB 19-236 that result in an affordable, reliable, and clean electric system. The clean energy targets are: (1) reducing carbon dioxide ("CO2") emissions associated with electricity sales to the Company's electric customers by 80 percent from 2005 levels, and (2) for the years 2050 and thereafter, or sooner if practicable, the Company shall seek to achieve the goal of providing its customers with energy generated from 100 percent clean energy resources so long as doing so is technically and economically feasible and in the public interest. A "clean energy resource" means any electricity-generating technology that generates or stores electricity without emitting carbon dioxide into the atmosphere. Clean energy resources include, without limitation, eligible energy resources as defined in § 40-2-124(1)(a).

Contents and Organization of the 2021 ERP and CEP

The 2021 ERP and CEP filing is comprised of the following three volumes:

Volume 1: 2021 Electric Resource Plan and Clean Energy Plan

Volume 2: Technical Appendix and References

Volume 3: Requests for Proposals and Model Contracts

Volume 1 contains an Executive Summary and high-level overview that outlines the essential elements of the Company's 2021 ERP & CEP. Appendix 1 of Volume 1 provides the Company's Workforce Transition Plan.

Volume 2 contains the Technical Appendix that provides detailed information required by the Commission's ERP Rules and additional technical information supporting the Company's 2021 ERP & CEP.

Volume 3 (including three separate sub-parts identified as 3.1, 3.2, and 3.3), contains the Request for Proposals ("RFPs") and model contracts for use in the proposed Phase II competitive solicitation process.

ERP Process Overview and How This 2021 ERP Differs

The ERP Rules require electric utilities to develop and file ERPs generally on a four-year cycle. The ERP Rules also specify what must be contained in the ERP and the process electric utilities must undertake to implement their ERPs. The Colorado ERP process is looked to nationally as a model for the acquisition of cost effective and increasingly clean generation resources. As specified by the Commission's rules, the ERP process focuses on identifying the need for additional generation resources or changes to existing generation resources that are needed to meet certain future objectives in a cost effective and reliable manner.[2] An ERP consists of two phases: Phase I and Phase II.

Phase I

Phase I involves the utility's ERP filing which includes information regarding the utility's electric system, an assessment of the need for additional resources, and the utility's plan to acquire those resources. Following a litigated proceeding, the Commission renders a decision on the utility's proposed ERP, its assessment of the need for resources and its proposal to acquire resources to meet the need. The Commission also approves the process for evaluating bids to the utility's competitive solicitation and establishes the modeling parameters, including inputs and assumptions, the utility shall use for the presentation and consideration of potential cost-effective resource portfolios. For this 2021 ERP & CEP, where specific legislation (i.e., SB 19-236) directs the inclusion of a CEP, Phase I will also evaluate potential actions with regard to the Company's remaining coal fleet as discussed throughout the plan. Through this Phase I process, the Company is seeking approval of its preferred plan, including a specific set of actions to the remaining coal fleet to ensure the Company solicits the right resource need in the Phase II process. Phase I typically takes about one year from the time the Company files its plan to the Commission's Phase I decision.

Phase II

Following the Phase I decision, the Company updates its modeling inputs and assumptions in accordance with the Phase I decision and issues its RFP to initiate Phase II, the competitive solicitation process. Public Service evaluates bids and develops

[2] *See* 4 CCR 723-3-3600, *et seq.*

portfolios of bids that meet the Commission's Phase I directives (overseen by an Independent Evaluator). Within 120 days from bid receipt, the Company files its "120-Day Report" that sets forth the results of its bid evaluation process and identifies a preferred portfolio of resources to acquire. Phase II is a non-litigated, comment-based phase in which parties to the proceeding have an opportunity to file comments on the 120-Day Report. Within 90 days of filing the 120-Day Report, the Commission renders its Phase II decision, which ultimately selects specific resources to satisfy the resource need. The Company then pursues the acquisitions of those generation resources through follow-on Certificate of Public Convenience and Necessity ("CPCN") proceedings and Power Purchase Agreement ("PPA") negotiations. The Phase II process also takes about one year from the time the Company issues its RFPs to the Commission's Phase II decision.

2021 ERP Distinctions

The 2021 ERP & CEP is the first ERP cycle with specific clean energy targets that the generation portfolio(s) must meet as a result of the passage of SB 19-236. Specifically, the Company is required to file a plan that achieves an 80 percent reduction in CO_2 from 2005 levels by 2030, which equates to a plan that emits approximately 5.4 million short tons ("MST") of CO_2 in 2030. This emissions target changes the ERP process in some ways because it is the first time Public Service has completed resource planning and modeling with a specific emissions cap in place.

This 2021 ERP & CEP process is also different because the Company is using the social cost of carbon ("SCC") in the optimization of resource planning portfolios in the modeling. This value has been used as a sensitivity in previous ERPs, but in this plan it is included in the optimization of portfolios as directed by SB 19-236. The modeling of portfolios to meet statutory clean energy targets and use of the SCC in the modeling are two foundational changes from SB 19-236 that materially influenced the preparation of this Phase I 2021 ERP & CEP.

Summary of the 2016 ERP and Colorado Energy Plan Portfolio

The Company filed its last ERP on May 27, 2016 in Proceeding No. 16A-0396E ("2016 ERP"). The 2016 ERP ultimately resulted in the approval of the Colorado Energy Plan Portfolio ("CEPP"), which also drove a significant transformation of our generation fleet. The CEPP was the outcome of a Stipulation Agreement formed through the collaboration of Public Service and fifteen additional parties to the 2016 ERP that set forth general parameters for the presentation of the CEPP in the Phase II process of the Company's 2016 ERP.

The presentation of the CEPP was driven by the desire to present a portfolio that could save money for customers in the long-term on a present value basis by taking advantage of available federal renewable energy production tax credits and investment tax credits at their highest levels and bring more renewable energy resources onto the system while retiring coal-fired generation. The CEPP involved a voluntary proposal to retire 660 MW of coal-fired generation—Comanche 1 (325 MW) by the end of 2022 and Comanche 2 (335 MW) by the end of 2025—and replacing these units with utility-owned and independent power producer-owned (“IPP”) resources, including wind and solar, and dispatchable and semi-dispatchable resources.

In November 2017, the Company received over 400 bids in response to its Phase II 2017 All-Source Solicitation, including an unprecedented number of low-cost bids across diverse technology types. Following an evidentiary hearing and extensive stakeholder engagement and public comment, the Commission approved the Preferred CEPP (Portfolio 6) and issued its Phase II Decision (Decision No. C18-0761) on September 10, 2018.

The approved CEPP included over 1,800 MW of wind and solar generation, paired with 275 MW of battery storage, and 383 MW of existing gas assets, all while retiring 660 MW of coal-fired generation. In September 2019, the Company filed an Application for an Amendment to its 2016 ERP (Proceeding No. 19A-0530E) to replace two approved CEPP projects for which the developer was unable to deliver as bid. Consistent with the Commission’s direction, the Company issued a targeted request for proposals (“2019 Solar RFP”) to solicit replacement bids. By Decision No. R20-0285, the Commission approved the Company’s proposed replacement bids and back-up bids. As detailed in status reports filed in Proceeding No. 19A-0530E, the Company successfully executed both replacement PPAs by the end of 2020 and the projects are expected to be online by 2023.

Table 1.1-1 below is a summary of the generation resources that comprise the CEPP approved in Phase II of the 2016 ERP and the two replacement projects approved as part of the 2016 ERP Amendment.

Table 1.1-1 Colorado Energy Plan Portfolio & Replacement Projects

Bid ID	Technology	MW	Ownership	In-Service[1]
X645	Solar w/ Storage	250/125	IPP	2023
X647	Solar w/ Storage	200/100	IPP	2023
056	Solar w/ Storage	100/50	IPP	2023
077	Solar	200	IPP	2023
S085	Solar	72	IPP	2023
W192	Wind	500	Own	2021
W602	Wind	300	IPP	2021
W090	Wind	169	IPP	2021
W301	Wind (repower)	162	IPP	2019
G215	Gas (existing)	301	Own	2022
G065	Gas (existing)	82	Own	2020[2]

[1] In-Service refers to the first summer the unit is available.

[2] The 2020 In-Service date reflects the Commission's approval to bring Valmont on-line approximately two years earlier than the 2022 acquisition and in-service date of the facility contemplated in the approval of the CEPP (*S*ee Decision No. R20-0108, Proceeding No. 19A-0409E).

In addition to approving the CEPP, the Commission's Phase II Decision directed Public Service to file CPCN applications: (1) to acquire the 500 MW utility-owned wind generation facility (i.e., the Cheyenne Ridge Wind Project); (2) to acquire the existing natural gas-fired generation resources included in the approved CEPP (i.e., Valmont 7 & 8 and Manchief); and (3) for the additional transmission investment associated with the approved CEPP (i.e., network upgrades, voltage control, and interconnection facilities). The Commission also directed the Company to file a limited-scope CPCN application to review the detailed cost estimates and schedules associated with the closure and decommissioning of Comanche Units 1 and 2. The status of these CPCNs is summarized below.

- Cheyenne Ridge Wind Project (Proceeding No. 18A-0905E): The Company filed its CPCN Application on December 21, 2018. Pursuant to the CPCN approved by Decision No. C19-0367 (mailed April 25, 2019), the Company began construction of the 500 MW Cheyenne Ridge Wind Project in June 2019 and filed quarterly construction progress reports in Proceeding No. 18A-0905E. As discussed in the final quarterly report filed on October 30, 2020, the Cheyenne Ridge Wind Project was completed and placed into service in August 2020.

- Valmont and Manchief Acquisition (Proceeding No. 19A-0409E): The Company filed its CPCN Application on July 23, 2019 for: (1) approval of a CPCN to acquire, own, and operate the existing 301 MW Manchief facility; and (2) approval of a CPCN to acquire, own and operate the existing 82 MW Valmont 7 & 8 facility and to exercise an Early Purchase Option afforded by the terms of the Purchase and Sale Agreement with the owner of Valmont in order to bring that resource online in 2020, approximately two years earlier than the 2022 acquisition and in-service date of the facility contemplated in the approval of the CEPP. A Settlement Agreement was reached among Settling Parties and approved by Decision No. R20-0108 (mailed February 18, 2020). Valmont 7 & 8 came on-line in June 2020 and was a critical resource during the Company's 2020 summer peak.

- Transmission CPCNs for Implementation of the CEPP: Implementation of the CEPP involves three categories of transmission investment, including: network upgrades, voltage control, and interconnection facilities. The Company filed a CPCN Application for the voltage control facilities in Proceeding No. 19A-0728E on December 20, 2019 and a CPCN Application for the network upgrades on February 21, 2020 in Proceeding No. 20A-0063E. By Decision No. C20-0648 in Consolidated Proceeding Nos. 19A-0728E and 20A-0063E, the Commission approved a CPCN for the voltage control facilities and the network upgrades (i.e., Denver-Greenwood Terminal 230 kV Transmission Line Project and three minor uprate projects) necessary to implement the CEPP. The CPCN(s) for the interconnection facilities will be filed later in 2021 for the interconnection facilities necessary to implement certain CEPP projects and replacement projects that are anticipated to be online by 2023.

- Comanche Units 1 and 2 Retirement CPCN: The Company anticipates filing the required limited-scope CPCN application later in 2021 to review the detailed cost estimates and schedules associated with the closure and decommissioning of Comanche Units 1 and 2 prior to the scheduled end of year 2022 and 2025 retirement dates, respectively.

Stakeholder Engagement

Stakeholder engagement has been and will continue to be an important aspect of the Company's resource planning process. The changing regulatory and policy landscape in recent years has made the resource planning process more complex and the interests of stakeholders more diverse. While our stakeholders have wide-ranging perspectives on the vast number of issues at stake, we believe there are opportunities to find common ground as we work toward our collective energy future and Colorado's energy and environmental goals.

Prior to filing our 2021 ERP & CEP, the Company hosted five stakeholder workshops to present and discuss a variety of resource planning issues. The stakeholder workshops were intended to be educational, informative, and to facilitate dialogue over the course of developing the plan. The stakeholder workshops covered the following topics:

- ***December 13, 2019***: Legislative and Policy Landscape; Resource Planning Phase I/Phase II Overview; New EnCompass Model;
- ***April 10, 2020***: Overview of Energy and Demand Forecasting Process and Inputs; Generic Resources;
- ***November 6, 2020***: Modeling Framework: EnCompass Model; Key Modeling Inputs and Assumptions; SB 19-236 Framework; Study Updates: Effective Load Carrying Capability; Planning Reserve Margin; Flex Reserve;
- ***February 25, 2021:*** Clean Energy Plan Actions; Colorado's Power Pathway 345 kV Transmission Project; Carbon Targets; and
- ***March 25, 2021:*** Preview of the Company's 2021 ERP & CEP; Forecast Overview; Asset Recovery Methods; Analysis Framework; and, Workforce and Community Transition.

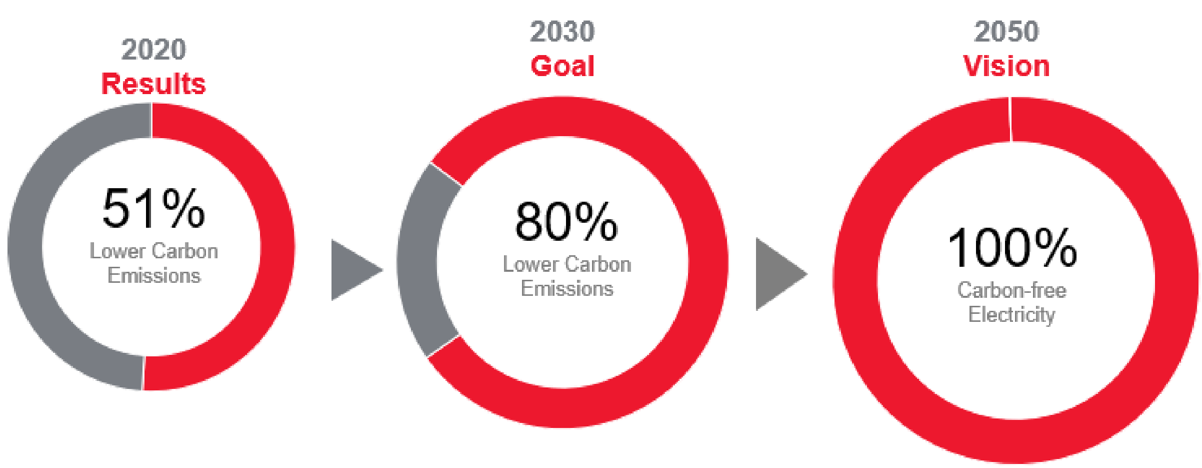
1.2 REGULATORY AND PLANNING LANDSCAPE

Xcel Energy's Bold Vision for a Carbon-Free Future

The Company's vision for this 2021 ERP & CEP was launched in December 2018 when Xcel Energy announced a first-of-its-kind commitment, pledging to reduce carbon dioxide emissions by 80 percent from 2005 levels by 2030 and to deliver 100 percent carbon-free electricity to customers by 2050. In setting these ambitious goals, we collaborated with an Intergovernmental Panel on Climate Change lead author at the University of Denver to understand how our trajectory aligned with the climate science. Based on analysis of climate scenarios that met both the 2-degree and 1.5-degree temperature rise outcomes, the trajectory of 80 percent reductions by 2030 and 100 percent by 2050 is consistent with achieving these temperature goals in a developed economy.

Our leadership on this issue spurred similar commitments across the utility sector nationally, with over twenty utilities having since adopted carbon-free electricity pledges. We have already reduced carbon emissions approximately 51 percent company-wide from the electricity provided to customers — a reduction level that puts us over halfway to delivering 100 percent carbon-free electricity by 2050.

Figure 1.2-1: Xcel Energy's Vision for a Carbon-Free Future



Colorado's Landmark Climate Legislation

Shortly after Xcel Energy's announcement, the Colorado General Assembly embarked on its 2019 legislative session, which made history from a clean energy and climate policy perspective with two landmark bills:

- House Bill 19-1261 ("HB 19-1261"), which set economywide emission reduction goals of 26 percent from 2005 levels by 2025, 50 percent from 2005 levels required by 2030, and 90 percent by 2050; and
- Senate Bill 19-236 ("SB 19-236"), which directed large regulated utilities to reduce emissions by 80 percent from 2005 levels by 2030 and 100 percent by 2050 using Colorado's well established ERP process.

These two bills are both directed at emission reductions, with SB 19-236 focused specifically on emission reductions from the power sector and HB 19-1261 focused on emission reductions across sectors.

Senate Bill 19-236

SB 19-236 established a regulatory pathway that requires certain utilities in Colorado to engage in long-term planning towards deep carbon reductions in the electric sector. As discussed above, SB 19-236 requires Public Service to reduce CO_2 emissions associated with electric sales to customers by 80 percent from 2005 levels by 2030. This statute creates the first mandatory CO_2 reduction target for resource planning in Colorado. Beyond the 2030 clean energy target, SB 19-236 directs qualifying retail utilities to seek to achieve the goal of providing customers with energy generated from 100 percent clean energy resources by 2050 so long as doing so is technically and economically feasible, in the public interest, and consistent with the law. Utilities meet this requirement through the filing of a CEP for Commission approval.

The CEP must set forth a plan of actions and investments that are projected to meet the 2030 carbon reduction goal while maintaining an affordable, reliable, and clean electric system. The ERP must include a Resource Acquisition Period that extends through 2030 and must distinguish between two sets of resources: those needed to meet customer demand during the resource acquisition period, and those needed to meet the clean energy targets. Activities detailed in the CEP may include retirement of existing facilities, changes in system operations, or any other necessary actions. The CEP must also describe the effect of the plan on the safety, reliability, renewable energy integration, and resilience of electric service in the state.

SB 19-236 requires the use of a competitive bidding process that has long been a part of resource planning in Colorado to fill the cumulative resource need both from the ERP and

CEP. However, the bill also recognized that utilities will be bringing forward assets for retirement that have received previous Commission approval for cost recovery as assets, and to ensure fairness to the utility's shareholders upon giving up financial assets to achieve worthy state policy goals, provides a fifty percent ownership target for the utility for new clean energy resources acquired in the plan if the Commission finds that the cost of utility ownership comes at a reasonable cost and rate impact. The achievement of this ownership target will not be designated in the Company's preferred plan or other portfolios in this Phase I filing but will be addressed in proposed portfolios assembled from actual bids under Phase II.

As discussed throughout our 2021 ERP & CEP, our plan satisfies the requirements of SB 19-236 and continues Public Service's path toward a cleaner electric system for our customers and the State.

House Bill 19-1261

HB 19-1261 set new economywide greenhouse gas ("GHG") emissions reduction targets for the state below 2005 levels, including:

- 26 percent by 2025
- 50 percent by 2030
- 90 percent by 2050

The Air Quality Control Commission ("AQCC") is directed to promulgate rules and regulations to achieve the targets. In recognition of the critical role that electric utilities will play in achieving emissions reductions for Colorado, HB 19-1261 created a "safe harbor" provision for utilities that file a CEP. Utilities that file a CEP that will achieve at least an 80 percent reduction in GHG emissions caused by the utility's retail sales below 2005 levels by 2030 may not be subject to additional reduction requirements or direct non-administrative costs on the utility's remaining emissions by the AQCC if the reductions are achieved and the Air Pollution Control Division has verified that the approved CEP will achieve at least a 75 percent reduction in emissions below 2005 levels by 2030 (see Section 1.2 below).

The Colorado Greenhouse Gas Pollution Reduction Roadmap

In January 2021, the State of Colorado finalized the Colorado Greenhouse Gas Pollution Reduction Roadmap ("Roadmap"), which lays out the State's own approach to developing a regulatory architecture to advance emission reductions across the economy, by pursuing sector-specific emission regulations that take into account the unique nature of the diverse segments of the economy regulated under any program. The Roadmap is an expansive document that contains numerous "Near Term Actions to Reduce GHG

Pollution" across key sectors of the Colorado economy, including in part: electricity; transportation; residential, commercial, and industrial fuel use; oil and gas; and natural and working lands.[3] The Roadmap represents the State of Colorado's template for its deliberative development of sector-specific approaches toward the achievement of economy-wide emission reductions of 50 percent by 2030 and 90 percent by 2050.

In many ways, this 2021 ERP & CEP has always been the centerpiece of these broader efforts—it will require contributions and changes from many, but the architecture developed by the General Assembly was built to have the power sector lead the way in the State's clean energy transition. The Roadmap notes that "the largest single opportunity for near term reductions is in the electricity sector, where the Roadmap is targeting an 80 percent reduction, or 32 million tons, below 2005 emissions levels by 2030."[4] It further provides that "[t]he combination of a 2030 GHG pollution reduction target and the potential for any utility to file a Clean Energy Plan provides an important framework to implement enforceable emissions reductions."[5]

The emission reduction trajectory outlined in the Roadmap relies on eligible utilities—not just Public Service—filing resource plans that meet the 80 percent clean energy target of Senate Bill 19-236. The Roadmap states that "[t]he six utilities that operate more than 99 percent of the state's fossil-fired generation, Xcel Energy, Tri-State Generation and Transmission, Colorado Springs Utilities, Platte River Power Authority, Black Hills Energy, and Holy Cross Energy, have already committed to resource plans that meet or exceed an 80% GHG reduction by 2030."[6] Finally, it states that "[t]he state is not proposing to require reductions greater than 80% by 2030 across the board, although it is hopeful that the 80% reductions might be reached earlier or exceeded by 2030."[7]

The Company's 2021 ERP & CEP demonstrates that we are prepared to meet this charge and constitutes a substantial emission reduction step forward for the State. Simply put, emission reductions from the power sector are a lynchpin to put the State of Colorado on the path it needs to be on to achieve the economywide emission reduction goals of HB 19-1261. The graphic below illustrates the contribution of the power sector—and the Company's 2021 ERP & CEP standing alone—to the State of Colorado's policy objections.

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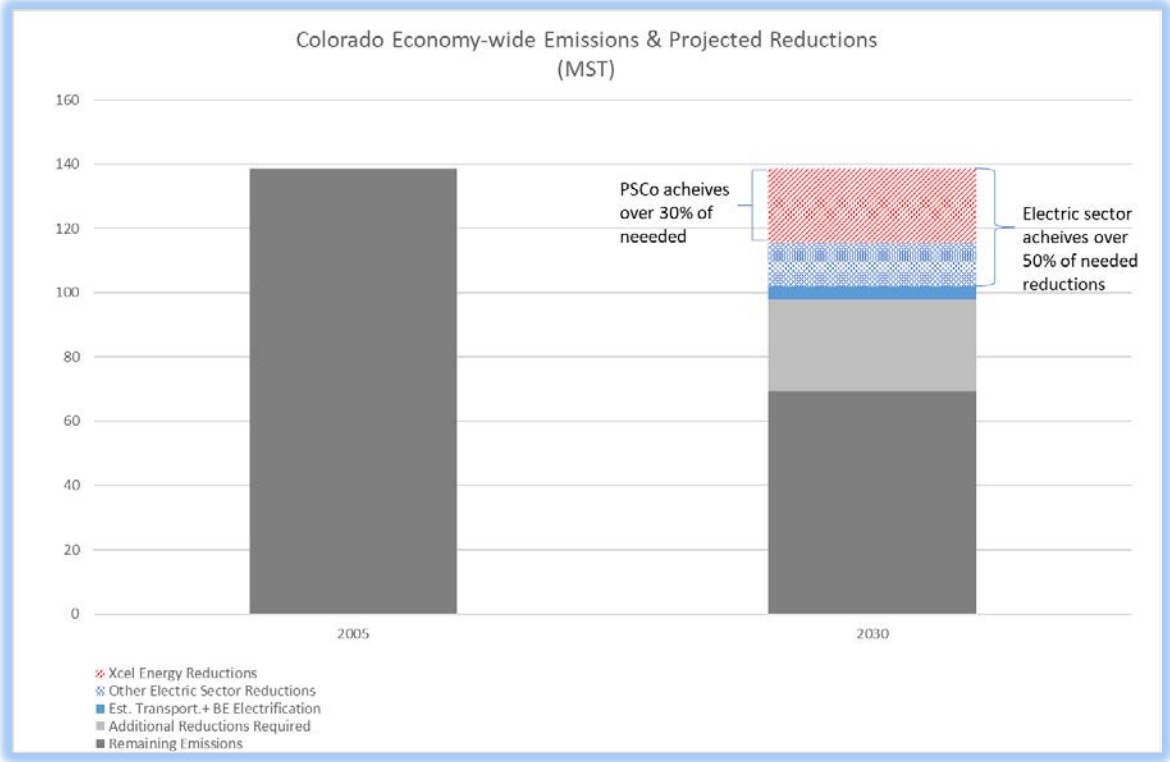
[3] Attachment AKJ-4, at 29-34 (Table 1).
[4] Attachment AKJ-4, at 88.
[5] Attachment AKJ-4, at 91.
[6] Attachment AKJ-4, at 79.
[7] Attachment AKJ-4, at 79.

Figure 1.2-2: Colorado Economy-wide Emissions and Projected Reductions (MST)



Clean Energy Plan Guidance and Emissions Verification

SB 19-236 and HB 219-1261 laid out the high-level responsibility of the Air Pollution Control Division ("Division"), within the Colorado Department of Public Health and Environment ("CDPHE"), to verify emission reductions and clean energy plans and participate in the CEP proceedings held by the Commission. The language of the statutes, however, did not specify the details or requirements of the verification process.

The Division embarked on a collaborative stakeholder effort to develop a guidance document that would clarify the roles of the Division and establish the data requirements to evaluate CEPs and verify emissions reductions. The objective was to create clear and consistent guidance to provide utilities and all interested parties a common understanding of the requirements and the criteria by which a CEP will be evaluated.

The Clean Energy Plan Guidance document ("CEP Guidance") was ultimately created by the Division with the input from stakeholders, including utilities, environmental groups, and local governments, that met consistently throughout 2020. The stakeholders developed a spreadsheet tool, i.e., the verification workbook, to standardize data provision and worked through detailed carbon accounting issues to support the Division in writing the final CEP Guidance document. As a result of these efforts, the CEP

Guidance can consider both carbon dioxide and all GHGs and also evaluate plans on both a retail sale and all electricity sales (both retail and wholesale sales) basis. Lastly, the stakeholder process was convened to ensure proper oversight and input from the AQCC. The AQCC approved the CEP Guidance and comprehensive safe harbor application through two resolutions in January 2021.

As demonstrated throughout our Phase I filing, the Company's 2021 ERP & CEP satisfies the CEP Guidance and achieves all the requirements of a CEP as defined in both HB 19-1261 and SB 19-236. The Company's preferred plan achieves 84.3 percent reductions in GHGs over 2005 levels on a retail sales basis and 84.5 percent reductions over 2005 levels for all electricity sales (based on the adjusted baseline).

Public Service supports the CEP Guidance methodology, which is in line with our own emissions reporting and ties together a variety of issues into clear, transparent verification workbooks and process. The Company has provided verification workbooks for our preferred plan and each portfolio modeled in Phase I (SCC and $0/ton carbon) as Appendix H of Volume 2. We will work with the Division and Commission to ensure a successful verification process.

Social Cost of Carbon

The Company has included the SCC in our optimization for the first time in an ERP, as required by SB 19-236, to consider the cost of CO_2 emissions when determining the cost, benefit, or net present value ("NPV") of the plan. SB 19-236 requires utilities to model an optimization of a base case portfolio of resources using the SCC with the cost applied to all existing and any new resources evaluated or proposed.

Beginning in 2020, the Commission was directed to use a SCC based on the most recent assessment of the SCC developed by the federal government, but in any case starting at no less than $46 per short ton, modified based on escalation rates contained in the federal Interagency Working Group on the Social Cost of Greenhouse Gases' 2016 Technical Support Document.

Our preferred plan is one of the SCC cases as opposed to the $0/ton cases as discussed in detail in Section 1.6. Therefore, in addition to this being the Company's largest resource plan ever, it also marks the first time we are proposing a preferred plan that accounts for the SCC, or value of the impacts of carbon emissions.

Federal Tax Credits for Renewable Energy Development

The Consolidated Appropriations Act, 2021 passed by Congress and signed into law at the end of 2020 included legislative aspects that affect resource acquisition timing in this 2021 ERP & CEP. The legislation extended the in-service date when wind and solar facilities need to be placed in service from end-of-year 2024 to end-of-year 2025. More specifically, wind and solar facilities placed in-service by December 31, 2025 can qualify for 60 percent PTC and 26 percent ITC, respectively, so long as the project has begun construction by January 1, 2022 for the PTC and January 1, 2023 for the ITC.[8] Prior to the passage of the legislation, wind facilities placed in-service after December 31, 2025 would not receive any PTCs. Solar facilities placed in-service after December 31, 2025 would receive 10 percent ITC. The ability of a generation facility to qualify for these tax credits provides considerable cost savings to customers.

As discussed in Section 1.9, the estimated in-service date of certain segments of the Pathway Project are aligned to bring tax-advantaged clean energy resources online and begin to advance early emission reductions—two of the primary reasons why the Company brought the Pathway Project before the Commission in a separate CPCN proceeding (Proceeding No. 21A-0096E) and have requested a decision on that CPCN prior to the Phase I decision in this proceeding.

Energy Imbalance Market Participation

Public Service is working towards beginning participating in the Western Energy Imbalance Market ("WEIM") administered by the California Independent System Operator ("CAISO") in April 2022. The WEIM is a wholesale energy trading market that optimizes the dispatch of participating generators to serve load the most economically in real-time within the operational limitations of the grid. As part of joining the WEIM, the Balancing Authority Area that Public Service manages ("PSCo BAA") will be included in the economic dispatch of the WEIM, along with approximately 80 percent of the load in the Western Interconnection. The WEIM is expected to enable production cost savings and improved long-term integration of variable energy resources for Public Service and the other utilities in the PSCo BAA participating in the market.

Importantly, WEIM participation does not impact Public Service's ERP requirements or process. The Commission continues to retain oversight over resource planning and procurement of resources by Public Service. The WEIM does not include a capacity market or ancillary services market and transmission service providers retain their individual Open Access Transmission Tariffs ("OATT") and existing Balancing Authority Areas remain unchanged.

However, the WEIM includes a resource sufficiency evaluation that Public Service will be responsible for satisfying. As an Energy Imbalance Market ("EIM") Entity, the PSCo BAA will be required to demonstrate on an hourly basis that it has the resources and ramping capability to satisfy the load requirements of the BAA. The non-PSCo generation and load

[8] The start of construction requirement can be met by safe harboring (e.g., spending 5 percent of the project's cost) before January 1, 2022 and January 1, 2023 for the PTC and ITC respectively.

within the BAA will be included in the calculation performed by the WEIM. The purpose of the resource sufficiency test is to ensure that entities participating in the WEIM can satisfy their own reliability obligations and entities do not lean on the capabilities of others. The resource sufficiency tests evaluate things like balancing requirements, dispatchable ranges and ramping capability of resources within the BAA, and transfer feasibility of schedules submitted by participants. If the PSCo BAA fails the resource sufficiency test within an hour, the PSCo BAA will be prevented from EIM transfers from other EIM Entities during that timeframe. Public Service anticipates satisfying these requirements similarly to how it manages the PSCo BAA today. For example, as the Balancing Authority Operator, Public Service is currently responsible for ensuring adequate resources are available to satisfy reliability obligations within the BAA.

Given the WEIM does not change resource planning requirements, consolidate Tariffs or BAAs, and does not change reliability obligations of the PSCo BAA, Public Service did not make changes within the model to reflect an organized market within the planning period of its 2021 ERP & CEP. The Company did run portfolios through an expanded import and export sensitivity, as explained in more detail in Volume 2.

1.3 2021 ERP & CEP PLAN FRAMEWORK

Resource Acquisition Period and Planning Period

The resource acquisition period ("RAP") is the is the period of time over which the utility acquires specific generation resources to meet projected resource needs. For this 2021 ERP & CEP, SB 19-236 requires that the Company use a RAP through 2030 to align with the clean energy target of 80 percent emission reduction by 2030 from 2005 levels. Thus our bounded RAP is from 2021 through 2030.

The "planning period" represents the future period for which the Company develops its plan, and the period over which the costs and benefits of new resources are evaluated and the time over which net present value of revenue requirements and emission costs for resources are calculated. For this 2021 ERP & CEP Phase I filing, the Company used a planning period from the plan filing year of 2021 extending through 2055. Additional details regarding the proposed planning period are included in Section 2.1 of Volume 2.

EnCompass Model

For this 2021 ERP & CEP, the Company is using a resource planning model called "EnCompass" to replace its previous model, Strategist, which had been used for over 20 years. With the increasing complexity of the electric system, including reliance on energy storage and increasing levels of intermittent generation (primarily wind and solar), it was necessary to find a more modern model that is better able to analyze these complex factors. The Company selected the EnCompass planning model from Anchor Power Solutions as the replacement tool for resource planning modeling across all of the Xcel Energy jurisdictions.

The ultimate purpose of EnCompass model is to develop and analyze capacity expansion plans and associated production costs of those plans under a variety of scenarios and sensitivities. Unlike Strategist, EnCompass uses a more modern numerical methodology called mixed-integer programming (see Appendix G of Volume 2 for more details). The model simultaneously solves the capacity expansion plan, production costs, environmental constraints, and ancillary service markets in a single simulation that "converges" on the optimal solution to all these factors in a single co-optimization process. In addition, the EnCompass model conducts production costing in a true hourly chronological manner, enforcing constraints such as start times/costs and ramp rates for resources, which requires a chronological dispatch to fully capture. Another key feature of EnCompass concerns the granularity of the time blocks modeled and the options for determining unit commitment. The EnCompass model has the capability to model every hour of every year of the modeling period in a full chronological process – this is what is typically termed an "8760" dispatch, meaning every hour of the year is modeled.

EnCompass also has settings to reduce the overall problem size by looking at fewer days and/or fewer hours per day by aggregating hours into a single block (i.e., considering 12 A.M. – 4 A.M. as a single simulation block versus 4 discrete hours). In the Phase I modeling presented in this filing, the Company modeled the full 24 hours in each day and did not use the hourly aggregation feature. However, different settings for the number of days to model and commitment logic were used depending on the simulation type. Additional details about EnCompass are provided in Volume 2.

Carbon Baseline

The baseline calculation was developed by CDPHE and addressed as part of two AQCC resolutions in support of the CEP Guidance and comprehensive safe harbor approach. The adjusted baseline and comprehensive safe harbor approach ensures that each utility follows robust carbon accounting protocols while also accounting for Colorado specific policy.

The comprehensive safe harbor is a consensus solution that allows utilities to receive "safe harbor" from future regulations under HB 19-1261 for emissions associated with both retail and wholesale sales. While the HB 19-1261 provisions specify retail only emissions, electricity delivery is planned to meet all load on the system, including retail and wholesale customers, which is reflected in SB 19-236. Bifurcating the wholesale emissions would create a situation where just a small sliver of the system would be subject to regulation, despite the fact that sales are treated equally as part of total load in resource planning. Moreover, providing a safe harbor for all sales could create double counting if multiple utilities file a CEP. The comprehensive safe harbor addresses these discrepancies by adding an additional pathway to provide a safe harbor for emissions from retail and wholesale sales, while addressing double counting through an adjusted baseline approach.

Utilities filing a CEP may achieve comprehensive safe harbor for retail and wholesale emissions if:

(1) The CEP, as filed, achieves at least an eighty percent reduction in GHG emissions associated with retail sales by 2030.

(2) The approved CEP achieves at least seventy five percent reductions in retail sales from 2005 levels and at least seventy five percent reductions in all electricity sales based on an adjusted 2005 baseline.

The baseline starts with The Climate Registry ("TCR") accounting and includes all emissions associated with delivering service to native customers, regardless of whether or not that customer is a wholesale customer that may re-sell that electricity to another party in Colorado. To address the double counting concern, the CEP Guidance lays out a process whereby Public Service adjusts its baseline for three distinct cases. Specifically, the adjusted 2005 baseline excludes emissions associated with wholesale requirements customers that are: (1) out of state; (2) no longer a wholesale requirements customer of Public Service as of 2019; or (3) planning to file their own CEP. This one-time adjustment will also be applied in 2030 to avoid double counting in both 2005 and future years.

The double counting issue applies to both 2005 and 2030; therefore, the adjustments need to be made symmetrically in both years. In 2030, this means that we do not include any wholesale contracts that we know today will be no longer on the system in 2030, such as Intermountain Rural Electric Association ("IREA"). In this case, the contract will be terminated by 2026 and would not be included in our modeling, therefore, no emissions associated with serving IREA would be included in our 2030 emissions. Secondly, we will also exclude emissions associated with wholesale contracts that plan to file a CEP, specifically Holy Cross Energy. In this case, our modeling is inclusive of serving this load since they will be a wholesale customer in 2030. We therefore make a back-end adjustment to remove these emissions, using the same methodology as the 2005 baseline adjustment. The adjusted baseline using this approach is shown in Figure 1.3.1.

Figure 1.3.1: Adjusted Baseline

CO2 Tons (Million Short Tons)	Original Baseline and Target - No Adjustments	Adjusted baseline and target
Baseline	33.9	27.3
80% Reduction	6.8	5.5
75% Reduction	-	6.9

Reliability Framework

System reliability was factored into the development of the Phase I portfolios in an iterative process that involved inputting various reliability requirements upfront into the EnCompass modeling process, post-modeling reliability review of model output/results, adjusting model inputs if needed, and then rerunning the adjusted model. The results of technical studies, including planning reserve margin requirements, Flex Reserve requirements, and effective load carrying capability ("ELCC") capacity credit were applied within the EnCompass modeling of all portfolios.[9] In addition to the results of these

[9] See Volume 2, Section 2.18 and identified Appendices for these study reports.

technical studies, the operating requirements established by the Northwest Power Pool ("NWPP") Reserve Sharing Group were reflected as inputs into the modeling process. [10]

The post-modeling reliability review process involved reviewing hourly model output for year 2030. A team of Company subject matter experts reviewed the overall generation composition of portfolios from both a generation reliability perspective and a transmission reliability perspective. The hourly data review process for generation reliability involved an assessment of 8760 hourly model output to determine if the model was properly enforcing planning reserve, flex reserve, and NWPP operating reserve requirements. The review also analyzed whether the current gas supply system would be sufficient to reliably supply the hourly volumes and fluctuations in gas burns that the modeling predicted.

The hourly data review process for real-time transmission reliability also involved an assessment of 8760 hourly model output. The purpose of the review was to determine if the current and planned transmission system could reliably deliver, in real-time, the output of the generation resources in each portfolio to customer load. In addition to this real-time assessment of hourly data, the Company's transmission reliability review and planning process involved an assessment of the Company's resource planning projections to determine if the planned transmission system expansion could reliably deliver the Company's resource acquisition target to meet the 2030 emission reduction goals.[11]

If these reliability reviews identified that a particular reliability input requirement needed adjusting, then the adjustments would be made, the model would be rerun, and the output would be reviewed to see if the adjustment worked as intended. For example, if certain generating units were viewed as contributing more spinning reserves than they should or could, the modeling inputs that define a generating unit's contribution to spin would be adjusted and the model would be rerun. In addition, there are certain aspects of this type of modeling that are a function of the model output and therefore cannot be fully captured through the various upfront inputs into the model. For example, the required transmission upgrades that might be needed to reliably deliver the new generation resources than were added to the system as a result of the optimization cannot be known until after the model is run. In this instance the cost for any additional transmission requirements would be a post-modeling addition to the cost of the portfolio.

All ERP and CEP portfolios were built to a comparable and acceptable level of reliability and therefore, as discussed in Section 1.6 below, this was not a distinguishing factor in

[10] As a member of the NWPP Reserve Sharing Group, Public Service carries operating reserves in accord with the NWPP established methodology. See Section 2.9 of Volume 2 for additional details.
[11] This planned transmission eventually became the Pathway Project that the Company filed a CPCN for on March 2, 2021.

selecting the preferred portfolio. Additional discussion regarding system reliability is discussed in Section 2.9 of Volume 2.

Key Modeling Assumptions and Inputs

Section 2.14 of Volume 2 of the 2021 ERP & CEP summarizes the key inputs and assumptions used in the Company's Phase I modeling and proposed for use in the Phase II modeling. Consistent with past practice, the Company will update the modeling inputs and assumptions, as necessary, consistent with the Commission's Phase I Decision and prior to commencement of the Phase II competitive solicitation.

Additionally, in accordance with Commission directives from the 2016 ERP Phase I and Phase II decisions, the Company has updated certain studies for inclusion with this 2021 ERP & CEP.[12] The results of the updated studies have been incorporated into the Phase I modeling as discussed throughout the Company's Phase I filing, and the study reports are provided as Appendices to Volume 2, including:

- Planning Reserve Margin and Resource Adequacy Study (Appendix A);
- Flex Reserve Study (Appendix B);
- Supplemental Flex Reserve Study (Appendix C);
- Wind and Solar Integration (Appendix D); and
- Effective Load Carrying Capability Study (Appendix E)

Of particular note among the modeling inputs and assumptions included in this 2021 ERP & CEP is the Company's inclusion of assumptions regarding electric vehicle ("EV") adoption and non-transportation related electrification in its demand forecasts. The Company has developed and modeled a range of demand forecasts with base, high and low demand and sales, as described in detail in Volume 2.2 of Volume 2. The base forecast reflects Commission-approved demand side management ("DSM") assumptions, Commission-approved Renewable Energy Plan ("RE Plan") distributed energy resources ("DERs"), and a Commission-approved Transportation Electrification Plan ("TEP"). The Company's high load scenarios (or Roadmap scenario) is based on the Colorado Greenhouse Gas Pollution Roadmap report and, in particular, its higher electrification outcomes for both transportation related and non-transportation related electrification.

This approach is consistent with the direction of a consensus discussion that took place in Proceeding No. 19R-0096E (Rulemaking proceeding) in which the Commission

[12] See Decision No. C17-0316, at ¶¶49 and 145 and Decision No. C18-0761, at ¶¶139-140 in Proceeding No. 16A-0396E.

requested that the Colorado Energy Office ("CEO") work with interested stakeholders to develop consensus regarding the provision of a range of energy and demand forecasts. Accordingly, in late 2019 CEO facilitated a process through which numerous stakeholders reached consensus on several proposed rules that were filed on December 20, 2019 in Proceeding No. 19R-0096E. Although the consensus rules will not be ultimately adopted by the Commission, given the consensus nature of this effort and the interest of the Commission and stakeholders in transportation electrification and non-transportation electrification and related impacts on the load forecast, the Company incorporated this information into its 2021 ERP & CEP.

The forecast scenarios are used to assess how the composition of resources in the 2021 ERP & CEP portfolios change as a function of increased or decreased customer load, including the timing as to when those resources would be needed to achieve specific carbon dioxide reduction targets as discussed throughout the Company's Phase I filing.

1.4 RESOURCE NEED ASSESSMENT

ERP Portfolios and CEP Portfolios

A key aspect of Phase I is establishing the resource need. For this 2021 ERP & CEP, SB 19-236 requires the Company to clearly distinguish between: (1) the resources necessary to meet customer demands in the RAP; and (2) the additional need created by actions taken to meet the 80 percent clean energy target (e.g., retirement of existing generating facilities, changes in system operations, etc.).

As discussed throughout the Phase I filing, the Company developed “ERP portfolios” and “CEP portfolios” to clearly distinguish between these two resource needs as required by SB 19-236. These two sets of portfolios are generally described as follows:

- **ERP Portfolios**: ERP portfolios meet the “base need,” or the needs reflected in the Company’s load and resource balance inclusive of the previously announced retirements of Craig 2, Hayden 1, and Hayden 2. ERP portfolios are not required within the modeling to meet the 80 percent carbon reduction target in 2030.
- **CEP Portfolios:** CEP portfolios reflect additional coal transitions at Pawnee and Comanche 3 and the additional resource acquisitions required to meet the 80 percent carbon reduction target in 2030 as established by SB 19-236. All CEP portfolios were required to meet at—a minimum— the 80 percent clean energy target by 2030, while ERP portfolios were not required to do so.

Both ERP and CEP portfolios were also required to achieve a 100 percent emission reduction by year 2050. In other words, all portfolios are carbon-free by 2050—but the CEP portfolios achieve earlier reductions through additional actions on the coal fleet prior to 2030.

The ERP portfolios serve two key purposes: (1) to provide a plan that focused on meeting the resource needs of the system absent the clean energy target; and, (2) to serve as a cost foundation against which the costs and benefits of CEP portfolios are compared.

Generic Resources

For purposes of developing the Phase I portfolios, which are considered “indicative portfolios,” the Company developed a suite of “generic resource” representations to serve as proxies for actual bids the Company might expect to receive in the Phase II competitive solicitation. Generic resource representations were developed for wind, utility-scale solar, four-hour duration battery storage, gas-fired combined cycle, gas-fired combustion turbine (sometimes referred to as “simple cycle”), and gas-fired reciprocating engine technology. Wind, solar, and storage estimates were developed from the 2020 National Renewable Energy Laboratory (“NREL”) Annual Technology Baseline (“ATB”). Gas-fired estimates were developed by employees within the Company's engineering and construction department. Detailed information on the generic resource representations is provided in Section 2.14 of Volume 2.

Areas of Resource Need Assessment

The Company's assessment of need for additional resources focused on five areas:

1. Generation capacity needs for system reliability;
2. Generation needed to reduce emissions;
3. Flexible resource needs for integrating intermittent resources;
4. Dispatchable resource needs for system reliability; and
5. Resources needed to comply with the RES.

Each of these five areas is discussed, in turn, below. In summary, the results of the resource need assessment identified:

- No currently identified need in years 2021 through 2025 for additional generation capacity to maintain acceptable system reliability;[13]
- Increasing needs for each year from 2026 to 2030;
- No need for additional renewable resources for the purpose of meeting the "minimum amounts" reflected in the percentage requirements of the RES;[14]
- The Flex Reserve study identifies the volume of flexible resources needed to accommodate up to 3 gigawatts ("GW") of incremental wind generation; and
- A need for additional emission reduction efforts to meet the 2030 statutory clean energy target of SB 19-236.

Generation Capacity Needs

To determine whether additional generation capacity is needed for system reliability purposes, the Company forecasts whether sufficient planning reserve margin would be maintained throughout each summer peak season during the RAP. The planning reserve margin is the amount of generation capability in excess of peak firm obligation load that

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[13] Of course, short term capacity purchases may be needed during this time depending on circumstances affecting system conditions. Rule 3615 provides avenues for these acquisitions outside of the ERP process, if necessary and if certain conditions are satisfied by the utility.

[14] No additional wholesale DG or non-DG resources are needed to comply with the RES through beyond 2030. The need for additional retail-DG resources are determined in the Company's Renewable Energy Plan filings.

a utility carries on its system in order to meet customer demand under system uncertainties. The Company proposes utilizing an 18 percent planning reserve margin for purposes of acquiring resources in Phase II of this 2021 ERP (see Appendix A of Volume 2). The peak electric demand forecast is compared with the existing and planned generation resources. This is commonly referred to as the load and resource balance or, load and resource table ("L&R").

Consistent with prior ERPs, the forecast of summer peak load is reduced by the combined effects of the Company's Demand Side Management ("DSM")[15] based on goals approved by the Commission in other proceedings. After accounting for DSM programs, the resulting load is referred to as firm obligation load. The 18 percent planning reserve margin is applied to the forecast of firm obligation load for each year of the RAP.

Table 1.4-1 summarizes the L&R forecast of summer capacity needs for years 2021-2030 (i.e., the RAP) needed to meet the 18 percent planning reserve margin. Two capacity need forecasts are provided in Table 1.4-1: (1) a starting level of need in which the capacity of all currently operating coal units are included through 2030;[16] and (2) a capacity need reflecting the impact of recently announced coal unit retirements ahead of schedule at Craig 2, Hayden 1, and Hayden 2, respectively. A more detailed load and resource balance is included in Section 2.12 of Volume 2.

Table 1.4-1: Generation Capacity Needs (MW)
(needs as of summer of year shown)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Starting Capacity Need long/(short)	**102**	**296**	**210**	**61**	**17**	**(203)**	**(672)**	**(1,354)**	**(1,411)**	**(1,474)**
Announced early coal retirements:										
Craig 2									(40)	(40)
Hayden 1									(135)	(135)
Hayden 2								(98)	(98)	(98)
Capacity Need with announced retirements long/(short)	**102**	**296**	**210**	**61**	**17**	**(203)**	**(672)**	**1,452)**	**1,684)**	**(1,747)**

Consistent with past ERP practice, prior to receipt of proposals in the 2021 ERP Phase II competitive acquisition process, Public Service will update the L&R using the most current forecasts of peak demand and generation supply—as well as any resource-related impacts of the Commission's Phase I decision or other pending proceedings. The RAP capacity needs that will be identified in that updated L&R will establish the level of

[15] Demand-side management programs include both energy efficiency and demand response (e.g. interruptible load and Saver's Switch) programs.
[16] Table 5.2-1 includes only Public Service's share of Comanche 1, Craig 2, Hayden 1 and Hayden 2.

additional generation resources to be acquired through the Phase II competitive acquisition process to meet the Company's resource need, inclusive of a planning reserve margin of 18 percent.

The acquisition of additional resources to meet our capacity needs in the RAP of this 2021 ERP & CEP is just part of the picture; the more impactful drivers of resource needs in the RAP are associated with the need to achieve the 2030 carbon emission reduction targets of SB 19-236 as discussed below.

Generation Needed to Reduce Emissions

To assess additional generation resources needed to comply with the 2030 clean energy target established by SB 19-236, the Company used the EnCompass model to develop a set of optimized indicative resource plan portfolios that would meet the projected resource needs of the Company for years 2021-2030 along with the estimated costs of those plans over a 2021-2055 planning period. These portfolios were optimized to meet the Company's planning reserve margin target (and other reliability requirements as discussed in Section 1.4) *and* achieve the 80 percent emission reduction by 2030 from 2005 levels.

These portfolios are referred to as CEP portfolios throughout the Phase I analysis. The CEP portfolios were developed using two different assumptions for the cost of carbon emissions: (1) the SCC as delineated in SB 19-236; and (2) a $0/ton assumption. With this approach, two different planning paradigms are captured: one with a cost placed on carbon emissions (i.e., SCC), and one where there is no cost placed on carbon emissions (i.e., $0/ton). A detailed discussion on how these indicative resource portfolios were developed is included in Section 2.13 of Volume 2.

Based on the Phase I modeling, the CEP portfolios developed using the SCC included resources ranging from approximately 1,800-2,400 MW of additional wind generation resources, 2,400-2,700 MW of additional solar generation resources (inclusive of both distributed solar and utility-scale solar), 400 MW of additional storage resources, and 1,500-2,300 MW of new firm fueled and flexible dispatchable generation resources. The additional resources of the Company's preferred CEP portfolio (SCC 7) are discussed in Section 1.6 below.

It is important to note that the timing, total nameplate amounts, and mix of new wind, solar, storage, gas generation included in the indicative portfolios will undoubtedly change in the Phase II process when ERP and CEP portfolios are developed from actual bids with actual locations versus generic resource representations with no implied location. In the last 2016 ERP cycle, the Company received unexpected and cost-effective bids for solar plus storage technologies in the Phase II competitive solicitation. The Company expects to see similar outcomes and continued innovation and progress with resource technologies and pricing in Phase II of this 2021 ERP & CEP. The Company expects the Phase II portfolios to include total nameplate amounts that are directionally consistent with the levels of renewables, storage, and dispatchable resources as what was included in the indicative Phase I portfolios.

Need for Flexible Generation Resources

To assess the need for flexible resources to help integrate wind generation onto the system, the Company updated its analysis of Flex Reserve to accommodate current and incremental wind generation on its system. (See Appendix B and Appendix C of Volume 2 for the updated Flex Reserve Study and Supplement to the Flex Reserve Study, respectively). The Company incorporated the results of the Flex Reserve study into the Phase I modeling of the ERP and CEP portfolios to ensure the portfolios contain the levels of flexible generation resources identified in the updated Flex Reserve study work as a function of the total amount of wind generation (both existing and new) contained in each portfolio. The Flex Reserve requirements will similarly be incorporated into ERP and CEP portfolios developed in the Phase II process.

Dispatchable Resource Needs for System Reliability

The term "dispatchable resources" in this context refers to generation resources that system operators can start anytime day or night. The output of these generation resources can be ramped up or down as needed—i.e., dispatched— and can operate continuously for multiple days regardless of local meteorological conditions.

To assess the need for dispatchable generation resources and ensure a sufficient amount of dispatchable generation resources on the system, operating reserve requirements and flex reserve requirements were directly input into the EnCompass model to maintain a continued balance between hourly customer load and generation. As discussed in Section 1.4, the Company conducted significant analysis of the hourly generation output from these EnCompass runs to ensure that the modeled operation of the Company's generation and storage resources were realistic and that the various reserve requirements were being adequately enforced by the model.

Section 2.11 of Volume 2 documents a recent four-day long weather event in November 2015 in Colorado with very low wind generation output and significantly reduced solar generation output. That analysis shows that, in the extreme scenario where there was no dispatchable generation available to the system, approximately 69,000 MW of 5-hour storage[17] would have been required to serve customer net load (net load = native load – renewable generation). The analysis also shows that approximately 1,000 MW of 5-hour storage would have been required to serve customer net load if approximately 3,900 MW

[17] The results of the analysis were presented on a basis of 5-hour duration storage to align with the storage duration of the Company's existing Cabin Creek pumped hydro facility.

of dispatchable generation were available. This simple analysis shows that a combination of intermittent renewable, short-duration storage, and dispatchable generation work together to reliably meet customer load.

Need for Additional Resources to Comply with the RES

To assess whether the additional renewable resources are needed to comply with Renewable Energy Standard ("RES") requirements, the Company compared the forecast of wholesale distributed generation ("DG") (i.e., DG resources over 30 MW in nameplate capacity) and non-DG Renewable Energy Credits ("RECs") over time with the minimum percentage requirements in the RES statute and RES Rules. This comparison shows that the existing and planned wholesale DG and non-DG renewable resources will generate enough RECs to comply with the minimum amounts in the RES beyond 2030. Details about the Company's REC projections to meet the Retail DG requirement are included in the 2020-2021 RE Plan that was filed with the Commission on July 1, 2019 in Proceeding No. 19A-0369E.

1.5 PORTFOLIO DEVELOPMENT AND ANALYSIS

Development of Phase I ERP and CEP Portfolios

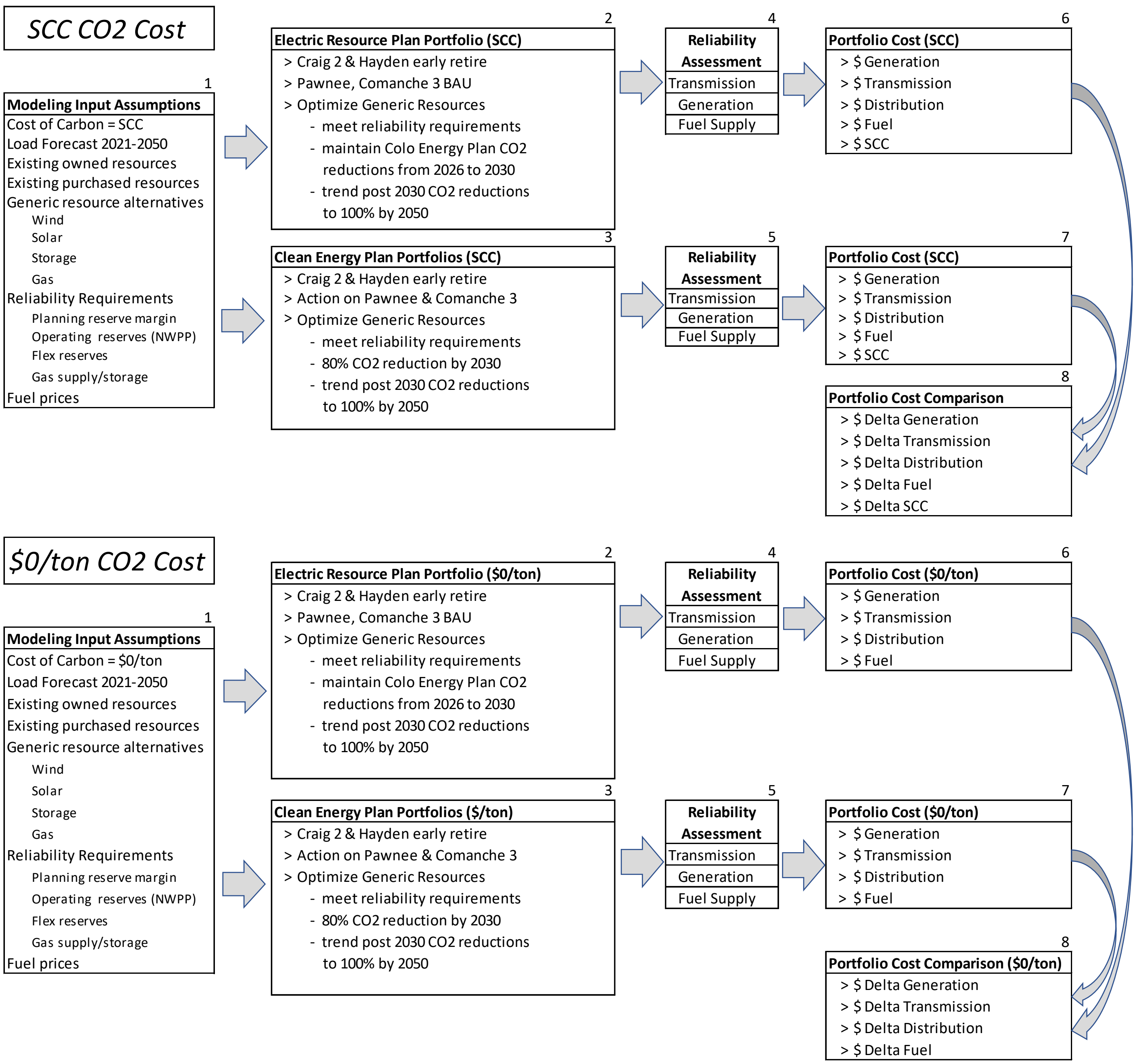
To develop the Phase I ERP and CEP portfolios, the Company used EnCompass model to develop a set of optimized resource plan portfolios that would meet the Company's projected resource needs and reliability requirements while reducing carbon emissions by at least 80 percent by 2030. These portfolios were optimized under two different assumptions for the cost of carbon emissions, as described above: (1) portfolios using the SCC; and (2) portfolios using a $0/ton carbon cost assumption.

Each ERP or CEP portfolio contains all the information needed to represent the characteristics and composition of the Public Service electric generation fleet for a given set of future assumptions for years 2021-2055 (i.e., the planning period). Some of the key assumptions include:

- A forecast of future electric customer load (wholesale and retail) (see Section 2.2 of Volume 2);
- The cost, performance, and emission projections for existing generating units;
- The cost, performance, and emission projections for potential future generation resource additions:
- Forecasted fossil fuel prices;
- Total system emission projections;
- An estimate of cost for new transmission investment (recognizing that additional transmission investment will be necessary to interconnect portfolios evaluated in Phase II once generation locations are noted); and
- Annual system revenue requirements.

Figure 1.5-1 below provides a high-level illustration as to the Company's analysis framework for creating these portfolios, and a detailed discussion on this process is included in Section 2.13 of Volume 2.

Figure 1.5-1: ERP and CEP Portfolio Analysis



Coal Transitions Considered

The ERP portfolios and the CEP portfolios include the recently announced accelerated retirements of Craig 2 in 2028, Hayden 1 in 2028, and Hayden 2 in 2027. The Company also performed EnCompass modeling to inform the costs and benefits of the decisions to retire Craig 2 and Hayden 1 and 2 ahead of their scheduled business as usual ("BAU") retirement dates. This analysis is discussed in Section 2.13 of Volume 2.

For the two remaining Company coal units, Pawnee and Comanche 3, all ERP portfolios assume continued operation of these coal units to 2041 and 2070, respectively (denoted as BAU below).[18] In contrast, CEP portfolios assess different combinations of coal transitions on Pawnee and Comanche 3 as illustrated by combined or paired actions 2 through 8 in Table 1.5-1. The various actions include combinations of accelerated retirements, gas conversions, and reduced operations beginning in 2030. By combining these actions in different ways, the Company has provided a diverse set of carbon emission reduction scenarios to drive toward the 2030 clean energy target.

Table 1.5-1: Pawnee and Comanche 3 Transitions Considered

	Pawnee				Comanche 3				
Paired Action	Early Retire EOY 2028	Convert to Gas EOY 2027	Convert to Gas EOY 2024	BAU	Early Retire EOY 2029	Early Retire EOY 2039	Convert to Gas EOY 2027	Early Retire EOY 2039, Reduced Operations starting 2030	BAU
1				X					X
2	X				X				
3	X							X	
4		X					X		
5		X			X				
6		X				X			
7		X						X	
8			X					X	

[18] The revenue requirements for Comanche 3 for the 2021-2055 planning period modeled in EnCompass are based off depreciating the unit to a 2070 retirement date.

Summary of ERP and CEP Portfolio Analysis Using SCC

The results of the ERP and CEP portfolio optimizations that were optimized using an assumption that the cost for each ton of carbon emitted is equal to the SCC are summarized below.

Table 1.5-2 below summarizes the results of the EnCompass modeling optimization, and details which generic resources were optimized for each of the of the eight paired Pawnee and Comanche 3 coal transitions[19] and summarizes the projected 2030 emission reductions.

Table 1.5-2 SCC ERP and CEP Portfolio Generic Resource Additions and CO_2 Reduction

	Portfolio	SCC 1	SCC 2	SCC 3	SCC 4	SCC 5	SCC 6	SCC 7	SCC 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP Preferred	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
	2030 CO2 % Reduction	**-69%**	**-88%**	**-85%**	**-86%**	**-88%**	**-81%**	**-84%**	**-85%**
	Resource Additions 2021-2030 (Nameplate MW)								
1	Wind	1,650	2,350	2,300	2,300	2,300	1,850	2,300	2,350
2	Utility-Scale Solar	1,150	1,550	1,550	1,500	1,550	1,250	1,550	1,550
3	Distributed Solar	1,158	1,158	1,158	1,158	1,158	1,158	1,158	1,158
4	Storage	400	450	400	450	400	400	400	400
5	Firm Dispatchable	1,276	2,352	1,960	1,568	1,764	1,505	1,276	1,233

The ERP portfolio (SCC 1) includes 1,650 MW of wind and 1,150 MW of utility-scale solar resources, which is less than the amount of wind and solar added in the CEP portfolios. The CEP portfolios (SCC 2 through SCC 8) add between 1,850-2,350 MW of nameplate wind and 1,250-1,500 MW of nameplate solar. From an emission reduction perspective, SCC 1 achieves a 69 percent carbon reduction, while SCC 2 through SCC 8 achieve between 81-88 percent reductions by 2030.

As to firm and flexible dispatchable resources, SCC 1 includes a comparable amount of firm dispatchable resources at 1,276 MW as SCC 7 and SCC 8. The remaining SCC portfolios add between 1,500-2,350 MW of firm dispatchable resources.

Figure 1.5-2 below shows the resource additions of each ERP and CEP portfolio in graphical format.

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[19] Each portfolio, i.e., SCC 1 through SCC 8, also includes early retirement of Craig 2 and Hayden 1 and 2, as noted earlier.

Figure 1.5-2 Nameplate MW Resource Additions 2021-2030

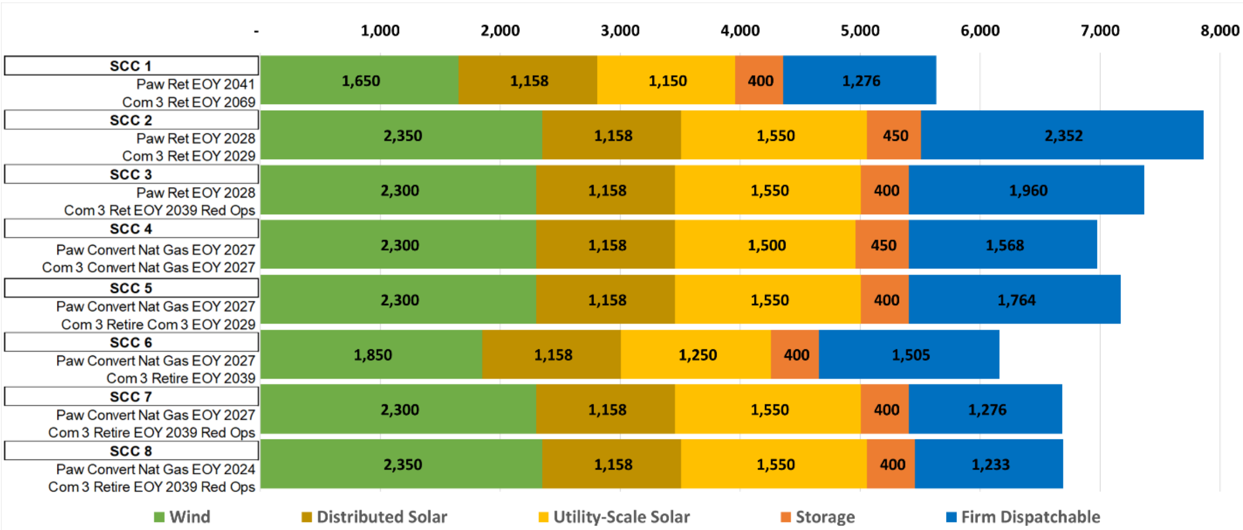

Table 1.5-3 below shows the estimated generation and transmission infrastructure associated with the generic resource additions in Figure 1.5-2 for years 2021-2030. The generation investment values represent the general level of dollars one could expect to be spent in constructing the generation resources in each portfolio.[20] The transmission investment values are reflective of the cost of the Pathway Project (see Section 1.9).

Table 1.5-3 SCC ERP and CEP Portfolio Infrastructure Investment Potential

	Portfolio	SCC 1	SCC 2	SCC 3	SCC 4	SCC 5	SCC 6	SCC 7	SCC 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP Preferred	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
	Infrastructure Investment Potential ($M)								
1	Generation 2021-2030 ($M)	$ 4,282	$ 6,223	$ 5,814	$ 5,519	$ 5,650	$ 4,847	$ 5,378	$ 5,360
2	Transmission 2021-2030 ($M)	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667

Table 1.5-4 below includes several metrics to represent the costs and benefits of the clean energy actions in SCC 1 through SCC 8, including:

- The present value of the total annual carbon emissions of each portfolio multiplied by the SCC as established in SB 19-236;

[20] Estimated construction costs for the different generic resource technologies can be found in Section 2.14 of Volume 2.

- The present value revenue requirements ("PVRR") over the entire 2021-2055 planning period (i.e., utility costs given they are representative of what is included in customer bills); and

- PVRR over different portions of the planning period to enable the Commission to see how costs/benefits are distributed over time.

Table 1.5-4 below contains different combinations of the present value of carbon emissions and PVRR utility costs.

Table 1.5-4 SCC ERP and CEP Portfolio Projected Costs

	Portfolio	SCC 1	SCC 2	SCC 3	SCC 4	SCC 5	SCC 6	SCC 7	SCC 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP Preferred	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
1	**PVRR Utility Cost 2021-2055 ($M)**	$ 38,814	$ 39,582	$ 39,429	$ 39,373	$ 39,450	$ 39,230	$ 39,306	$ 39,453
	PVRR Utility Cost Delta vs. SCC 1								
2	2021-2030 ($M)	$ -	$ 271	$ 192	$ 284	$ 265	$ 177	$ 206	$ 302
3	2021-2040 ($M)	$ -	$ 951	$ 621	$ 622	$ 786	$ 387	$ 479	$ 591
4	2021-2055 ($M)	$ -	$ 768	$ 616	$ 560	$ 637	$ 417	$ 492	$ 639
5	**NPV CO2 2021-2055 ($M)**	$ 8,625	$ 6,296	$ 6,719	$ 6,295	$ 6,234	$ 6,809	$ 6,646	$ 6,329
6	**PVRR Utility Cost + NPV CO2 2021-2055 ($M)**	$ 47,439	$ 45,877	$ 46,148	$ 45,669	$ 45,684	$ 46,040	$ 45,951	$ 45,782
	PVRR Utility Cost + NPV CO2 Delta vs. SCC 1								
7	2021-2030 ($M)	$ -	$ (124)	$ (77)	$ (271)	$ (226)	$ (153)	$ (158)	$ (370)
8	2021-2040 ($M)	$ -	$ (1,063)	$ (970)	$ (1,410)	$ (1,289)	$ (1,112)	$ (1,185)	$ (1,389)
9	2021-2055 ($M)	$ -	$ (1,561)	$ (1,290)	$ (1,770)	$ (1,755)	$ (1,399)	$ (1,487)	$ (1,657)

The incremental costs and benefits of the additional clean energy actions in CEP portfolios are determined by comparing the PVRR Utility costs and NPV CO_2 costs of each CEP portfolio to those of the ERP portfolio. In this instance the ERP portfolio serves as a reference case for costing purposes. For example, when considering *both* the PVRR of utility costs and the NPV of CO_2 costs, SCC 2 shows $124 million in savings compared to SCC 1 over the 2021-2030 timeframe. When considering *only* the PVRR of utility costs, SCC 2 shows $271 million of additional costs compared to SCC 1 over the 2021-2030 timeframe.

The bottom three rows of Table 1.5-5 below show projections of the average annual increase in retail customer rates for three different portions of the planning period: 2024-2030; 2024-2040; and 2024-2055. Given these are average values for a specific timeframe, in some years the annual rate increase is higher than the average indicated and in other years it is below the average. The Company believes, however, that an average value over the three time periods referenced provides a useful comparison across portfolios.

The modeling results of ERP and CEP portfolios begin to include clean energy actions in year 2025. Accordingly, the Company felt it appropriate to begin measuring the change in customer rate impacts of such actions from year 2024 to 2025. In doing so, the Company differentiates between the rate impacts of clean energy actions in this ERP and the rate impacts of the Colorado Energy Plan in years 2021-2023—during which some of the Colorado Energy Plan resources and related facilities come online.

Table 1.5-5 SCC ERP and CEP Portfolio Projected Rate Impacts

	Portfolio	SCC 1	SCC 2	SCC 3	SCC 4	SCC 5	SCC 6	SCC 7	SCC 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP Preferred	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
	Average Annual Rate Impact								
1	2024-2030 (%)	2.1%	3.1%	2.8%	2.8%	2.9%	2.4%	2.6%	2.5%
2	2024-2040 (%)	1.5%	1.5%	1.6%	1.5%	1.5%	1.6%	1.5%	1.6%
3	2024-2055 (%)	1.7%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%

Table 1.5-5 shows customer impacts being at their highest levels between years 2024-2030 when the clean energy actions to achieve 80 percent clean energy target are being implemented. While the costs for clean energy actions to achieve the 80 percent clean energy target continue beyond 2030, the additional costs year over year tend to decrease, resulting in lower average annual rate impacts. This is evident by the lower average annual rate increases for years 2024-2040. For years 2040-2055, both ERP and CEP portfolios drive toward the carbon-free by 2050 target, adding more renewables and an assumption of higher fuel prices due to an ever-increasing blend of hydrogen into the fuel supply of the gas-fired fleet. These modeled actions to drive toward the carbon-free by 2050 target drive the average annual rate increases for 2021-2055 up to about 2 percent.

The Company developed a metric to quantify: (1) the additional 2021-2030 costs of CEP portfolio clean energy actions above those of the ERP reference case; and (2) the additional year 2030 carbon reductions achieved above those of the ERP reference case as a result of those additional actions. In short, the metric shows how effective or efficient the incremental costs of clean energy actions compare with the incremental carbon reductions brought by those actions. Row 2 of Table 1.5-6 below contains this carbon reduction efficiency metric for each of the seven CEP portfolios. Lower $/ton values are better, indicating higher carbon reductions for each incremental dollar spent.

Table 1.5-6 SCC ERP and CEP Portfolio CO_2% Reduction Efficiency

	Portfolio	SCC 1	SCC 2	SCC 3	SCC 4	SCC 5	SCC 6	SCC 7	SCC 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP Preferred	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
1	**2030 CO2 % Reduction**	**-69%**	**-88%**	**-85%**	**-86%**	**-88%**	**-81%**	**-84%**	**-85%**
2	**CO2 Reduction Efficiency ($/ton)**	-	$ 46	$ 48	$ 34	$ 36	$ 36	$ 38	$ 28
3	**PVRR Utility Cost Delta vs. SCC 1** 2021-2030 ($M)	$ -	$ 271	$ 192	$ 284	$ 265	$ 177	$ 206	$ 302

The CO_2 Reduction Efficiency values in row 2 of Table 1.5-6 are calculated by taking the PVRR Utility Cost Delta values from row 3 and dividing by the present value of each CEP portfolios' additional 2030 CO_2 tonnage reductions above those of the ERP reference case. For example, the $46 value for SCC 2 is calculated by taking the $271 million PVRR Utility Costs Delta versus SCC 1 and dividing by 5.9 MST which represents the present value of the additional CO_2 reductions each year for years 2021-2030 compared to those of SCC 1.[21]

Summary of ERP and CEP Portfolio Analysis Using $0/Ton

The results of the ERP and CEP portfolio optimizations using an assumption that the cost for each ton of carbon emitted has a $0/ton cost are summarized below.

Table 1.5-7 below summarizes the results of the EnCompass modeling optimization, where generic resources were optimized for each of the of the eight paired Pawnee and Comanche 3 coal transitions[22] and the projected 2030 carbon reductions.

[21] This metric focuses on the front-end years of each CEP portfolio, years 2021-2030, and does not take into account incremental costs and associated carbon reductions between CEP and ERP portfolios for years 2031-2055.
[22] Each portfolio $0/ton 1 through $0/ton 8 also include early retirement of Craig 2 and Hayden 1 and 2 as noted earlier.

Table 1.5-7 $0/ton ERP and CEP Portfolio Generic Resource Additions and CO_2 Reduction

	Portfolio	$0/ton 1	$0/ton 2	$0/ton 3	$0/ton 4	$0/ton 5	$0/ton 6	$0/ton 7	$0/ton 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
	2030 CO2 % Reduction	**-63%**	**-81%**	**-81%**	**-81%**	**-81%**	**-81%**	**-81%**	**-81%**
	Resource Additions 2021-2030 (Nameplate MW)								
1	Wind	1,000	1,000	1,150	1,000	1,000	1,700	1,150	1,150
2	Utility-Scale Solar	100	550	1,050	850	600	1,150	1,050	1,050
3	Distributed Solar	1,158	1,158	1,158	1,158	1,158	1,158	1,158	1,158
4	Storage	50	50	50	50	50	-	50	100
5	Firm Dispatchable	1,764	3,269	2,352	1,960	2,548	1,764	1,764	1,764

ERP portfolio $0/ton 1 includes 1,000 MW of wind and 100 MW of utility scale solar resources, while CEP portfolios $0/ton 2 through $0/ton 8 add between 1,000-1,700 MW of nameplate wind and 550-1,150 MW of nameplate solar. From a carbon reduction perspective, $0/ton 1 achieves a 63 percent CO_2 reduction while $0/ton 2 through $0/ton 8 all achieve emission reductions of approximately 81 percent by 2030. From a firm and flexible dispatchable resource perspective, $0/ton 1, 6, 7, and 8 include 1,764 MW of firm dispatchable resources. The remaining $0/ton portfolios add between 1,960-3,269 MW of firm dispatchable resources. Figure 1.4-3 below shows the resource additions of each ERP and CEP portfolio in graphical format.

Figure 1.5-3 $0/ton ERP and CEP Portfolio Nameplate MW Resource Additions 2021-2030

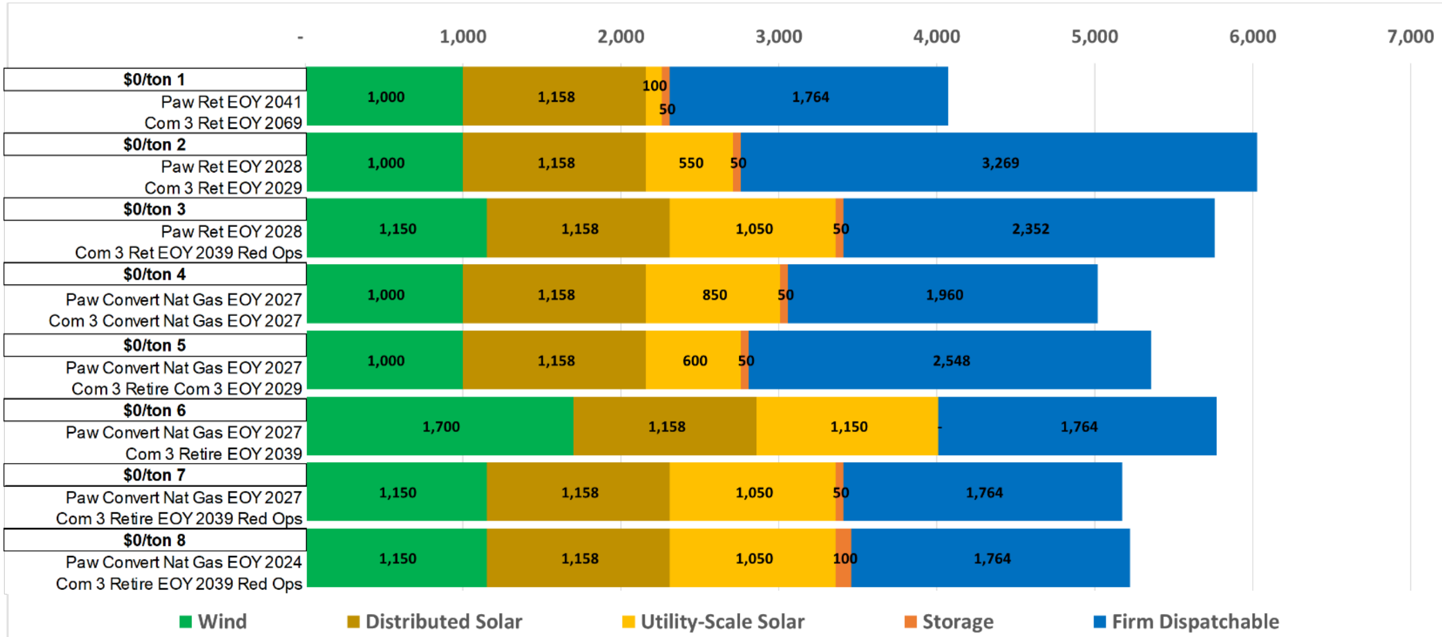

Table 1.5-8 below shows the estimated generation and transmission infrastructure associated with the generic resource additions in Figure 1.5-3 for years 2021-2030. The generation investment values represent the general level of dollars one could expect to be spent in constructing the generation resources in each portfolio.[23] The transmission investment values are reflective of the cost of the Pathway Project (see Section 1.9).

[23] Estimated construction costs for the different generic resource technologies can be found in Section 2.14 of Volume 2.

Table 1.5-8 $0/ton ERP and CEP Portfolio Infrastructure Investment Potential

	Portfolio	$0/ton 1	$0/ton 2	$0/ton 3	$0/ton 4	$0/ton 5	$0/ton 6	$0/ton 7	$0/ton 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
	Infrastructure Investment Potential ($M)								
1	Generation 2021-2030 ($M)	$ 2,528	$ 4,226	$ 3,942	$ 3,301	$ 3,540	$ 4,186	$ 3,495	$ 3,558
2	Transmission 2021-2030 ($M)	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667

Table 1.5-9 below includes several metrics to represent the costs and benefits of the clean energy actions in $0/ton 1 through $0/ton 8, including:

- The present value of the total annual carbon emissions of each portfolio multiplied by the SCC as established in SB 19-236;
- The PVRR over the entire 2021-2055 planning period (i.e., the utility costs given they are representative of what is reflected on customer bills); and
- PVRR over different portions of the planning period to enable Commission to see how cost/benefits are distributed over time

Table 1.5-9 contains different combinations of present value of carbon emissions and PVRR utility costs.

Table 1.5-9 $0/ton ERP and CEP Portfolio Projected Costs

	Portfolio	$0/ton 1	$0/ton 2	$0/ton 3	$0/ton 4	$0/ton 5	$0/ton 6	$0/ton 7	$0/ton 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
1	**PVRR Utility Cost 2021-2055 ($M)**	$ 38,280	$ 38,875	$ 38,898	$ 38,692	$ 38,791	$ 38,913	$ 38,752	$ 38,898
	PVRR Utility Cost Delta vs. $0/ton 1								
2	2021-2030 ($M)	$ -	$ 221	$ 153	$ 189	$ 193	$ 163	$ 160	$ 248
3	2021-2040 ($M)	$ -	$ 808	$ 647	$ 497	$ 649	$ 605	$ 510	$ 613
4	2021-2055 ($M)	$ -	$ 595	$ 617	$ 412	$ 511	$ 633	$ 472	$ 617
5	**NPV CO2 2021-2055 ($M)**	$ 9,107	$ 7,051	$ 7,141	$ 6,924	$ 6,971	$ 7,027	$ 7,046	$ 6,758
6	**PVRR Utility Cost + NPV CO2 2021-2055 ($M)**	$ 47,387	$ 45,926	$ 46,039	$ 45,616	$ 45,762	$ 45,940	$ 45,798	$ 45,656
	PVRR Utility Cost + NPV CO2 Delta vs. $0/ton 1								
7	2021-2030 ($M)	$ -	$ (157)	$ (133)	$ (330)	$ (266)	$ (210)	$ (222)	$ (422)
8	2021-2040 ($M)	$ -	$ (974)	$ (1,044)	$ (1,421)	$ (1,212)	$ (1,182)	$ (1,277)	$ (1,462)
9	2021-2055 ($M)	$ -	$ (1,461)	$ (1,348)	$ (1,771)	$ (1,625)	$ (1,447)	$ (1,589)	$ (1,731)

The incremental costs and benefits of the additional clean energy actions in CEP portfolios are determined by comparing the PVRR Utility costs and NPV CO_2 costs of each CEP portfolio to those of the ERP portfolio. This is the same exercise as that performed above for the SCC cases.

The bottom three rows of Table 1.5-10 below show projections of the average annual increase in retail customer rates for three different portions of the planning period, 2024-2030, 2024-2040, and 2024-2055. Given these again represent average values for a specific timeframe, in some years the annual rate increase is higher than the average indicated and in other years it is below the average.

Table 1.5-10 $0/ton ERP and CEP Portfolio Projected Rate Impacts

	Portfolio	$0/ton 1	$0/ton 2	$0/ton 3	$0/ton 4	$0/ton 5	$0/ton 6	$0/ton 7	$0/ton 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
	Average Annual Rate Impact								
1	2024-2030 (%)	1.8%	2.7%	2.3%	2.2%	2.5%	2.4%	2.1%	2.1%
2	2024-2040 (%)	1.5%	1.4%	1.5%	1.4%	1.4%	1.6%	1.4%	1.5%
3	2024-2055 (%)	1.7%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%

Similar to the SCC ERP and CEP portfolios, Table 1.5-10 shows customer rate impacts at their highest levels between years 2024-2030 when the clean energy actions to achieve 80 percent clean energy target are being implemented. The costs for clean energy actions to achieve 80 percent continue beyond 2030, but generally at lesser amounts resulting in lower average annual rate impacts. For years 2040-2055, both ERP and CEP portfolios drive toward the carbon-free by 2050 target, adding more renewables and an assumption of higher fuel prices due to an ever-increasing blend of hydrogen into the fuel supply of the gas-fired fleet. These actions to drive toward the carbon-free by 2050 target result in average annual rate increases for 2021-2055 up to about 2 percent.

Total or cumulative rate increases can be estimated by multiplying the average annual rate increase by the number of years in each time frame. For example, the total or cumulative rate increase for the 2024-2030 timeframe for ERP $0/ton 1 would be 10.8 percent, which is equal to 1.8 percent times 6 years. Assuming 2024 retail rates were 10₵s/kWh, 2030 rates would be 11.08₵/kWh. Similarly, the cumulative rate increase for the 2024-2055 timeframe for ERP $0/ton 1 would be 52.7 percent. Assuming 2024 retail rates were 10₵s/kWh, 2055 rates would be 15.27₵/kWh.

Table 1.5-11 below shows how efficient the incremental costs of clean energy actions compare with the incremental carbon reductions achieved through those actions. Lower $/ton values are better, indicating higher carbon reductions for each incremental dollar spent.

Table 1.5-11 $0/ton ERP and CEP Portfolio CO_2 Percent Reduction Efficiency

	Portfolio	$0/ton 1	$0/ton 2	$0/ton 3	$0/ton 4	$0/ton 5	$0/ton 6	$0/ton 7	$0/ton 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
1	**2030 CO2 % Reduction**	**-63%**	**-81%**	**-81%**	**-81%**	**-81%**	**-81%**	**-81%**	**-81%**
2	**CO2 Reduction Efficiency ($/ton)**	-	$ 39	$ 36	$ 24	$ 28	$ 29	$ 28	$ 23
3	**PVRR Utility Cost Delta vs. $0/ton 1** 2021-2030 ($M)	$ -	$ 221	$ 153	$ 189	$ 193	$ 163	$ 160	$ 248

Sensitivity Analyses

In addition to the evaluation of ERP and CEP portfolios under base assumptions, the Phase I portfolios were further analyzed through sensitivity analyses. These sensitivity analyses involve changing a single key input assumption and assessing how that change impacts a portfolio's carbon cost (i.e., repricing sensitivity) or the composition of resources added within the portfolio (i.e., reoptimized sensitivity). The primary purpose of sensitivity analyses is to test the robustness of a particular portfolio under different futures.

The difference between a repricing sensitivity and a reoptimized sensitivity is whether the capacity expansion plan of the portfolio (i.e., the new resources that are added) is re-optimized. Some sensitivities, such as change in fuel prices, do not require that a new optimized expansion plan be developed in order to assess the impact of the changed assumption. These types of sensitivities are referred to as repricing sensitivities. In contrast, there are certain sensitivities, such as changes in load, where it is necessary to develop a new optimized expansion plan in order for a meaningful comparison of the sensitivity results with the base assumption results. In these sensitivity analyses, the model is given the flexibility to select a different mix of generic resources from those selected in the optimization performed using base assumptions. These types of sensitivities are referred to as reoptimized sensitivities.

Repricing sensitivities were performed on each ERP and CEP portfolio under the following assumptions:

- High Gas Prices: Increase natural gas prices by using twice the annual year-over-year growth rate of base gas price forecast.
- Low Gas Prices: Reduce natural gas prices by using one-half the annual year-over-year growth rate of base gas price forecast.

Reoptimized sensitivities were performed on each ERP and CEP portfolio under the following assumptions:

- High Load: Widespread electrification consistent with the Greenhouse Gas Emission Reduction Roadmap developed by State of Colorado agencies and described in more detail in the Direct Testimony of Company witness Ms. Jackson.
- Low Sales: Widespread adoption of distributed energy resources.
- Expanded Market Access: Double the MW import and export capacity within the modeling.
- Sunk Transmission Upgrade Cost: Assumes transmission network upgrade costs are sunk.
- No New Gas Resources: Assumes no new gas-fired generation are added to the system.
- Lower Hydrogen Costs: Reduce the hydrogen price assumption from $20/MMBTU to $10/MMBTU for the 2041-2055 period of the modeling. This is the period over which hydrogen blending occurs at an increasing rate of 10 percent each year, reaching 100 percent by 2050, for all gas-fired resources.

High and low load sensitivities were run for all ERP and CEP portfolios 1-8 for both SCC and $0/ton. Expanded Market Access, Sunk Transmission Upgrade Cost, No New Gas Resources, and Lower Hydrogen Cost sensitivities were run for ERP portfolio 1 and CEP portfolios 2,4,7 for the assumption that CO_2 emissions are priced at the SCC.

The impacts of the sensitivity analyses for each portfolio were assessed by applying a colored heat mapping concept to the analyses results. The colored heat mapping illustrates at a high level how the different portfolios compare or rank relative to one another for a particular portfolio characteristic (e.g., CO_2 reductions, PVRR utility costs, etc.) under a particular sensitivity. The Company applied a three-tiered color scale in which green represents the highest rank, yellow a middle rank, and red the lowest rank.

A detailed presentation of the sensitivity analyses performed is provided in Section 2.13 of Volume 2.

1.6 PREFERRED PLAN

Summary of Preferred Plan

Based on the portfolio optimization and analysis presented in Section 1.5, the Company selected its preferred plan, SCC 7. Specifically, the coal transitions of the preferred plan include:

- Early retirement of Craig 2 in 2028 and Hayden 1 in 2028 and Hayden 2 in 2027;
- Conversion of Pawnee to burn natural gas in 2028, and
- Reducing generation from Comanche 3 to a level representative of a 33 percent annual capacity factor beginning in 2030 and early retiring the unit in 2040.

Coupled with these coal transitions are indicative levels of generic wind, solar, storage, and firm and flexible dispatchable resources of approximately 2,300 MW, 1,600 MW, 400 MW, and 1,300 MW respectively. The actual level and composition of these and other resource technologies in the preferred plan will be determined through the Phase II competitive solicitation and bid evaluation process discussed in Section 1.10.

The Company draws several conclusions from our analyses of the ERP and CEP portfolios:

- There are multiple paths by which we can reduce emissions by 80 percent or more by 2030 from 2005 levels, all while maintaining an acceptable level of system reliability and affordability for customers;
- The previously announced early retirement of 273 MW of coal fired generation at Craig 2 and Hayden[24] are key aspects of any plan to achieve 80 percent by 2030;
- Multiple paired actions can be taken at the two remaining coal-fired units, Pawnee and Comanche 3, to cost-effectively and reliably reduce the emission of carbon from these units;
- A relatively balanced mix of new wind and solar resources (distributed and utility scale) will be needed in concert with accelerated coal retirements and paired actions at Pawnee and Comanche 3 to achieve or exceed the 80 percent clean energy target by 2030;
- Additional firm dispatchable generation resources are needed that can do the following:

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[24] Public Service's ownership share.

- Operate continuously for multiple days to ensure operators can dispatch the level of resources needed to continually serve customer load at all times, particularly during prolonged events in which we experience droughts in wind and solar generation output;
- Provide the fast and flexible generation resources needed to reliably manage around the increased level of variability we will see with increasing levels of wind and solar generation on our system; and

➢ Additional energy storage devices will be needed to provide a host of services that contribute to system reliability and reduced costs to customers through the provision of a variety of benefits including but not limited to: generation capacity credit, various operating reserves, energy arbitrage, and reduction in renewable generation curtailment.

Factors Influencing Selection of the Preferred Plan

The Company considered several factors in its selection of a preferred plan, including: (1) the level of projected carbon reductions by 2030; (2) customer cost impact; (3) carbon reduction efficiency; and (4) the community and workforce transition impacts of clean energy actions. Each of these factors is summarized below. All ERP and CEP portfolios were built to a comparable and acceptable level of reliability and therefore, this was not a distinguishing factor in selecting the preferred portfolio.

Level of Carbon Emission Reduction by 2030

Given that the indicative levels of wind and solar additions in each portfolio are in large part directly reflected in the projected carbon emission reductions of each portfolio, the levels of wind and solar additions were not considered a distinguishing factor in selecting the preferred portfolio. The CEP portfolios developed using the SCC show higher CO_2 emission reductions than portfolios developed using $0/ton for carbon, and therefore, the Company focused on the results of the modeling optimizations that used the SCC in selecting a preferred portfolio. As shown in Figure 6.3-1, each of the seven CEP portfolios developed using SCC exceed 80 percent emission reductions, with SCC 2 and 5 showing the highest reductions at 88 percent, SCC 3, 4, 7, 8 showing between 84 to 86 percent, and SCC 6 showing the lowest reductions at 81 percent. From this perspective, SCC 7 provides a level of CO_2 emission reductions toward the middle of the range, but well beyond the 80 percent clean energy target set forth by SB 19-236.

Customer Cost Impact

Customer costs were considered from two general perspectives: (1) average annual rate impacts: and (2) the efficiency of the dollars spent on clean energy actions at reducing CO_2 emissions. As shown in Figure 6.3-5, SCC 6, 7, 8 show the lowest 2024-2030 annual average rate impacts of 2.4 percent, 2.6 percent, and 2.5 percent, respectively. SCC 2, 3, 4, 5 show higher impacts of 3.1 percent, 2.8 percent, 2.8 percent, and 2.9 percent, respectively. From this perspective, SCC 7 shows costs to customers at the lower end of the range. The average annual rate impacts of all CEP portfolios for years 2024-2040 and years 2024-2055 converge to 1.6 percent; as a result, we did not see rate impacts for these longer timeframes as a distinguishing characteristic of portfolios from a decision-making perspective.

Carbon Reduction Efficiency

As shown in Figure 6.3-6, SCC 8 shows the highest CO_2 reduction efficiency at $28/ton. SCC 4, 5, 6, 7 show CO_2 reduction efficiencies between $34/ton and $38/ton and SCC 2 and 3 show $46/ton and $48/ton, respectively. As discussed earlier, a lower $/ton value is better in that it indicates higher CO_2 reductions for each incremental dollar spent. From this perspective, SCC 7 shows a CO_2 reduction efficiency at the middle of the range.

Workforce Transition and Community Assistance

The Company placed considerable importance on minimizing the impacts of the preferred plan coal transitions on local communities and our workforce (as discussed further in Sections 1.7 and 1.8). SCC 7 minimizes these impacts by continuing to operate the Pawnee and Comanche 3 units to 2041 and 2039, respectively. The Pawnee plant located in Brush, Colorado will be converted to burn natural gas and operated to year 2041, which is the current retirement date of the unit. The Comanche 3 unit will continue to operate on coal at reduced levels from 2030-2039 and then will be retired.

Other Factors Considered

The Company also considered several factors that favored SCC 7 with Comanche 3 reduced operations. A good comparison point for SCC 7 is against SCC 6 because SCC 6 has the same action at Pawnee (conversion to natural gas at the end of 2027) while keeping Comanche 3 on through 2040 *without reduced operations.* This scenario, using the SCC, only gets to an 81 percent CO_2 emission reduction by 2030. This shows the emission reduction value of the reduced Comanche 3 operations post-2029. Moreover, SCC 6 results in more firm dispatchable acquisitions (1,505 MW) as compared to SCC 7

(1,276 MW), and SCC 6 has less wind (1,850 MW) than SCC 7 (2,300 MW), and less utility-scale solar (1,250 MW) then SCC 7 (1,550 MW).

The "dual 2030 retirement scenario," *i.e.*, where both Pawnee and Comanche 3 are retired at end of year 2029, is SCC2. This scenario achieves an 88 percent emission reduction by 2030; however, it is important to go a layer deeper and look at the projected resource additions under this scenario. The dual retirement scenario results in the acquisition of 2,350 MW of wind, 1,550 MW of solar, and 450 MW of storage. In other words, it contains only 50 MW more wind and 50 MW more storage, with the exact same amount of solar, as compared to our preferred plan. The key difference is in the addition of firm dispatchable resources; the dual retirement scenario adds approximately 2,300 MW of these resources while the preferred plan adds only 1,300 MW. With 1,400 MW of gas resources having expiring PPAs or retiring, the net result is that the dual retirement scenario requires substantial potential incremental gas additions over and above that of our preferred plan.

Last, Comanche 3 continues to get a full accredited capacity credit under a reduced operations scenario, which is a benefit to the system and a benefit associated with the preferred SCC 7 portfolio. Comanche 3 is limited but, in certain circumstances, it is still a generator the Company can rely on to maintain system reliability if system conditions and circumstances warrant.

Sensitivity Analysis of Preferred Plan

The sensitivity analysis of our preferred plan demonstrates that SCC 7 is a robust plan that can be expected to deliver on the CO_2 emission reduction targets of SB 19-236 and do so in an affordable and reliable manner for customers. The following observations can be made from a review of the results of the sensitivity analyses discussed in Section 1.5 and provided in Section 2.13 of Volume 2:

- From a carbon reduction perspective, SCC 7 shows no erosion of CO_2 reductions from the approximately 85 percent level projected under base assumptions. In fact, in four of the eight sensitivities, SCC 7 CO_2 reductions were shown to improve by increasing up to between 85 percent and 89 percent;

- From a customer cost perspective, SCC 7 consistently ranks between the middle and the top relative to other portfolios across all eight sensitivities. This is evident by the green and yellow rankings of SCC 7 for PVRR Utility Costs Deltas versus the SCC 1 reference case, as well as in Average Annual Rate Impacts; and

- From a CO_2 reduction efficiency perspective, SCC 7 ranks between the middle and the top relative to other portfolios in seven of the eight sensitivities. This is evident by the green and yellow rankings of SCC 7 for CO_2 Reduction Efficiency ($/ton).

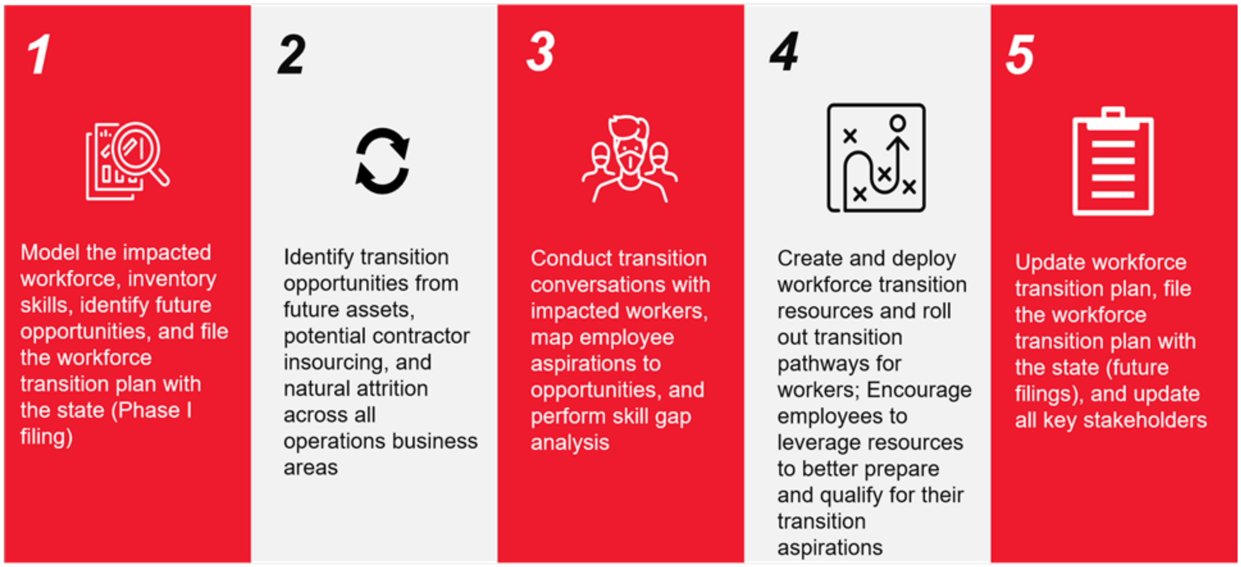
1.7 WORKFORCE TRANSITION PLAN AND JUST TRANSITION

For decades, Xcel Energy has been an employer of choice amongst Coloradans – particularly for skilled workers – as we provide a safe and respectful working environment and a prevailing wage and benefits package that is multiples above of the state or federal minimums and for full time employees, income above the US median household income. And over that time, we have exhibited long-standing support for our employees and the communities we serve, and we recognize the impact plant retirements and conversions have on our employees and the communities where they are located. We have already retired 11 coal-fired units across our operating companies and managed those workforce transitions primarily with staff retirements or normal attrition, reassignment of employees to other facilities, and training and education opportunities. Based on our experience with closing or converting plants over roughly the past 15 years, the Company has been successful in transitioning the workforce at these plants without any forced layoffs. Building on our track record of working with our employees and communities to successfully manage the clean energy transition is a key priority and one we take very seriously. We have a highly skilled workforce and it is our desire to retain these skilled workers, to leverage their expertise across the organization, and to help the Company meet our clean energy future.

Consistent with the requirements of SB 19-236, Public Service addresses workforce transition at Hayden 1 and 2, Pawnee, and Comanche 3 with a specific Workforce Transition Plan provided as Appendix 1 to this Volume 1 of the Company's 2021 ERP & CEP.

As discussed in detail in the Workforce Transition Plan rt, the Company's approach to workforce transition planning includes five key phases as depicted in Figure 1.7-1 below. For purposes of the Company's Phase I 2021 ERP & CEP filing, the Company has modeled the impacted workforce at each of the plants proposed for accelerated retirement or fuel conversion, completed the first phase in inventorying skills, and is identifying future opportunities that will arise due to natural attrition and retirements across the Company.

Figure 1.7-1 Workforce Transition Plan Approach



To develop estimated costs associated with workforce transition planning, the Company first determines the number of employees at each plant to transition. The Company uses a target headcount and attrition forecast in the workforce planning models to estimate the number of impacted employees at each plant. The Company's Energy Supply team captures the target headcount in resource planning models and the Workforce Analytics team provides the retirement and non-retirement attrition protection data. In addition, the Company uses an actuarial-based attrition simulator to forecast employee turnover, both retirement and non-retirement. The number of employees to transition is then multiplied by an estimated cost for each transition support type. Assumptions used in our cost modeling, include, but are not limited to, costs associated with internal technical training, enterprise-wide learning courses, external industry training (e.g., certifications, micro credentials, courses), on-the-job training, tuition reimbursement, relocation, and severance. Based on similar transitions of other coal plants across our service territory (e.g., Clean Air Clean Jobs), we were able to determine primary transition resources needed to transition a workforce and apply high-level estimates to cost projections associated with the anticipated closure or conversion of our remaining coal units in Colorado. Workforce transition cost estimates were provided as inputs into the resource plan modeling for this Phase I filing. Detailed calculations, costs, and assumption descriptions are outlined in the Workforce Transition Plan provided as Appendix 1.

Given the accelerated retirements associated with our preferred coal transition plan are several years in the future, and there will be additional ERP cycles before these units retire, the Company will provide workforce transition plan and associated modeling cost updates in future ERP cycles as retirement dates approach.

Additionally, the Company has worked with, and will continue to work with, the Office of Just Transition ("OJT") as it continues to develop and implement its workforce transition plans. The OJT was established by House Bill 19-1314 based on a "moral commitment to assist the workers and communities that have powered Colorado for generations" by supporting a just and inclusive transition away from coal. The Company is represented on the Just Transition from Coal Advisory Committee that resides within the OJT and was actively involved in the collaborative development of the recommendations submitted to Governor Polis on December 31, 2020.[25] The Company plans to submit future and ongoing updates of its Workforce Transition Plan Report to the OJT to keep the OJT informed of the details and timing of the Company's plans to support and transition our workforce in the coming years.

[25] Colorado Just Transition Plan: https://cdle.colorado.gov/sites/cdle/files/documents/Colorado%20Just%20Transition%20Action%20Plan.pdf.

1.8 COMMUNITY ASSISTANCE PLAN

An important component of the clean energy transition involves our approach to working with our host communities that will be affected by the accelerated retirements of coal units as part of the clean energy transition -- specifically, the affected communities that have an economic tie with the coal transitions proposed for Hayden 1 and 2, Pawnee, and Comanche 3, respectively. SB 19-236 requires Public Service to evaluate, consider and in some instances provide community assistance to counties, towns, and cities who are impacted by an accelerated coal plan retirement. As we take the next step in the clean energy transition, it is imperative to the State of Colorado, our customers, and our host communities that we bring our impacted communities with us and that they have an opportunity for economic prosperity in this new energy economy that lasts beyond a planned coal plant retirement date.

If the preferred coal transitions plan is approved by the Commission, we will continue the work already underway in our host communities, including Routt County, the Town of Hayden, and Pueblo County, as described below. We will also continue to work with the OJT to identify and execute on win-win solutions for these communities and our broader customer base. SB 19-236 provides separate cost recovery provisions for workforce and community transition, and the Company anticipates a post-ERP filing to begin to lay out how these activities and cost recovery can be addressed by the Commission. We are not in a position now to bring these requests forward as we do not yet know the coal transition plan that will be approved by the Commission.

While our community assistance coordination and local engagement will continue to develop after this 2021 ERP & CEP, the cost of community assistance has been modeled for purposes of this proceeding and these costs have been considered in the evaluation of the Company’s preferred coal transition plan. Specifically, the Company has modeled community assistance costs as the property tax payments end after a unit retires. For modeling purposes, this represents a reasonable proxy for the impacts of community assistance payments resulting from early retirements and these costs have been incorporated into the generic Phase I modeling.

Hayden 1 and 2

The Hayden Generation Station has been a significant part of the Town of Hayden and Routt County community since the mid-1960s, when Unit 1 first came online. For over 50 years, this plant has not only paid significant tax revenue to the town and county, but it has offered quality well-paying jobs for rural Coloradoans. Public Service is proud to be an important part of this community. Public Service is the majority owner of Hayden Unit 1 and a minority owner in Unit 2 with an ownership stake of 75.5 and 37.4 percent, respectively. While SB 19-236 does not require that we compensate the Hayden community, it does require the Company to submit a transition plan that is developed in collaboration with the community, the state, and our union partners.

One approach to community assistance involves additional utility investments that would offset estimated economic impacts of shutting the plant down early. However, in evaluating the options for Hayden redevelopment, we recognize that the location presents a challenge for typical generation solutions being broadly considered in this proceeding (i.e., the geography of the location does not lend itself to large scale solar or wind resources, nor is there substantial gas pipeline infrastructure nearby to enable repowering or locating new gas fired generation at the site). Therefore, the Company has been collaborating with the community to explore innovative, carbon-free redevelopment opportunities such as molten salt storage, biomass, solar electrolysis, and parks and wildlife usage. The Company will continue to work closely with the community and local stakeholders to regarding redevelopment opportunities that can have a positive economic impact on the community and can maintain a commensurate level of property tax payments to the local communities as they would have received without the early plant shutdowns.

Many of the concepts considered by Public Service and the Hayden community do not fit neatly within the ERP Rules and will require different regulatory pathways for approval. Public Service envisions that a community assistance plan may evolve to include concepts bid in through the competitive solicitation as part of Phase II, post-ERP CPCNs, and standalone applications. For replacement generation solutions, the Company recognizes that such projects would need to be successfully bid into the Phase II competitive solicitation. The Company will continue to take steps to advance potential projects so that they can be bid in. Given the potential just transition benefits of these replacement generation projects, we believe such projects would merit strong consideration for inclusion in Phase II bid portfolios.

Pawnee and Comanche 3

The Company is proposing to convert Pawnee Station to a natural gas combustion turbine and maintain its current retirement date of 2041. Accordingly, there is no accelerated retirement of this facility. The Company's preferred coal transition plan for Comanche 3 involves an accelerated retirement from its current date of 2070 to 2040. Beginning in 2030, the Company would reduce Comanche 3 operations by limiting it to a 33 percent annual capacity factor. This balanced proposal would have the unit stay online and avoid the significant local property tax impact that would result from an even earlier retirement.

Community assistance planning for Pueblo is needed given the accelerated retirement of Comanche 3 proposed as part of our preferred coal transition plan. Thus far, our planning efforts have included the initiation of conversations with Pueblo County, City of Pueblo, and other impacted stakeholders on our proposed plans. Public Service will work with local governments and key community stakeholders going forward to develop robust community assistance; however, it is difficult to have specific contours for such community assistance at this time, as the proposed retirement date for Comanche 3 is nearly 20 years from now. However, the Company recognizes the need to start now through initial conversations with local partners and continue to build on our successful partnership with the Pueblo area that was fostered through the Colorado Energy Plan involving the accelerated retirement of Comanche 1 and 2.

Craig 2

Public Service is a minority owner in the Craig Generating Station and as such defers to the majority owner, Tri-State Generation and Transmission Association ("TSGT") regarding any community assistance requirements associated with the early retirement of Craig 2. However, Public Service maintains open communication with the other owners regarding potential redevelopment plans and is deferring to TSGT on the appropriate transition plan for the community.

1.9 TRANSMISSION PLANNING

Colorado's Power Pathway 345 kV Transmission Project

A key component of achieving our 2030 clean energy target is the development of transmission infrastructure to interconnect and deliver new clean energy resources to our customers. As Public Service accelerates the clean energy transition, the Company needs to expand its highly reliable transmission "backbone" to create a power pathway around the clean energy-rich areas of the State to enable the generation fleet of the future. Colorado is fortunate to have some of the best wind and solar resources in the country– particularly in the eastern and southeastern part of the State; however, the current lack of transmission infrastructure is a limiting factor in the ability to harness the potential wind and solar resources in the region.

On March 2, 2021, Public Service filed an Application for a CPCN in Proceeding No. 21A-0096E for Colorado's Power Pathway 345 kV Transmission Project (the "Pathway Project"). The Pathway Project is a 560-mile, 345 kV double circuit transmission facility that will provide 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.

As detailed in Proceeding No. 21A-0096E, the Pathway Project is comprised of five Project segments. The northern terminus of the Pathway Project will be at the Company's existing Fort St. Vrain Substation (located at the Fort St. Vrain generating station) in Platteville in western Weld County. The Pathway Project will then span east to a new substation near Pawnee, east/southeast to near the Cheyenne Ridge Wind Project, south to near Lamar, and then west to the Tundra Substation, near the Comanche generating plant. The Pathway Project will then run north to the Company's existing Harvest Mile Substation, located adjacent to the City of Aurora in Arapahoe County.

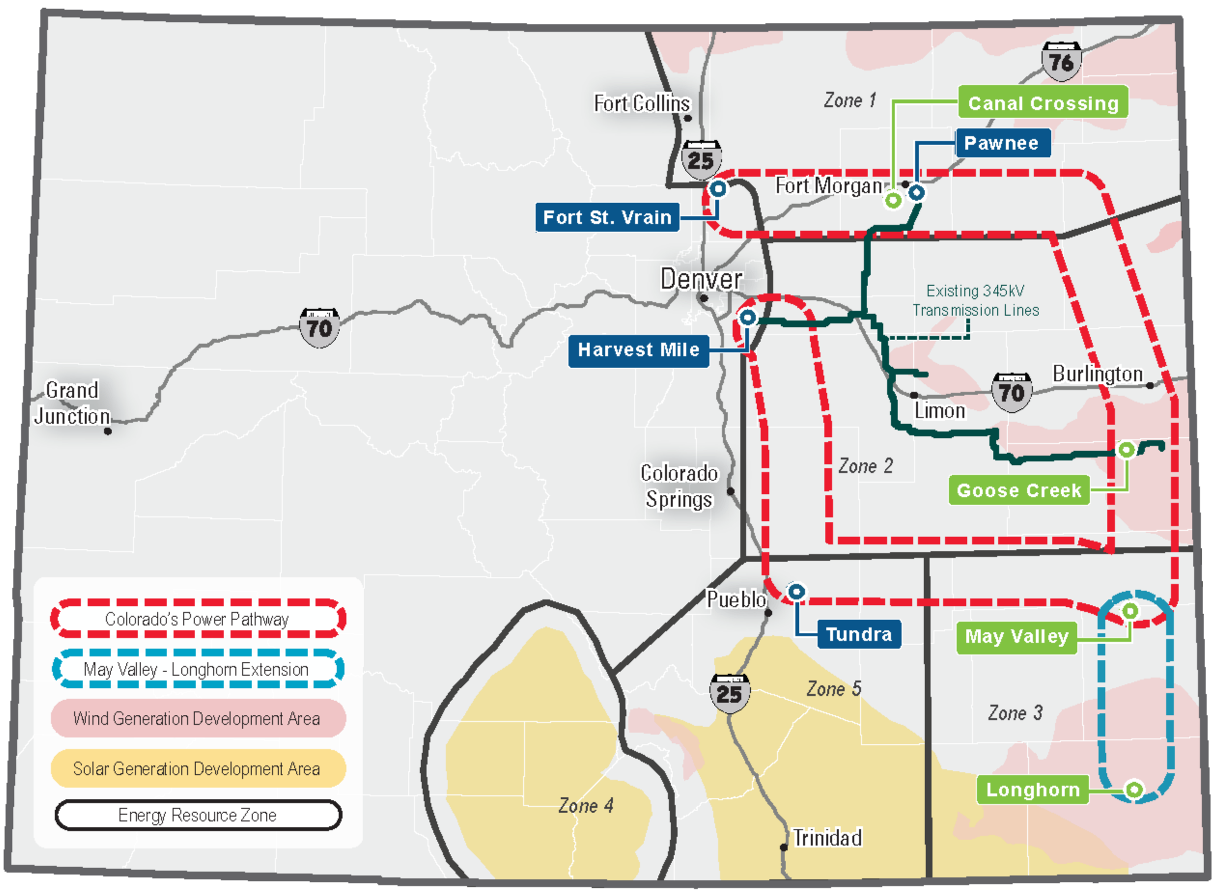
In its CPCN Application, Public Service also presented for Commission consideration a 90-mile, 345 kV extension to the Pathway Project called the May Valley-Longhorn Extension. The May Valley-Longhorn Extension would involve constructing approximately 90 miles of new 345 kV double circuit transmission line from the new May Valley Substation, at the southeastern corner of the Pathway Project near Lamar,[26] 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

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

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.

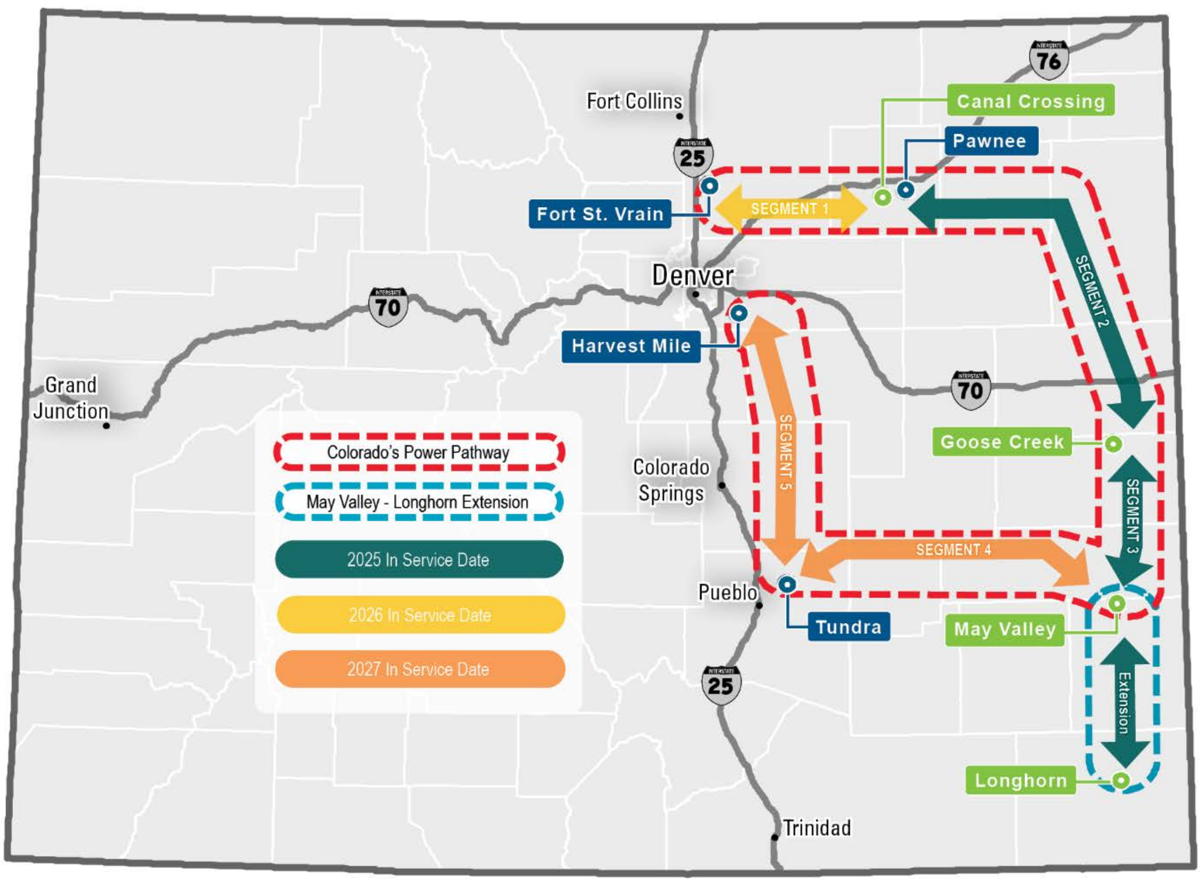
A vicinity map of the five segments comprising the Pathway Project and the May Valley-Longhorn Extension relative to the ERZs is shown in Figure 1.9-1 below. As discussed in the Company's CPCN filing in Proceeding No. 21A-0096E, a transmission line route has not been identified. Therefore, the vicinity map below shows the general study area within which the transmission line will be routed as the project develops.

Figure 1.9-1 Pathway Project and May Valley-Longhorn Extension Vicinity Map



The Pathway Project 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. Segments 2 and 3 will traverse the wind-rich areas in eastern Colorado. By having those segments and substations constructed and in-service by the end of 2025, wind and solar developers will be able to interconnect their resources prior to the expiration of the Production Tax Credits ("PTCs") and Investment Tax Credits ("ITCs"). Bids submitted by generation developers will enable significant cost savings to customers if those generating resources can be online before the end of 2025, which is when the PTC is set to expire and the ITC steps down. Thus, Public Service anticipates that placing Segments 2 and 3 and the May Valley-Longhorn Extension (if approved) in service by the end of 2025 could drive clean energy cost savings for customers. A map showing the estimated in-service dates of the Pathway Project segments and the May Valley-Longhorn Extension is shown in Figure 1.9-2 below.

Figure 1.9-2 Estimated In-Service Dates for the Pathway Project and May Valley-Longhorn Extension



The Pathway Project will effectuate an interconnected transmission system that: (1) achieves improved reliability and operational flexibility while interconnecting needed clean generation resources; and (2) enables the delivery of electric energy from these generation resources to the Company's load centers. An additional benefit of the Pathway Project is that it will network a large portion of the existing Rush Creek and Cheyenne Ridge 345 kV transmission line(s) that together effectively comprise a 153-mile radial generator tie-line currently connected to Public Service's networked transmission system only at Missile Site Substation.

Section 2.8 of Volume 2 provides additional Transmission Resources information.

Joint Transmission Proposal

On October 30, 2020, the Company filed the Updated Joint Transmission Proposal and Joint Final Comments (the "Joint Transmission Proposal") in response to Decision No. C20-0661-I in the ERP rulemaking proceeding (Proceeding No. 19R-0096E). The Joint Transmission Proposal was a consensus proposal put forward by a diverse coalition of stakeholders that aimed to better align transmission planning and resource planning by allowing bidding into bid-eligible planned transmission projects in the Phase II competitive solicitation without burdening developers with costs from the transmission project.[27] The Joint Transmission Proposal also sets forth a process whereby the Commission approves a "menu" of bid-eligible planned transmission projects as part of the Phase I decision.[28] The Joint Transmission Proposal did not preclude the filing of CPCNs for new transmission ahead of an ERP, as the Company has done with the Pathway Project (filed in Proceeding No. 19A-0096E).

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.[29] However, one of the items the Commission focused on in those deliberations was the Joint Transmission Proposal. During their deliberations, the Commission lauded the collaboration among stakeholders which yielded the Joint Transmission Proposal and encouraged the use of the process, absent new ERP Rules, if applicable. The Commission directed the Company to address in its 2021 ERP & CEP, to the extent necessary, how the Company has incorporated the Joint Transmission Proposal into its 2021 ERP & CEP, but recognized that since the development of the Joint Transmission Proposal, the Company has filed a CPCN for the Pathway Project.

[27] 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.
[28] 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.
[29] As of the writing of this testimony, the Commission's written Decision is pending.

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 the Company should move forward with CPCNs for the designated planned transmission projects. An ERP Phase II decision is not expected until late 2022 or early 2023, which will not allow time to develop the Pathway Project and have certain segments in service by 2025. Given these timing issues, the Company filed its CPCN for the Pathway Project ahead of this ERP.

The Company is not proposing any bid-eligible planned transmission under the Joint Transmission Proposal. The Company 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.

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, the Company views the Pathway Project as being consistent with the spirit of the Joint Transmission Proposal and goes towards the same ends—identifying strategic transmission investment that can unlock cost-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.

1.10 PHASE II RESOURCE ACQUISITION PLAN

Competitive All-Source Solicitation

Consistent with the requirements of SB 19-236 and past practice, the Company is proposing to utilize an all-source competitive solicitation process in Phase II to acquire the resources necessary to meet the various needs and objectives of this 2021 ERP & CEP. The use of competitive procurement is the foundation of the successful ERP paradigm here in Colorado. The Company received over 400 bids in the last ERP cycle (2017 All-Source Solicitation) and we expect to see a similarly robust response again in the upcoming competitive solicitation. In addition to tax-advantaged wind and solar bids, the Company is also hopeful that we will see technology advancement and dispatchable carbon-free generation bids to fill the need for flexible dispatchable generation to keep our system reliable as we integrate an increasingly large proportion of variable renewable resources.

The Company is also taking affirmative steps to ensure that gas additions are compatible with our future goals and State energy policy objectives to the extent possible. We are encouraging bids in the Phase II competitive solicitation for new-build natural gas resources that are capable of combusting at least 30 percent hydrogen on a volumetric basis. While this is not a requirement, it is something we propose to consider in the bid evaluation process. Further, the Company will analyze obtaining any natural gas associated with new gas additions from “certified” or “responsibly-sourced” natural gas sources. This purchasing approach would use third-party measurement and certification to ensure that our sourcing of natural gas would come from producers that are responsibly controlling upstream methane emissions.

Volume 3 of the ERP contains the specifics of the proposed competitive solicitation process including three distinct requests for proposal (“RFP”) documents: (1) a Dispatchable Resources RFP; (2) a Renewable Resources RFP; and (3) a Company Ownership RFP. The RFPs allow a variety of supply-side generation technologies to be offered, as well as a variety of ownership and contracting structures (PPA, Company Self-Build, and Build-Own-Transfer). Additional details regarding the Phase II competitive acquisition process are provided in Section 2.16 of Volume 2.

Phase II Modeling Assumptions

The Company will use the modeling inputs and assumptions set forth in our 2021 ERP & CEP, inclusive of any modifications ordered by the Commission through the Phase I decision. These modeling inputs and assumptions are outlined in Section 2.14 of Volume 2 and discussed throughout the Phase I filing. Consistent with past practice in prior ERP cycles, the Company will make the final modeling inputs and assumptions available through a compliance filing after the Phase I decision but prior to the issuance of the RFPs that will commence the Phase II competitive solicitation process.

Bid Evaluation Process

The Company's proposed bid evaluation process for this 2021 ERP & CEP is consistent with the overall process employed by the Company and monitored by the Independent Evaluator in the 2017 All-Source Solicitation in Phase II of the 2016 ERP. Generally, the process involves three primary activities: 1) proposal processing and initial due diligence, 2) static economic screening, and 3) computer modeling.

A more detailed description of the bid evaluation process is provided in Section 2.16 of Volume 2. An indicative timeline of Phase II activities is shown in Figure 2.16-1.

Best Value Employment Metrics

SB 19-236 made changes to § 40-2-129, C.R.S to strengthen statutory provisions regarding best value employment metrics ("BVEM") and establish a framework that holds utilities and non-utility bidders to similar standards when it comes to providing BVEM information.

The Company is required to obtain from bidders and provide to the Commission BVEM information for each bid submitted in the Phase II competitive solicitation, including information regarding:

(I) the availability of training programs, including training through apprenticeship programs registered with the United States Department of Labor, Office of Apprenticeship and Training;

(II) the employment of Colorado workers as compared to importation of out-of-state workers;

(III) long-term career opportunities; and

(IV) industry-standard wages, health care, and pension benefits.

To ensure that the BVEM information provided by either a bidder or the utility is substantive, § 40-2-129, C.R.S. requires: (1) provision of the BVEM documentation; or, (2) in the alternative, certification of compliance with objective BVEM performance standards set forth in the solicitation document. The Commission may waive the requirements of (1) and (2) where a Project Labor Agreement ("PLA") is utilized.

At the Commissioners' Weekly Meeting on March 24, 2021, the Commission discussed the rulemaking in Proceeding No. 19R-0096E at length. One of the items the Commission focused on in those deliberations was BVEM and Proposed Draft Rule 3613 that had been put forward in that proceeding (based on collaboration between Public Service and Rocky Mountain Environmental Labor Coalition and Colorado Building and Construction Trades Council, AFL-CIO (jointly, "RMELC/CBCTC"), which further detailed the BVEM information requirements. The Commission decided to not adopt new rules as a result of the proceeding.[30] However, the Commission stated that the more detailed BVEM-related provisions reflected in Proposed Rule 3613 will be required and that bidders should know that this information is necessary for their bids to be accepted. Additionally, the Commission stated that it expects the Company to include the more detailed BVEM requirements in its RFP documents. Accordingly, the RFP documents contained in Volume 3 state that the Company can and will disqualify bids that provide insufficient BVEM as part of their bid packages. Additional details, including the detailed language of Proposed Draft Rule 3613, are provided in Section 2.16 of Volume 2.

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

APPENDIX 1 - WORKFORCE TRANSITION PLAN (2021)