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Pages 23, 42, 47, 48, 52, and 67.

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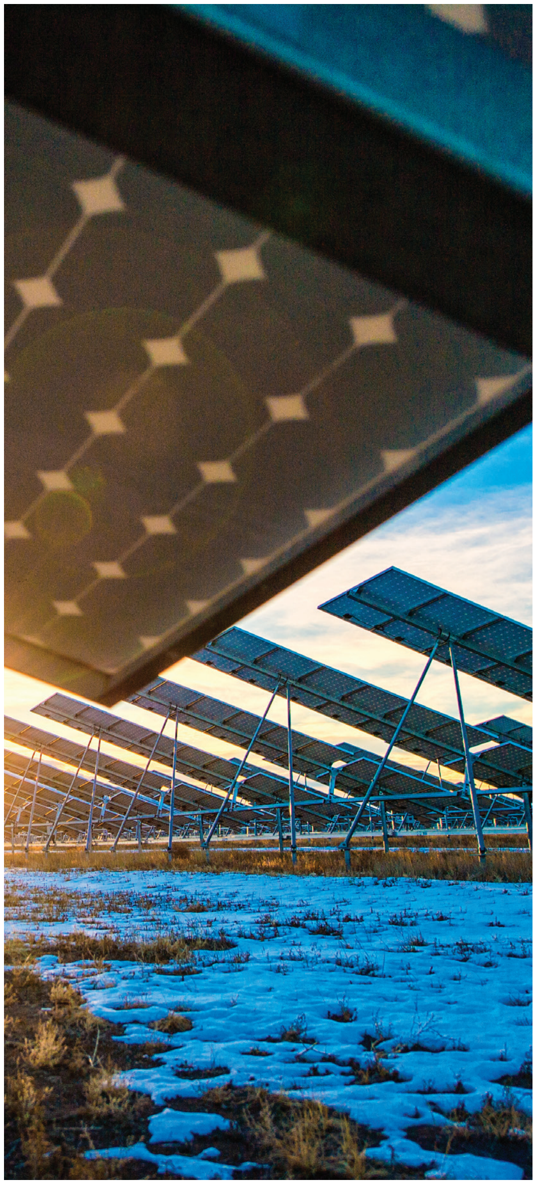

Public Service Company of Colorado

2016 Electric Resource Plan

120-Day Report

PUBLIC VERSION

(CPUC Proceeding No.16A-0396E)

June 6, 2018

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1.0 Executive Summary

Public Service Company of Colorado's ("Public Service" or the "Company") preferred Colorado Energy Plan Portfolio ("Preferred CEPP") provides an attractive path for our customers and the State of Colorado. This 120-Day Report presents an opportunity for the Commission to continue the transformation of the Public Service generation portfolio in a manner that simultaneously achieves economic and environmental benefits. Through approval of the cost-effective resource plan presented below, the Commission can harness Colorado's natural resources to dramatically reduce carbon and other emissions, and deliver value for Coloradans in the form of economic development and long-term savings to customers on their electric bills. The benefits of the Preferred CEPP are substantial and include:

- Customer savings of more than $200 million on a net present value basis relative to the business as usual Preferred ERP plan (filling 450 MW need and continuing operations of Comanche 1 and Comanche 2);
- Statewide investment of $2.5 billion across eight different Colorado counties;
- Nearly 55% renewable energy by 2026 driven by over 1,800 MW of new wind and solar generation;
- Deep emissions reductions that, by 2026, include nearly 60 percent lower CO_2 emissions and 90 percent lower SO_2 and NO_X emissions than 2005 levels;
- Increased operational flexibility and reliability by pairing increased renewable generation with dispatchable battery storage and flexible gas generation; and,
- A beneficial path forward for Pueblo County, a long-time host community for the Comanche plant.

Our Preferred CEPP is the product of the Commission's oversight in developing a process and framework to allow for the robust evaluation of the Colorado Energy Plan as well as the work of sixteen diverse parties, each of whom worked to develop and ultimately coalesced around the possibility of a transformative plan – a plan that can now come to fruition and is presented in this 120-Day Report. Notably, the Plan produces greater savings than contemplated by the Stipulation. The Preferred CEPP consists of the following course of action:

- Accelerating the retirement of Comanche 1 and Comanche 2;
- Adding 1,100 MW of wind to our system;
- Adding 700 MW of solar to our system;

- Introducing 275 MW of battery storage to the system (all embedded in solar plus storage projects); and

- Ensuring system reliability by utilizing 380 MW of existing flexible gas resources.

Our Preferred CEPP was the beneficiary of a Phase II competitive solicitation that generated over 400 bids, including an unprecedented number of diverse and low-cost bids. After assessing thousands of bid combinations and working closely with the Independent Evaluator, the Company synthesized this information and developed two primary paths to help frame the decision at hand for the Commission and other interested parties – which portfolio should be selected as the final cost-effective resource plan. Path one is that of the Electric Resource Plan portfolio with its 450 MW resource need and the continued operations of Comanche 1 and Comanche 2. Path two is the Colorado Energy Plan that incorporates the early retirement of 660 MW of coal-fired generation at Comanche 1 and Comanche 2. These two paths result in the two foundational portfolios for this 120-Day Report: the Preferred ERP and the Preferred CEPP. While the economic benefits of both approaches are reasonable, the compelling aspect of the Preferred CEPP is that it delivers lower costs with substantial environmental and renewable energy gains that are greater than in the traditional ERP as presented here.

The 120-Day Report contains information and analysis to allow for a comprehensive evaluation of these two paths, consistent with Commission directives. In particular, this 120-Day Report provides a robust body of data and detailed information to allow the Commission a full record on which to identify a cost-effective portfolio that lays out a prudent path forward for Colorado. The suite of data to evaluate the portfolios includes various sensitivities including gas price, discount rate, and carbon price along with other portfolios including least-cost portfolios, and other relevant data points. The 120-Day Report also provides the Commission with the information it needs to evaluate different sizes of portfolios based on the level of resource need that can be satisfied with bids submitted in this competitive solicitation.

After extensive evaluation using the criteria established by the Commission, the Company is excited to present the Preferred CEPP as the recommended path forward. The Preferred ERP provides a reasonable and cost-effective path forward for the Public Service system and State of Colorado, but the Preferred CEPP does much more. The Preferred CEPP continues the cost-effective transition of our generation fleet to cleaner more diverse resources while delivering tangible benefits to our customers and state and local communities. The Preferred CEPP includes a strong commitment to new wind and solar resources, takes a large step into the utilization of battery storage, and leverages the use of existing gas generation.

Moreover, the Preferred CEPP provides a wide range of benefits including customer savings, beneficial environmental impacts, generation technology and geographic diversity, balanced ownership between utility and IPPs (and among several different

IPPs), system operational benefits, economic development benefits, and host community benefits. All of these factors support our recommendation, and we believe further support a finding from the Commission that the Preferred CEPP is "a designated combination of new resources that the Commission determines can be acquired at a reasonable cost and rate impact" and therefore a cost-effective resource plan.[1]

While the benefits of the Preferred CEPP are described in more detail in the following section and supported throughout this 120-Day Report, below is a brief summary of the plan and related benefits:

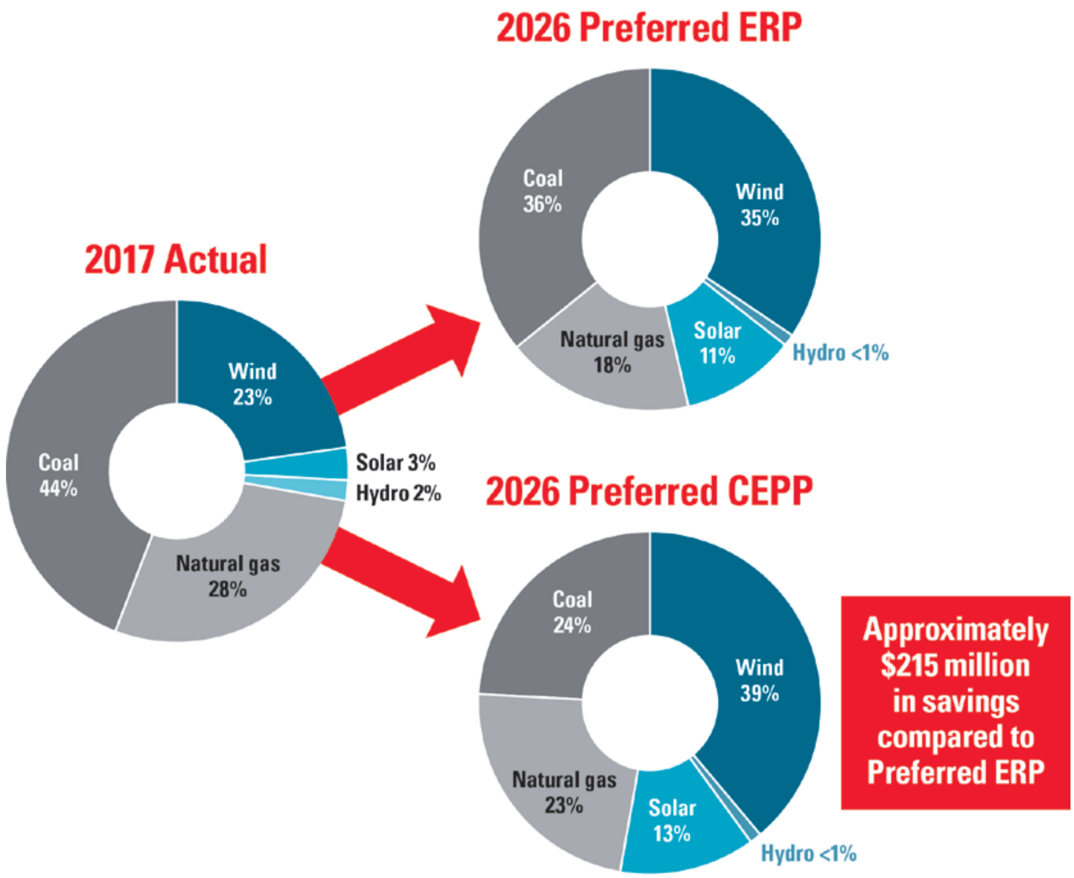
- Preferred CEPP Summary. The Preferred CEPP offers diversity of technologies, with approximately 1,100 MW of wind, 700 MW of solar, 275 MW of storage (all embedded in solar plus storage projects), and 380 MW of existing gas resources. The Preferred CEPP provides balance in generation ownership. The Company will own 27% of the renewable resources (500 MW of wind) and 58% of dispatchable and semi-dispatchable resources (380 MW of gas generation). While less than the ownership targets contemplated in the Stipulation, the Company believes that moving forward with a transition to clean energy is preferred. We believe the Preferred CEPP achieves the "value of maintaining both robust utility and IPP ownership," as acknowledged by the Commission as an important resource planning goal.[2]

- Customer savings. The Preferred CEPP is projected to save approximately $215 million on a present value basis as compared to the Preferred ERP.[3] Further, as set forth in this document, the Company believes there are additional opportunities that could drive further savings for customers. The approximately $215 million in savings is a reasonable yet conservative figure for the Commission to use in determining a cost-effective resource plan in this proceeding.

- Clean energy benefits. Many customers and communities are seeking more renewable energy. Under the Preferred CEPP, we would achieve nearly 55% renewable energy by 2026. The energy mix would include a diverse blend of generation, and also add flexible battery resources to the system.

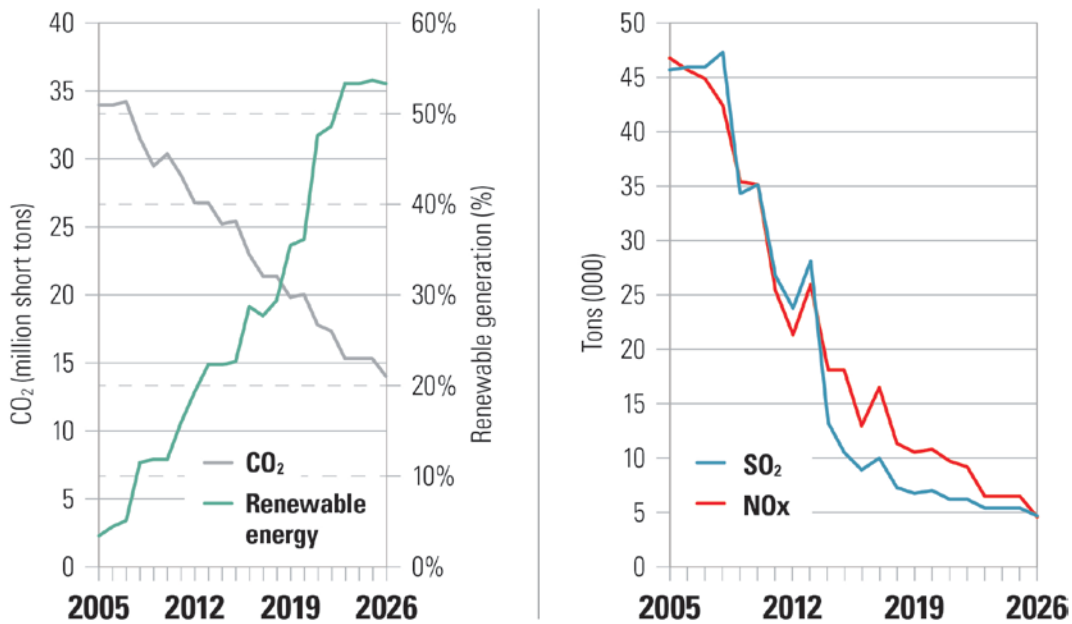
[1] Rule 3602(c).
[2] Decision No. C18-0191, at ¶ 50 (mailed Mar. 22, 2018).
[3] Projected savings over the Planning Period are $213 million on a present value basis using the replacement backfilling method and $374 million on a present value basis using the annuity backfilling method. These savings were calculated without any carbon cost adders.

Estimated Energy Mix Under the Preferred CEPP



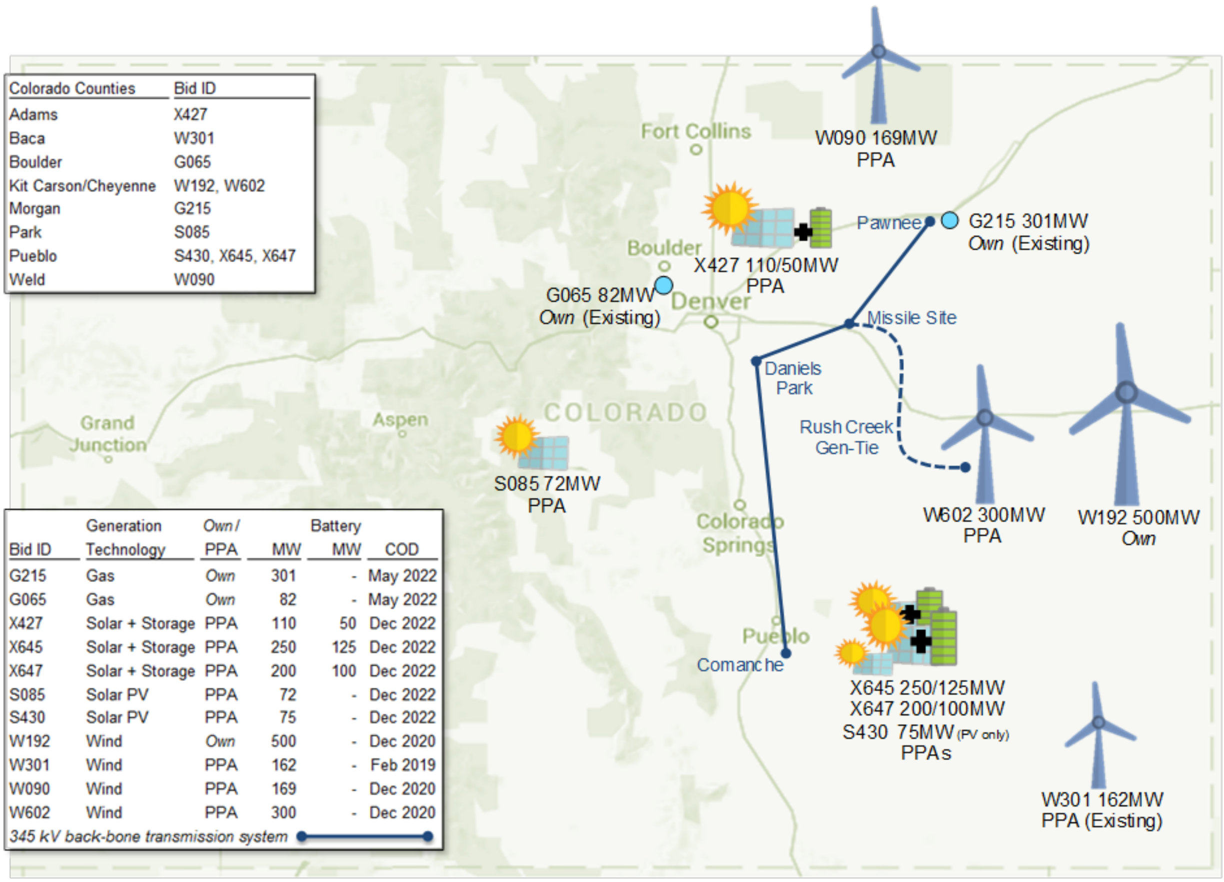
- Environmental benefits. The Preferred CEPP can deliver significant cost savings while making deep cuts in the Company's CO_2, SO_2, and NO_X emissions. With the implementation of the Preferred CEPP, we estimate Public Service's CO_2 emissions will be approximately 60% lower in 2026 than in 2005, and we also anticipate that SO_2 and NOx emissions would be 90% lower than 2005 by 2026.

Energy Transition: CO_2, SO_2 and NO_X Reduction and Renewable Energy Growth Under the Preferred CEPP



➢ <u>Geographic diversity.</u> The Preferred CEPP offers substantial geographic diversity, with selected generation resources in eight different Colorado counties. The plan includes approximately 1,100 MW of new wind resources in the northern and eastern part of the State of Colorado and over 500 MW of new solar and 225 MW of battery storage resources in the southern half of the State (with the balance of solar in the northern and western part of the State). The Figure below shows a map depicting the dispersion of the Preferred CEPP resources across different regions of Colorado.

Preferred CEPP Generation Locations



Colorado Counties	Bid ID
Adams	X427
Baca	W301
Boulder	G065
Kit Carson/Cheyenne	W192, W602
Morgan	G215
Park	S085
Pueblo	S430, X645, X647
Weld	W090

Bid ID	Generation Technology	Own / PPA	MW	Battery MW	COD
G215	Gas	Own	301	-	May 2022
G065	Gas	Own	82	-	May 2022
X427	Solar + Storage	PPA	110	50	Dec 2022
X645	Solar + Storage	PPA	250	125	Dec 2022
X647	Solar + Storage	PPA	200	100	Dec 2022
S085	Solar PV	PPA	72	-	Dec 2022
S430	Solar PV	PPA	75	-	Dec 2022
W192	Wind	Own	500	-	Dec 2020
W301	Wind	PPA	162	-	Feb 2019
W090	Wind	PPA	169	-	Dec 2020
W602	Wind	PPA	300	-	Dec 2020

345 kV back-bone transmission system

- Use of existing and new infrastructure. Geographic and technological diversity combine with the use of existing infrastructure and development of necessary new transmission infrastructure to provide the reliability customers know and expect from Public Service.

- Economic development benefits. The Preferred CEPP supports the economic vitality of our state and local communities. It provides economic development benefits across Colorado with approximately 2,500 MW of generation assets (including battery storage) developed or acquired in different regions of Colorado, totaling approximately $2.5 billion in generation investment alone.

- Host community benefits. The Preferred CEPP is a catalyst for benefits to Pueblo, the long-time host community for Comanche 1 and Comanche 2. It would result in the development of high levels of new solar and battery storage and other supporting infrastructure in the Pueblo area, benefit the Pueblo County “1A Community Improvement Program,” and provide the ability for the Company to enable an EVRAZ contract to help keep this anchor of the Pueblo business community in Colorado. The contract and net metered on-site solar facility (between approximately 200 MW and 240 MW), combined with other incentives provided to EVRAZ by state and local government authorities, could enable substantial investments in new production facilities at the EVRAZ steel mill in Pueblo as well as on-site solar, which will increase the overall economic impact of our plan.

Recognizing the importance of providing the Commission with good alternatives to consider, and that the Preferred CEPP would add resources in this Resource Acquisition Period (“RAP”) that are not needed until the early retirement of Comanche 2 at the end of 2025, the Company is receptive to the Commission’s consideration of a slightly different CEPP that would effectively defer one solar with battery storage project for acquisition to the next ERP. We fully expect that this approach would achieve the same environmental benefits outlined above, but it would provide greater economic benefits and allow a staged introduction of new battery storage technology. This “Alternative CEPP” would capitalize on and maximize acquisition of 100% PTC wind, which we do not anticipate being available in the next ERP cycle. However, it would implement a phased, but still progressive approach to the acquisition of solar and solar with battery storage projects, which we anticipate will continue to be available at even lower prices in the next ERP cycle with the full 30% Investment Tax Credit (“ITC”). While this last solar with battery storage project is cost-effective, it results in the acquisition of capacity before it is needed by the system. Even assuming the price of solar and storage remain flat through the next ERP, delaying this last contract until the next ERP cycle would save customers approximately $20 million. As noted above, we expect these prices to continue their decline so this savings estimate is conservative. This Alternative CEPP would result in the acquisition of 250 MW less of solar and 125 MW less of battery storage than the Preferred CEPP, but would still result in the addition of 1,100 MW of wind, 450 MW of solar, 150 MW of battery storage (again embedded in solar plus battery storage projects), and 380 MW of existing gas resources in this ERP.

There are many reasons, outlined above and throughout this 120-Day Report, that the Commission *should* approve the Preferred CEPP or its alternative. Here we note that the Commission *can*, consistent with Colorado law, approve the Preferred CEPP. The State of Colorado prioritizes economics and environment in its energy mix and employs a cost-effectiveness standard in resource planning. The Preferred CEPP is undoubtedly a cost-effective resource plan—and one that delivers economic and environmental benefits that can transform the energy landscape of Colorado.

Accordingly, the Company requests the Commission find the Preferred CEPP to be a cost-effective resource plan and approve it by the Commission’s Phase II Decision in this proceeding. This 120-Day Report provides extensive detail and support for the conclusion that the Preferred CEPP is the right plan for our customers, our stakeholders, the Company, and the State.

The remainder of the Report proceeds as follows:

- **Section 2.0** provides an overview of the preferred portfolios;
- **Section 3.0** describes how the Company coordinated with the Independent Evaluator through the solicitation process;
- **Section 4.0** sets forth the analysis supporting the preferred portfolios;
- **Section 5.0** details the key modeling inputs, assumptions and methodologies;
- **Section 6.0** provides an overview of the Phase II process; and
- **Section 7.0** includes a conclusion and proposal for next steps.

2.0 Overview of Preferred Portfolios

This section of the 120-Day Report provides an overview of and background on key characteristics associated with the Preferred CEPP, the Alternative CEPP described in the Executive Summary, and the Preferred ERP.

2.1 The Preferred Colorado Energy Plan Portfolio

The Preferred CEPP provides an attractive path for our customers and the State of Colorado. It is an opportunity for this Commission to continue the transition of the Public Service generation fleet, bolster economic development across Colorado, *and* lower customer bills. The extensive body of information provided in this report demonstrates that the Preferred CEPP portfolio is a cost-effective resource plan. The Commission can approve the CEPP, and it should. It can because Colorado law gives the Commission flexibility and discretion to look beyond the narrow parameters of "least cost" to the broader picture of what is good for customers, stakeholders, the Company, and the State of Colorado. The Preferred CEPP is good for customers, stakeholders, and the State of Colorado. It will result in approximately $2.5 billion of generation investment and $200 million of transmission investment across the State, with Public Service's investment at approximately $1 billion, and attendant economic development benefits across numerous Colorado counties and the State generally. It is projected to save customers over $200 million relative to the Preferred ERP. And it will also dramatically reduce emissions by 2026.

The Preferred CEPP delivers economic and environmental benefits by adding 1,838 MW of renewable generation, paired with 275 MW of battery storage, and 383 MW of existing gas assets, all while retiring 660 MW of coal-fired generation (approximately one-third of the Company's remaining coal fleet). This approach furthers the development of a flexible system that takes advantage of intermittent renewable resources while adding battery storage and existing gas generation to our existing fleet of dispatchable resources that includes pumped hydro storage, natural gas combined cycle, and gas combustion turbine peaking resources. Beyond bolstering reliability and environmental performance, this increasingly diverse fuel mix serves as a customer protection by acting as a natural hedge against commodity prices. Public Service also forecasts that implementation of the Preferred CEPP can be accomplished at an annualized rate of less than 1% through 2030.

This section provides further detail regarding the benefits associated with the Preferred CEPP, and these benefits show the Company has identified a "cost-effective resource plan" for Commission consideration — the stated goal of the ERP process. Below we identify the customer savings, environmental benefits, clean energy benefits, diversity benefits, economic development benefits, and host community benefits that illustrate what the Preferred CEPP can provide to customers, communities, and the State of Colorado. These benefits are central to the Commission's charge to evaluate cost-effectiveness based on quantitative and qualitative factors. Indeed, the Commission reinforced the scope of the cost-effectiveness evaluation used in the ERP process in its order allowing the CEPP to be brought forward, confirming that "[t]he Phase II process is designed to consider both quantitative (i.e., modeled PVRR cost comparison between portfolios) and qualitative factors such as jobs or certain environmental benefits." The quantitative and qualitative factors outlined below support a finding by the Commission that the Preferred CEPP is cost-effective and merits approval.

Customer Savings of the Preferred CEPP

The Preferred CEPP saves money for customers. Indeed, it is projected to save between $213 million and $374 million on a present value basis as compared to the preferred ERP 450 MW portfolio.[4] These two portfolios are the foundational portfolios for this 120-Day Report, and the key metrics of each are set forth in the table below.

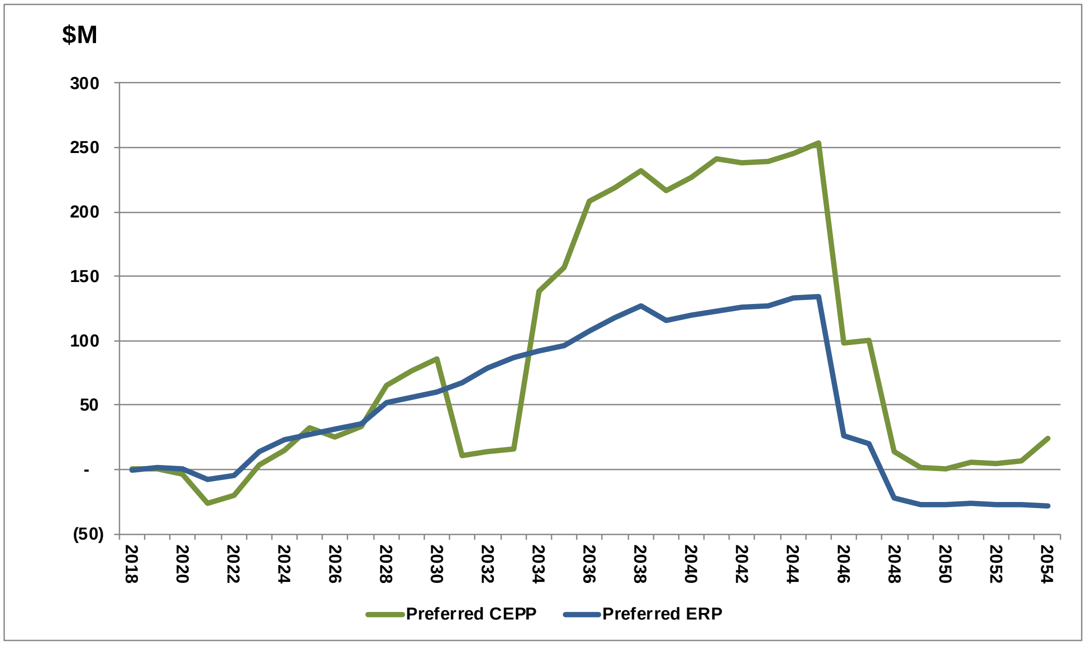
Table 1 - Preferred CEPP and Preferred ERP Portfolio

	Preferred ERP	**Preferred CEPP**
Comanche 1 & 2 Retire Year	2033/2035	2022/2025
Targeted Resource Acquisition (MW)	450	1,110
Portfolio Generation		
Wind (MW)	789	1,131
Solar (MW)	322	707
Battery Storage (MW)	50	275
Gas (MW)	301	383
Portfolio Firm Capacity (MW)	554	993
Total Generation Investment ($M)	$1,460	$2,550
Company Ownership (% of Nameplate)		
Eligible Energy Resources (%)	0%	27%
Dispatchable/Semi-Dispatchable (%)	86%	58%
Total Transmission Investment ($M)	$175	$204
2016 – 2054 Planning Period PVRR	$34,901	$34,687
PVRR Savings vs. Preferred ERP ($M)	**-**	**$213**
Total Investment ($M)	$1,636	$2,754
2026 CO_2 Reduction (%)	47%	59%

Another key comparison illustrating the savings to customers of our Preferred CEPP is as against the costs of the All Thermal ERP portfolio – a portfolio that meets the 450 MW need solely with gas-fired projects. The comparison chart below shows savings to customers on an annual basis associated with the Preferred ERP and Preferred CEPP as compared to the All Thermal ERP portfolio.

[4] Projected savings over the Planning Period are $213 million on a present value basis using the replacement backfilling method and $374 million on a present value basis using the annuity backfilling method.

Figure 1 - Annual Savings (Cost) of Preferred ERP and Preferred CEPP to All Thermal ERP



On a present value basis the Preferred ERP saves $510 million as compared to the All Thermal ERP portfolio. The savings of the Preferred CEPP against the All Thermal ERP portfolio are even more substantial, saving customers $723 million on a present value basis over the Planning Period.

Clean Energy Benefits

Our Colorado customers want clean energy at a reasonable price. In fact, we have surveyed individual customers, and a majority of the Company's customers and citizens of Colorado surveyed support clean energy progress and emissions reduction — a trend seen in statewide surveys as summarized in the graphic below. The Preferred CEPP supports exactly that outcome: transitioning to clean energy while lowering customer costs and continuing our unwavering commitment to system reliability.

Figure 2 - Results From Colorado Statewide Voter Survey: Percentage of Survey Respondents Supporting These Statements, June 2017

57%
Coal use should be decreased

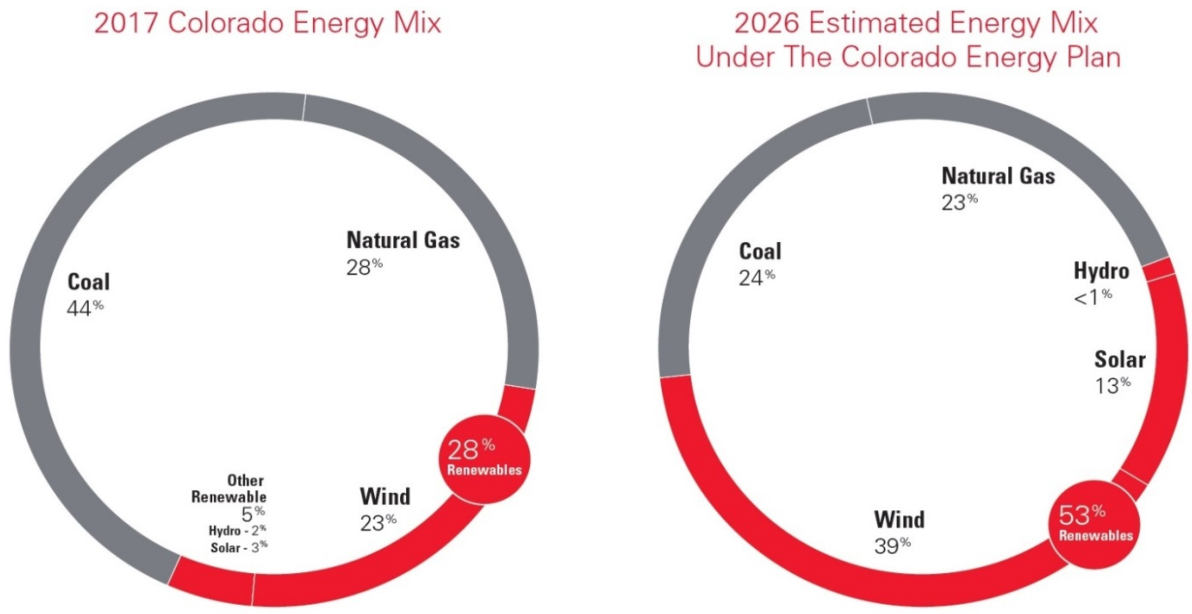
83%
Colorado utilities should increase clean renewable energy if it means no increase in energy costs

89%
The state of Colorado and utilities should reduce carbon emissions while providing reliable and affordable energy

95%
The state of Colorado and utilities should work together to achieve the most significant increases in the use of clean renewable energy that can be accomplished while providing reliable and affordable energy

The Preferred CEPP would transform the energy mix we use to provide electric service to our customers. The figure below shows the Company's projected energy mix in 2026 with the Preferred CEPP as compared to the 2017 energy mix. By 2026, we will serve customers with an energy mix that includes nearly 55% renewable energy, up from 28% in 2017. Natural gas remains relatively steady in the fuel mix, going from 28% in 2017 to 23% in 2026. Coal would decrease substantially from 44% in 2017 to 24% in 2026. Our energy mix would remain balanced and diverse, while at the same time continuing its transformation into one of the most progressive energy portfolios in the country.

Figure 3 - Current Energy Mix Versus Preferred CEPP 2026 Energy Mix



<u>Environmental Benefits of the Preferred CEPP</u>

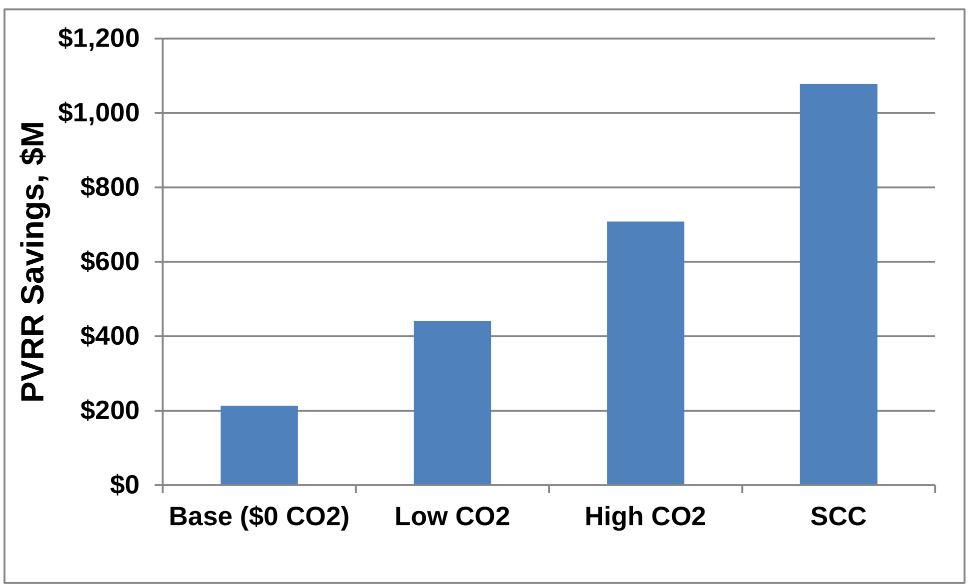
The environmental benefits of the Preferred CEPP are as compelling as its economic benefits. The Preferred CEPP can deliver significant cost savings while simultaneously making deep cuts in our CO_2, SO_2, and NO_X emissions. With the implementation of the Preferred CEPP, we estimate Public Service's CO_2 emissions will be approximately 60% lower in 2026 than in 2005, and we also anticipate that SO_2 and NOx emissions could be about 90% lower than 2005 by 2026. These reductions surpass the goals set forth in Executive Order D 2017-015, Supporting Colorado's Clean Energy Transition, issued by Governor John Hickenlooper on July 11, 2017, as set forth in Table 2 below.

Table 2 - Preferred CEPP and Executive Order D 2017-015 Emission Targets

Exec. Order Target		Colorado Energy Plan Portfolio Estimated Result
Economy-wide multi-sector GHG target	26% below 2005 by 2025	Public Service's emissions reductions would achieve about half of the total state economy's reduction need as expressed in tons by 2025. The Company would achieve 18 million short tons of reduction against a goal that requires 35 million short tons of reduction by 2025.
Electric sector CO_2 target	25% below 2012 by 2025	42% below 2012 by 2025
Electric sector CO_2 target	35% below 2012 by 2030	48% below 2012 by 2026.

The Preferred CEPP also acts as a hedge against future environmental regulation — an express concern of this Commission. To help quantify that risk, the Commission ordered the Company to run sensitivities based on varying levels of future CO_2 costs. These sensitivities included a low CO_2 cost case, high CO_2 cost case, and social cost of carbon case.[5] Taken together, the results show that under all scenarios, the Preferred CEPP has significant value as a hedge against future environmental regulations.

Figure 4 - Preferred CEPP Savings Compared to Preferred ERP Under Future CO_2 Costs



[5] See Appendix E, Modeling Assumptions Update, for more detail on the low CO_2, high CO_2, and social cost of carbon sensitivity cases.

Diversity of the Preferred CEPP

While the Preferred CEPP delivers significant customer savings and environmental benefits, it also introduces additional geographically diverse generators to the system and, with it, reliability benefits to the system. The table below identifies the generation diversity of the Preferred CEPP by county.

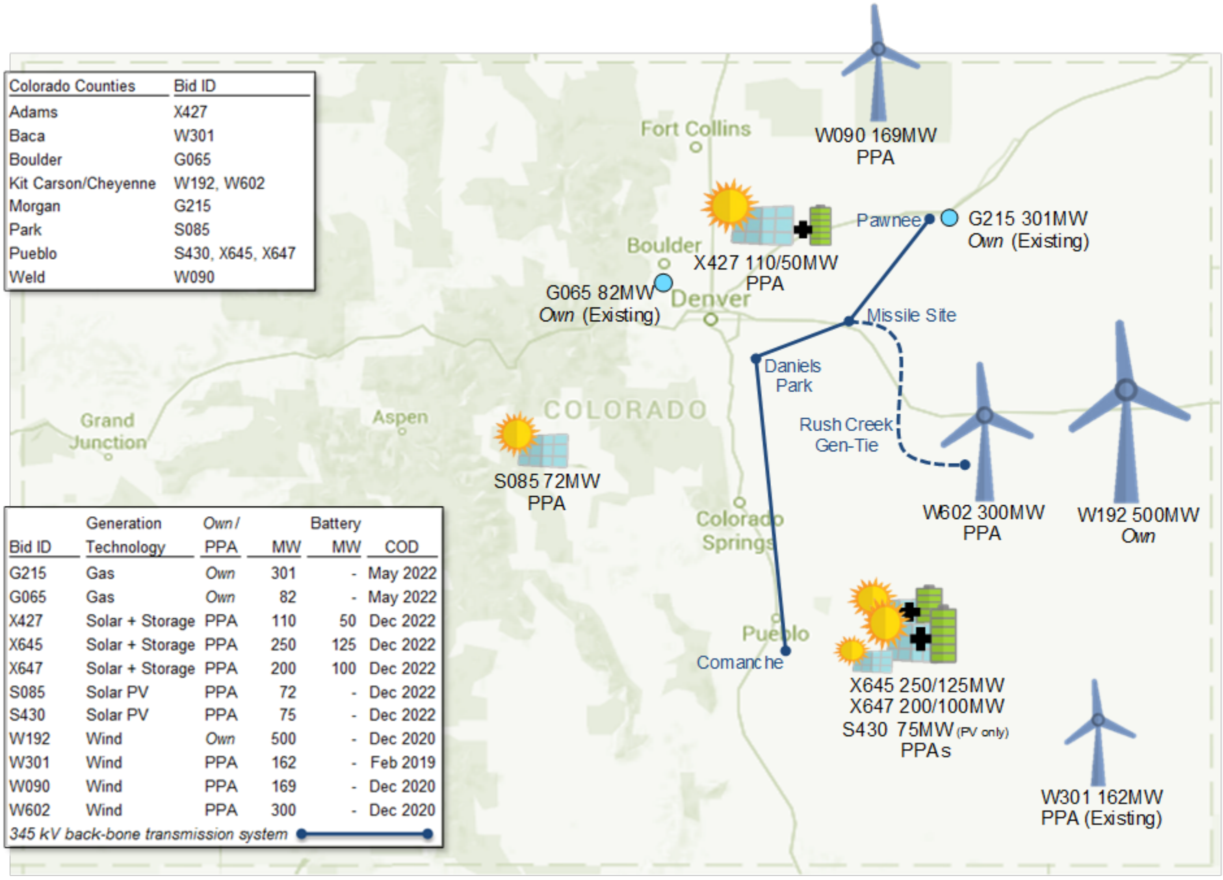
Table 3 - Preferred CEPP Generation Diversity

County	MW
Adams	110 MW (solar), 50 MW (storage)
Baca	162 MW (wind repower of existing)
Boulder	82 MW (existing gas)
Kit Carson/Cheyenne[6]	800 MW (wind)
Morgan	301 MW (existing gas)
Park	72 MW (solar)
Pueblo	525 MW (solar), 225 MW (storage)
Weld	169 MW (wind)

The figure below provides a map showing the dispersion of the Preferred CEPP resources across different regions of Colorado.

[6] The two wind projects in this area of Colorado cover territory in both Kit Carson and Cheyenne counties; therefore, these counties are grouped together.

Figure 5 - Preferred CEPP Generation Locations



Colorado Counties	Bid ID
Adams	X427
Baca	W301
Boulder	G065
Kit Carson/Cheyenne	W192, W602
Morgan	G215
Park	S085
Pueblo	S430, X645, X647
Weld	W090

Bid ID	Generation Technology	Own / PPA	MW	Battery MW	COD
G215	Gas	Own	301	-	May 2022
G065	Gas	Own	82	-	May 2022
X427	Solar + Storage	PPA	110	50	Dec 2022
X645	Solar + Storage	PPA	250	125	Dec 2022
X647	Solar + Storage	PPA	200	100	Dec 2022
S085	Solar PV	PPA	72	-	Dec 2022
S430	Solar PV	PPA	75	-	Dec 2022
W192	Wind	Own	500	-	Dec 2020
W301	Wind	PPA	162	-	Feb 2019
W090	Wind	PPA	169	-	Dec 2020
W602	Wind	PPA	300	-	Dec 2020

The Preferred CEPP also provides balance in generation ownership. The Company will own 27% of the renewable resources (all wind) and 58% of dispatchable and semi-dispatchable resources (all gas). While the Preferred CEPP results in utility ownership levels short of ownership targets envisioned in our Stipulation (i.e., a target of 50% of eligible energy resources and 75% of dispatchable and semi-dispatchable resources), we believe this represents an appropriate path forward for the Commission that preserves diversity of ownership. With these additions, the Company would own approximately 20% of the overall renewable resources on the Public Service system.

The Commission recognizes the value of balanced ownership, and the Preferred CEPP provides that balance. The Commission's Decision No. C18-0191 at Paragraph 50 hit this point directly, where the Commission held:

> We agree with past Commission statements raised by Public Service recognizing the value of maintaining both robust utility and IPP ownership.

The Commission further noted that utility ownership is particularly important where, as here, the Company has brought forward a "voluntary proposal to retire Comanche 1 and 2" and advanced a plan that included "other concessions from Public Service such as restricted utility-builds, deferral of utility construction under Rule 4 CCR 723-3-3660(h), a requirement for cost neutrality or savings of the CEP Portfolio, and the presenting of the CEP Portfolio within an ERP proceeding." The geographic, resource and ownership diversity is yet another reason why the Preferred CEPP warrants approval.

Use of Existing and New Infrastructure

The Preferred CEPP leverages the existing or already planned transmission network and contemplates additional transmission investments to deliver these resources to load. As we continue the transition of the Company's generation fleet and replace aging coal-fired generation with significant amounts of low-cost renewables, maintaining the reliability of our system is critical—and, for our customers, non-negotiable. Transmission takes on an increasingly important role in both enabling access to very cost-effective resources located in the most beneficial renewable areas of the state and supporting the ongoing reliability needs of the system. Notably, the cost savings analysis includes the transmission investments—meaning, we have accounted for those investments in our modeling and still show significant customer savings from the Preferred CEPP.

And while new infrastructure investments are required, our approach also utilizes existing infrastructure to the maximum extent practicable. For example, existing gas generation is acquired to maximize the use of existing electric interconnection and natural gas supply infrastructure, as well as minimize the environmental impacts and permitting associated with new gas construction. While the Preferred CEPP contains no new gas generation and utilizes only existing, low-cost gas projects, the use of existing infrastructure is not limited to gas delivery and generation only. Indeed, the Preferred CEPP also contains the repowering of an existing wind project in southeastern Colorado. This collective use of existing infrastructure and generation helps to create a Preferred CEPP that is cost-effective and saves money for customers.

Economic Development Benefits of the Preferred CEPP

Adding geographic diversity to the system not only supports reliability, but it also benefits the State of Colorado through dispersed investments supporting the economic vitality of communities in numerous regions of Colorado. The statewide economic attributes of the Preferred CEPP are significant — and, for some areas of our State, critical. The table below identifies the dispersed generation investment of the Preferred CEPP by county.

Table 4 - Preferred CEPP Generation Investment Location

County	Investment ($M)[7]
Adams	[redacted]
Baca	[redacted]
Boulder	[redacted]
Kit Carson/Cheyenne[8]	$1,110
Morgan	[redacted]
Park	[redacted]
Pueblo	$670
Weld	[redacted]

These projects will help to create construction jobs in the development of new projects and necessary delivery infrastructure. There will also be on-going jobs and employment opportunities at new and existing generators. This investment and these opportunities will help drive both short- and long-term economic development benefits for these counties and communities in Colorado.[9] The Company also stands behind its commitments in the Stipulation, including its commitments to use union labor for any conversion of the generators at Comanche 1 and Comanche 2 to synchronous condensers. In addition, the acquisition of existing gas generation by the Company through this plan will expand the opportunity for union labor to operate and maintain these plants.

Host Community Benefits of the Preferred CEPP

In evaluating the Preferred CEPP, the Commission considers qualitative factors.[10] One of the critical qualitative benefits delivered by the Preferred CEPP is a renewed commitment to our long-time host community of Pueblo. The Preferred CEPP is a catalyst for qualitative benefits because it can enable certain actions from the Company that should be integral to the Commission's evaluation of the proposal.

For over 40 years, Pueblo has acted as a host for Comanche 1 (commercial operation in 1973) and Comanche 2 (commercial operation in 1975). We value that partnership and we place significant value on a plan — like the Preferred CEPP — that reinforces our commitment to a long-time host community — like Pueblo — by providing construction jobs, property taxes, and solidifying a continued presence in Southern Colorado.

[7] For counties with only single projects the total investment is provided as Highly Confidential information.
[8] The two wind projects in this area of Colorado cover territory in both Kit Carson and Cheyenne counties; therefore, these counties are grouped together.
[9] The best value employment metrics provided by bidders in Appendix M also show some of the benefits associated with these projects.
[10] Decision No. C18-0191, at ¶ 27 (mailed Mar. 22, 2018) ("The Phase II process is designed to consider both quantitative (*i.e.,* modeled NPVRR cost comparisons between portfolios) and qualitative factors such as jobs or certain environmental factors.")

These local benefits are realized in several ways. First, the development of substantial amounts of solar and battery storage and other supporting infrastructure in the Pueblo area has a beneficial property tax impact that more than offsets for the loss of property tax income from the early retirement of Comanche 1 and Comanche 2. Stated simply, under the Preferred CEPP, local taxing authorities are projected to receive *more* revenue than they do today with Comanche 1 and Comanche 2 operating in Southern Colorado.

Table 5 - Preferred CEPP Impacts on Pueblo Taxing Authorities[11]

	Pueblo County	School District 60	Library District
Tax Without Units 1 and 2	$6,599,340	$7,325,783	$1,129,287
Loss From Units 1 and 2 Retirement	$(252,264)	$(280,032)	$(43,168)
Additional Tax From Switching Station(s)	$204,093	$234,012	$34,925
Additional Tax from 525 MW Solar + 225 MW Storage	$1,385,928	$1,589,101	$237,162
Tax position after retirements with Switching Station(s) 525 MW Solar + 225 MW Storage	***$7,985,268***	***$9,148,896***	***$1,401,374***

Second, the Company and Pueblo County have reached agreement regarding an amendment to an existing Property Tax Incentive Agreement. This agreement is conditioned on the approval of the Company's Preferred CEPP in this proceeding and would help further Pueblo County's economic development and community improvement objectives through the Pueblo County "1A Community Improvement Program."

Third, approval of the Preferred CEPP and the investments for the Company included as part of this plan puts Public Service in a position to be able to move forward with its EVRAZ contract. EVRAZ employs approximately 1,000 people in Pueblo and is the largest customer on the Public Service system but has expressed its intention to move its facilities out of Colorado. Assuming Public Service and EVRAZ can reach agreement on terms, the contract enabled by the Preferred CEPP would result in the installation of an on-site 200 to 240 MW solar facility that can help EVRAZ to stabilize its energy costs — a key component of keeping EVRAZ in Pueblo. The State of Colorado and local economic development authorities are similarly motivated to keep EVRAZ in Colorado and have stepped up to provide incentives to retain EVRAZ. The contract enabled by the Preferred CEPP is Public Service's contribution to the team approach to retain EVRAZ, reflecting its importance as a matter of statewide concern. As discussed

[11] This assumes that battery storage is treated as renewable energy property for property tax purposes. If it is treated as non-renewable energy property, then there are additional revenues beyond those reflected in the table to each taxing authority. These estimates are therefore conservative.

above, the contract and net metered on-site solar facility, combined with other incentives provided to EVRAZ by state and local government authorities, create favorable conditions for substantial investments in new production facilities at the EVRAZ steel mill in Pueblo as well as on-site solar, which will increase the overall economic impact of our plan. This effort represents an unprecedented attempt by the Company to retain a large customer whose presence in Pueblo either directly or indirectly impacts the economic welfare of so many in the community. The Company and EVRAZ have structured the contract in a manner that can be (1) cost-justified to the Commission and our other customers and (2) economically justified to EVRAZ and the Company's investors, recognizing the investment opportunity represented by the Preferred CEPP. Moreover, retaining EVRAZ ultimately benefits all Public Service customers as remaining customers avoid cost increases associated with the departure of the largest customer on the Public Service system.

If the Preferred CEPP is approved, the Company will also carry out a workforce management plan for Comanche 1 and Comanche 2. As the Commission knows from this and prior proceedings, the Company has deep experience with developing and implementing successful, low impact workforce transition plans. With Cameo, Arapahoe, Valmont, and Cherokee retirements in Colorado, we did not implement an official layoff or forced workforce reduction. We intend to achieve the same result here for Comanche employees.

<u>The Cost-Effectiveness Standard</u>

There are many reasons, outlined above and throughout this 120-Day Report, that the Commission *should* approve the Preferred CEPP. It provides customer savings, environmental benefits, clean energy benefits, diversity and system operation benefits, economic development benefits, and host community benefits. Here we note the Commission *can*, consistent with Colorado law, approve the Preferred CEPP. The State of Colorado prioritizes economics and environment in its energy mix and employs a cost-effectiveness standard in resource planning. The Preferred CEPP is a cost-effective resource plan.

Rule 3601 embodies the Commission's shift from least-cost planning to cost-effective planning in response to legislative directives from the General Assembly in 2006 and 2007. The Commission explained "our new ERP Rules establish a framework for the Commission to approve a plan for resource acquisition in Phase I, similar to the previous LCP Rules, but adds a Phase II process wherein the Commission weighs the various risks and benefits of proposed resources to establish a preferred resource portfolio." Rule 3601 defines the purpose and goals of an ERP, which include minimizing the present value of revenue requirements while giving "the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies." The Commission reinforced the scope of the cost-effectiveness evaluation used in the ERP process in its order allowing the Preferred CEPP to be brought forward, providing that "[t]he Phase II process is designed to consider both quantitative (i.e., modeled NPVRR cost comparison between portfolios) and qualitative factors such as jobs or certain environmental benefits."

Cost-effectiveness, as opposed to least-cost, therefore guides the Company's development of its preferred portfolio in this proceeding. To assist in the evaluation of the cost-effectiveness of the Preferred CEPP under Rule 3601, the Commission ordered the Company to develop other portfolios and run numerous sensitivities to further the evaluation. These additional portfolios are included throughout this 120-Day Report, but the table below provides comparisons across select portfolios and key metrics.

Table 6 - Preferred CEPP and Select Other Portfolios

Portfolio ID		3	6	5	10
Portfolio Name		**Preferred ERP**	**Preferred CEPP**	**CEP LCP**	**CEP 775 500 Owned**
Comanche 1 & 2 Retire Year		2033/2035	2022/2025	2022/2025	2022/2035
RAP Resource Need (MW)		450	775	775	775
Targeted Resource Acquisition (MW)		450	1,110	1,110	775
Portfolio Generation	(1)				
Wind (MW)		789	1,131	830	1,131
Solar (MW)		322	707	982	457
Battery Storage (MW)		50	275	275	150
Gas (MW)		301	383	448	383
Portfolio Firm Capacity (MW)	(2)	554	993	1,143	780
Total Generation Investment ($M)	(3)	$1,460	$2,550	$2,300	$2,220
Company Ownership (% of Nameplate)	(4)				
Eligible Energy Resources (%)		0%	27%	0%	31%
Dispatchable/Semi-Dispatchable (%)		86%	58%	42%	72%
Portfolio Transmission	(5)				
Badger Hills Switching Station ($M)		$0	$12	$0	$12
Pueblo Area Reliability ($M)		$0	$10	$10	$10
Transmission Upgrades ($M)		$132	$100	$100	$132
Total Transmission Investment ($M)		$175	$204	$201	$221
2016 – 2054 Planning Period PVRR ($M)	(6)	$34,901	$34,687	$34,573	$34,794
PVRR Savings vs. Preferred ERP ($M)		**-**	**$213**	**$328**	**$106**
PVRR Costs vs. CEP LCP ($M)		$328	$114	-	$222
Total Investment ($M)		$1,636	$2,754	$2,499	$2,439
2026 CO_2 Reduction (%)	(7)	47%	59%	58%	54%

Notes:

(1) MW Nameplate by Technology
(2) MW of firm capacity added within the Resource Acquisition Period (RAP)
(3) Total portfolio generation investment is estimated based on industry averages of costs by size and technology type of the resource types within each portfolio. Estimates are rounded to the nearest $10M.
(4) % of Portfolio nameplate generation owned by PSCo for Eligible Energy (as defined by CO Rev Stat § 40-2-124 (2016)) and Dispatchable/Semi-Dispatchable resources (as defined in Section 1.3 of the Dispatchable and Semi-Dispatchable RFPs)
(5) Total Transmission related capital costs (interconnection and delivery)
(6) Present Value of Revenue Requirements, discounted at 6.78%
(7) Year 2026 CO_2 percent reduction from 2005 levels

As in the last ERP process, the least-cost resource portfolio in this ERP is not the preferred portfolio for either the ERP 450 MW case or the CEPP - as the qualitative benefits substantively outweigh the incremental cost. As noted above, the Company's Preferred CEPP is cost-effective. On a quantitative level, it utilizes diverse and low-cost renewable and battery storage projects to drive hundreds of millions in savings for customers as compared to a future where Comanche 1 and Comanche 2 each remain online for an additional decade. It satisfies the cost test of providing savings on a present value basis as compared to the Preferred ERP to the tune of over $200 million.

The Preferred CEPP is more expensive than the CEP LCP, in this instance by $114 million on an NPV basis. The $114 million difference between the CEP LCP and the Preferred CEPP is based on reasonable assumptions and modeling. However, they are also conservative. This 120-Day Report lays out two additional approaches that, if adopted, will provide additional savings to the Preferred CEPP and, in turn, bring the two portfolios closer together in cost. First, the DTA associated with Company-owned wind for unused PTCs and its revenue requirement comprise $82 million of the $114 million difference between the CEP LCP and the Preferred CEPP. As outlined in Section 4, the Company has taken steps to mitigate DTA impacts, and is also evaluating the alternative approach to the treatment of unused PTCs that could result in approximately $20 million in customer savings. Second, as discussed later in this section, the Company estimates that pursuing the Alternative CEPP as opposed to the Preferred CEPP and deferring filling the Comanche 2 resource need to the next ERP could yield an additional $20 million in savings over and above the savings of the Preferred CEPP. This potential for additional savings illustrates that the $114 million difference between the CEP LCP and Preferred CEPP, while reasonable, is conservative and a boundary analysis for the Commission to evaluate the cost-effectiveness of the Preferred CEPP (or the Alternative CEPP if that path is preferable to the Commission).

Equally as important, the CEP LCP — a portfolio provided as a comparative benchmark — does not confer the benefits delivered by the Preferred CEPP. In particular, the Preferred CEPP delivers significant value in three important ways. First, the Preferred CEPP and the associated renewable ownership financially positions the Company to move forward with the EVRAZ contract and amendment to the Property Tax Incentive Agreement in Pueblo. Second, the Preferred CEPP keeps an anchor employer in Pueblo while simultaneously plotting a new energy and economic future for that community. Third, it encourages companies in Colorado to come forward with innovative ways to transform their environmental performance. In that way, the Commission could acknowledge (as it has before) the voluntary nature of the Comanche 1 and Comanche 2 early retirements and the significant concessions made by Public Service in order to develop and advance the Colorado Energy Plan.[12] For these and many other reasons, the Preferred CEPP represents a unique and transformative opportunity that will set Colorado on a course that will benefit Public Service customers, local communities, and the State of Colorado as a whole.

[12] Decision No. C18-0191, at ¶ 50 ("[W]e recognize the particular importance of utility ownership in the voluntary proposal to retire Comanche 1 and 2, which includes other concessions from Public Service such as restricted utility-builds, deferral of utility construction under Rule 4 CCR 723-3-3660(h), a requirement for cost neutrality or savings of the CEP Portfolio, and the presenting of the CEP Portfolio within an ERP proceeding.")

2.2 Alternative Colorado Energy Plan Portfolio

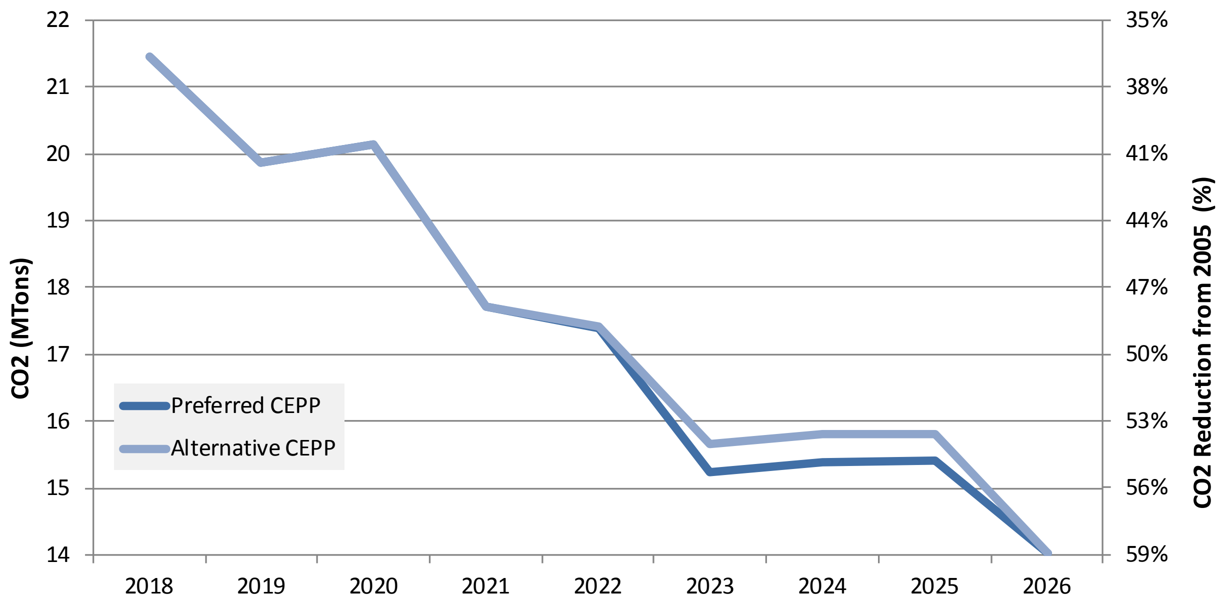
The Alternative CEPP is also an opportunity for this Commission to continue the transition of the Public Service generation fleet, bolster economic development across Colorado and lower customer bills. As discussed above, this portfolio offers a moderately different path for the Commission if it prefers to defer the resource acquisition opportunities created by the retirement of Comanche 2 to the next ERP cycle. This approach notably provides many of the same benefits as the Preferred CEPP and therefore the Company believes this represents a slightly modified plan that is still a cost-effective resource plan, which - as discussed above is - the goal of the ERP Rules. This slightly different CEPP would result in the addition of 1,131 MW of wind, 457 MW of solar, 150 MW of storage (again embedded in solar plus battery storage projects), and 383 MW of existing gas resources in this ERP. In sum, it results in the acquisition of 250 MW less solar and 125 MW less battery storage in this ERP cycle as compared to the Preferred CEPP.

The Company is receptive to this approach if the Commission believes it represents a more measured and appropriate path for customers. The Company has selected a solar with storage project to eliminate in the Alternative CEPP. This modification is appropriate given that solar projects can still benefit from the full ITC into the next ERP cycle. Deferring new construction as opposed to selecting an existing project to defer avoids stranding an existing asset and, by selecting a project located in Southern Colorado to defer, it defers a project from an area that will still see substantial renewable development through the Alternative CEPP. In doing so, the Alternative CEPP also maintains geographic and supplier diversity in its generation mix. The plan still would bring on substantial amounts of solar and storage, with 457 MW of solar coming online during the RAP and an additional 150 MW of battery storage embedded in solar projects. From a firm capacity standpoint, the Alternative CEPP would fill the entirety of the 450 MW resource need and Comanche 1 replacement capacity, while deferring the Comanche 2 replacement capacity to the next ERP.

The Alternative CEPP was assembled based on the full suite of information developed as a result of the Commission decisions addressing both Phase I of this proceeding and the Stipulation that outlines the framework for the CEPP. The Company decided to bring the Alternative CEPP forward given the magnitude of resource acquisitions contemplated in the Preferred CEPP, which would result in the acquisition of nearly 2.5 GW of new generation resources based on nameplate capacity. First and foremost, this portfolio would still result in the voluntary early retirement of Comanche 1 no later than the end of 2022 and Comanche 2 no later than the end of 2025, consistent with the Stipulation. This has not changed and the Company remains committed to the voluntary retirement of both units if either the Preferred CEPP, or this variation on it, is approved by the Commission.

In fact, the Alternative CEPP bears far more similarities to the Preferred CEPP than differences. The voluntary early retirements are the same under this plan and this plan would still achieve customer savings, clean energy benefits, environmental benefits, geographic diversity and system operation benefits, economic development benefits, and host community benefits. For example, the Company's energy mix in 2023 would feature approximately 51% renewable energy in 2023 with the Alternative CEPP and 53% renewable energy by 2026. Further, if this plan were chosen by the Commission in lieu of the Preferred CEPP, emissions reductions would still be achieved through the early retirement of the coal-fired generation, with approximately 60% reduction in CO_2 emissions by 2026 (from 2005 levels), as reflected below.

Figure 6 - Preferred CEPP / Alternative CEPP CO_2 Emissions



Given the geographic diversity of the resource in the portfolio, it would also allow for the development of and investment in communities in different regions of Colorado. In addition, approval of this portfolio would still put the Company in a position to move forward with the EVRAZ contract and amendment to the Property Tax Incentive Agreement in Pueblo. Accordingly, it would still retain EVRAZ in Pueblo and free up funds for Pueblo County to use on economic development and community improvement objectives through the Pueblo County "1A Community Improvement Program." These host community benefits do not change with this portfolio.

The only difference between this approach and the Preferred CEPP lies in the procurement of new and existing generation resources to fill the resource need inclusive of the retirements of Comanche 1 and Comanche 2. While it would result in the acquisition of less solar and battery storage in Southern Colorado, Pueblo County would still see 275 MW of solar and 100 MW of storage developed in the county with corresponding economic benefits. To the extent the Commission prefers this approach, it could achieve additional savings in the future by better aligning the timing for acquiring the last tranche of resources to fill the need created by the early retirement of Comanche 2 with the timing of the actual retirement of Comanche 2 at the end of 2025. By aligning new low-cost solar resources and storage (or any other low-cost resources available at that time) with the Comanche 2 retirement date in the next ERP we anticipate that we could achieve approximately $20 million in additional savings on a present value basis – above and beyond the savings of the Preferred CEPP as compared to the Preferred ERP. This assumes that these resources see no decline in price and is, in that way, a conservative assumption given that we anticipate solar and storage will continue to be available at low, if not lower, prices in the next ERP cycle, and the next ERP will still be timed to take advantage of the full 30% ITC. Moreover, the Alternative CEPP would maximize the acquisition of 100% PTC wind and stay at the 1,131 MW level in the Preferred CEPP. Capitalizing on this low-cost wind now is a feature of both the Preferred CEPP and this portfolio. As the PTC is already beginning to step down to lower amounts, we believe moderating the solar and associated storage is the most appropriate moderation path for this smaller portfolio.

This portfolio offers a slightly different path than the Preferred CEPP but is progressive and transformative in its own right. It simply fills the resource need from Comanche 1 and Comanche 2 across both this ERP and the next ERP as opposed to filling all of the resource need in this ERP. And it does so while still taking advantage of low-cost renewable and battery storage resources available now for customers. In addition, assuming the continued availability of low-cost solar and storage into the next ERP – a reasonable assumption in our estimation – the Alternative CEPP creates an opportunity for additional savings above and beyond that of the Preferred CEPP by deferring resource acquisitions into our next ERP cycle.

2.3 Preferred ERP Portfolio

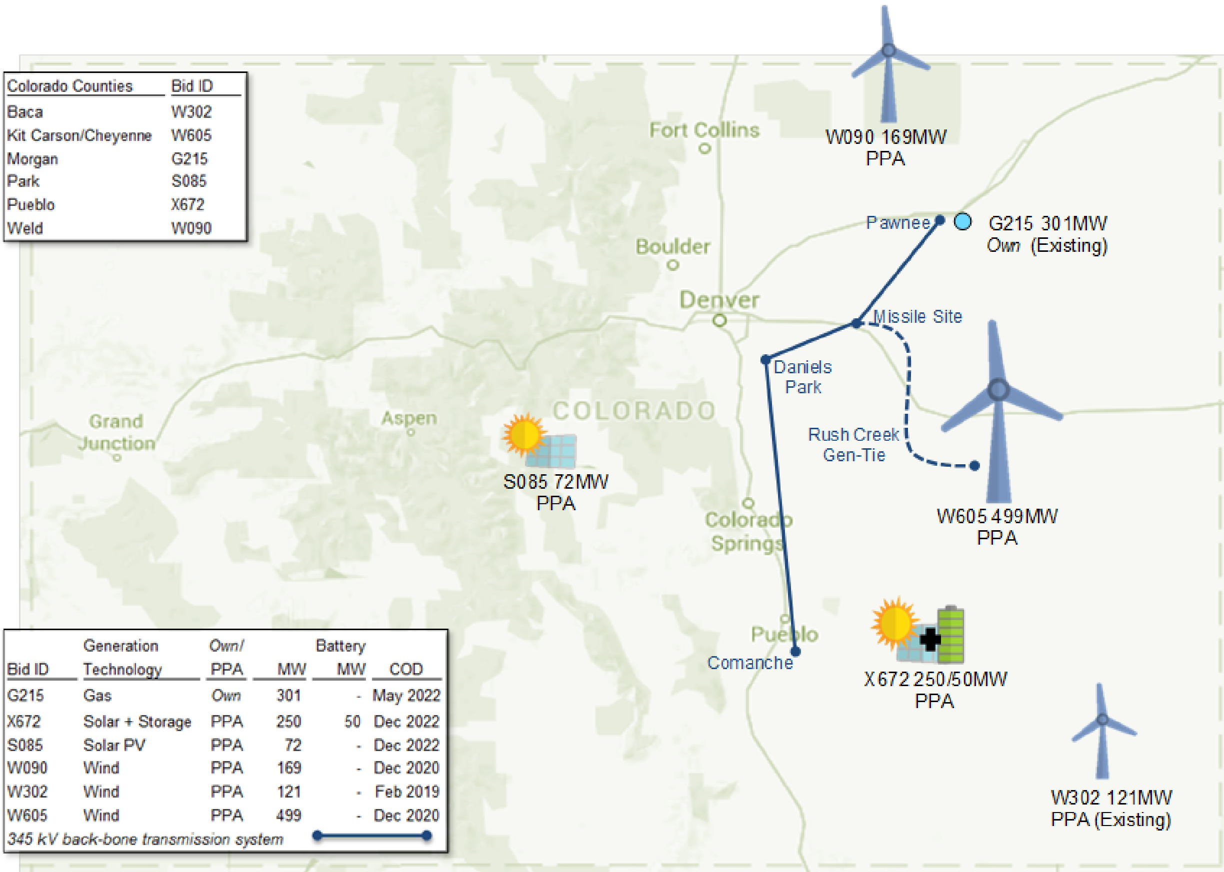
The Company's Preferred ERP is identified consistent with the Commission's Phase I Decision (Decision No. C17-0316, "Phase I Decision"). While the Preferred ERP Portfolio fills the 450 MW resource need, it looks very different than the Preferred CEPP in that Comanche 1 and Comanche 2 remain online until 2033 and 2035, respectively. And although the Preferred ERP Portfolio still results in the addition of renewable resources, some storage, and acquisition of existing gas generators, it does not deliver the same level of emissions reduction benefits, customer savings, and economic development benefits of either the Preferred CEPP or the Alternative CEPP.

That said, the Preferred ERP would represent a step forward for the Public Service generation fleet by providing an incremental shift in the Company's generation fleet toward a cleaner energy future, although at a greater cost to customers. With respect to resource additions, the Preferred ERP would add 789 MW of wind, 322 MW of solar, 50 MW of storage, and 301 MW of gas. As with the Preferred CEPP, the Preferred ERP is not the least-cost portfolio to fill the 450 MW need. The primary difference between the Preferred ERP and the least-cost ERP portfolio is that the Preferred ERP takes less battery storage and instead acquires an existing gas generator. This results in a Preferred ERP that is $14 million more expensive on a present value basis than the least-cost ERP portfolio over the Planning Period. Notwithstanding the relatively small cost differential, the Company identified the Preferred ERP as preferable to the least-cost ERP portfolio for several reasons, including the reliability benefits of acquiring existing gas at a very favorable price for customers. Additionally, the Preferred ERP is a cost-effective resource plan if the Commission determines it is not appropriate to move forward with the early retirement of Comanche 1 and Comanche 2 at this time.

A comparison between the Preferred ERP and the Preferred CEPP makes clear the basis for the Company's decision to advance the Preferred CEPP as the recommended path. The Preferred ERP is $213 million more expensive for customers on a present value basis than the Preferred CEPP. In addition, this portfolio does not achieve the CO_2, SO_2, and NO_X emission reductions of the Preferred CEPP because Comanche 1 and Comanche 2 would remain on the system for an additional decade. Moreover, because Comanche 1 and Comanche 2 remain online until their terminal retirement dates of 2033 and 2035, there are more limited opportunities for new low-cost renewable generation to come onto the system with the Preferred ERP.

Turning to diversity benefits, the Preferred ERP delivers some geographical diversity as reflected in the map below, but it falls short of delivering the balance of ownership that this Commission has rightly identified as an important customer protection. Specifically, the Preferred ERP would result in IPP ownership of 1,111 MW of renewable resources through PPAs (100% of all renewables in the Preferred ERP) and utility ownership of 301 MW of dispatchable and semi-dispatchable resources (86% of all dispatchable and semi-dispatchable resources in the Preferred ERP). This is inconsistent with past Commission statements regarding the importance of balanced ownership, which were reaffirmed in this proceeding in Decision No. C18-0191.

Figure 7 - Preferred ERP Generation Locations



In addition to diminished wind, solar and storage acquisitions generally, the Preferred ERP does not deliver the level of host community benefits of either the Preferred CEPP or the Alternative CEPP. For instance, the Preferred ERP does not enable the EVRAZ contract from an economic perspective. The Company would obtain very low levels of new investment from the Preferred ERP, which in turn makes it difficult to take on the shareholder risk that is necessary to enable the EVRAZ contract. Further, because Comanche 1 and Comanche 2 remain online under the Preferred ERP, the amendment to the Pueblo County Tax Incentive Agreement would also fall away.[13] And while Pueblo County would retain the property tax revenues tied to Comanche 1 and Comanche 2, the local government would not obtain the benefits of the amendment, which is designed to help further Pueblo County's economic development and community improvement objectives through the Pueblo County "1A Community Improvement Program." For all of these reasons, the Pueblo area and Southern Colorado generally stand to benefit less from the Preferred ERP as compared to the Preferred CEPP or Alternative CEPP.

[13] Approval of the Preferred CEPP or Alternative CEPP is a condition precedent to the amendment of the Pueblo County Tax Incentive Agreement. The amendment is premised on Comanche 1 and Comanche 2 retiring early and leaving only Comanche 3 in the Pueblo County tax base at the Comanche site.

If the Commission determines the early retirement of Comanche 1 and Comanche 2 is not appropriate or in the public interest, then the Company believes the Preferred ERP represents a cost-effective resource plan under the circumstances and should be approved by the Commission. When taking a broader view and comparing the Preferred ERP to the Preferred CEPP in a world where Comanche 1 and Comanche 2 retire early, the strength of the Preferred CEPP becomes apparent from all sides – namely, lower costs to customers and improved environmental benefits, diversity benefits, economic development benefits, and benefits to Pueblo and Southern Colorado. The Preferred CEPP saves customers money while delivering significantly more and varied benefits to a diverse set of stakeholders across the state.

3.0 Independent Evaluator Coordination

The Company has worked in close coordination with the Independent Evaluator ("IE") throughout the bid solicitation, bid receipt, and bid evaluation process to ensure the process was fair and in full alignment with conditions set out by the Commission. As described below, the Company consulted with the IE throughout the Phase II process consistent with ERP Rules and Commission decisions.

3.1 Role of the Independent Evaluator

In its Phase I Decision, the Commission determined that an IE was necessary for Phase II of this ERP "for the limited purposes of fulfilling certain roles contemplated under Rule 4 CCR 723-3-3613." Paragraph 176 of the Phase I Decision requires the IE to perform the following tasks:

> The IE shall provide a report to the Commission, pursuant to paragraph 3613(e) of the ERP Rules, containing an analysis of whether Public Service conducted a fair bid solicitation and bid evaluation process, with any deficiencies specified in the report.
>
> The IE shall include in the report how Public Service implemented the Commission's Phase I decision in the bid evaluation process. The IE shall independently review the inputs and outputs from the bid evaluation modeling, including in the report an assessment as to whether the resulting outputs are feasible, and alerting the Commission and parties through the report where there may be deficiencies in the outputs. The IE will not provide opinions regarding whether the public interest may be served through the acquisition of any particular resource. Also, the IE will not make any findings of fact or render legal conclusions, as those duties rest solely with the Commission.
>
> The IE shall also provide a log of contacts with the utility and other parties pursuant to paragraph 3612(d) of the ERP Rules.

The Commission further directed that the IE should be engaged before the release of the All-Source Solicitation Request for Proposals ("RFPs") and directed Public Service to provide the IE with full copies of each bid received and all information used in the bid evaluation process.

At the Phase I evidentiary hearing on February 6, 2017, the Company reported that the Company, Staff, and the Colorado Office of Consumer Counsel ("OCC") had conferred and agreed on an IE, Accion Group, LLC ("Accion"). The Commission subsequently approved Accion as the IE for Phase II of the proceeding and approved the contract between Accion and Public Service for IE services, pursuant to Rule 3612(b) (Decision No. C17-0494, mailed June 15, 2017).

In Paragraph 125 of the Commission's decision granting approval for the Company to present a Colorado Energy Plan Portfolio in Phase II (Decision No. C18-0191, the Commission required the IE to "assess the reasonableness of the modeling of the baseline and CEP Portfolios, and the resulting cost-effectiveness of the proposed early retirement of Comanche 1 and 2, consistent with the Phase I Decision and [Decision No. C18-0191]." The Company discussed this requirement with the IE and this assessment will be addressed in the IE's Report in addition to the requirements set forth in the Commission's Phase I Decision.

As required by Rule 3613(e), the IE will file a report with the Commission no later than 30 days after the filing of this 120-Day Report that includes its assessment and conclusions regarding the Company's bid solicitation and evaluation process, with any deficiencies specifically reported.

3.2 Summary of Independent Evaluator Coordination

<u>Pre-RFP Issuance</u>

Prior to issuing the 2017 All-Source Solicitation RFPs on August 30, 2017, the Company provided the IE with drafts of each of the RFP documents before their release, and a final copy of each, consistent with Volume III of the ERP as approved in the Phase I Decision.

<u>Separation Protocol</u>

Additionally, prior to issuing the 2017 All-Source Solicitation, the Company issued an internal Separation Protocol that went into effect with the issuance of the RFPs. The Separation Protocol divided Company personnel into three teams: (1) the Bid Evaluation Team, (2) the Company Self-Build Team, and (3) Specialized Technical Support Personnel. The protocol was designed to manage communications with bidders and avoid any improper communications with, between, or among members of the Company Self-Build Team and/or the Bid Evaluation Team. All impacted personnel were required to sign an acknowledgement stating they had read the Separation Protocol and agreed to abide by it. The Separation Protocol was reviewed with the IE prior to implementation.

<u>Bidder Communications Protocol</u>

The Company established a dedicated email address through which all communications between bidders and the Company occurred. The Company took this step in order to ensure that all bidders were similarly situated in how they sent and received information related to the RFP. Importantly, the IE had full access and visibility into all emails sent to or from the dedicated email address.

Pre-Bid Conference

On September 28, 2017, the IE participated in the Pre-Bid conference held at the Company's Denver offices and via webinar. The purpose of the Pre-Bid conference was to provide an overview of the solicitation process and allow potential bidders to ask questions and seek additional information about the Phase II process. During the Pre-Bid conference, the IE provided an overview of Accion's experience, its role as the IE in this process, and Accion's objective of keeping the bid evaluation process fair for all bidders. A copy of the IE's presentation and an audio recording of the presentation was posted to the 2017 All-Source Solicitation website located at this link:

https://www.xcelenergy.com/psco2017allsource

Model Lock-Down

The IE utilized a model "lock down" process to ensure the models used to evaluate bids and select portfolios were fair, unbiased and consistent with the approved Phase I assumptions. Prior to bid receipt, the Resource Planning Analytics group provided to the IE a "locked-down model," consisting of all of the various inputs to Strategist, a number of mock bids of varying resource types, and all of the outputs associated with running the Strategist model with those mock bids. The IE consulted on the design of these mock bids before they were run in Strategist and reviewed the model outputs with the Company for reasonableness.

The purpose of this process is to demonstrate the portfolio analysis tools remained unchanged throughout the bid evaluation process - the same mock bids are re-run in Strategist at the end of the process and the model outputs are compared to ensure no changes were made.

However, during the bid evaluation process, the model sometimes needed to be "re-locked" when changes or updates to the model needed to be made either to correct errors or to implement changed modeling processes. This un-locking and re-locking of the model is a normal part of the process[14] and each change was monitored by the IE. Moreover, prior to any adjustments, the change and the rationale for the change were discussed with the IE and the IE made the final determination on whether the change was valid and necessary. After the agreed upon change was made, the IE was provided a new version of the locked-down model and mock bid outputs incorporating the change.

[14] As an example, the original locked down model is done prior to bid receipt. Per the Phase I order, the costs of the "replacement CT" used to backfill bids in the replacement method are reset to match the lowest cost Company self-build CT proposal. To accomplish this in the model, a routine "re-lock" is necessary.

Bid Receipt

On November 29, 2017, the IE was present at the Company's Denver offices to oversee the Company taking possession of all bid packages received by the November 28, 2017 bid receipt deadline. The IE personally opened all bids from the Company self-build team. The IE remained on-site during the entire bid opening process, observing firsthand and working closely with the Bid Evaluation Team during the opening and logging of all bids received. The IE was provided with a hard copy and an electronic copy of all bids received.

Information Access and Procedures

The Company maintained a SharePoint site for the purposes of bid evaluation and disseminating information internally with Subject Matter Experts. The IE was granted full access to all materials pertaining to the bids and the Company's evaluation of those bids, including unrestricted access to the Company's internal 2017 All-Source SharePoint site and all supplemental data the Company requested from bidders during the bid review process.

Bid Affirmation and Refresh Process

On January 12, 2018, Public Service made a filing with the Commission that addressed the Company's need to implement a bid affirmation and refresh process that would require all bidders to either affirm or refresh bid prices based on the passage and signing into law of new federal tax legislation, the Tax Cuts and Jobs Act ("TCJA"), and a final decision from President Trump in the Suniva/SolarWorld trade case regarding solar equipment tariffs. By Decision No. C18-0051-I (mailed January 19, 2018), the Commission granted the Company's request for a partial waiver of Rule 3613(a) to accommodate the bid affirmation and refresh process. The bid affirmation and refresh process was closely coordinated with the IE prior to and following its implementation. Further details of the bid affirmation and refresh process are found in Section 6.0.

Bid Advancement to Computer-Based Modeling

Prior to advancing bids to computer-based modeling, the Company discussed with the IE the proposed criteria for bid advancement and how the Company intended to conduct the 45-day notifications pursuant to Rule 3613(a). The Company reviewed with the IE each bid it proposed to move forward to computer modeling, and received concurrence from the IE regarding the bid advancement determination and the bidder notification process. Similarly, the Company notified the IE of each bid that was not advancing to the computer-based modeling stage of the Phase II process.

Request to Renewable BOT Bidders to Identify Financing Related Costs

On April 6, 2018, following coordination and discussion with the IE, Public Service requested that developers who had proposed competitive wind and solar build-own transfer ("BOT") proposals provide construction payment-related information (i.e., engineering, procurement, and construction costs and other project payments) for their proposals based on the assumption that Public Service would provide financing for construction. This request was intended to explore whether additional customer cost savings could be realized as a result of Public Service financing the construction of renewable BOT projects in lieu of the developer financing these costs. Through this exercise it was determined that, for this set of projects, there were not material cost savings to customers as a result of having Public Service finance the construction. As a result, the pricing information provided in response to this request was not used in the evaluation of BOT bids. In its consultation with the IE, the IE agreed with the Company regarding the process and purpose of this additional information request.

Portfolio Selection and Results Review

The Company worked with the IE in the initial stages of the modeling process to jointly develop a methodology to evaluate bids and select portfolios and together created a modeling process “map” to document the process. This initial map was adhered to throughout the modeling phase. Periodically during the modeling process, including at each discrete step discussed in Section 6.0, the Company shared interim results with the IE and discussed current findings and conclusions. Extensive modeling data was delivered to the IE via electronic media so the IE could review and comment on the same data the Company was evaluating.

Following final completion of the computer modeling and selection of the portfolios presented in this report, the Company met with the IE, first via conference call and later in-person, to discuss the results and explain the rationale and methodology in the selection of the preferred ERP and CEPP portfolios. All modeling data and results were forwarded to the IE for inspection and validation

Ongoing Coordination Meetings

In addition to the key coordination described above, the IE regularly met with the Company’s Resource Planning Analytics group to discuss modeling procedures and interim results and, separately, with the Company’s Transmission Access group to discuss the interconnection and delivery requirements and costs of individual bids and bid combinations. These regular updates provided an opportunity for the Company to keep the IE updated throughout the process. As discussed in the modeling process narrative (Section 6.0), the IE provided valuable insight and suggestions that were utilized in the process to identify the top bids and sequentially re-focus the analysis to smaller subsets of optimal portfolios.

4.0 Analysis of Preferred Portfolios

Section 4.0 provides an overview of the suite of bid portfolios developed to comply with the Commission directives in the Phase I Decision and Decision No. C18-0191. This section has four discrete parts. First, it provides an overview of the eleven bid portfolios developed to meet differing levels of capacity need and satisfy Commission directives issued over the course of this ERP proceeding. Second, it focuses in on the Preferred ERP and Preferred CEPP, building on the discussion in Section 2.0 regarding these two portfolios and provides a more detailed comparison of key aspects of the Preferred ERP and Preferred CEPP, including a comparative analysis of generation mix, costs, ownership, and the level of firm capacity. Third, it addresses tax impacts associated with portfolio development, including the TCJA and DTA impacts for utility-owned wind projects. Fourth, and finally, Section 4.0 discusses the generation interconnection queue, explains the process for estimating potential transmission upgrades and describes how selected projects may advance through the interconnection queue.

4.1 General Overview of Portfolios

The Strategist model was used to construct a variety of bid portfolios that meet two distinct levels of RAP capacity need ordered for the ERP proceeding (0 MW and 450 MW). In addition, the model was used to develop bid portfolios involving aspects of the CEP that consider the early retirement of Comanche 1 and Comanche 2 and replacing the capacity of either one or two units within this ERP (775 MW and 1,110 MW).[15] The early retirement of the 325 MW Comanche 1 in 2022 increases the RAP capacity need for the CEP to 775 MW.[16] Consistent with Commission directives in this proceeding, eleven individual portfolios, summarized in Table 7 below, are presented for Commission evaluation in this 120-Day Report.

In Section 4.1.1, we begin by summarizing each portfolio and then in Section 4.1.2 discuss the results of applying the annuity method for backfilling bids versus the replacement method. Following that, we provide a comparative analysis of preferred portfolios and a discussion of the required sensitivity analyses that were applied to the portfolios.

[15] A portfolio that replaces the capacity of both Comanche 1 and Comanche 2 would include a total of 1,110 MW of firm capacity within the RAP which is 335 MW more than is needed to fill the RAP resource needs in this ERP.

[16] ERP need 450 MW + 325 MW = 775 MW CEP capacity need.

Table 7 - Bid Portfolio Analysis Summary Results (Replacement Method)

		ERP 0 MW Portfolio	ERP 450 MW Portfolios (Com 1 & 2 Continue Operation)			CEP 1110 MW Portfolios (Early Retire Com 1 & 2)				CEP 775 MW Portfolios (Early Retire Com 1)		
Portfolio #		1	2	3	4	5	6	7	8	9	10	11
Portfolio Name		LCP	LCP	Preferred	All Thermal	LCP	Preferred	Full Replacement	MLEP	LCP	500 Owned	MLEP
Nameplate Capacity (MW)	Notes:											
Solar		0	432	322	0	982	707	707	907	782	457	582
Wind		789	789	789	0	830	1131	1131	930	830	1131	889
Storage		0	175	50	0	275	275	275	225	175	150	200
Gas		0	82	301	583	448	383	530	501	301	383	383
Total Nameplate MW		789	1478	1462	583	2535	2496	2643	2563	2088	2121	2054
Owned EER MW	1	0	0	0	0	0	500	500	761	0	500	599
Owned D/SD MW	2	0	82	301	583	301	383	383	501	301	383	383
Owned EER %	3	0%	0%	0%	0%	0%	27%	27%	41%	0%	31%	41%
Owned D/SD %	4	0%	32%	86%	100%	42%	58%	48%	69%	63%	72%	66%
RAP Firm Capacity (MW)												
Total Firm Capacity	5	79	503	554	534	1143	993	1125	1137	856	780	859
Excess of 2023 Need	6	(375)	49	100	80	363	213	346	358	76	0	80
2023 Reserve Margin %	7	11.0%	17.0%	17.7%	17.4%	21.5%	19.3%	21.2%	21.4%	17.4%	16.3%	17.4%
Planning Period PVRR ($M)												
Base Portfolio	8	$34,709	$34,672	$34,691	$35,399	$34,339	$34,345	$34,363	$34,428	$34,352	$34,433	$34,475
Electric Interconnection	9	$14	$47	$42	$4	$97	$73	$73	$91	$83	$57	$58
Electric Delivery	10	$113	$149	$149	$1	$113	$113	$113	$113	$149	$149	$113
LCI and Voltage Control	11	$12	$12	$12	$6	$17	$44	$44	$23	$17	$44	$23
DTA	12	$0	$0	$0	$0	$0	$82	$82	$169	$0	$82	$103
Operating Reserves	13	$7	$7	$7	$0	$7	$30	$30	$13	$7	$30	$13
Total PVRR		$34,854	$34,887	$34,901	$35,410	$34,573	$34,687	$34,704	$34,836	$34,608	$34,794	$34,785
PVRR Delta vs Preferred ERP	14	($47)	($14)	$0	$510	($328)	($213)	($196)	($65)	($293)	($106)	($116)

Table notes:
(1) Nameplate MW of Eligible Energy Resources (EER) to be utility owned
(2) Nameplate MW of Dispatchable and Semi-dispatchable (D/SD) resources to be utility owned
(3) % of Eligible Energy Resources (EER) to be utility owned
(4) % of Dispatchable and Semi-dispatchable (D/SD) resources to be utility owned
(5) Total firm generation capacity added in RAP that serves to meet the resource need
(6) Amount of firm generation capacity within the RAP in excess of that required to meet 16.3 % reserve margin
(7) Level of reserve margin in summer 2023 that will result by adding the projects contained in the portfolio
(8) Baseline Strategist model with individual bids of portfolio added
(9) Costs to interconnect the portfolio projects to the Public Service electric transmission system
(10) Costs to deliver output of portfolio projects from the point of interconnection to customer load
(11) Costs for LCI equipment and equipment to ensure adequate transmission system voltages
(12) Costs associated with the DTA for deferred Production Tax Credits (see Section 4.3 for details)
(13) Costs associated with operating reserves carried to respond to contingency events
(14) Delta in Total PVRR compared to Portfolio 3 (Preferred ERP)

4.1.1 Brief Discussion of Bid Portfolios

The Commission directed the Company to present portfolios beyond the Preferred ERP and Preferred CEPP in this 120-Day Report. For ease of reference, we have included below a summary description of each such portfolio. Additional information as to the specific bids/projects contained within each of these portfolios and the characteristics of those projects can be found in Appendix B.

- Portfolio 1 (ERP 0 MW LCP): This portfolio is comprised of three wind facilities totaling 798 MW. The portfolio has a reserve margin of 11.0%, which is 5.3% lower than the 16.3% reserve margin approved by the Commission. As a result, it represents a Public Service system with a lower level of system reliability when compared against the other ten portfolios in Table 7. Given this difference in system reliability, we concluded that a comparison between the 0 MW LCP portfolio and other portfolios does not provide meaningful results and is therefore not included within the discussion of portfolio comparisons and sensitivity analyses. Moreover, this is not a portfolio the Company can recommend given the potential reliability issues associated with this reduced level of reserve margin.

- Portfolio 2 (ERP 450 MW LCP): This portfolio has the lowest cost PVRR of all 450 MW portfolios.

- Portfolio 3 (Preferred ERP): This portfolio is the Company's Preferred ERP—a detailed discussion of which can be found in Section 2.0 as well as in this section at 4.2.

- Portfolio 4 (All Thermal): This portfolio meets the 450 MW need solely with gas-fired projects. Presentation of this portfolio is intended to provide the Commission a PVRR benchmark for comparative purposes in analyzing the savings of the Preferred ERP against a future that fills the 450 MW ERP need entirely with gas-fired bids.

- Portfolio 5 (CEP LCP): The Commission required presentation of this portfolio by Paragraph 48 of Decision No. C18-0191, where it directed Public Service "to include in the 120-Day Report a least-cost portfolio to meet the 775 MW need and a least-cost portfolio to meet the 1,110 MW need." Consistent with Commission directives, this portfolio includes bids "based solely on the net present value of revenue requirements (PVRR) of the bids" and does "not have ownerships targets." The Commission also held in Paragraph 44 of Decision No. C18-0191 "that the presentation of a least-cost portfolio in Phase II is essential for our analysis of the cost-effectiveness of the CEP Portfolio, and is necessary to determine whether the early retirement of Comanche 1 and 2 is in the public interest." Portfolio 5 is provided for this purpose, i.e., to allow for the evaluation of whether the Preferred CEPP is cost-effective and whether the voluntary early retirement of Comanche 1 and Comanche 2 is in the public interest.

- Portfolio 6 (Preferred CEPP): This portfolio is the Company's Preferred CEPP. It is discussed in Section 2.0 of this 120-Day Report and in more detail later in this section at 4.2.

- Portfolio 7 (CEP Full Replacement): The full replacement portfolio is provided pursuant to Paragraph 47 of Decision No. C18-0191, which required Public Service "to include in the 120-Day Report both a 775 MW need CEP Portfolio (only the Comanche 1 capacity is replaced in this ERP) and an 1,110 MW need CEP Portfolio (capacity for Comanche 1 and 2 replaced in this ERP)." This portfolio deals with the latter scenario. It assumes both Comanche 1 and Comanche 2 are retired early and contains the same projects as the Preferred CEPP; however, it adds one additional gas project, the existing 147 MW [redacted] (Bid ID C172). With the addition of this project, the full replacement portfolio fills the entire 335 MW of Comanche 2. Portfolio 7 results in $196 million in savings compared to the Preferred ERP.

- Portfolio 8 (CEP MLEP):[17] Presentation of this portfolio was required by Paragraph 49 of Decision No. C18-0191, where the Commission found "that the presentation of an MLEP, with reduced ownership percentages, will be useful to our analysis of the overall cost effectiveness of the CEP Portfolio" and therefore directed the Company "to include in the 120-Day Report an MLEP for the 775 MW level of need and an MLEP portfolio for the 1,110 MW level of need." Portfolio 8 represents the least cost combination of ownership projects that fall within the 40% to 60% band of ownership for eligible energy resources and the 60% to 75% band of ownership for dispatchable and semi-dispatchable resources. The MLEP provides higher levels of ownership than the Preferred CEPP given the Company's decision to bring forward a CEPP with ownership levels below the targets for eligible energy resources and dispatchable and semi-dispatchable resources established in the Stipulation. The Stipulation contemplated that a MLEP would need to be $50 million less expensive on a present value basis than the preferred plan. This MLEP does not satisfy this cost metric given that it is $149 million more expensive than the Preferred CEPP on a present value basis. However, it is important to note that the MLEP provides $65 million of savings relative to the Preferred ERP thus meeting the fundamental cost test of the Stipulation. This portfolio also has a considerably higher level of DTA costs. As discussed further below, this portfolio would have been strongly considered to be the Company's preferred plan, however, the decision to mitigate DTA impacts by taking the lower levels of wind ownership ultimately led the Company to the Preferred CEPP. Under Portfolio 8, the Company owns 761 MW of wind resources, representing 41% of the total eligible energy resources.

- Portfolio 9 (CEP 775 LCP): As with Portfolio 5, the Commission required presentation of this portfolio by Paragraph 48 of Decision No. C18-0191 because "the presentation of a least-cost portfolio in Phase II is essential for our analysis of the cost-effectiveness of the CEP Portfolio, and is necessary to determine whether the early retirement of Comanche 1 and 2 is in the public interest." Accordingly, the Company has developed this portfolio to support the Commission's analysis of the cost-effectiveness of the Preferred CEPP. The portfolio assumes the early retirement of Comanche 1 at the end of 2022 and continued operation of Comanche 2 until its terminal retirement date in 2035. The portfolio was developed based solely on the net present value of revenue requirements of the bids absent any ownership targets and fills a resource need of 775 MW.

- Portfolio 10 (CEP 775 500 Owned): As with Portfolio 7, this portfolio is provided pursuant to Paragraph 47 of Decision No. C18-0191, which required Public Service "to include in the 120-Day Report both a 775 MW need CEP Portfolio

[17] Materially Less Expensive Portfolio ("MLEP").

(only the Comanche 1 capacity is replaced in this ERP) and an 1,110 MW need CEP Portfolio (capacity for Comanche 1 and 2 replaced in this ERP)." The portfolio assumes the early retirement of Comanche 1 at the end of 2022 and continued operation of Comanche 2 until its terminal retirement date in 2035. This portfolio provides information as to the costs associated Company ownership of the same 500 MW wind project that is included in the Preferred CEPP.

- Portfolio 11 (CEP 775 MLEP): As with Portfolio 8, presentation of this portfolio was required by Paragraph 49 of Decision No. C18-0191, where the Commission found "that the presentation of an MLEP, with reduced ownership percentages, will be useful to our analysis of the overall cost effectiveness of the CEP Portfolio" and therefore directed the Company "to include in the 120-Day Report an MLEP for the 775 MW level of need and an MLEP portfolio for the 1,110 MW level of need." Similar to Portfolio 8, this MLEP provides higher levels of ownership than the Preferred CEPP given the Company's decision to bring forward a CEPP with ownership levels below the targets for eligible energy resources and dispatchable and semi-dispatchable resources established in the Stipulation. Moreover, the Stipulation contemplated that a MLEP would need to be $50 million less expensive on a present value basis than the preferred plan. This portfolio does not satisfy this cost metric, given that it is $97 million more expensive than the Preferred CEPP on a present value basis. Nevertheless, in compliance with the Commission decision, the Company presents this MLEP.

The Company has provided the best value employment metrics for each resource included in one of the eleven portfolios described in this section. This is provided consistent with Rule 3613(d), which provides in part that "[t]he utility's plan shall also provide the Commission with the best value employment metrics information provided by bidders under rule 3616 and by the utility pursuant to rule 3611."[18] This information is provided in Appendix C.

The Company has also provided projections of the RESA deferred account balance for three scenarios, including the Preferred ERP portfolio, Preferred CEPP, and CEP 775 500 Owned portfolio. The forecasted RESA deferred account balances are included as Appendix D.

4.1.2 Application of the Annuity Method to Bid Portfolios

The terms annuity method and replacement method represent different approaches for backfilling bids with lives that expire within the 2016-2054 Planning Period. In Paragraph 98 of Decision No. 18-0191, the Commission required the Company to

[18] Rule 3613(d) is not clear whether the best value employment metrics need to be provided for just the generation resources included in the preferred plan or all plans shown in the 120-Day Report. Public Service interprets Rule 3613(d) as requiring the Company to provide the best value employment metrics for generation resources included in all plans shown in the 120-Day Report, not just the "preferred plan," i.e., the Preferred CEPP.

present in the 120-Day Report portfolios developed using both backfilling methods. In compliance with that directive, the annuity method was applied in the development of bid portfolios that meet two distinct levels of RAP capacity need ordered for the ERP proceeding (0 MW and 450 MW). In addition, the model was used to develop bid portfolios involving aspects of the CEP that consider the early retirement of Comanche 1 and Comanche 2 and replacing the capacity of either one or two units within this ERP (775 MW and 1,110 MW). The resulting portfolios developed from that analysis are summarized in Table 8. The portfolios shown in Table 8 were selected using the same selection criteria used to develop the replacement method portfolios shown in Table 7 except that the portfolios were optimized using the annuity method. In some cases, applying the same selection criteria to the two sets of optimized portfolios resulted in the same portfolio of bids; in other cases, it did not.

Table 8 - Bid Portfolio Analysis Summary Results (Annuity Method)

		ERP 0 MW Portfolio	ERP 450 MW Portfolios (Com 1 & 2 Continue Operation)			CEP 1110 MW Portfolios (Early Retire Com 1 & 2)				CEP 775 MW Portfolios (Early Retire Com 1)		
Portfolio #		1	A2	3	4	A5	6	7	A8	A9	10	A11
Portfolio Name		LCP	LCP	Preferred	All Thermal	LCP	Preferred	Full Replacement	MLEP	LCP	500 Owned	MLEP
Nameplate Capacity (MW)	Notes:											
Solar		0	457	322	0	707	707	707	807	382	457	510
Wind		789	789	789	0	1131	1131	1131	1131	1131	1131	930
Storage		0	150	50	0	275	275	275	150	150	150	250
Gas		0	147	301	583	530	383	530	583	530	383	383
Total Nameplate MW		789	1543	1462	583	2643	2496	2643	2672	2193	2121	2073
Owned EER MW	1	0	0	0	0	0	500	500	800	0	500	599
Owned D/SD MW	2	0	0	301	583	383	383	383	583	383	383	383
Owned EER %	3	0%	0%	0%	0%	0%	27%	27%	41%	0%	31%	42%
Owned D/SD %	4	0%	0%	86%	100%	48%	58%	48%	80%	56%	72%	61%
RAP Firm Capacity (MW)												
Total Firm Capacity	5	79	547	554	534	1125	993	1125	1132	872	780	866
Excess of 2023 Need	6	(375)	93	100	80	346	213	346	353	93	0	87
2023 Reserve Margin %	7	11.0%	17.6%	17.7%	17.4%	21.2%	19.3%	21.2%	21.3%	17.6%	16.3%	17.5%
Planning Period PVRR ($M)												
Base Portfolio	8	$34,522	$34,394	$34,439	$35,366	$33,872	$33,934	$33,952	$33,966	$34,001	$34,056	$34,161
Electric Interconnection	9	$14	$57	$42	$4	$73	$73	$73	$97	$45	$57	$46
Electric Delivery	10	$113	$149	$149	$1	$113	$113	$113	$149	$113	$149	$113
LCI and Voltage Control	11	$12	$12	$12	$6	$44	$44	$44	$44	$44	$44	$23
DTA	12	$0	$0	$0	$0	$0	$82	$82	$203	$0	$82	$103
Operating Reserves	13	$7	$7	$7	$0	$30	$30	$30	$30	$30	$30	$13
Total PVRR		$34,667	$34,618	$34,649	$35,377	$34,133	$34,276	$34,294	$34,490	$34,232	$34,418	$34,458
PVRR Delta vs Preferred ERP	14	$17	($31)	$0	$727	($517)	($374)	($355)	($159)	($417)	($231)	($192)

Portfolios 1, 3, 4, 6, 7, and 10 in Table 8 are identical to those presented in Table 7 but with their Total PVRR calculated using the annuity method.[19] Portfolios A2, A5, A8, A9, and A11 contain variations of bid/projects different than those in Portfolios 2, 5, 8, and 9 of Table 8, as described above, and have therefore have been designated with the letter "A".

As discussed, Public Service has based its primary determination that the Preferred CEPP is cost-effective for customers through a comparison of portfolios that were

[19] Under the annuity method the lives of bids were extended to the end of the planning period at a price that equaled the annuity of the bidder proposed price (i.e., the levelized price) without any effects of inflation. For example, a 20 year PPA bid with a levelized cost of energy of $30/MWh and a 2020 in-service date, was extended under the annuity method at $30/MWh for each year from 2041-2054.

developed using the replacement method. Through that comparison, the Preferred CEPP shows $213 million in customer savings versus the Preferred ERP. Performing the same comparison using the portfolios developed with the annuity method shows the Preferred CEPP would provide $374 million in customer savings versus the Preferred ERP, which is $161 million higher than the level of savings derived using the replacement method.

In Decision No. C18-0191, the Commission noted “it is appropriate to give little weight to the annuity method applied to the CEP Portfolio for purposes of determining the cost-effectiveness of the early retirements of Comanche 1 and 2.” For that reason, the Company’s comparative analysis focuses on the replacement method for backfilling bids. Nevertheless, application of the annuity method as reflected above further reinforces the economic value the Preferred CEPP brings to customers as compared to the Preferred ERP.

Additional information regarding the development of bid portfolios analysis using both the annuity method and replacement methods for backfilling bids is included in Section 6 of this report.

4.2 The Preferred ERP and Preferred CEPP

This section compares the Preferred ERP and Preferred CEPP, the two foundational portfolios in this 120-Day Report, and builds on the discussion of these portfolios found in Section 2.0. This section first discusses how the Preferred ERP was developed and how it is different from the ERP LCP (Portfolio 2). Second, it goes into a more detailed comparison of the Preferred ERP and Preferred CEPP which, in turn, supports the Company’s recommendation that the Preferred CEPP is a cost-effective resource plan.

4.2.1 Development of the Preferred ERP

Consistent with Rule 3601, the Company selected ERP Portfolio 3 to represent its preferred portfolio for meeting a 450 MW level of resource need. The Company started our selection process leading to the Preferred ERP by evaluating the results of modeling the least-cost ERP portfolio, which is reflected as Portfolio 2 in the table above. The Preferred ERP was determined as a result of the same extensive analysis that led to the development of all eleven portfolios discussed in detail in this section. The Company developed optimized portfolios using both the replacement method and the annuity method, as described above. This exercise resulted in many of the same bids being selected, illustrating the value of the bids under either approach. The analysis focused on the replacement method given Commission directives but all of this information was considered in evaluating the different portfolios and ultimately landing on Portfolio 3 as the Preferred ERP.

Another key part of this analysis, discussed in more detail below, was running the different portfolios through a suite of eleven sensitivities required by the Commission through both the Phase I Decision and Decision No. C18-0191. The results of these sensitivities are described below in Section 4.2.3 and all of the data associated with the analyses is provided in Appendix E. The sensitivity runs, as well as the annuity method optimizations, provided valuable stress-testing of the various portfolios using different modeling assumptions and under different futures. After evaluating this information, the Company ultimately determined that Portfolio 3 was the Preferred ERP. While Portfolio 3 carries a $14 million higher cost than the least-cost ERP portfolio, the Company believes Portfolio 3 contains attributes that make it a more balanced and more cost-effective ERP portfolio. These attributes include:

- Continued utilization of the existing 301 MW [redacted] gas-fired facility. This facility provides fully dispatchable and flexible generation to the system at a very low cost.

- A balance of dispatchable/flexible gas and solar generation at 301 MW and 322 MW, respectively.

- 250 MW of solar with 50 MW of battery storage technology, which will enable the Company to advance understanding of this technology.

Portfolio 3 consists of the resources shown in Table 8 being added to fulfill the 450 MW need.

The Preferred ERP is used throughout this report as the benchmark against which the cost-effectiveness of the Preferred CEPP is measured. While the term “preferred” is used to describe Portfolio 3, the Company does so to comply with Commission directives to identify a preferred portfolio to meet the 450 MW RAP need. To be clear, the Company is not recommending Commission approval of the Preferred ERP; rather, Public Service recommends the Commission approve the Preferred CEPP.

4.2.2 Comparison of the Preferred CEPP and Preferred ERP

This section builds on the discussion of the Preferred CEPP in Section 2.0 and the discussion of the Preferred ERP in Section 2.0, as well as above. It provides additional comparative metrics between the Preferred CEPP and Preferred ERP.

Specific Projects of the Preferred CEPP and Preferred ERP

The Preferred CEPP is comprised of the eleven separate generating projects identified in Table 9.

Table 9 - Preferred CEPP Projects

Bid ID	Project Name	Technology	MW	Ownership	In-Service
X645	[redacted]	Solar w/ Storage	250/125	IPP	2023
X647	[redacted]	Solar w/ Storage	200/100	IPP	2023
X427	[redacted]	Solar w/ Storage	110/50	IPP	2023
S430	[redacted]	Solar	75	IPP	2023
S085	[redacted]	Solar	72	IPP	2023
W192	[redacted]	Wind	500	Own	2021
W602	[redacted]	Wind	300	IPP	2021
W090	[redacted]	Wind	169	IPP	2021
W301	[redacted]	Wind (repower)	162	IPP	2019
G215	[redacted]	Gas (existing)	301	Own	2022
G065	[redacted]	Gas (existing)	82	Own	2022

Note: In-Service refers to the first summer the unit is available.

The Preferred CEPP strikes a balance of IPP and Company ownership of generation resources, though as discussed in Section 2.0 it does not result in the Company meeting the ownership targets established in the Stipulation of 50% for eligible energy resources and 75% for dispatchable and semi-dispatchable resources. The Preferred CEPP also contains a diverse mix of generation technologies including wind, solar, storage, and gas that in aggregate serve to replace 100% of the energy and 82% of the capacity provided from Comanche 1 and Comanche 2. As discussed below, the Preferred CEPP more than satisfies the 775 MW RAP firm capacity need resulting from the retirement of Comanche 1 in 2022.

The Preferred ERP is comprised of the six separate generating projects identified in Table 10.

Table 10 - Preferred ERP Projects

Bid ID	Project Name	Technology	MW	Ownership	In-Service
X672	[redacted]	Solar w/ Storage	250/50	IPP	2023
S085	[redacted]	Solar	72	IPP	2023
W605	[redacted]	Wind	499	IPP	2021
W090	[redacted]	Wind	169	IPP	2021
W302	[redacted]	Wind (repower)	121	IPP	2019
G215	[redacted]	Gas (existing)	301	Own	2022

Note: In-Service refers to the first summer the unit is available.

Generally speaking, all six of these projects are also contained within the Preferred CEPP. Three projects in the Preferred ERP (X672, W605 and W302) are variants (i.e., different sizes) of the projects included in the Preferred CEPP.

Portfolio Generation Mix Comparison

The Preferred CEPP includes four wind projects totaling 1,131 MW, three solar with battery storage projects totaling 560 MW, and two solar only projects totaling 147 MW. The Preferred CEPP also includes two existing gas-fired projects totaling 383 MW that provide both flexible generation to support overall operations and renewable integration as well as firm generation capacity to serve the peak needs of the system. Table 11 provides a summary comparison of the generation mix between the Preferred CEPP and the Preferred ERP portfolios.

Table 11 - Preferred CEPP and Preferred ERP Portfolio Generation Comparison

Generation Technology	Preferred CEPP (MW)	Preferred ERP (MW)	Delta MW
Wind	1131	789	+342
Solar	707	322	+385
Battery Storage	275	50	+225
Gas	383	301	+82
Comanche 1	0	325	(325)
Comanche 2[20]	0	335	(335)
Total	2496	2122	374

Portfolio Cost Comparison

The bid portfolio analysis captured both the costs and benefits of individual bid projects and the attendant system costs that arise when individual projects are combined into portfolios. The following costs were factored into the evaluation of bid portfolios:

1. *Base Portfolio:* Baseline Phase II model costs inclusive of the costs and benefits resulting from the addition of the individual bids contained in a portfolio.

2. *Electric Interconnection:* Costs associated with interconnecting projects to the Public Service electric transmission system (see Section 5 for details).

3. *Electric Delivery:* Costs associated with delivering the power of each project from the point of interconnection to customer load (see Section 5 for details).

4. *LCI & Voltage Control:* Costs associated with increasing the flexibility of existing Company-owned generation through installation of Load Commutated Inverter (LCI) equipment and costs associated with installation of additional equipment to maintain adequate transmission system voltages (see Section 5 for details).

5. *Deferred Tax Asset:* Costs associated with the DTA for deferred Production Tax Credits (see Section 4.3 for details).

[20] Comanche 2 retires EOY 2025 which is outside the RAP for this ERP.

6. *Operating Reserves*: Costs associated with the level of operating reserves Public Service carries on its system to respond to contingency events (see Section 5 for details).

Table 12 provides a summary comparison of costs between the Preferred CEPP and Preferred ERP.

Table 12 - Preferred CEPP and Preferred ERP Portfolio Cost Comparison (PVRR $ Millions)

Cost Category	Preferred CEPP	Preferred ERP	Delta PVRR $M
Base Portfolio	$34,345	$34,691	($346)
Electric Interconnection	$73	$42	$31
Electric Delivery	$113	$149	($36)
LCI & Voltage Control	$44	$12	$32
Deferred Tax Asset	$82	$0	$82
Operating Reserves	$30	$7	$23
Total PVRR $ Millions	$34,687	$34,901	($213)

After incorporating the additional power supply-related costs discussed above, the Preferred CEPP is still the lower cost portfolio by $213 million on a present value basis. The favorable economics of the Preferred CEPP are influenced by the following factors:

1. *Robust pool of low cost renewable bids:* Bidders' ability to take full advantage of the full federal PTC and ITC combined with falling costs for renewable technologies resulted in a robust pool of wind, solar with battery, and solar bids at unprecedented pricing.

2. *Access to transmission made available by voluntary early coal retirements*: The voluntary early retirement of Comanche 1 and Comanche 2 serve to free up capacity on the existing Public Service transmission system, enabling more low cost renewable projects to be acquired before triggering the need for transmission system upgrades.

3. *Low cost flexible gas and battery bids:* Bidders offered flexible gas-fired and battery projects (paired with solar) at very competitive prices. These technologies bring a dual benefit to the Preferred CEPP in that they provide: (1) flexibility benefits for purposes of integrating the increased level of intermittent renewables in the Preferred CEPP, and (2) firm generation capacity for meeting the added peak resource needs attendant with the Preferred CEPP. The ability to acquire both benefits at favorable pricing is an important element of the economics of the Preferred CEPP.

In sum, the Preferred CEPP takes full advantage of these factors and as a result, provides considerable savings to customers. The Preferred CEPP includes unprecedented low pricing across a range of generation technologies including wind at levelized pricing between $11-18/MWh, solar between $23-$27/MWh, solar with storage between $30-$32/MWh and gas between $1.50 - $2.50/kW-mo.

Portfolio Ownership Comparison

With the Preferred CEPP, the Company is proposing to own three of eleven total generation projects that make up the portfolio: a single wind project and two gas projects. The owned wind project represents 500 MW (27%) of the 1,838 MW total eligible energy resources (EER) in the portfolio. The two gas facilities represent 383 MW (58%) of the total dispatchable and semi-dispatchable (D/SD) facilities in the portfolio.

In contrast, in the Preferred ERP all 1,111 MW (100%) of eligible energy resources are IPP-owned, and 301 MW of the total 351 MW (86%) of dispatchable and semi-dispatchable resources are utility-owned. Accordingly, the Preferred CEPP delivers more diversity of ownership than the Preferred ERP.

Portfolio RAP Firm Capacity Comparison

In Phase I of this proceeding, the Commission approved a 16.3% reserve margin to be used in establishing the minimum amount of firm generation capacity (i.e., resource need) to be acquired within the RAP of this ERP. For the ERP portfolios, the minimum resource need that all portfolios were required to fill was 454 MW.[21] For the CEP portfolios where both Comanche 1 and Comanche 2 were retired early or, where only Comanche 1 was retired early, the minimum resource need that all portfolios were required to fill was 779 MW (454 MW plus 325 MW).

Table 13 - Preferred CEPP and Preferred ERP Firm Capacity Comparison

Firm Capacity	Preferred CEPP	Preferred ERP
Resource Need (MW)	779	454
Resources Acquired within RAP (MW)	993	554
Resources in Excess of Need (MW)	213	100
Resulting Reserve Margin (%)	19.3%	17.7%
Portion of Comanche 2 filled early (MW)	213	NA

The combination of projects contained in the Preferred CEPP result in a 19.3% reserve margin in 2023 (at the end of the RAP), 3% above the minimum reserve margin ordered by the Commission. The practical effect of this outcome is that the Preferred CEPP fills 213 MW of Comanche 2 three years in advance of that unit's retirement.

[21] For simplicity, parties to this proceeding refer to the two levels of resource need as 450 MW for the ERP and 775 MW for the CEP.

As part of its decision in this proceeding, the Commission also directed the Company to present a portfolio that fills all of Comanche 2 within the RAP. In response, the Company has provided CEP Portfolio 7 (Full Replacement). The full replacement portfolio contains the same projects that make up the Preferred CEPP and adds one additional gas project, the existing 147 MW [redacted] (Bid ID C172). With the addition of this project, the full replacement portfolio fills the entire 335 MW of Comanche 2 within the RAP at an added cost of $17 million PVRR.

Section 123 Resources in the Preferred ERP and Preferred CEPP

The Preferred CEPP includes two solar with battery storage projects that claim Section 123 status (Bid IDs X645 and X647) and another solar with battery storage project that did not claim Section 123 status (Bid ID X427). In comparison, the Preferred ERP includes one solar with battery storage project that claims Section 123 status. The Company notes that these projects were selected for inclusion in the Preferred CEPP and Preferred ERP based on the economic value of the bids, and *not* based on the Section 123 sensitivity methodology outlined in the Company's 30-Day Report Update. In other words, these projects were able to compete based upon economics and were included in bid portfolios as a result of their competitiveness. Results of the Section 123 sensitivity methodology are provided in Appendix F.

4.2.3 Sensitivity Analysis

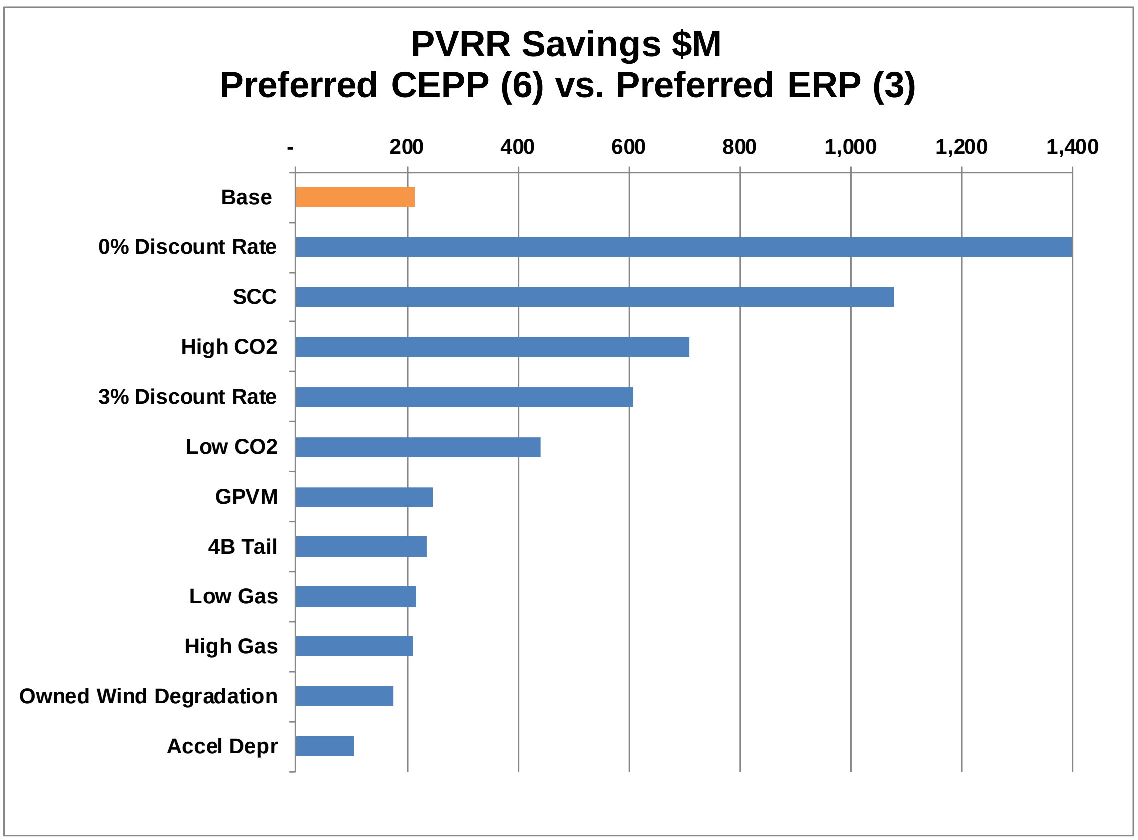
To assess how changes to key modeling assumptions impact the costs and benefits of bid portfolios, a range of sensitivities were evaluated by the Company as part of the bid evaluation process. Sensitivities involve repricing the various bid portfolios developed under base case assumptions by varying a single base assumption such as future gas prices. Sensitivities do not result in changes to the timing or mix of bids in a portfolio. Ultimately, sensitivity analyses are a useful technique for assessing the robustness of a portfolio under different futures. Additional information regarding these sensitivities is provided in Appendix E of this report. For ease of reference, however, the list of sensitivities is provided below (including a citation to the decision where the Commission ordered inclusion of the sensitivity):

- Low Gas (Phase I Decision)
- High Gas (Phase I Decision)
- GPVM Adder (Phase I Decision)
- Low CO_2 (Phase I Decision)
- High CO_2 (Phase I Decision)
- Social Cost of Carbon (Phase I Decision)
- 0% Discount Rate (Phase I Decision)
- 3% Discount Rate (Phase I Decision)
- 4B Tail (Decision No. C18-0191)
- Accelerated Depreciation included (Decision No. C18-0191)
- Owned Wind Degradation (Decision No. C18-0191)

Figure 8 below shows the relative savings of the Preferred CEPP compared to the Preferred ERP portfolio under the various sensitivities. As can be seen, the base savings of $213 million either hold or increase under nearly all sensitivity cases. Under certain sensitivities, the savings increase significantly (e.g., 0% Discount Rate totaling nearly $1.4 billion in savings or Social Cost of Carbon showing over $1.0 billion in savings). Under other sensitivities, the savings remain stable at the $200 million level (e.g., High Gas, Low Gas).

In only the Owned Wind Degradation and Accelerated Depreciation sensitivities do the savings of the Preferred CEPP drop below the $200 million level. The Owned Wind Degradation sensitivity assumes higher than anticipated levels of wind degradation to only Company-owned wind projects. As the Preferred CEPP contains Company-owned wind projects and the Preferred ERP does not, the savings of the CEPP are impacted in that scenario. In the Accelerated Depreciation sensitivity, the value brought to the Preferred CEPP from the RESA reduction and rider recovery of accelerated depreciation is eliminated, leaving the CEPP to bear the full incremental cost of the early retirement. Nevertheless, even under this sensitivity, the Preferred CEPP shows over $100 million in savings versus the Preferred ERP portfolio.

Figure 8 - CEPP Sensitivity Analysis Results



4.3 Tax Issues Related to Portfolio Development

This section addresses the impacts of federal tax reform at a high-level and, more specifically, the impacts on wind Build-Own-Transfer ("BOT") proposals in this ERP.

4.3.1 Federal Tax Reform Impacts & Deferred Tax Asset

The Tax Cuts and Jobs Act ("TCJA") passed by Congress at the end of 2017, after bid receipt on November 28, 2017, resulted in changes that affected numerous aspects of the bid evaluation and portfolio selection process. The primary change from the TCJA was the reduction in the corporate income tax rate from 35% to 21%, but several other components of the legislation also affected the Phase II process. Additionally, the corporate tax rate reduction has cascading effects on other financial components beyond the annual tax obligation.

The TCJA results in a significant net decrease to our cost of service and annual revenue requirements for both the Company's electric and gas departments. Public Service has been and continues to work proactively with the Commission and stakeholders to deliver the benefits of the TCJA to customers in a fair and meaningful way. While the overall net effect of the TCJA is a decrease to our revenue requirements, the TCJA does increase the revenue requirements of certain individual tax advantaged investments such as wind and solar. The Company therefore developed the final ongoing costs associated with BOT projects in accordance with the new TCJA provisions. Moreover, bidders were afforded the opportunity to revise their pricing to account for TCJA via the bid affirmation and refresh process described in Section 6. To make the Company's projections of the costs of continued operation and early retirement of Comanche 1 and Comanche 2 comparable to the refreshed bids, the Company also adjusted the ongoing revenue requirements for Comanche 1 and Comanche 2 as discussed in Section 5.

The Company has previously explained the impact of the TCJA on utility-owned projects, and the DTA in particular, in this proceeding. Public Service's Statement of Position filed February 21, 2018 cited a discovery response from the Stipulation proceeding (Response to discovery request CPUC 18-1) that explained the impacts of the TCJA as it applies to the DTA:

> The TCJA had two impacts on our DTA. The first was the elimination of bonus depreciation, which makes the Company a projected cash taxpayer at PSCo in both 2018 and 2019 and beyond absent further wind or solar additions. The second is that the lower tax rates mean we utilize deductions and credits more slowly. On a net basis, the passage of the TCJA will have the Company paying cash taxes sooner than it would have without tax reform, but the overall amount of cash taxes being paid in the long run will be less. Therefore, the key analysis is to incorporate the level of incremental renewable ownership and its impact on PSCo's tax position in the cost of ERP/CEP portfolios. It is important to understand that some

inefficiency can exist while still delivering very cost-effective projects, as this is the case in our other operating companies.

It is important to note that the consideration of taxes and tax reform is done solely on a standalone basis for Public Service. Accordingly, the TCJA impacted Public Service's tax position in two ways, and as further noted in our Statement of Position, "it is Public Service's tax position - *not the tax position of the parent …* - that determines the existence of a NOL position and the impact of any DTA for retail rate purposes" (emphasis in original).[22]

With regard to the interaction of the TCJA and PTCs from utility-owned wind, the TCJA does not actually change the value of PTCs for utility-owned wind projects. They will continue to be earned at $0.024/kWh, adjusted annually for inflation and year of in-service. However, the PTCs are grossed-up at the applicable tax rate in ratemaking and as credited to customers. As a result, the TCJA's lower corporate tax rate reduces the tax gross-up factor and this lowers the customer credit associated with PTCs on wind assets. Offsetting the lower credit from PTC gross-up is a lower gross up on the equity component of the cost of capital. Because the PTC is a large part of the value of a wind project and it is all experienced in the first 10 years, the reduction in gross up value outweighs the reduction in revenue requirements due to the lower tax rate on our asset investment and increases the levelized energy cost ("LEC") associated with the project. Additionally, the deferred tax liability associated with the project is likely to decrease due to the lower tax rate, which tends to increase the project-specific revenue requirement because a deferred tax liability is an offset to rate base. These effects are then partially offset by a decrease in total income tax expense for the project. Finally, while the Company will continue to return the PTCs to customers over the first ten years of the project by crediting the Electric Commodity Adjustment ("ECA"), the lower tax rate extends the timeframe for recovery of the DTA.

The impacts of the TCJA on utility-owned wind projects were compounded by the Company's agreement in the Stipulation to not bid in any self-build eligible energy resources. If we had direct contractual relationships with turbine suppliers and balance of plant contractors as part of self-build projects, we may have been able to offset the impacts of the TCJA by working with suppliers to take capital costs out of the project, reduce the overall revenue requirements associated with the utility-owned wind projects, and by extension reduce the LEC for the projects as we have done with wind projects at other Xcel Energy operating companies. This was not possible here, as all projects for utility ownership were bid as BOTs where the utility acquires the as-built project from an IPP. In a BOT situation, the IPP has the relationship with its project partners such as turbine supplier and construction contractors. Without a direct relationship, we were not in a position to lower project costs in the same way. The Company relied on IPPs to provide competitive project bids and agreed to "stay-out" for self-build purposes in a significant concession included as part of the Stipulation. Although these TCJA benefits did not all flow through in the BOT bids from IPPs, the BOT projects offered still contain

[22] NOL stands for "net operating loss."

significant economic value for our customers. The more than $200 million of savings of the Preferred CEPP as compared to the Preferred ERP supports this conclusion.

Turning to DTA impacts of the Preferred CEPP, the impact is $82 million on a PVRR basis over the Planning Period. In the Company's Statement of Position filed February 21, 2018 in this proceeding, it stated as follows:

> [T]he Company will not allow DTA impacts associated with the CEPP to inhibit the ability to present a plan that meets the customer neutrality or savings standard of the Stipulation. While we believe that the elimination of bonus depreciation in the TCJA will cause the Company to have sufficient taxable income to own renewables that meet the cost neutrality or savings tests set forth above, to the extent that there are concerns about the magnitude of a potential DTA, the Company is willing to look at some form of mitigation of potential DTA impacts through either a cap on the amount of any DTA for unused PTCs or a limit on the duration of the DTA. Until we select actual portfolios, we will not know whether any DTA impacts are triggered and whether or to what extent mitigation would be appropriate. Public Service will work with stakeholders leading up to the workshops and 120-Day Report regarding the nature and scope of any potential DTA, its magnitude, and potential mitigation approaches.

The Company conducted a technical DTA workshop with parties to this proceeding on May 31, 2018, and will conduct a second follow on workshop to review the specifics of the DTA impacts in this 120-Day Report on June 11, 2018. After reviewing the DTA impacts, the Company is not proposing as part of its 120-Day Report any cap on the amount of any DTA for unused PTCs or a limit on the duration of the DTA. Rather, we used a different and simpler mitigation strategy by reducing the level of utility ownership of wind resources in our Preferred CEPP (and Alternative CEPP, which contains the same level of utility ownership of wind resources). While the Stipulating Parties negotiated a target ownership level for eligible energy resources of 50 percent, the Preferred CEPP includes 500 MW of wind ownership, resulting in 27% ownership of the total amount of eligible energy resources in the Preferred CEPP. This ownership level represents a more transparent and simpler way of mitigating any DTA impacts in this proceeding.

To quantify this impact, the MLEP (Portfolio 8) includes 762 MW of wind ownership for a total of 41% utility-ownership of eligible energy resources. The DTA impact on a PVRR basis for this MLEP is $169 million as compared to $82 million with the Preferred CEPP. As discussed above, the MLEP (Portfolio 8) meets the fundamental cost metric in the Stipulation as it beats the Preferred ERP by $65 million. The Company would have brought this plan forward with a DTA mitigation strategy, such as a cap on the DTA or a limit on the duration of the DTA, which would have increased these savings. This MLEP (Portfolio 8) with a mitigated DTA would have been the Company's preferred plan, but for the Company's decision to instead mitigate the DTA through reduced utility ownership of renewable resources as opposed to a cap or limit on duration of the DTA. Given this decision, the Company's move to the Preferred CEPP with its reduced

ownership levels provides meaningful and substantial mitigation of DTA impacts. We believe this represents a reasonable approach to mitigate the impact of the DTA on customers while still presenting a transformative plan that meets the customer savings standard set forth in the Stipulation. To the extent the Commission prefers mitigation of the DTA through a cap on the amount of the DTA or a limit on its duration, the starting point for that discussion should be the MLEP (Portfolio 8) with its higher level of wind ownership. This is appropriate because the decision to pursue the Preferred CEPP is the result of the Company's decision to mitigate the DTA through reduced ownership.
Public Service appreciates the concerns raised in these proceedings regarding the Company's tax efficiency and DTA balance. While we believe that the approach we have taken - immediately flowing through the benefits of PTCs to customers - is a fair approach, an alternative approach was raised by a participant in the DTA workshop hosted by the Company on May 31, 2018, and we believe this alternative approach has merit and may yield savings to customers. This alternative approach would only pass through the benefits of PTC credits as these tax credits are utilized by Public Service. This would eliminate the revenue requirement associated with the DTA asset. However, it would also increase the revenue requirement of any Company-owned wind project for the first few years of operation. On a net present value basis, this approach could produce approximately $20 million of additional customer savings. Public Service will also use our second DTA workshop as a forum to discuss the alternative discussed above with stakeholders and solicit additional feedback.

While Public Service is receptive to Commission direction on this issue, out of deference to our understanding of the Commission's directive on rate recovery, we are not asking for a final decision in this proceeding.[23] The CPCN proceeding associated with the proposed Company-owned BOT wind project (included in both the Preferred CEPP and Moderated CEPP) is the forum where Public Service will solicit specific treatment of the PTCs.

4.4 Generation Interconnection Queue

The transmission upgrade costs used as modeling inputs to determine the preferred portfolios are Public Service's estimates of the cost of transmission upgrades required to both interconnect and deliver the recommended resource portfolios to Public Service's native load using Interconnection Service combined with Network Integration Transmission Service ("NITS").[24]

Under Public Service's FERC Open Access Transmission Tariff ("OATT"), the Company is to evaluate generation interconnection requests in queue order, but Public Service may also study ERP-related requests outside of the OATT interconnection process. The transmission studies that underlie the ERP/CEPP estimates in this report were conducted outside of the OATT interconnection or transmission service processes. The

[23] Decision No. C18-0191, at ¶ 95 (mailed Mar. 22, 2018) ("We further conclude that it is premature and beyond the scope of this ERP proceeding to address any specific ratemaking provisions.")
[24] Note that Interconnection Service and Transmission Service are evaluated in separate processes, and that Interconnection Service does not confer Transmission Service.

transmission studies estimated transmission enhancements required to interconnect and deliver each portfolio, as described in Section 5. The portfolios were studied in relation to this resource plan and were studied as stand-alone portfolios, meaning that they do not take in to account projects in the Public Service generation interconnection queue. We believe this stand-alone study approach is realistic because of the limited likelihood that generation projects in the interconnection queue that are not selected as part of the ERP process will move forward to construction and operation. This assumption is driven by the fact that virtually all of the requests in the queue propose to serve network load on the Public Service system, and the developers of those projects are unlikely to find a buyer for the output of their facilities absent selection by Public Service through this ERP process, since Public Service serves approximately 94% of network load on the Public Service system. Tri-State, Western Area Power Administration ("WAPA") and Municipal Energy Agency of Nebraska ("MEAN") combined constitute the remaining roughly 6% of network load on the Public Service system.[25]

The fact that in some cases there may be projects that have higher priority queue ranking than bids/projects recommended in this 120-Day Report should not impede development of these recommended bids/projects. These higher queued projects may or may have not bid into the resource solicitation process, and to the extent that they did bid, they were determined to be less economic for Colorado customers. Under FERC rules, a lower queued project may move forward before a higher queued project using the capabilities that were "set aside" in the study process for the higher queued project or projects. If the higher queued project ultimately moves to interconnect, then the lower queued project will be responsible for the costs of the network upgrades required to restore the capability that had previously been "set aside" for the higher queued project. However, as discussed above, that risk is low. The most likely scenario where this could occur would be if the higher queued project is offered in to a subsequent resource solicitation by Public Service. In that case, the cost of additional upgrades on a lower queued project that would result from selection of that higher queued project would be considered in selection of that subsequent portfolio. The timing of costs or even the upgrades identified in the initial study could change, but if the total costs of this second resource solicitation portfolio were beneficial, the costs of the required transmission enhancements would be rolled into Public Service transmission rates borne by all loads on the Public Service network. To the extent that either Tri-State, MEAN or other load serving non-network customers on the Public Service system were to contract for the output of a higher queued project, under FERC policy the network transmission upgrades required to provide Interconnection Service would similarly be rolled in to Public Service's transmission service rates — even if Public Service is not the off-taker of energy and capacity from the project.

In addition, under FERC policy, Public Service has other options to mitigate the risk of additional transmission requirements for the preferred portfolio. As an example, the

[25] 94% includes all Public Service native load, including wholesale load. Public Service's retail load is approximately 84% of all network load on the Public Service transmission system.

preferred portfolio can leverage existing queue positions or transmission capacity that will be released upon retirement of generation.

As the Commission is aware, there are an extensive number of interconnection requests in the PSCo queue. As of May 31, 2018, there are 85 requests in the queue representing 23,247 MW of resources. These figures compare to Public Service's peak network load of 7,044 MW and the Public Service balancing authority's peak load of 8,522 MW.[26] The oversubscription of the Public Service queue creates challenges in terms of identifying accurate upgrade costs and moving projects through the queue in an expeditious manner. Under Public Service's current Open Access Transmission Tariff ("OATT") process, we expect extended delays in the study process as extensive restudies may be required whenever a higher queued project drops out of the queue.

Public Service is concerned that restudies and other delays in the interconnection study process may have a negative impact on developers that have viable projects in the interconnection queue, including but not limited to developers selected through the ERP/CEPP process. Public Service is working through a stakeholder process to identify reforms that will enhance the ability of viable projects to move forward without unreasonable delays. Public Service's recent request for approval of limited revisions to its OATT to forestall the potential for numerous projects to opt for a three-year suspension as a matter of right immediately upon execution of an interconnection agreement was denied by FERC on May 24, 2018, in part because this targeted request was not rolled in to a larger queue reform proposal. Public Service plans to continue its efforts to reform its interconnection process as expeditiously as possible in order that viable projects, including those selected in this ERP process, may move forward.

[26] Arkansas River Power, Black Hills/Colorado Electric Utility, Platte River Power Authority and Tri-State serve load in the PSCo balancing authority area, but use their own transmission to deliver to their load.

5.0 Key Modeling Inputs, Assumptions, and Methodologies

Section 5.0 of the 120-Day Report provides an overview and discussion of the key modeling inputs, assumptions, and methodologies used to evaluate the cost-effectiveness of the ERP and CEP portfolios presented in this report in compliance with the Phase I Decision and Decision No. C18-0191. We also explain additional modeling inputs, sensitivities and methodologies utilized to understand the portfolios, including transmission costs, operating reserves and storage modeling. The balance of the Section proceeds as follows:

- Section 5.1 describes the Company's application of the base modeling assumptions and other requirements set forth in the Commission's Phase I Decision;
- Section 5.2 explains additional modeling inputs applied to the ERP and CEP portfolios;
- Section 5.3 sets forth the modeling inputs that were applied only to the CEP portfolios;
- Section 5.4 addresses other requirements that emerged from Commission Decision No. C18-0191; and
- Section 5.5 discusses the role of cost recovery in this proceeding and any forthcoming proceedings.

5.1 Phase I Decision Modeling Assumptions and Requirements

5.1.1. Base Modeling Assumptions

Pursuant to paragraph 129 of the Phase I Decision, the Company filed its Modeling Assumptions Update on August 30, 2017 prior to commencing the Phase II competitive solicitation (see Appendix G). As discussed throughout this 120-Day Report, the Company applied the approved base modeling assumptions in evaluating the ERP and CEP portfolios in compliance with the Phase I Decision.

5.1.2 Required Sensitivities

Consistent with the requirements of the Phase I Decision, Public Service re-priced the optimized portfolios for the following sensitivities (summarized in Paragraph 132 of the Phase I Decision)[27]:

[27] The Company also re-priced optimized portfolios for additional sensitivities required by Decision No. C18-0191 allowing for presentation of the CEPP. These are discussed in more detail later in this section and in section 4.0.

- High Gas Price
- Low Gas Price
- GPVM Adder
- Low CO_2 Cost Case
- High CO_2 Cost Case
- Social Cost of Carbon ("SCC") Case
- Zero Discount Rate
- 3 Percent Discount Rate

The results of these various sensitivity requirements are discussed in Section 4.0. Additional details are included in Appendix E.

5.1.3 Point Costs for Capital and O&M Estimates in Utility Proposals

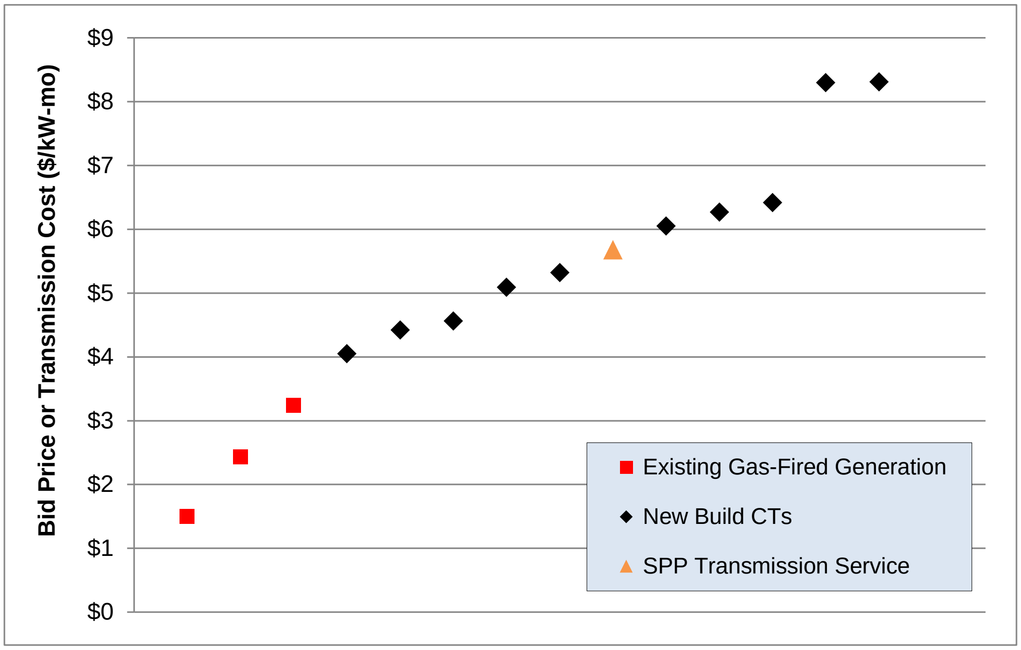
Paragraphs 117 and 118 of the Phase I Decision require the Company to provide (1) a point cost for capital and (2) detailed O&M estimates consistent with the types of information the Company requires for IPP bids. Accordingly, for all utility self-build bids and BOT bids, the Company used a point cost to represent the capital cost to construct the project and developed detailed cost estimates to represent the on-going costs (both O&M and capital) to operate and maintain the projects over their useful lives.

5.1.4 SPS Diversity Exchange

Paragraph 166 of the Phase I Decision directs Public Service to model the Southwestern Public Service ("SPS") Diversity Exchange as a resource bid. The SPS Diversity Exchange allows the Company to claim 101 MW of capacity from the load diversity that exists between Public Service and SPP. This exchange is effectuated through the AC-DC-AC converter and associated transmission lines in southeastern Colorado that serve to connect the WECC and Southwest Power Pool ("SPP") systems.

The primary cost of the SPS Diversity Exchange is the cost to purchase firm transmission service from SPP, currently $5.86/kW-mo. This value is plotted in Figure 9 below and compared to the levelized costs of bids for existing gas-fired generation and new build combustion turbines. As shown in the figure, the current cost of SPP transmission service is not cost-effective when compared to generation bids received in this Solicitation—and the Company expects the cost of the transmission service to be higher in the future. As a result, neither the costs nor the capacity of the SPS Diversity Exchange are included in any portfolio presented in this 120-Day Report.

Figure 9 - Comparison of Current SPP Transmission Service with Gas-Fired Generation Bids



5.2 Other Modeling Inputs That Apply to ERP and CEP Portfolios

5.2.1 Transmission Inputs

Interconnection Facilities & Costs

As part of the Phase II competitive solicitation, bidders were requested to provide initial interconnection cost estimates within each separate bid proposal including the source or basis for the estimate. Using publicly available generator interconnection study information, the Company's Transmission Access group reviewed the reasonableness of the bidder provided estimates. The review focused on two categories of costs: (1) interconnection facilities that will be owned by Public Service but funded by the generator; and (2) network interconnection facilities that will be funded and owned by Public Service. With regard to the first category of costs, to the degree an adjustment to the bid price was warranted as a result of the Transmission Access group's review, an adjustment was made consistent with the publically available cost information as to interconnection location, voltage, and nameplate MW. Regarding the second category of costs involving Company funded interconnection facilities, those costs were assigned on a bid portfolio basis because they do not affect individual bid pricing. Appendix H contains additional information regarding this second category of interconnection costs.

Rush Creek Gen-Tie

The evaluation of bid portfolios included consideration of the need to add voltage support devices that ensure the operation of the Gen-Tie line remained within acceptable limits. Table 14 summarizes the costs that were applied to specific bid portfolios based on the level of Gen-Tie wind contained in the portfolio.[28]

Table 14 - Rush Creek Gen-Tie Voltage Equipment

Added Gen-Tie Wind (MW)	Added Voltage Support (MVARS)	Added Capital Cost ($M)
0-500	0	0
500-600	5	$5
600-800	100	$10
800-1000	250	$25
>1000	400	$40

The added capital costs noted above were converted to annual costs over the planning period using a levelized charge rate of 12%.

<u>Pueblo Area Reliability</u>

The evaluation of bid portfolios included costs associated with mitigating the potential for localized reliability impacts to the Pueblo area transmission system that could arise at the time Comanche 1 and Comanche 2 reach their terminal retirement dates. There are several readily available and relatively low cost equipment options the Company can employ at or near the Comanche Station to remedy this potential issue including a synchronous condenser (at either or both of Comanche 1 and Comanche 2), a Static VAR Compensator ("SVC"), or a Static Compensator ("STATCOM"). To reflect the cost of these options within the ERP portfolios in which Comanche 1 and Comanche 2 operate until 2033 and 2035, respectively, it was assumed that mitigation equipment would be installed in 2034 at a cost of $10 million.[29] To reflect the cost of these options within the CEP portfolios in which Comanche 1 and Comanche 2 are retired early in 2022 and 2025, respectively, it was assumed that mitigation equipment would be installed in 2023 at a cost of $10 million.

<u>Network Upgrade Costs for Delivery</u>

As stated in Appendix C of the RFP documents, given the period of time available to evaluate bids, the Company's evaluation team employed an abbreviated process for estimating the transmission network upgrades necessary to deliver power from the proposed facilities to customer loads. That process involved the Company's Transmission Planning group performing power flow studies to assess the capability of the existing Public Service system to accommodate additional generation injection. The

[28] The MW levels identified in Table 14 are in addition to the 600 MW Rush Creek Wind Project that is currently under construction and utilizes the Rush Creek Gen-Tie to deliver its output to the Missile Site substation.
[29] Any conversion of Comanche 1 or Comanche 2 to a synchronous condenser will utilize a Project Labor Agreement consistent with the Stipulation and as agreed to by Public Service.

studies were performed in increments of 100-200 MW of added injection onto the Company's 345 kV system[30] up to 800 MW total for ERP portfolios (which assumed continued operation of Comanche 1 and Comanche 2) and up to 1450 MW total for CEP portfolios that assumed early retirement of these units. Table 15 summarizes the results of this study work. Upgrade cost estimates were applied to the evaluation of bid portfolios based on the level of added injection contained within each portfolio. Table 16 below shows the network upgrade estimates applied to ERP portfolios.

Table 15 - Network Upgrade Estimates Applied to ERP Portfolios (Comanche 1 and Comanche 2 Continue Operation)

Added Generation Injection (MW)	Incremental Cost of Network Upgrades ($M)	Total Cost of Network Upgrades ($M)
0-200	$1	$1
200-400	$23	$24
400-500	$35	$59
500-700	$42	$100
700-800	$32	$132

Table 16 - Network Upgrade Estimates Applied to CEP Portfolios (Comanche 1 and Comanche 2 Early Retirement)

Added Generation Injection (MW)	Incremental Cost of Network Upgrades ($M)	Total Cost of Network Upgrades ($M)
0-850	$1	$1
850-1050	$23	$24
1050-1150	$35	$59
1150-1350	$42	$100
1350-1450	$32	$132

The added capital costs noted above were converted to annual costs over the planning period using a levelized charge rate of 12%.

During the bid evaluation process, it was determined that network upgrades that would be required to support injection above the 800 MW and 1450 MW levels studied, could present significant challenges with regard to completing all required permitting and construction of the upgrades by 2022 when the new generators would be placed in-service. As a result, the Company is not presenting any ERP or CEP portfolios in this report that exceed those levels of added injection onto the 345 kV transmission system. A detailed discussion of the various transmission studies along with descriptions of the

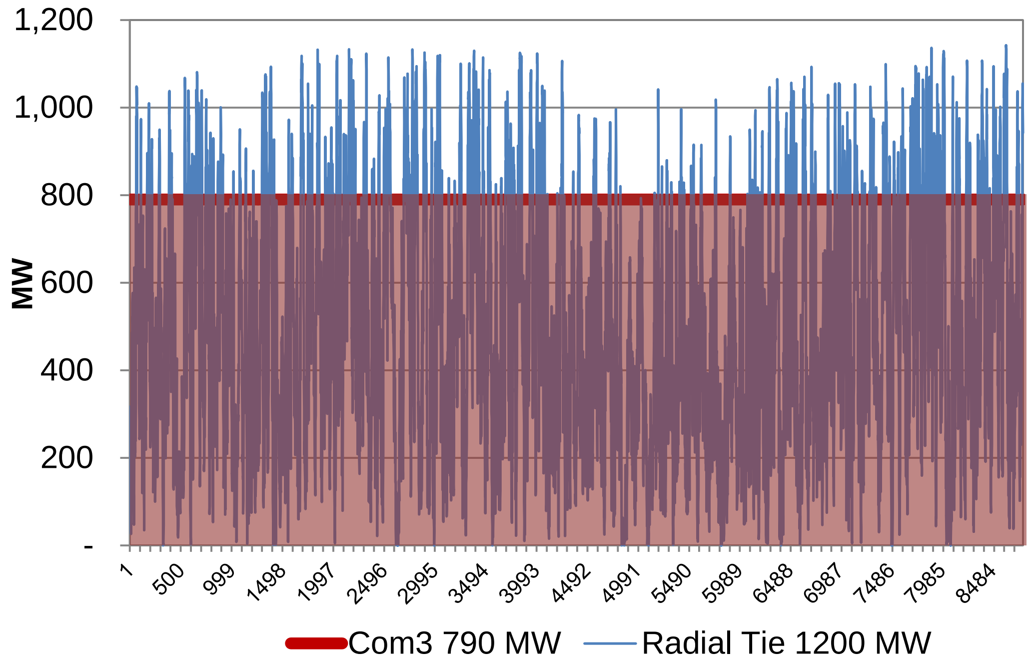
[30] The double-circuit 345 kV transmission network from Brush (Pawnee) to the Denver-metro area, to Pueblo (Comanche).

various network upgrades identified through those studies is included in Appendix I of this 120-Day Report.

5.2.2 Operating Reserve Costs

As part of the Rocky Mountain Reserve Group ("RMRG"), Public Service is required to maintain 426 MW of operating reserves, representing its share of the RMRG's Most Severe Single Contingency ("MSSC").[31] Currently the MSSC for the RMRG is the 790 MW Comanche 3 unit. In August 2017, the Company performed an analysis to assess how its costs of carrying operating reserves (i.e., its RMRG load-ratio share of 53%) might increase if 1,200 MW of total wind were interconnected to the Rush Creek Gen-Tie ("Gen-Tie Wind").[32] Figure 10 illustrates the degree to which output from 1,200 MW of Gen-Tie Wind could be expected to exceed the current 790 MW MSSC (see blue line above 790 MW) and cause the need for additional operating reserves. Using the PLEXOS production simulation model, the Company preliminarily estimated the cost of carrying the increased levels of operating reserves illustrated in Figure 10 to be approximately $150,000 per year. The Company concluded this level of cost was immaterial and therefore need not be reflected in the evaluation of bid portfolios.[33]

Figure 10 - Annual Hourly Generation from 1200 MW of Gen-Tie Wind vs 790 MW Comanche 3 MSSC



[31] MSSC is defined as a generation or transmission element that could result in the greatest loss of resource output used by the reserve sharing group.
[32] The Rush Creek Gen-Tie is an approximately 90-mile radial transmission line that delivers the output of the 600 MW Rush Creek Wind Project to the Missile Site Substation.
[33] This information was provided to bidders at the pre-bid conference and posted to the Company's Solicitation web page.

As the Company progressed through the bid evaluation process in early 2018, it became clear that the most cost-effective wind bids were sited in eastern Colorado and proposed utilizing the Rush Creek Gen-Tie. While the Company anticipated construction of the Rush Creek Gen-Tie would facilitate development of more cost-effective wind from this region of Colorado, the Phase II bid response exceeded the Company's expectations in this area. Ultimately, the lowest cost bid portfolios contained more than the originally studied level of wind on the Rush Creek Gen-Tie. This development required the Company to revisit its August 2017 study.

The final analysis also involved using the Company's PLEXOS model to assess the cost to accommodate increased levels of operating reserves to cover the added MSSC represented by Gen-Tie Wind.[34] The Company performed these calculations on three levels of total Gen-Tie Wind (1,100 MW, 1,400 MW, and 1,600 MW) and conservatively assumed Public Service would be assigned all additional operating reserve costs above the current 790 MW MSSC. Operating reserves costs for the study year 2021 were calculated at each wind level, then escalated at 2% annually over the 25-year period from 2022-2045 to reflect the potential that these added costs will reside with Public Service for the full 25-year life of the relevant wind facilities. It is important to note that portfolios with additional generation on the Rush Creek Gen-Tie were fully burdened for all incremental costs including both capital and operating reserves. Despite this burden, every portfolio added additional generation on the line demonstrating the strong wind resources in this part of the State and the value of the Gen-Tie. Table 17 summarizes the final calculation results.

[34] See Appendix J for more detailed discussion of the final analysis.

Table 17 - Analysis Results of Additional Operating Reserves

Year	1100 MW Gen-Tie Wind ($M)	1400 MW Gen-tie Wind ($M)	1600 MW Gen-Tie Wind ($M)
2021	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]
2034	[redacted]	[redacted]	[redacted]
2035	[redacted]	[redacted]	[redacted]
2036	[redacted]	[redacted]	[redacted]
2037	[redacted]	[redacted]	[redacted]
2038	[redacted]	[redacted]	[redacted]
2039	[redacted]	[redacted]	[redacted]
2040	[redacted]	[redacted]	[redacted]
2041	[redacted]	[redacted]	[redacted]
2042	[redacted]	[redacted]	[redacted]
2043	[redacted]	[redacted]	[redacted]
2044	[redacted]	[redacted]	[redacted]
2045	[redacted]	[redacted]	[redacted]
2016 PV	[redacted]	[redacted]	[redacted]

These results show higher operating reserve costs than the preliminary August 2017 analysis. The main drivers of the increased costs are the evaluation of higher levels of Gen-Tie Wind, and the assumption that Public Service would bear all of the incremental responsibility and costs of increased operating reserves and refinements in the model including the actual projects selected.[35] The assumption that Public Service will bear the full burden of all additional costs for the next 25 years, absent any sharing amongst other RMRG members, is a conservative assumption. Similarly conservative is the Company's assumption that the Rush Creek Gen-Tie will continue to be the system's MSSC for the next 25 years. Nevertheless, Public Service determined it appropriate to apply these operating reserve costs to the evaluation of both ERP and CEP bid

[35] The final calculations also included increased net capacity factors (NCF) and updated hourly generation profiles for Gen-Tie Wind, both of which contributed to the increased levels of operating reserve costs.

portfolios that contained commensurate levels of Gen-Tie Wind. While the economics of these projects (including this operating reserves cost burden) show they are cost-effective, Public Service will look for potential cost mitigation strategies with regard to these operating reserve costs. To the extent these costs can be mitigated, an attendant increase to the $213 million savings associated with the Preferred CEPP would be realized.

5.2.3 Storage Modeling

In its Phase I Decision, the Commission approved the Company's proposed methodology for evaluating storage bids in Phase II. A detailed description of that methodology is included in Appendix K of this report. In summary, the Company storage evaluation and modeling methodology included consideration of the following storage configurations and attributes:

- Standalone storage and storage paired with wind, solar, and gas-fired technologies,
- Storage pricing and model PPA terms and conditions,
- Storage duration and capacity credit,
- IRS requirements related to tax credits afforded storage, and
- Battery degradation and performance warranties.

5.2.4 Inclusion of LCI

Any ERP or CEP portfolio that included over 800 MW of additional wind generation on the Rush Creek Gen-Tie was assigned an additional $3.5 million to reflect the costs of adding a second Load Commutated Inverter ("LCI") to the Company's Blue Spruce dual CT facility . Currently the facility has a single LCI, which requires the two combustion turbines be started in series (i.e., one first, then the other). Installation of a second LCI will allow the two turbines to start simultaneously and provide an additional 130 MW of 30-minute capable flexible generation to the system.

5.3 Modeling Inputs Unique to CEP Portfolios

5.3.1 Comanche 1 and Comanche 2 Early Retirement

In modeling the CEP portfolios, it was necessary to apply a set of additional inputs and assumptions that are unique to the early retirement of the units. The set of assumptions used to model the ERP portfolios represent continued operation of Comanche 1 and Comanche 2 (i.e., business as usual or "BAU"), whereas the set of assumptions used to model the CEP portfolios represent the accelerated retirement of one or both Comanche units. For reference, these assumptions were introduced in the Company's November 28, 2017 supplemental direct testimony filing.

Notably, the application of unique sets of assumptions allows for an apples to apples economic comparison to be made between bid portfolios that assume the continued operation of Comanche 1 and Comanche 2 (i.e., the 450 MW ERP Portfolios) and the early retirement CEP portfolios (i.e., the CEP 1110 MW and CEP 775 MW portfolios). Common to the economic modeling of all CEP portfolios were assumptions pertaining to:

- Creation of a regulatory asset to collect the incremental depreciation and related costs of the early retirement;
- A reduction in the Renewable Energy Standard Adjustment ("RESA") collection to 1% from the current 2%; and
- Development of a rider mechanism to collect the equivalent of the 1% reduction of the RESA for use in extinguishing the regulatory asset.

These costs, including the carrying costs associated with the regulatory asset, were included in the Strategist modeling.

Table 18 provides a summary of the Comanche unit cost and recovery assumptions that were applied in the modeling of both the ERP and CEP bid portfolios presented in this report. The assumptions for current plant balances, forecasted O&M and capital expenditures are the same as those provided in the Company's Supplemental Direct Testimony filed November 28, 2017. Subsequent to that filing, the Tax Cuts and Jobs Act ("TCJA") was passed into law, which required the previously provided revenue requirement projections for Comanche 1 and Comanche 2 to be updated in order to reflect the collective impacts of TCJA. These updated revenue requirements have been included in the portfolio modeling for this 120-Day Report. The detailed modeling inputs supporting the table below are provided in Appendix L.

Table 18 - Summary of Base Comanche Ongoing Cost Assumptions

NPV $million, 2016-2038	Com 1&2 Depreciation Expense (Included in Rev Reqs)	Comanche Capital Rev Reqs	Rider Recovery of Reg Asset	RESA	Comanche OM & Property Taxes	Total	Delta from BAU
ERP 0 and 450MW Portfolios (BAU, Com 1 & 2 continue operation)	$245	$1,251	$0	$672	$900	$2,823	
CEP Portfolios (Early retire Com 1 & 2)	$116	$1,083	$136	$536	$769	$2,524	-$298
CEP 775 MW Portfolios (Early retire Com 1)	$184	$1,169	$71	$601	$833	$2,674	-$149

5.3.2 Comanche 1 and Comanche 2 Depreciation Rates

The passage of time has also impacted the revenue requirement inputs in one additional way. The revenue requirements for Comanche 1 and Comanche 2 early retirement were developed prior to the dismissal of the Company's 2017 Electric Rate Case. In the 2017 Electric Rate Case, the Company sought approval to implement new depreciation rates for Comanche 1 and Comanche 2 consistent with the 2016 Depreciation Settlement reached and approved by the Commission in Proceeding No. 16A-0231E. As such, the new depreciation rates were assumed in the modeling to begin mid-2018. However, after dismissal of the rate case, it is clear that the new depreciation rates for Comanche 1 and Comanche 2 will not be implemented in mid-2018.

To incorporate this changed circumstance, the Company has also developed a new revenue requirement forecast that will be presented in the AD/RR proceeding (Proceeding No. 17A-0797E) with calculations consistent with a revised depreciation schedule (implementing the depreciation rates for Comanche 1 and Comanche 2 from the 2016 Depreciation Settlement in mid-2019) and a rider mechanism that will be offered as an option for recovery of the regulatory asset. This data is shown in Table 19 below. As shown, the revenue requirements for the CEPP early retirement scenario as compared to the BAU scenario are $26 million *less* than the revenue requirements in the base assumptions. This means that the savings of the Preferred CEPP compared to the Preferred ERP would *increase* by $26 million over what is shown in the current modeling. For example, the NPV savings of Portfolio 6 (Preferred CEPP) compared to Portfolio 2 (ERP Preferred) would go from savings of $213 million to savings of $239 million. The comparison to the CEP LCP would remain unchanged as both the Preferred CEPP and the CEP LCP have the same revenue requirements for Comanche 1 and 2—resulting in the same delta between scenarios.

Table 19 - Summary of Base Comanche Ongoing Cost Assumptions, Delayed Rate Case

NPV $million, 2016-2038	Com 1&2 Depreciation Expense (Included in Rev Reqs)	Comanche Capital Rev Reqs	Rider Recovery of Reg Asset	RESA	Comanche OM & Property Taxes	Total	Delta from BAU	Delta from BAU Base	Change
ERP 0 and 450MW Portfolios (BAU, Com 1 & 2 continue operation)	$240	$1,261	$0	$672	$900	$2,832			
CEP Portfolios (Early retire Com 1 & 2)	$105	$1,067	$136	$536	$769	$2,508	-$324	-$298	-$26
CEP 775 MW Portfolios (Early retire Com 1)	$176	$1,157	$71	$601	$833	$2,662	-$170	-$149	-$21

To be clear, the bid portfolios were modeled using the higher revenue requirements for the Comanche 1 and Comanche 2 early retirement scenario (i.e., assuming mid-2018 implementation of the new depreciation rates (approved in Proceeding No. 16A-0231E) for Comanche 1 and Comanche 2). Public Service therefore used a conservative set of assumptions to model the Comanche 1 and Comanche 2 retirement scenario. That said, the Company wanted to make the Commission aware of the additional savings that could be realized as a result of the new revenue requirement forecast (and bill rider option) that will be presented in the AD/RR proceeding as described above.

5.4 Additional Modeling Analyses Required by Decision No. C18-0191

The Commission's Decision No. C18-0191 granted to Company's request to present the CEP portfolio in Phase II, while also requiring additional modeling analyses as discussed below.

5.4.1. Accelerated Depreciation - Inclusion/Exclusion in Modeling

As discussed above, Public Service has filed a separate application in the AD/RR proceeding (Proceeding No. 17A-0797E) for approval to, in applicable part: (1) modify the depreciation schedules for Comanche 1 and Comanche 2 to accelerate the depreciation associated with these units to reflect new retirement dates of 2022 and 2025; (2) create a regulatory asset to collect the incremental depreciation from the early retirement of Comanche 1 and Comanche 2; (3) reduce the RESA rider collection to 1 percent from the current 2 percent; and (4) revise the General Rate Schedule Adjustment (GRSA) to collect an offsetting amount of revenue approximately equivalent to 1 percent reduction of the RESA and extinguish the regulatory asset using these dollars collected through the GRSA. Based on the schedule in Proceeding No. 17A-0797E, the disposition of these requests related to future treatment of the RESA and other cost recovery will not be decided before the Commission's decision on the Preferred CEPP. However, it is expected that the Commission will make a decision in Proceeding No. 17A-0797E at or near the same time as its Phase II decision in this ERP proceeding.

In Decision No. C18-0191, the Commission determined it was "necessary to capture the full range of costs of the CEP portfolios both with, and without, the cost of accelerated depreciation when considering the cost-effectiveness of the CEP portfolio." Specifically, Paragraph 61 of Decision No. C18-0191-I directs the Company, as part of its Comanche 1 and Comanche 2 early retirement cost analysis, to include in the modeling: (1) CEP portfolio costs excluding accelerated depreciation costs, as contemplated in the Stipulation as a result of the RESA offset; and (2) CEP portfolio costs including accelerated depreciation costs, assuming the accelerated depreciation costs are not offset by the RESA reduction.

To comply with this requirement, the Company developed an additional set of revenue requirements that show the impact of recovery of the accelerated depreciation as it occurs (i.e. GAAP methodology), and without the regulatory asset or the associated RESA reduction and GRSA/rider mechanism. Table 20 below shows these adjusted revenue requirements, which were the input assumptions used for the "Accelerated Depreciation" sensitivity case. The detailed Strategist inputs that support Table 20 are included in Appendix L.

Table 20 - Summary of Base Comanche Ongoing Cost Assumptions, Accelerated Depreciation

NPV $million, 2016-2038	Com 1&2 Depreciation Expense (Included in Rev Reqs)	Comanche Capital Rev Reqs	Rider Recovery of Reg Asset	RESA	Comanche OM & Property Taxes	Total	Delta from BAU
ERP 0 and 450MW Portfolios (BAU, Com 1 & 2 continue operation)	$245	$1,251	$0	$672	$900	$2,823	
CEP Portfolios (Early retire Com 1 & 2)	$269	$1,194	$0	$672	$769	$2,635	-$188
CEP 775 MW Portfolios (Early retire Com 1)	$266	$1,223	$0	$672	$833	$2,728	-$95

As discussed in Section 4.0, the "Accelerated Depreciation" sensitivity case reflects that the Preferred CEPP shows savings of $103 million as against the Preferred ERP even without the benefit of the RESA reduction and after accounting for the impact of immediate recovery of accelerated depreciation using the GAAP methodology.

5.4.2. Deferred Tax Asset Modeling

Paragraph 93 of Decision No. C18-0191 requires Public Service to address the creation of Deferred Tax Assets ("DTA") with respect to the resource portfolios presented in this 120-Day Report in accordance with the Company's proposal for determining DTAs and the associated costs as set forth in Attachment B to Public Service's Statement of Position filed on February 21, 2018 in Proceeding No. 16A-0396E.

In accordance with Attachment B, the DTA modeling analysis was performed for Public Service as a standalone entity by employing the following steps:

1. Bid evaluation Due Diligence with the Company's Resource Planning function developed preliminary costs for BOT bids absent any assumed carrying cost impact of a DTA.

2. With these costs, a set of initial portfolios (Pre-DTA portfolios that include both PPA and ownership bids) were developed using the optimization capabilities of Strategist that (a) filled the potential range of MWs associated with early Comanche 1 and Comanche 2 retirement and (b) adhered to the terms of the Stipulation with regard to both the CEP portfolios and any MLEP.

3. These Pre-DTA portfolios (both the CEPP and any MLEP) were ranked by lowest Planning Period present value revenue requirements ("PVRR") consistent with Commission Rules. A subset of the Pre-DTA portfolios that contain a range of ownership proposals were passed forward from Resource Planning to Treasury for analysis of the collective impacts of the Tax Cuts and Jobs Act ("TJCA"), including any DTA carrying costs.

4. Treasury provided back to Resource Planning the results of its analysis on both a portfolio basis and project-specific basis (i.e., allocated to the individual-owned projects).

5. Post-DTA Portfolio PVRRs were calculated within Strategist and include Treasury's TJCA analysis results. These results include a full accounting of any DTA carrying costs.

6. Resource Planning evaluated the potential existence of additional cost-effective portfolios within Strategist by applying the results provided from Treasury in Step 5 to other portfolios.

7. Resulting PVRRs for all portfolios identified through this process were ranked to assess whether the initial portfolio rankings for CEPP and MLEP from Step 3 hold.

8. If the ranking results differed, then Steps 4 through 8 were repeated as needed until the PVRR CEPP and any MLEP (if applicable) rankings were unchanged.

The DTA costs are fully incorporated into the ERP and CEP portfolio analysis and a DTA cost comparison across portfolios is included in Appendix B.

To help parties gain a better understanding of the DTA modeling analysis process and the impacts on the bid portfolios, the Company committed to hosting two technical workshops. The first was held as a webcast on May 31, 2018 in advance of filing this 120-Day Report to discuss the modeling methodology. The webcast was recorded and distributed to parties following the workshop. The slide presentation from the first workshop is included as Appendix M. The second workshop will be held on June 11, 2018 in person and via webcast to discuss the specific results and impacts presented in this 120-Day Report. DTA impacts are discussed in more detail in Section 4.0.

5.4.3. Utility-Owned Wind Benchmarking

Paragraphs 101 and 102 of Decision No. C18-0191 require Public Service work with Staff to develop a wind degradation sensitivity analysis for utility owned wind resources consistent with Attachment GLC-05[36] to Mr. Gene Camp's Answer Testimony filed on January 10, 2018.

On May 15, 2018, the Company met with Staff to discuss a proposed methodology for implementing the wind degradation sensitivity analysis. As a result of that meeting, the Company and Staff agreed to a methodology that accounts for the potential effects of degradation on both the production of owned wind facilities as well as the cost of those facilities. That process is outlined below.

[36] Attachment GLC-05 is the Rush Creek Wind Project performance metric as approved in Proceeding No. 16A-0117E.

Degradation effects on BOT Wind Production: The Company modeled owned wind facilities at their expected/projected production level for the first five years of operation. Starting in year 6, annual expected generation will be degraded by 0.78% each year for all remaining years until the 25-year end of asset life. This approach aligns with the "Reasonability Limit" of the Rush Creek Performance Metric, which is based on a wind farm's projected production.

Degradation effects on BOT Wind Revenue Requirements: The Company modeled the effects of reduced PTCs on both the revenue requirements and DTA associated with owned wind facilities These effects will be determined using the same degraded wind production pattern discussed above (i.e., 0.78% annual degradation in years 6-25).

5.4.4 Alternative Plan "4B" Sensitivity

As required by Paragraph 77 of Decision No. C18-0191, the Company performed sensitivity analyses based on Alternative Plan 4B as presented in ERP Volume 1, Table 1.5-11. This is sometimes referred to as the "4B Tail," and this 4B sensitivity involves re-pricing bid portfolios assuming Post-RAP levels of generic wind and solar of approximately 3,100 MW and 700 MW respectively, consistent with the upper end of levels presented and approved in Phase I referred to as "4B Wind" and "4B Solar." The analysis informs how bid portfolios perform in a future that includes higher levels of renewables versus the levels in the baseline model established in Phase I. Detailed results of the sensitivity are included in Appendix E.

5.5 Other Requirements of Decision No. C18-0191

5.5.1 Annual Cost Impact

Paragraph 79 of Decision No. C18-0191 requires the Company to present annual cost impacts, including any deferred tax assets, for the baseline and CEP portfolios, including the least-cost CEP portfolios. Appendix N includes the detailed annual costs of the presented portfolios and these annual costs reflect the full DTA impact. Appendix N also separately delineates the DTA annual costs over the Planning Period as modeled under the replacement method and the annuity method for each portfolio.

5.5.2 Estimated Emissions

Paragraph 108 of Decision No. C18-0191 requires the Company to present the total estimated portfolio emissions that result from the baseline and CEP portfolios, including SO2, NOX, CO2, mercury, and particulate matter shall be included, in terms of pounds per MWh (lbs/MWh) and short-tons per year, consistent with the requirements of Rule 4 CCR 723-3-3604(g). Appendix O includes the detailed estimated emissions across all eleven portfolios over the Planning Period as modeled under the replacement method and the annuity method for backfilling resources.

5.5.3. Pueblo Economic Impact Analysis

Paragraph 123 of Decision No. C18-0191 requires Public Service to provide an economic impact analysis within two weeks of filing this 120-Day Report. Public Service has contracted with the Business Research Division of the Leeds School of Business at the University of Colorado at Boulder to perform the economic impact analysis of the Preferred CEPP on both a statewide and Pueblo County basis ("Leeds study"). The Leeds study will be filed with the Commission by June 20, 2018.

5.6 Cost Recovery

The Company is not seeking final Commission approval of any cost recovery treatment for utility-owned resources through this 120-Day Report. However, Rule 3611(f) provides in part that, with regard to bids that will be owned by the Company as a rate-based investment, the Commission may "address the regulatory treatment of such costs with respect to future recovery." The Stipulation filed by 16 Stipulating Parties in this proceeding on August 29, 2017, addressed cost recovery as follows:

> The Stipulating Parties agree that it is appropriate for the Commission to address cost recovery in this ERP for all utility-owned resources consistent with Rule 3611(f).
>
> With regard to eligible energy resources, the Stipulating Parties agree that the Company will not seek to recover Construction Work in Progress ("CWIP") and a current return on CWIP at the most recently authorized WACC through the RESA during construction of any utility-owned eligible energy resource approved as part of the Colorado Energy Plan Portfolio, notwithstanding that the Company is permitted to seek such recovery pursuant to § 40-2-124(1)(f)(IV), C.R.S. and Rule 3660(i). The Company will instead accrue interest at the AFUDC rate during the construction period. The Stipulating Parties further agree that the Company may recover costs for any utility-owned eligible energy resource approved as part of the Colorado Energy Plan Portfolio from the time of commercial operation until the resource is placed in base rates through a combination of the RESA and ECA, as contemplated by § 40-2-124(1)(f)(IV), C.R.S. and Rule 3660(i).
>
> In addition, consistent with Rule 3611(f), the Company may also include cost recovery proposals for utility-owned non-eligible energy resources, such as gas-fired resources, as a condition of its Colorado Energy Plan Portfolio.

Public Service will ultimately seek cost recovery for utility-owned projects in follow-on CPCN filings consistent with Rule 3617(d) and the provisions of the Stipulation. Consistent with Rule 3611(f), however, the Company wishes to make the Commission aware of the cost recovery treatment modeled for utility-owned wind and gas generators as this reflects the cost recovery treatment the Company will seek in future CPCN proceedings. For utility-owned wind, the Company will forego the statutory ability to seek to recover CWIP and a current return on CWIP at the most recently authorized WACC through the RESA during construction of the resource. The Company will instead seek the same recovery approach approved by the Commission in Proceeding No. 16A-0117E (Rush Creek Wind Project) and Proceeding No. 15A-0502E (Peak View Wind Project), with recovery through a combination of the RESA and ECA consistent with § 40-2-124(1)(f)(IV), C.R.S. and Rule 3660(i) from COD until the project is placed in base rates. BOT wind bids have been modeled in the Phase II process to match this recovery, i.e., with cost recovery commencing upon COD and continuing over the life of the project.

For utility-owned gas projects, the Preferred CEPP, Moderated CEPP, and Preferred ERP all contemplate utility-owned gas that are the result of the acquisition of existing gas generators. The Company intends to seek cost recovery for these generators consistent with the cost recovery approved by the Commission in Proceeding No. 10A-327E. Proceeding No. 10A-327E involved two existing gas generators owned by Calpine Corporation, Blue Spruce Energy Center and Rocky Mountain Energy Center, the acquisition of which was included as part of the portfolio approved in the Phase II decision in the 2007 ERP. The Commission approved recovery of (1) the non-fuel revenue requirements through the PCCA until the utility-owned generators were placed in base rates and (2) fuel costs through the ECA.[37] The Company has modeled this cost recovery treatment for utility-owned, existing gas generators in its analysis.

As noted, these issues will be addressed in the required follow-on CPCN filings for utility-owned resources, but the Company believes it is necessary to lay out its cost recovery intentions with regard to these utility-owned projects given commitments made by the Company and Stipulating Parties in the Stipulation and the effect of a Phase II decision by the Commission under Rule 3617(d).

With regard to transmission, the Company will file CPCNs as necessary based on the approved portfolio. Cost recovery for these transmission projects would occur through the TCA.

[37] A divided Commission also imposed a termination date on the PCCA recovery in the specific circumstances surrounding the acquisition of Blue Spruce Energy Center and Rocky Mountain Energy Center. Decision No. 10A-327E, at Ordering ¶ 5, Proceeding No. 10A-327E (mailed Nov. 4, 2010) ("The PCCA rate recovery shall terminate on April 30, 2012. However, so long as Public Service files a Phase I rate case prior to April 30, 2012, the rate recovery mechanism shall be extended until base rates are reset in such a proceeding.")

6.0 Phase II Process Overview

This section of the 120-Day Report provides an overview of the Phase II process, including the bid solicitation, the bid receipt process, and key steps in the Company's bid evaluation process.

6.1 Bid Solicitation

6.1.1 Modeling Assumptions Update

In Paragraph 129 of its Phase I Decision, the Commission required that the Company update its modeling assumptions prior to commencing the competitive solicitation. The Company filed its Modeling Assumptions Update on August 30, 2017, and it updated base case and sensitivity values and methodologies to be used to evaluate bids in Phase II, including gas price assumptions, CO_2 pricing, and capacity credit and integration costs for wind and solar resources. Additionally, the Modeling Assumptions Update included a new resource need forecast through the Resource Acquisition Period ("RAP") based on the updated demand forecast completed in June 2017 and other changes in generation pursuant to Commission decisions. This updated demand forecast resulted in a resource need of 454 MW in 2023 (rounded here to 450 MW). The Company posted the Modeling Assumptions Update document on its 2017 All-Source Solicitation webpage in advance of issuing the solicitation.

6.1.2 Issuance of 2017 All-Source Solicitation Request for Proposals

The Company issued its 2017 All-Source Solicitation on August 30, 2017 with a bid due date of November 28, 2017. The 2017 All-Source Solicitation included four separate Requests for Proposals ("RFPs"):

- Company Ownership RFP
- Dispatchable Resources RFP
- Semi-Dispatchable Resources RFP
- Renewable Resources RFP

Through the 2017 All-Source Solicitation, the Company sought power supply bids that could be utilized to fill a range of resource capacity acquisitions from a low of zero MW (per paragraph 45 of Commission Decision No. C17-0316) to over 1,110 MW (which could result from Commission approval of the Colorado Energy Plan Portfolio).[38] For purposes of simplicity, the Company refers elsewhere in this report to the various capacity acquisition targets as; 0 MW, 450 MW, 775 MW, and 1,110 MW. The table below is excerpted from the RFP documents and shows the range of potential resource capacity need by year that was sought through the solicitation:

[38] The Resource Needs Assessment section of the RFPs included the following footnote: "The Colorado Energy Plan Portfolio includes the Updated Demand Forecasted need of 454 MW in 2023, as well as addresses the potential for voluntary early retirement of Comanche units 1 and 2 totaling an additional 660 MW."

Table 21 - Range of Potential Resource Capacity (MW) Need by Year

Scenario	2017	2018	2019	2020	2021	2022	2023
Zero-Need	0	0	0	0	0	0	0
Updated Demand Forecast (unadjusted)	0	0	0	0	0	0	454
Colorado Energy Plan	0	0	0	0	0	0	779-1,114

On September 28, 2017, the Company hosted a Pre-Bid conference at the Company's Denver offices and via webinar to allow potential bidders to ask questions and seek additional information about the Phase II process. As discussed in Section 3.0, the IE also participated in the Pre-Bid conference.

6.2 Bid Receipt

On November 29, 2017, the Resource Planning group took possession of all bid packages received by the bid due date. As described in Section 3.0, the IE was present at the Company's Denver offices to oversee the opening and logging of all bids received including the Company's self-build proposals.

6.2.1 Overview of Bids Received

The All-Source Solicitation yielded 417 eligible bids,[39] representing 238 distinct projects, across a diverse set of generation technologies and geographic locations.

The Company received bids across fourteen different generation type categories as shown in Table 22 below. Highlights include over 350 renewable energy or renewable energy with storage bids and over 100 bids included some level of storage. The Company received five bids with nameplate capacity ratings between 100 kW and 10 MW.[40] Of the 238 distinct projects, over 70 claimed Section 123 status.

A variety of ownership structures were proposed by bidders. These structures included Power Purchase Agreements ("PPAs"), Company ownership, and a small number of split-ownership structures whereby the Company would purchase power through a PPA as well as provide some capital or otherwise have some equity stake in the project. Company ownership projects include self-build resources, build-own transfers ("BOTs"), and projects offering the sale of existing assets. Many bidders submitted multiple bids

[39] There were additional bids that were received but deemed ineligible. Two bids were deemed ineligible on account of their in-service dates. Six bids from two different bidders were set aside at the request of those bidders due to bid fee non-payment. One bid was deemed ineligible due to its lack of sufficient bid materials. Approximately 430 bids were received in total.

[40] In the RFP documents, the Company indicated the process it would use to evaluate small bids. To summarize, the Company indicated it would not routinely include small bids in computer based modeling but instead would compare the small bid levelized costs against the levelized costs of larger bids of similar generation technology that had been passed through to computer based modeling.

for the same project under different commercial structures and different in-service dates, leading to more bids than projects proposed.

The locations of the projects bid into the solicitation were spread across Colorado, representing wide geographic diversity. The wind bids represented four of the five Energy Resource Zones ("ERZs") within Colorado. The solar bids represented four distinct solar resource zones.

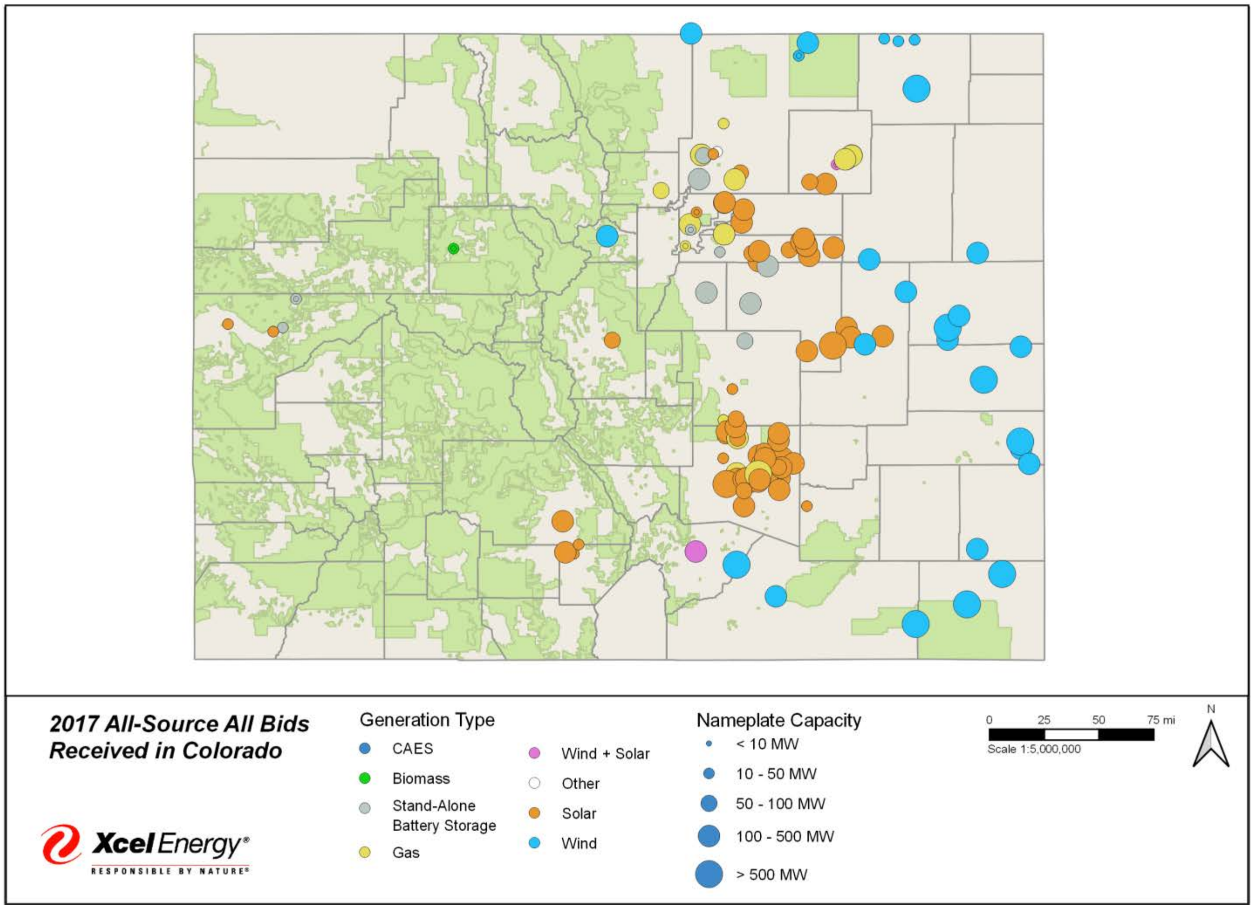
A summary of bid counts by generation technology type and ownership structure can be seen in Table 22. For comparison, the Company received approximately 60 total bids in the 2013 All-Source Solicitation.

Table 22 - Summary of Total Eligible Bids Received

Category	Build-Own Transfer	Company Self-Build	PPA	Split Ownership	Total
Battery Storage	4		24		**28**
Biomass			1		**1**
Combined Cycle			3	1	**4**
Combustion Turbine	5	10	8	4	**27**
Compressed Air Storage	1				**1**
CT + Storage	2		5		**7**
Internal Combustion	1				**1**
Other	1		1		**2**
Other Semi-Dispatchable	2		3		**5**
Solar PV	41		104	1	**146**
Solar PV + Storage	15		65		**80**
Wind	40		45	11	**96**
Wind + Solar Hybrid	1		7		**8**
Wind + Storage			11		**11**
Total	**113**	**10**	**277**	**17**	**417**

A map of the general geographic location, technology type, and nameplate capacity range of all bids received is shown in Figure 11 below.

Figure 11 - Map of Total Bids Received



6.2.2 30-Day Report

On December 28, 2017, the Company filed its 30-Day Report pursuant to Rule 3618(b)(l), reporting the number of bids received, breakdowns of bids by technology and nameplate capacity, and the median prices of the bids received (grouped by technology type). Additionally, the Company reported on how many bids claimed Section 123 status and provided its initial position on those resources.

6.2.3 Bid Affirmation and Refresh Process

On January 12, 2018, Public Service made a filing with the Commission related to the Company's need to implement a bid affirmation and refresh process that would require all bidders to either affirm or update bid prices to account for the passage and signing into law of new federal tax legislation, the Tax Cuts and Jobs Act ("TCJA"), and a final decision in the Suniva/SolarWorld trade case regarding solar equipment tariffs. At the time of the initial bid due date, many bidders included contractual conditions precedent tied to the uncertainty of the then-unknown outcomes of federal tax reform legislation and the trade case, leaving Public Service with the challenge of evaluating bids based on pricing conditioned on such conditions precedent. The Company's proposed process required all bidders to attest that they were removing these contractual conditions precedent related to the TCJA and final trade case decision. The affirmation or refresh of any bid related only to pricing. All other aspects of bids, such as size, technology, location, and term were required to remain unchanged. The Company conferred with the IE, and the IE concurred with the proposed bid affirmation and refresh process proposed by the Company and outlined in its January 12, 2018 filing. By Decision No. C18-0051-I (mailed January 19, 2018), the Commission granted the Company's request for a partial waiver of Rule 3613(a) to allow additional time for the bid affirmation and refresh process before notifying bidders at the 45-day mark of the status of their bids.

On January 23, 2018, the Company formally initiated the bid affirmation and refresh process via emails to all bidders. Included in the email were specific instructions and forms that bidders were required to complete. Consistent with the approach agreed upon with the IE, the Company's self-build bid affirmation and refresh responses were due January 29, 2018, and all other bid affirmation and refresh responses were due February 5, 2018.

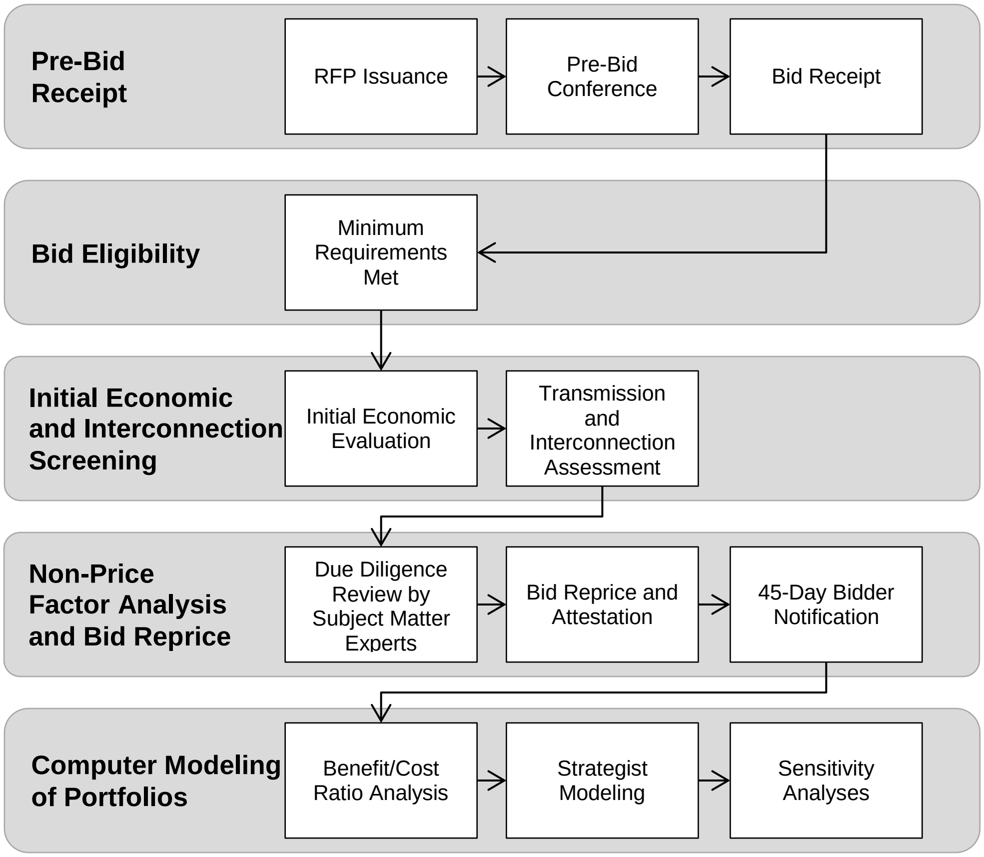
The Company received responses for all but one of the bids. Of these responses, 58% of the bids affirmed no change in pricing, 16% increased pricing, and 26% decreased pricing.

The Company filed an update to its 30-Day Report on March 1, 2018, in which the Company provided summary results of the bid affirmation and refresh process, including updated median bid prices.

6.2.4 Bid Evaluation Process

The Company evaluated bids in accordance with the evaluation process outlined in Section 5 of the RFP documents. Figure 12 below shows a general overview of the bid evaluation process.

Figure 12 - Bid Evaluation Process



6.2.5 Bid Eligibility Screening

The Company, in partnership with the IE, reviewed each bid to determine whether it satisfied the minimum requirements for eligibility as outlined in Section 4.2 of the RFPs.

Bids were deemed ineligible due to in-service dates being outside the RAP, incorrect bid fee payment, or incomplete or missing bid forms or narratives. Notification to bidders of bid eligibility was provided on December 14, 2017, within the requisite 15 days of bid receipt. Those bids deemed to be ineligible due to incorrect bid fee payment or incomplete bid forms or narratives were given five business days in order to supplement their materials.

6.2.6 Initial Economic Evaluation and Interconnection Assessment

Following the bid eligibility determination, the Company screened the eligible bids based on an initial economic evaluation. Dispatchable generation bids, including gas-fired generators and standalone storage, were evaluated on a levelized capacity cost basis (LCC, in $/kW-mo). Non-dispatchable generation bids, including wind, solar, and biomass, were evaluated on a levelized energy cost basis (LEC, in $/MWh). Renewable resources with a storage component were also evaluated on an LEC basis. Where the bid proposed separate payment rates for energy generated (on $/MWh terms) and for the storage component (on $/kW-mo terms), the Company converted the forecasted expenditures to an LEC.

The Company's Transmission Access group reviewed the reasonableness of the bidder-provided interconnection cost estimates and upgrade schedules using publicly available generator interconnection study information. When cost discrepancies or other issues arose, the Company sought clarification from bidders.

6.2.7 Non-Price Factor Analysis

In the next step of the bid evaluation process, due diligence teams reviewed the most competitive bids with the lowest levelized costs by technology as determined by the initial economic evaluation and interconnection assessment. The purpose of this stage of due diligence was to assess project feasibility and identify any fatal flaws.

For each bid, the due diligence team summarized bid risk and issued an overall review noting any flaws. If the teams needed clarification or additional information from the bidders, questions were asked of bidders through the designated email communications protocol described in Section 3.0.

Due diligence teams reviewed the following areas:

- ***Site Control & Permitting*****:** identified potential risks associated with the land and permitting attributes.

- ***Environmental*****:** identified and documented any federal, state and local environmental constraints associated with, for example, wildlife, air quality, NEPA requirements, Federal Aviation Administration restrictions, and historic/archeological resources.

- ***Technical Review and Ongoing Expenditures*****:** identified and documented potential risks of technologies and validated ongoing expenditures. For bids proposing Company ownership, operations and maintenance (O&M) and ongoing capital expenditures (capex) estimates were developed. Black and Veatch Corp. was retained to provide additional support in the area of solar technology and ongoing expenditures

- ***Finance, Legal and Tax*****:** reviewed PPAs and BOT term sheets for acceptability, including security terms, timelines/schedules, contract provisions and liability. This team also analyzed the financial, tax, and investment implications of each bid.

- ***Transmission:*** identify and document feasibility of the proposed transmission access plan. Validated generator interconnection costs and estimated transmission line losses.

- ***Wind Resource Assessment:*** Vaisala, Inc. was retained to provide additional support and validation of wind production forecasts.[41]

6.2.8 Bidder Notification of Advancement to Computer Modeling

Of the 417 total eligible bids, 160 bids (79 distinct projects) were advanced to computer-based modeling.

Prior to advancing bids to computer-based modeling, the Company and the IE discussed the proposed criteria for advancing bids and how the Company planned to conduct the 45-day bidder notification pursuant to Rule 3613(a). The Company and the IE reviewed each bid it proposed to move forward to computer-based modeling and received concurrence from the IE regarding this decision. Similarly, the Company discussed with the IE and received concurrence on those bids that were not proposed to be advanced to computer-based modeling. Bids were advanced based on a comprehensive set of factors, including size, technology, ownership structure, asset class, price/economics, geographic location, transmission interconnection, and the results of Non-Price Factor Analysis. Additionally, as discussed in its 30-Day Report Update filed on March 1, 2018, the Company advanced all bidder-claimed Section 123 resources to computer-based modeling.

On February 22, 2018, the Company provided email notice to the owner or developer of each bid stating whether the bid was being advanced to computer-based modeling, and, if not advanced, the reasons supporting this decision. Through this notification process, bidders were informed that: (1) bids not advanced would be set aside and not considered further; and (2) a bid being advanced to computer-based modeling did not in any way guarantee or otherwise represent that the bid would be included in any portfolio (ERP or CEP) presented for Commission consideration in the Company's 120-Day Report. This notification process was fully coordinated with the IE.

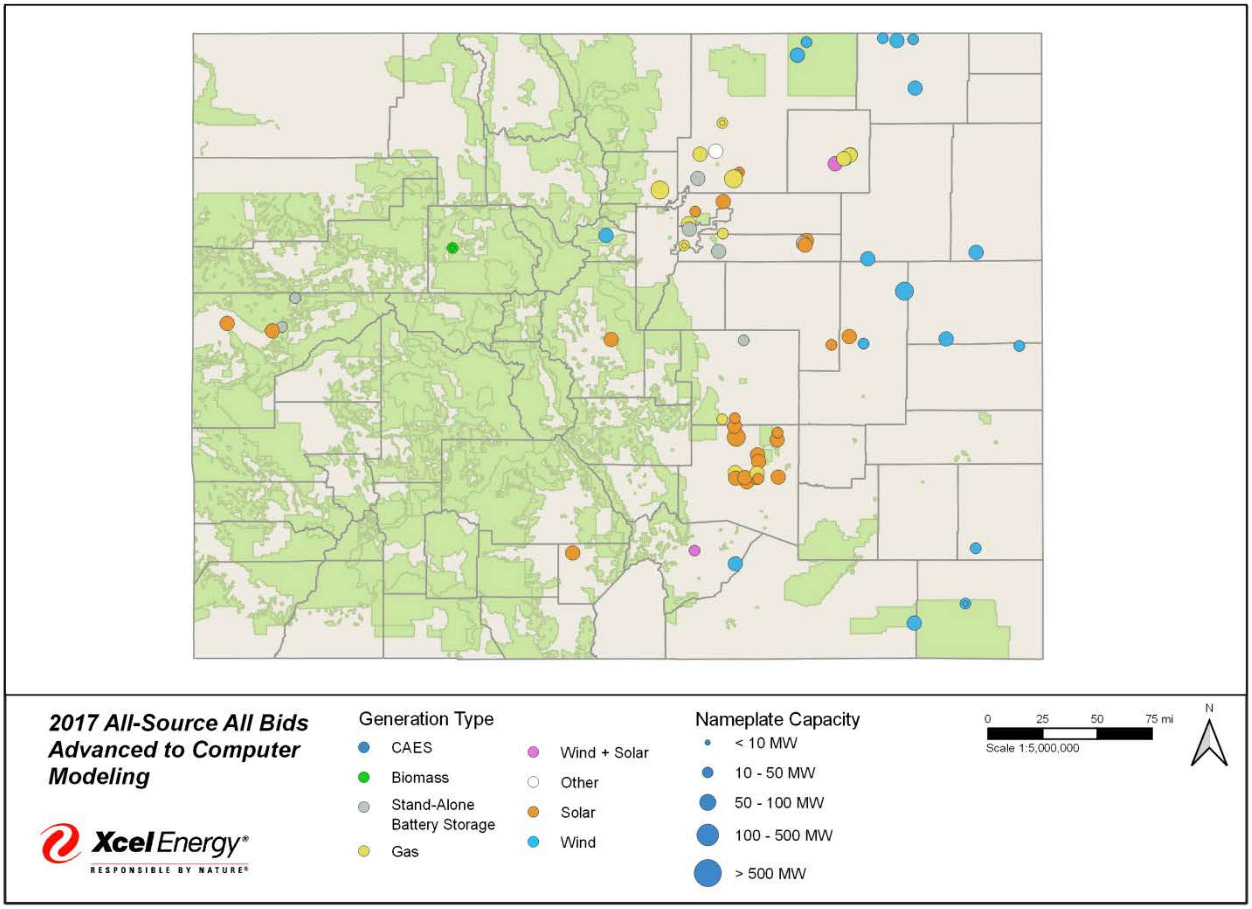
Table 23 below provides a summary of the bids that were advanced to computer-based modeling. Appendix H contains a complete list of all bids advanced to computer-based modeling. Figure 13 shows a map of the general location of bids advanced to computer-based modeling.

[41] Vaisala, Inc. provided similar wind assessments for the Rush Creek Wind Project in Proceeding No. 16A-0117E.

Table 23 - Summary of Bids Advanced to Computer-Based Modeling

Category	Build-Own Transfer	Company Self-Build	PPA	Split Ownership	Total
Battery Storage	4		13		**17**
Biomass			1		**1**
Combined Cycle			3	1	**4**
Combustion Turbine	5	10	8	4	**27**
Compressed Air Storage	1				**1**
CT + Storage	2		4		**6**
Internal Combustion					**0**
Other			1		**1**
Other Semi-Dispatchable	1		3	1	**5**
Solar PV	2		12		**14**
Solar PV + Storage	3		28	1	**32**
Wind	12		22		**34**
Wind + Solar Hybrid			7		**7**
Wind + Storage			11		**11**
Total	**30**	**19**	**113**	**7**	**160**

Figure 13 - Map of Bids Advanced to Computer-Based Modeling



6.3 Portfolio Development Process

As discussed in Section 6.2.8, the initial economic evaluation phase resulted in the advancement of 160 bids to computer-based modeling. That evaluation was performed on a static basis, considering only the costs of *individual* bids, and as a result was limited in application to comparing the costs of bids with similar technology (i.e. wind versus wind, CTs versus CTs). This initial evaluation was necessary to identify and focus the modeling process on the most competitive bids. However, in order to understand both the costs and benefits that bids can provide to the Public Service power supply system it is necessary to use computer-based modeling. Computer modeling captures these system costs and benefits not only for individual bids but more importantly for combinations of bids (i.e., bid portfolios) over the full operating lives of the bid facilities and allows an assessment of how these costs/benefits change when different future assumptions for key inputs such as gas prices or CO_2 costs are applied (sensitivity analyses).

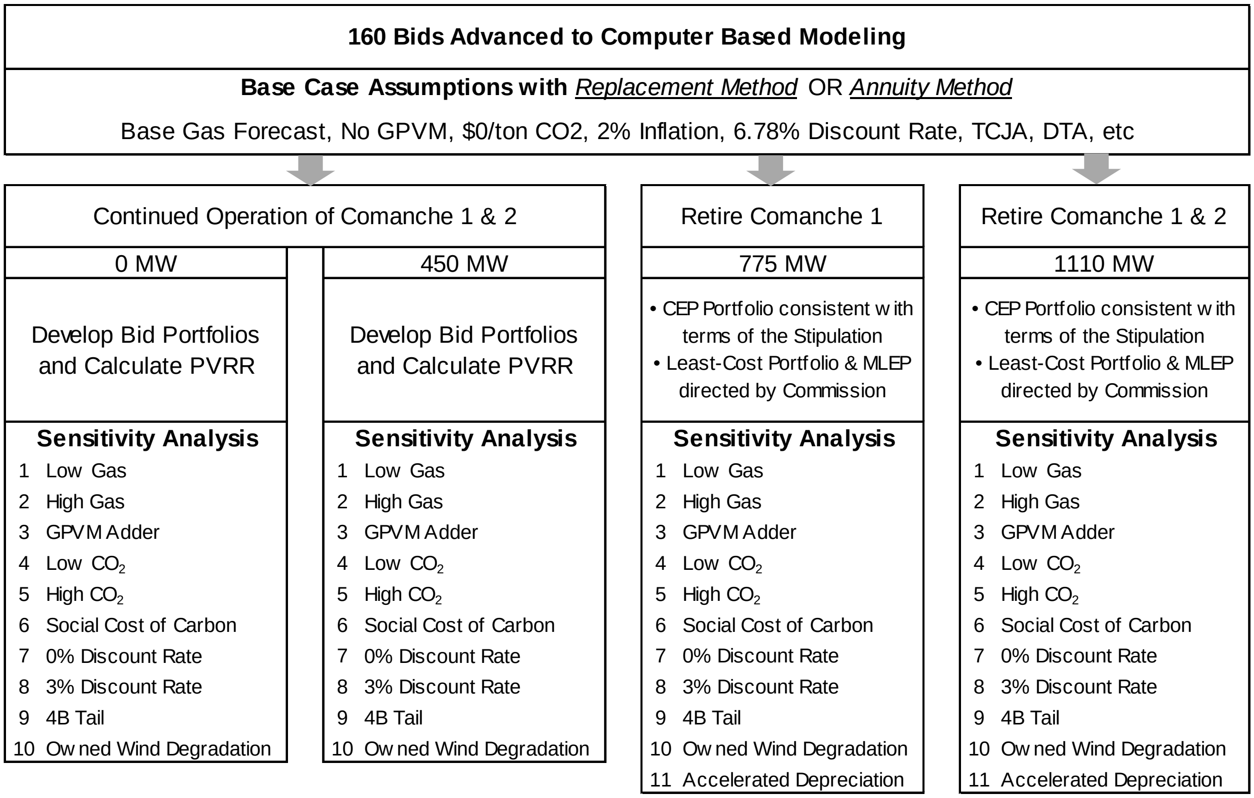
6.3.1 Portfolio Development Framework

As directed by the Commission in Decision No. C17-0316 and Decision No. C18-0191, bid portfolios were developed to meet four distinct levels of targeted resource acquisition. Two levels, 0 MW and 450 MW, were approved by the Commission in its Phase I Decision and two levels, 775 MW and 1,110 MW, were approved by the Commission in the decision addressing the Stipulation setting forth the Company's generation needs resulting from the early retirement of Comanche 1 or Comanche 2, respectively.

The two ERP levels of need (0 MW and 450 MW) both assume Comanche 1 and Comanche 2 will continue to operate beyond the RAP and will be retired in 2033 and 2035. Accordingly, these portfolios include all attendant costs for continued operation of Comanche 1 and Comanche 2 through their originally planned retirement dates. The 775 MW level of acquisition assumes Comanche 1 is retired in 2022 and Comanche 2 continues operation to 2035 along with all attendant costs. These portfolios therefore only include the accelerated depreciation of Comanche 1. Similarly, the 1,110 MW level of acquisition assumes Comanche 1 is retired in 2022 and Comanche 2 is retired in 2025, along with all attendant costs, including the accelerated depreciation of both Comanche units. Figure 14 provides a high-level illustration of the Company framework for developing the various bid portfolios (under both the replacement and the annuity backfilling methods) and the sensitivity analyses applied to each portfolio.[42] Further discussion on the sensitivity analysis is found below.

[42] The results of the sensitivity analyses and the basis for each sensitivity are discussed in more detail in Section 4.0 and Appendix E of this 120-Day Report.

Figure 14 - Bid Portfolio Development Framework



6.3.2 Benefit Cost Ratio Analysis

Given the robust market response to this solicitation and the low pricing offered across numerous generation technologies, the Company elected to take an inclusive approach when advancing bids to computer-based modeling. The Company advanced 160 bids, approximately three times the number of bids advanced to computer-based modeling in the Company's most recent 2013 All-Source Solicitation. Advancing a pool of bids of this size created new challenges in modeling.

The Strategist model is a powerful analytic tool specifically designed to analyze multiple power supply options (bids), and from those bids build portfolios that meet a specific resource need in a cost-effective manner. However, as the model evaluates every bid in all possible combinations with other bids, the number of potential portfolios grows dramatically with the inclusion of each additional bid.[43] Therefore, it was essential to develop an additional modeling step that would allow a comprehensive computer analysis of this large number of bids while avoiding unmanageable model run times and without exceeding the large, but limited, data storage capabilities of the model.

To address this issue, the Company worked closely with the IE to develop a separate "pre-processing" analytic tool to advance the most beneficial bids while still fully

[43] Without consideration of limiting factors, there were approximately 60 unique projects in the list of 160 advanced bids. This results in approximately 2^{60} potential portfolios, or in scientific notation 6 x 10^{20}.

analyzing all bids advanced to computer modeling. This approach greatly expanded the number of portfolios that could be analyzed within the Strategist model while maintaining the process and integrity in the modeling results. This pre-processing analytic tool narrowed the vast number of possible portfolios down to a manageable volume by focusing on a robust list of portfolios that were most likely to be cost-effective. The key aspects of this 5-step process included:

1. Conducting a Strategist simulation (a "run") for each individual bid on a standalone basis. This standalone run was used to calculate the total costs of the bid, including integration and coal cycling costs, as well as the total energy and capacity benefits of the specific bid. From these runs, a benefit cost ratio ("BCR") and the total net benefits (in NPV) was calculated for each bid under both the annuity and replacement methods. The BCR and NPV calculations reflect both costs and system benefits of adding each bid individually to the Public Service system.

2. Evaluating bids advanced to computer modeling based on technology type, location, and BCR. Based on these factors, the bids were categorized into "tiers" based on a combination of these three criteria. Similar to the process used to develop the list of bids to be advanced to computer-based modeling, the most economic bids of each technology type (based on BCR) were placed into the top tier ("Tier 1"). Additional bids were added to Tier 1 to provide geographic and technological diversity. The remaining bids were categorized into the second tier (Tier 2) if they were likely to be economically competitive (based on the same three criteria), or the third tier (Tier 3) if they were the top 1 or 2 bids of each of the seven Section 123 technology types the Company discussed in its updated 30-day Report. The remaining bids not placed into Tiers 1, 2 or 3 were not included in further modeling. The majority of these bids were: (1) lower benefit variations of bids that were already included in the top 3 Tiers; (2) bids that had significantly less benefit than other similarly situated (technology/geography) bids; and (3) in limited circumstances, bids determined to be unable to meet their proposed in-service dates as a result of the continued due diligence process. All of this was done in consultation with the IE.

3. Development of a "binary model", determining all possible portfolios of bids that could meet key feasibility criteria. To do this, the Company developed a spreadsheet tool that looked at all possible combinations of the bids entered into the tool and determined which combinations (i.e. portfolios) met the key feasibility criteria. Examples of the key feasibility criteria include: meeting minimum reserve margin, not exceeding maximum transmission injection limits, and not exceeding the amount of wind additions as determined in the Phase I Decision. This spreadsheet tool did not calculate the economics of various portfolios, but simply determined all feasible combinations (portfolios) of the bids input into the

spreadsheet model. The Company and the IE refer to this tool as the "binary model."[44]

4. Utilize the binary model to produce potential portfolios. This binary model was ultimately run with the Tier 1 bids for the 0 MW, 450 MW, 775 MW and 1,110 MW acquisition cases to determine initial portfolio combinations of the most economic bids. As a point of reference, the model produced millions of possible portfolios for the four tiers of need. The IE was provided these potential portfolios to evaluate the correct operation of tool.

5. Pre-screening all possible portfolios for the most cost-effective to select portfolios for Strategist. The internal memory of the Strategist model is limited to a maximum of 2,500 portfolios. In order to properly evaluate portfolios that numbered into the millions, the Company, at the IE's suggestion, implemented an approach to "pre-screen" the portfolios based on the composition of bids in each portfolio and the results of the BCR runs. The Company calculated an economic indicator metric for every valid portfolio (all 4 million-plus) that consisted of the sum of the individual bid NPVs from the BCR runs, with expected portfolio adders based on: required transmission upgrades, interconnection costs, Rush Creek Gen-Tie VAR compensation, and increased operating reserves. All of the portfolios were sorted by this economic indicator metric, and approximately 35,000 of the plans with the best metric were selected to run through Strategist. The 35,000 plans were passed individually to Strategist for detailed costing, and PVRRs of the plans were output to a spreadsheet, thus bypassing the internal memory 2,500 plan limit.

Through this 5-step process, jointly created by the Company and the IE, the Company was able to perform computer-based modeling on a far greater number of bid portfolios than could have been accomplished using the Strategist model's embedded optimization functionality. This process is more robust than solely using the embedded Strategist optimization engine and was critical based on the large bid pool received.

After the initial set of portfolios were developed using the initial Tier 1 bids, Public Service expanded the analysis to evaluate whether any of the Tier 2 or Tier 3 bids could contribute to development of portfolios with lower costs. Each of the Tier 2 and Tier 3 bids were included in the same 5-step process described above, except each bid was combined individually with a subset of those initial Tier 1 bids that consistently appeared in the top portfolios previously developed.

As an example, most of the initial top portfolios included 5-8 of the same bids. The Company evaluated the ranked list of portfolios, incrementally adding new bids that appeared in portfolios, until there was a pool of bids up to 3 times the number of bids appearing in the top plan. Generally, the pool consisted of 15-18 bids plus the

[44] A key component of the logic of the model is the representation of different combinations of bids (i.e., portfolios) as a single binary number (a 1 in a particular digit indicates a specific bid is contained in the given portfolio, a 0 indicates it is not).

individual bid being evaluated by the Company. The 5-step process was then used to determine if the best portfolio, which included the bid being studied, was more or less economic than the best portfolios that did not include the bid in question. Bids that passed this “challenger” evaluation were then advanced into the final pool of Tier 1 bids. Bids originally included in the Tier 1 analysis but that failed to appear in economic portfolios were eliminated from the final Tier 1 pool.

The 5-step process was then used one final time with a bid pool consisting of the final Tier 1 bids to develop the final set of portfolios from which the plans in this report were drawn. This final analysis yielded over 6 million plans from Step 4, and approximately 35,000 of these plans were selected in the Step 5 process to be evaluated using the Strategist model to determine the optimal portfolios.

This entire process was completed in parallel using both the replacement method and the annuity method to select the most cost effective portfolios under each methodology.

7.0 Next Steps and Conclusion

7.1 Next Steps and Follow-on Proceedings

Following this 120-Day Report, there are procedural next steps within the context of this proceeding and interdependent/follow-on proceedings before the Commission. These next steps and proceedings are as follows:

- **IE Report, Comment Period, and Commission Decision**

Pursuant to the Commission's Rules, after Public Service files this 120-Day Report, the IE will file its report within 30 days. Within 45 days after the filing of the 120-Day Report, interested parties may file comments on the Company's report and the IE's report. Within 60 days after filing the 120-Day Report, the Company may file comments responding to the IE's report and any comments from parties. Within 90 days after filing the 120-Day Report, the Commission will issue a written decision approving, conditioning, modifying, or rejecting the Company's preferred resource portfolio.

- **Contract Negotiations**

Public Service will pursue contract negotiations with bidders in the approved portfolio for both IPP-owned and utility-owned generation resources.

- **Accelerated Depreciation/RESA Reduction ("AD/RR") Proceeding**

The Company notes there are also several next steps scheduled to occur in the interrelated Accelerated Depreciation / RESA Reduction, or "AD/RR," proceeding (Proceeding No. 17A-0797E) following the Company's filing of this 120-Day Report. As described in the Procedural Background section in Appendix P, in the AD/RR proceeding, the Company is seeking additional, related approvals from the Commission to provide for the implementation of the Company's Preferred CEPP, if approved. To that end, the Company will file Rebuttal Testimony in the AD/RR proceeding on June 15, 2018. In that filing, the Company will provide updated information based on the projected costs of the Preferred CEPP. For example, this will include updated accelerated depreciation schedules and RESA balance projections. Parties will then have an opportunity to file Surrebuttal Testimony (due July 9, 2018) several weeks in advance of an evidentiary hearing with a final Commission decision in the AD/RR proceeding scheduled to occur contemporaneous with the Commission's Phase II decision in this ERP proceeding (i.e., early September 2018).

- **Certificate of Public Convenience and Necessity (CPCN) Applications**

The Company will prepare and file all necessary CPCN applications, including for: (1) "limited scope" CPCN applications that the Commission may require to authorize voluntary retirement of existing generation units; (2) utility-owned generation projects (whether build-transfers or purchase of existing assets); (3) construction of the proposed Badger Hills Station on the Company's southern transmission system, and/or (4) any other transmission facilities that are subject to CPCN requirements and are necessary to interconnect approved generation resources to the Public Service transmission system and deliver them to load.

For any CPCN filing for utility-owned wind generation projects approved by the Commission in its Phase II decision, the Company has agreed to propose a performance metric that is substantially similar to, but no more stringent than, the performance metric used for the Rush Creek Wind Project.[45] The Company will include this proposed performance metric as part of its CPCN filing for any utility-owned wind generation resources.

In addition, cost recovery issues described within this 120-Day Report can be adjudicated before the Commission through these CPCN proceedings. With regard to a CPCN for the Company-owned wind if the Commission approves the Preferred CEPP or Alternative CEPP, this proceeding can address the cost recovery treatment contemplated in the Stipulation and modeled as part of the bid evaluation process (i.e., RESA/ECA recovery from commercial operation date until the generator is placed in base rates, followed by base rate recovery after a post commercial operation rate case filing with the Commission). The Commission can also address the treatment of the DTA at this time and whether the Company should create a DTA for unused PTCs or pursue the alternative approach outlined in this report, which could result in savings of approximately $20 million for customers.

In a CPCN proceeding for Company-owned gas generators, the Commission can also address cost recovery at that time. The Company has discussed how the cost recovery for the two gas generators in the Preferred CEPP (and Alternative CEPP) were modeled in this proceeding, and Public Service will bring forward a formal cost recovery request for these two generators at that time.

- **EVRAZ Contract Application**

Assuming the Company and EVRAZ reach agreement on final terms, the Company will file an application for approval of the EVRAZ contract pursuant to § 40-3-104.3, C.R.S. and Rule 3106. This application will be considered by the Commission in a separate proceeding on the timelines set forth in the statute.

7.2 Conclusion and Request for Approval

This 120-Day Report provides extensive detail on multiple portfolios that would fill either the 450 MW ERP need or the larger CEP needs. We believe this analysis builds a clear record that supports approval of the Preferred CEPP (or the Alternative CEPP if the Commission deems this a better path). Indeed, the record demonstrates that both the

[45] See Proceeding No. 16A-0117E for details on the Rush Creek Wind Project performance metric.

Preferred CEPP and Alternative CEPP represent a transformative opportunity for the State of Colorado and our customers.

As outlined above, the $213 million of present value savings delivered by the Preferred CEPP, when measured against the Preferred ERP, is the result of reasonable and well-supported modeling assumptions and reflects significant customer savings from a conservative point of view. That said, we have also identified other actions that could drive additional savings:

- Pursuing the Alternative CEPP could result in additional customer savings of approximately $20 million by deferring the acquisition of resources to replace Comanche 2 to the next ERP, where we anticipate low-cost solar and storage will continue to be available by taking advantage of the full 30% ITC and we can better align replacement capacity with the retirement date of Comanche 2 at the end of 2025.

- Adopting the DTA alternative approach described above in a CPCN proceeding for the Company-owned wind project, which could result in additional savings of another approximately $20 million.

- Updating the AD/RR proceeding (Proceeding No. 17A-0797E) for an additional $26 million in savings through the new revenue requirement forecast with calculations consistent with a revised depreciation schedule (implementing the depreciation rates for Comanche 1 and Comanche 2 from the 2016 Depreciation Settlement in mid-2019) and a rider mechanism that will be offered as an option for recovery of the regulatory asset.

Taken together, these additional savings deliver nearly $50 million more in potential savings for the Preferred CEPP and almost $70 million more savings for the Alternative CEPP as compared to the Preferred ERP. In addition to the significant customer savings relative to the Preferred ERP, the Preferred CEPP and Alternative CEPP provide many other benefits to the State of Colorado that the Preferred ERP simply does not. The Company therefore requests the Commission find the Preferred CEPP, or the Alternative CEPP if that more measured approach is preferable, to be a cost-effective resource plan and approve it by the Commission's Phase II Decision in this proceeding.