BEFORE THE COLORADO PUBLIC UTILITIES COMMISSION

PROCEEDING 21A-0141E

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2021 ELECTRIC RESOURCE PLAN AND CLEAN ENERGY PLAN

HEARING EXHIBIT 1402

ANSWER TESTIMONY OF

TYLER COMINGS

ON BEHALF OF THE

CONSERVATION COALITION

NOTICE OF CONFIDENTIALITY

A PORTION OF THIS TESTIMONY AND ATTACHMENTS HAVE BEEN FILED UNDER SEAL

Confidential materials redacted on pages 25-28, and 33
Confidential Attachment TC-18C

October 11, 2021

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and position.

A. My name is Tyler Comings. I am a Senior Researcher at Applied Economics Clinic, located at 1012 Massachusetts Avenue, Arlington, Massachusetts.

Q. Please describe Applied Economics Clinic.

A. The Applied Economics Clinic is a 501(c)(3) non-profit consulting group housed at Tufts University's Global Development and Environment Institute. Founded in February 2017, the Clinic provides expert testimony, analysis, modeling, policy briefs, and reports for public interest groups, including many government entities, on the topics of energy, environment, consumer protection, and equity, while providing on-the-job training to a new generation of technical experts.

Q. Please summarize your work experience and educational background.

A. I have 15 years of experience in economic research and consulting. At Applied Economics Clinic, I focus on energy system planning, costs of regulatory compliance, wholesale electricity markets, utility finance, and economic impact analyses. I am a Certified Rate of Return Analyst (CRRA) and member of the Society of Utility and Regulatory Financial Analysts (SURFA).

I have provided expertise for many public-interest clients including: American Association of Retired Persons (AARP), Appalachian Regional Commission, Citizens Action Coalition of Indiana, City of Atlanta, Consumers Union, District of Columbia Office of the People's Counsel, District of Columbia Government, Earthjustice, Energy Future Coalition, Hawaii Division of Consumer Advocacy, Illinois Attorney General, Maryland Office of the People's Counsel, Massachusetts Energy Efficiency Advisory Council, Massachusetts Division of Insurance, Michigan Agency for Energy, Montana Consumer Counsel, Mountain Association for Community Economic Development, Nevada State Office of Energy, New Jersey Division of Rate Counsel, New York State Energy Research and Development, Nova Scotia Utility and Review Board Counsel, Rhode Island Office of Energy Resources, Sierra Club, Southern Environmental Law Center, U.S. Department of Justice, Vermont Department of Public Service, West Virginia Consumer Advocate Division, and Wisconsin Department of Administration.

I was previously employed at Synapse Energy Economics, where I provided expert testimony and reports on coal plant economics and utility system planning. Prior to that, I performed research on consumer finance and behavioral economics at Ideas42 and conducted economic impact and benefit-cost analysis of energy and transportation investments at EDR Group.

I hold a B.A. in Mathematics and Economics from Boston University and an M.A. in Economics from Tufts University.

My full resume is attached as Attachment TC-1.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Conservation Coalition (Natural Resources Defense Council and Sierra Club).

Q. Have you testified before the Colorado Public Utilities Commission previously?

A. Yes. I filed answer and surrebuttal testimony in Proceeding No. 17A-0797E on behalf of Sierra Club. My testimony in that case focused on Public Service of Colorado's ("PSCO" or "the Company") handling of the undepreciated plant balance for the planned retirement of Comanche Units 1 and 2. In that case, I supported PSCO's plan to both: 1) accelerate depreciation of those units' stranded costs, and 2) offset the rate impacts of that acceleration through the use of surplus revenue from the RESA (Renewable Energy Standard Adjustment). I also recommended that the Company consider other methods, e.g. securitization, for dealing with subsequent unit retirements.

Q. Have you testified before public utility commissions in other jurisdictions?

A. Yes. I have also testified before commissions in Arizona, the District of Columbia, Hawaii, Indiana, Kentucky, Maryland, Michigan, Missouri, New Jersey, New Mexico, Ohio, Oklahoma, West Virginia, and Nova Scotia (Canada).

Q. Has your work focused on electric resource planning?

A. Yes. Most of my testimony has focused on resource planning decisions, particularly on the evaluation of coal unit economics. I have also co-authored comments on electric utilities' resource plans in Indiana, Louisiana, Minnesota, Missouri, North Carolina, and Oregon.

Q. What is the purpose of your testimony in this proceeding?

A. The focus of my testimony is on the future of the Comanche Unit 3 coal unit and other existing coal units, as well as the selection of new replacement resources in PSCO's Phase I planning. I find that there is ample evidence that Comanche 3 should be retired earlier than under PSCO's preferred retirement date of 2039. I discuss how the Company's own modeling supports earlier retirement of Comanche 3. I also discuss alternative modeling conducted by my team to address concerns with the assumptions and methodology employed by PSCO. This modeling further bolsters the argument for earlier retirement of Comanche 3 and shows savings from converting the Pawnee unit to natural gas earlier than in PSCO's preferred plan.

Q. Please summarize your findings and recommendations.

A. Based on my analysis of the Company's filing and data responses in this case, I find the following:

1. **PSCO's own modeling makes a strong case for ending the burning of coal at Comanche 3 in the late 2020's.** Using the present value of revenue requirements ("PVRR") inclusive of carbon dioxide ("CO_2") emission costs, the Company's modeling shows that retiring Comanche 3 in 2029 would save $91 million or ceasing coal in 2027 would save $254 million, relative to 2039 retirement in the preferred plan. I discuss why the Company and Commission should rely on the utility system costs with carbon costs included as the key cost metric, especially given recent changes to greenhouse gas rules in the state (which, if incorporated in this filing, would increase emissions costs further).

2. **There are key flaws in the assumptions and methodology used in developing the Company's preferred plan.** the Company's assumptions for operating costs and availability of Comanche 3 are overly optimistic which bias the modeling in the unit's favor. Also, PSCO's preferred plan introduces substantial risks by investing in new gas generation while assuming it will be carbon-free after 2050 without including the costs that would be required to operate the units this way.

3. **Additional modeling makes a strong case for 2027 retirement of Comanche 3 and 2024 gas conversion of Pawnee.** My co-witness Dr. Maria Roumpani's modeling shows $1 billion in PVRR savings from 2027 retirement of Comanche 3 and 2024 conversion of Pawnee—without including carbon costs; when including carbon costs the savings are $2.7 billion. This modeling used more reasonable inputs that I developed for Comanche 3 operating costs and availability (relying in part on the Commission's requested supplemental modeling). It also includes my update of the Company's renewable and battery storage costs which follows its methodology—apart from a correction I make to the PSCO's calculation of the levelized cost of battery storage. Dr. Roumpani also included the more recent social cost of carbon in optimization, as required by state law.

4. **The Commission should instruct the Company to make several changes to its modeling in Phase II.** Apart from the change in portfolio, I also recommend that the Company's modeling of Phase II adopt the following: 1) a portfolio that includes the retirement of Comanche 3 in 2027 and

conversion of Pawnee to gas in 2024; 2) PSCO should comply with a 2050 carbon-free goal without assuming that gas units can convert to 100% hydrogen by that time; and 3) in order to comply with recent changes to state law, PSCO should incorporate the more recent social cost of carbon (SCC) and the social cost of methane in evaluating its Phase II resources.

II. PSCO'S OWN MODELING SHOWS THAT COMANCHE UNIT 3 SHOULD STOP BURNING COAL IN THE LATE 2020S.

Q. Please summarize this section of your testimony.

A. One of the main topics of my testimony is the selection of the retirement date for Comanche Unit 3. In this section, I show how the Company's own modeling results indicate that the unit should cease burning coal in 2027 or 2029 instead of the Company's choice to retire the unit in 2039. First, I briefly discuss the Company's modeling process and selection of its preferred plan. Second, I argue that the present value revenue requirements (PVRR) with carbon dioxide costs should be weighted more heavily than the PVRR alone when determining the future of Comanche 3 or any other existing unit in this case. Third, I show that the Company's modeling results using this cost measure clearly point to an earlier coal retirement for Comanche 3.

In this section, I take the Company' modeling at face value. In subsequent sections, I discuss alternative modeling assumptions to address shortfalls in the Company's analysis, and discuss how modeling conducted by my co-witness, Dr. Maria Roumpani, under these changes further reinforce the finding that Comanche 3 should be retired earlier than the Company is proposing. Dr. Roumpani's modeling also shows that conversion of Pawnee in 2024 is preferable to 2027.

Q. Please briefly summarize the Company's initial modeling process.

A. The Company's modeling was focused on the futures of two coal units-- Pawnee and Comanche Unit 3—and evaluating the procurement of new replacement resources around those actions. To do this, the Company tested eight "paired actions" that represented possible outcomes for the two coal units—shown in Table 1. These paired actions hard-wired the retirement or conversion to natural gas for the coal units to these dates, rather than allowing the model to select what to do with Pawnee and Comanche 3. The Company then conducted both capacity expansion and production cost modeling using the Encompass model to develop resource portfolios around these hard-wired decisions for Pawnee and Comanche 3.

Table 1: PSCO's Paired Actions[1]

	Pawnee	Comanche 3
1	Retire 2041	Retire 2069
2	Retire 2028	Retire 2029
3	Retire 2028	Retire 2039*
4	Convert gas 2027	Convert gas 2027
5	Convert gas 2027	Retire 2029
6	Convert gas 2027	Retire 2039
7	Convert gas 2027	Retire 2039*
8	Convert gas 2024	Retire 2039*

The Company's chosen portfolio under each of these paired actions was produced by optimizing the buildout of new resources in the Encompass model using its

[1] Exhibit 101, Attachment AKJ-1_Plan Overview, Table 1.5-1. The asterisk refers to where the Company assumes reduced operations for Comanche 3 in the 2030's. As a shorthand, I refer to these as "portfolios" throughout and will specify when referring to SCC or $0/ton portfolios (e.g. SCC 7). * refers to reduced operations at Comanche 3 in the 2030's.

capacity expansion capability. The capacity expansion modeling was done under two different assumptions for the cost of carbon: the social cost of carbon ("SCC") and zero carbon costs ("$0/ton"). For most of these modeling runs—such as under the base assumptions—eight portfolios matching the paired actions above are generated using the social cost of carbon ("SCC 1" through "SCC 8") and eight are generated assuming no carbon costs ("$/ton 1" through "$/ton 8").

The Company then conducted production cost modeling that fixed these portfolios in-place and projected individual generators' operations and costs throughout the modeling period (2020-2055). This final modeling step generates the PVRR and costs of carbon. In most of these runs, the Company assumed no carbon costs in dispatch for both SCC and $/ton portfolios; thus, carbon costs would not directly influence how often a unit would operate or its operating costs in these runs. But, in the initial base case runs, the Company also modeled the SCC portfolios with an SCC dispatch cost.

Q. Which portfolio did the Company select as a preferred plan?

A. The Company's preferred plan is SCC 7, where Comanche Unit 3 retires at the end of 2039 and Pawnee is converted to natural gas at the end of 2027 (see paired action 7 above in Table 1).[2] This portfolio adds approximately 2,300 MW of wind, 1,550 MW of utility-scale solar, 1,158 MW of distributed solar, 400 MW of battery

[2] Hearing Exhibit 101, Attachment AKJ-1_Plan Overview, p. 54

storage, and 1,276 MW of "firm dispatchable" capacity—the latter using combustion turbines as a proxy in the model.[3]

Q. When considering costs and emissions, is the retirement of Comanche 3 in 2039 the best option for a preferred plan?

A. No, as I discuss further below, when considering the costs to customers (PVRR) including carbon costs and the reduction in emissions, portfolios with earlier retirement of Comanche 3 are preferable.

Q. Please explain the difference between the two main cost measures reported by the Company.

A. The Company reports the PVRR in two ways: 1) the PVRR without carbon costs; and 2) the PVRR with carbon costs which includes the net present value of carbon emissions using the social cost of carbon. The Company's results highlight the difference between the PVRR or PVRR with carbon costs of portfolios 2 through 8, relative to portfolio 1.[4]

Q. Should the PVRR with carbon costs be given at least as much weight, if not more weight, than the PVRR without carbon costs?

A. Yes. The State of Colorado has taken strong steps towards reducing greenhouse emissions, including by directing that more stringent requirements are placed on utilities' planning practices. In 2019, Colorado House Bill 19-1261 specified that the state should achieve "at a minimum" a 90 percent reduction in 2005-level

[3] *Id.* p. 42
[4] See: Hearing Exhibit 101, CORRECTED Attachment AKJ-2_Technical Appendix_CLEAN, Table 2.13-2.

greenhouse gas emissions by 2050.[5] (The Company also has a goal to be carbon-free by 2050.) Senate Bill 19-236 revised Colorado Statute section 40-3.2-106 to direct the Commission to require that electric utilities consider the costs of carbon in determining "the cost, benefit, or net present value of any plan or proposal," including in ERP proceedings.[6] This statute states: 1) that the utility must "at a minimum, model an optimization of a base case portfolio;" 2) that the SCC should be used as the value for carbon dioxide; and 3), that the Commission must consider both the net present value of both the revenue requirements and costs of carbon.[7] In 2021, the Governor signed several bills into law, such as SB 21-264[8] SB 21-272,[9] that reinforce and expand the requirement that the Commission and utilities consider the social cost of carbon in utilities' electric resource plans.

While the Company reports the PVRR both with and without carbon costs, it appears to lean on the PVRR without carbon costs in its choice of preferred plan. Yet this PVRR measure alone is problematic because it includes $0 in carbon costs—be they regulatory or societal costs—through 2055.

Both SB 19-236 and SB 21-272 require the Commission to consider the PVRR with the social cost of carbon. This suggests that the PVRR with the social cost of carbon should be given at least as much weight as the PVRR without the social cost of carbon. As witness Jason Schwartz explains in his testimony, there are further

[5] Colorado HB 19-1261, Section 1, paragraph (g)
[6] Colorado SB, Section 13.
[7] *Id.*
[8] SB 21-246 revises section 40-3.2-106(1) to require the use of both the social cost of carbon dioxide and the social cost of methane emissions.
[9] SB 21-272 revises section 40-3.2-106(3) such that the Commission must require a comparison of the PVRR of a portfolio inclusive of the social cost of carbon dioxide.

compelling reasons to give more weight to the PVRR with the social cost of carbon. Thus, my testimony will place greater weight on the PVRR with carbon costs reported by PSCO.

Q. Does the Company's modeling indicate that retirement of Comanche 3 before 2039 is lower cost, when considering the PVRR inclusive of carbon costs?

A. Yes. Under the PVRR with carbon cost metric, ceasing coal at Comanche 3 before 2039 is clearly more favorable to retiring the unit in 2039. Table 2 below shows the ranking of portfolios under each optimization/dispatch modeling run for the base, low gas price, high gas price, low load and high load scenarios. The portfolios' costs were modeled by the Company under both SCC and $0/ton optimization, and mostly $0/ton dispatch costs—with the exception of the base modeling run where the Company also modeled SCC dispatch costs. With no alterations to the Company's results, I have simply reported the rank of "1" as the lowest-cost portfolio for that modeling run and "8" is the highest-cost. Portfolio 4, where both Pawnee and Comanche 3 are converted to gas in 2027, is the lowest-cost portfolio in most cases. Portfolio 5, in which Pawnee converts to gas in 2027 and Comanche 3 retires in 2029, is the second-lowest-cost portfolio in most cases.

Table 2: Ranking of Portfolios Based on PVRR with Carbon Costs[10]

			Portfolio							
			1	**2**	**3**	**4**	**5**	**6**	**7**	**8**
		Pawnee	*Retire 2041*	*Retire 2028*	*Retire 2028*	*Convert 2027*	*Convert 2027*	*Convert 2027*	*Convert 2027*	*Convert 2024*
		Comanche 3	*Retire 2069*	*Retire 2029*	*Retire 2039**	*Convert 2027*	*Retire 2029*	*Retire 2039*	*Retire 2039**	*Retire 2039**
Scenario	**Optimization**	**Dispatch**	**PVRR+CO2 Rank (1=lowest cost)**							
Base	SCC	$0/ton	8	3	7	1	2	6	5	4
Base	$0/ton	$0/ton	8	5	7	1	2	6	3	4
Base	SCC	SCC	8	3	7	1	2	6	4	5
High Gas	SCC	$0/ton	8	3	7	1	2	6	5	4
High Gas	$0/ton	$0/ton	8	6	7	2	5	3	4	1
Low Gas	SCC	$0/ton	8	3	7	1	2	6	5	4
Low Gas	$0/ton	$0/ton	8	4	7	1	2	6	3	5
High Load	SCC	$0/ton	8	3	7	1	2	6	4	5
High Load	$0/ton	$0/ton	8	3	7	1	2	5	4	6
Low Load	SCC	$0/ton	8	3	7	1	2	6	4	5
Low Load	$0/ton	$0/ton	8	6	7	2	3	5	4	1

Q. If one wanted to weight the two cost metrics equally, would that change your conclusion about the favorability of the portfolio 4 relative to portfolio 7?

A. No. As an illustrative exercise, I took the average of the PVRR results both with and without carbon costs—effectively giving each of the cost measures 50 percent weight. The resulting rankings, below in Table 3, show that portfolio 4 is the least-cost plan in 8 of the 11 runs conducted—remaining clearly superior to portfolio 7.

Table 3: Ranking of Portfolios Based on Average of PVRR with and without Carbon Costs[11]

			Portfolio							
			1	**2**	**3**	**4**	**5**	**6**	**7**	**8**
		Pawnee	*Retire 2041*	*Retire 2028*	*Retire 2028*	*Convert 2027*	*Convert 2027*	*Convert 2027*	*Convert 2027*	*Convert 2024*
		Comanche 3	*Retire 2069*	*Retire 2029*	*Retire 2039**	*Convert 2027*	*Retire 2029*	*Retire 2039*	*Retire 2039**	*Retire 2039**
Scenario	**Optimization**	**Dispatch**	**Average of PVRR and PVRR+CO2 (1=lowest cost)**							
Base	SCC	$0/ton	8	6	7	1	2	5	3	4
Base	$0/ton	$0/ton	8	4	7	1	2	5	3	6
Base	SCC	SCC	8	4	7	1	3	5	2	6
High Gas	SCC	$0/ton	8	6	7	4	5	3	1	2
High Gas	$0/ton	$0/ton	8	6	7	3	4	2	1	5
Low Gas	SCC	$0/ton	8	6	7	1	2	4	3	5
Low Gas	$0/ton	$0/ton	8	4	7	1	2	5	3	6
High Load	SCC	$0/ton	8	5	7	1	4	3	2	6
High Load	$0/ton	$0/ton	6	1	8	2	3	5	4	7
Low Load	SCC	$0/ton	8	5	7	1	2	4	3	6
Low Load	$0/ton	$0/ton	8	5	7	1	3	6	4	2

[10] 21A-0141E_CORRECTED_Public Workpaper_Volume 2_47_Results Tables
[11] Id.

Q. In the tables presented above, did you make any adjustments to the PVRR's reported by PSCO?

A. I made only one slight adjustment to the costs of portfolio 7. In its results, the Company reported the PVRR for its preferred plan assuming that securitization was employed for the 2039 retirement of Comanche 3—but only in portfolio 7.[12] This financing mechanism produced savings of $39 million for portfolio 7.[13] Because the reduced PVRR for portfolio 7 was reported among all other portfolios where securitization was <u>not</u> employed, the presentation of results was inconsistent and unfairly biased towards the preferred plan. To rectify this, I reversed the impact of securitization of Comanche 3 in portfolio 7 by adding back out the $39 million savings—making the treatment of the unit's costs consistent across portfolios.

Q. Which portfolios achieve the largest reduction in carbon emissions in 2030?

A. The portfolios in which Comanche 3 retires in 2029 had the most carbon emissions reductions. The Company reports the percentage reduction in carbon emissions by 2030 (relative to 2005) levels for each portfolio. Again, I re-framed the Company's modeling results by ranking the portfolios' performance—shown in Table 4. In this table, a ranking of "1" shows the portfolio with the most carbon reduction. By this measure, portfolios 2 and 5—where Comanche 3 fully retires in 2029 and Pawnee

[12] *See* Hearing Exhibit 1402, Attachment TC-2 (Company's Response to Discovery Request CIEA 1-5), Attachment TC-3 (Company's Response to Discovery Request CC 1-7), Attachment TC-4 (Company's Response to Discovery Request CC 1-14).
[13] Attachment TC-5 (21A-0141E_Attachment CC1-40.A1). The Company estimates savings from securitization of Comanche 3 costs under the preferred plan as $39 million, relative to the regulatory asset treatment.

either retires in 2028 or converts to gas in 2027—mostly provide more carbon reduction than the preferred plan.

Table 4: Ranking of Portfolios Based on Carbon Emissions Reduction[14]

			Portfolio							
			1	2	3	4	5	6	7	8
		Pawnee	*Retire 2041*	*Retire 2028*	*Retire 2028*	*Convert 2027*	*Convert 2027*	*Convert 2027*	*Convert 2027*	*Convert 2024*
		Comanche 3	*Retire 2069*	*Retire 2029*	*Retire 2039**	*Convert 2027*	*Retire 2029*	*Retire 2039*	*Retire 2039**	*Retire 2039**
Scenario	**Optimization**	**Dispatch**	**CO2 reduction (1=most reduction)**							
Base	SCC	$0/ton	8	1	7	3	2	5	4	6
Base	$0/ton	$0/ton	8	1	4	6	7	3	2	5
Base	SCC	SCC	8	1	5	3	2	7	4	5
High Gas	SCC	$0/ton	8	1	6	3	2	5	4	7
High Gas	$0/ton	$0/ton	8	1	4	6	7	3	2	5
Low Gas	SCC	$0/ton	8	1	6	3	2	5	4	7
Low Gas	$0/ton	$0/ton	8	1	4	6	7	3	2	5
High Load	SCC	$0/ton	8	1	7	3	2	5	4	6
High Load	$0/ton	$0/ton	8	6	4	3	2	5	1	7
Low Load	SCC	$0/ton	8	1	6	3	2	5	4	7
Low Load	$0/ton	$0/ton	8	2	4	7	1	6	3	5

Q. Did you estimate the savings of retiring Comanche 3 in 2029 using PSCO's modeling?

A. Yes. I quantified the relative savings of retiring Comanche 3 earlier than 2039 by comparing the PVRR inclusive of carbon costs of portfolios 5 in which the unit ceases burning coal in 2029 to the costs of portfolio 7. This estimate is possible because the Pawnee unit is converted to gas in 2027 in both portfolios 5 and 7, while Comanche is retired in 2029 and 2039, respectively. Since the Pawnee action is held constant across portfolios 5 and 7, comparing the costs of portfolios 5 and 7 indicates the impact from changing the Comanche 3 retirement date.

The estimated savings of retiring Comanche 3 in 2029 are $91 million, on average, by taking the costs of portfolio 7 minus portfolio 5—as shown in Table 5.

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[14] 21A-0141E_CORRECTED_Public Workpaper_Volume 2_47_Results Tables

Table 5: Savings from Retiring Comanche 3 in 2029 relative to 2039, Portfolio 7 minus Portfolio 5 ($mil PVRR+CO2 cost)[15]

Optimization	***SCC***	***SCC***	***$0/ton***	***Average savings***
Dispatch	***SCC***	***$0/ton***	***$0/ton***	
Base	$55	$177	$9	$80
Low Gas		$211	$63	$137
High Gas		$135	-$58	$38
High Load		$89	$29	$59
Low Load		$261	$34	$148
Average savings				**$91**

This comparison shows robust savings across the Company's modeling runs. Retiring Comanche 3 in 2029 produces savings in 10 of the 11 comparisons shown above—and most of which assume no carbon dispatch cost. In only one instance was retiring Comanche 3 in 2029 more costly: the $0/ton optimized portfolio with $0/ton dispatch cost in the High Gas scenario.

Q. Did you estimate the savings of ceasing coal operations at Comanche 3 in 2027?

A. Yes. I compared the costs of portfolios 7 minus portfolio 4; in both portfolios, Pawnee is converted to gas in 2027, but Comanche 3 is retired in 2039 in portfolio 7 and converted to gas in 2027 in portfolio 4. The average savings of 2027 conversion of Comanche 3 relative to retirement in 2039 is $254 million—shown below in Table 6. There were more costs to compare in this case because the Company developed versions of portfolios 1, 2, 4 and 7 under more scenarios: sunk transmission upgrade costs, no new natural gas generation, lower hydrogen costs, and expanded market access.

15 Id

Table 6: Savings from Converting Comanche 3 to Gas in 2027 relative to retirement in 2039, Portfolio 7 minus Portfolio 4 ($mil PVRR+CO2 cost)[16]

Optimization	*SCC*	*SCC*	*$0/ton*	*Average savings*
Dispatch	*SCC*	*$0/ton*	*$0/ton*	
Base	$111	$241	$132	$161
Low Gas		$308	$206	$257
High Gas		$154	$36	$95
High Load		$267	$89	$178
Low Load		$295	$134	$215
Sunk Tx		$419		$419
No New Gas		$898		$898
Lower Hydrogen		$267		$267
Expanded Mkt		$257		$257
Average savings				**$254**

Q. You rely on the cost metric of PVRR with carbon costs in estimating the savings shown above. Has state law recently been amended to include more stringent requirements for electric utilities to value greenhouse gas emissions than what Xcel modeled in this case?

A. Yes, the requirements for accounting for greenhouse gas emissions in planning have recently become more stringent since the Company filed its plan. Building off of SB 19-236, HB 21-1238 added new requirements, including that: 1) the social cost of methane emissions should also be considered by the Commission; 2) a higher value for the SCC be used ($68 per ton in 2020 at minimum); and 3) that the net present value of both carbon and methane emission values use a maximum discount rate of 2.5 percent.[17]

All three of these changes would increase the net present value of greenhouse gas emissions, compared to what is currently included in the Company's filing. First,

[16] Id
[17] Colorado HB 21-1238, Section 6.

the inclusion of the value of methane emissions would be a new addition whereas previously only carbon costs were considered. Second, the SCC value that utilities and the Commission must consider will increase significantly from the current level, in which the social cost of carbon starts at $48/ton in 2021,[18] to a value of $68/ton starting in 2020.[19] Third, a maximum discount rate of 2.5 percent would increase the present value of greenhouse gas emissions relative to the current use of the utility's weighted average cost of capital (WACC) of 6.53 percent. (These requirements and their future application are discussed in depth in the testimony of my co-witness, Jason Schwartz.)

Q. Given these recent changes, would the savings from retiring Comanche 3 before 2039 be larger than what you have presented under the required social cost of carbon and methane values?

A. Yes. The costs of greenhouse gases that PSCO's calculated for each portfolio significantly underestimates the cost of greenhouse gas emissions under the methodology now required by Colorado law. PSCO's calculations of the cost of greenhouse gas emissions includes no value for methane emissions, uses the lower SCC value (starting at $48 per ton in 2021), and uses the utility WACC as a discount rate for calculating the net present value. Moreover, the resources chosen under model optimization in the SCC model runs used the lower SCC cost.

I am not faulting the Company for failing to incorporate these new requirements in the Company's initial application, because the Company's plan was filed three

[18] Hearing Exhibit 101, CORRECTED Attachment AKJ-2_Technical Appendix_CLEAN, p. 281.
[19] Colorado HB 21-1238, Section 6.

months prior to the signing of HB 21-1238 into law. However, the Company filed corrected and supplemental modeling on August 13, 2021, nearly two months after HB 21-1238 was signed by the Governor on June 24, 2021. Thus, because the Company was already re-running its original modeling, and conducting supplemental modeling, the Company could have updated the social cost of methane and social cost of carbon values to reflect the new requirements in HB 21-1238. If the Company did not have time to re-optimize the SCC buildouts with the updated value, it could have at least applied the updated value in its calculation of carbon costs from each portfolio. But the Company did not do so.

Since the Company's plan was filed, the treatment of greenhouse gas emissions in resource planning has only become more comprehensive, and as a result, would only increase the costs of those emissions—and by extension the savings of decarbonizing the Company's fleet. The change in law in HB 21-1238 reinforces the need to, at a bare minimum, weigh the PVRR with carbon costs in this case more heavily because these costs are understated in PSCO's modeling (because PSCO's modeling does not use the higher SCC values now required by HB 21-1238).

Q. How else could the Company address these new greenhouse gas requirements in this docket?

A. In addition to relying on the PVRR with carbon cost metric, the value of carbon costs could be updated to account for the higher SCC value and the value of reducing methane emissions should also be considered, to the extent possible. The Company did not optimize its portfolios to account for the higher SCC value nor for methane emission value in HB 21-1238. As I discuss later, alternative modeling conducted by my co-witness Dr. Roumpani applied the more recent social cost of carbon in optimizing the portfolios. If the Company does not include such an evaluation in Phase I, then the legally-required values of those emissions should be applied in Phase II of the ERP where possible.

Q. What do you conclude about the future of Comanche 3 given the Company's modeling in this case?

A. Taking the Company's modeling results at face value,[20] I conclude that ceasing to burn coal in 2027 or 2029 at Comanche 3 is lower-cost compared to the Company's current plan to retire the unit in 2039. The new requirements in HB 21-1238, which includes the use of the social cost of methane and increases the minimum values for the social cost of carbon, reinforce the benefit of retiring the unit earlier.

Further in my testimony, I discuss several flaws in the Company's modeling approach and discuss alternative modeling (conducted by Dr. Maria Roumpani) done in this case that bolsters the case for early retirement of Comanche 3.

III. THERE ARE CRITICAL DEFICIENCIES IN THE COMPANY'S ANALYSIS

Q. Please summarize this section of testimony.

A. In this section, I discuss several key deficiencies in the Company's approach and modeling supporting the ERP. First, the Company only modeled the retirement of its coal units for a limited selection of years. Economic optimization should ideally

[20] As noted above, the only change I have made to the PVRRs that the Company reported is to remove the savings from securitization from portfolio SCC 7, to ensure an apples-to-apples comparison of the portfolios under the same cost recovery assumptions.

test all possible retirement dates endogenously by the model, or at least examine a fuller set of retirement possibilities if the dates must be hard-wired into the model. Second, the operating characteristics of operating Comanche 3 as a coal-fired unit are overly optimistic, making the unit appear more advantageous than it actually is. Third, the treatment of new natural gas generation in modeling does not adequately address the requirement of zero carbon emissions by 2050.

Some of these deficiencies were also addressed by the Commission's request for the Company to conduct supplemental modeling runs. I will discuss to what extent these issues were rectified in the Company's supplemental modeling. Further in my testimony, I discuss modeling done by my co-witness Dr. Maria Roumpani that also addressed some of these deficiencies, and how others can be addressed in Phase II.

A. The Company Did Not Sufficiently Explain How It Selected the Retirement Dates it Analyzed

Q. Did the Company sufficiently explain how it selected the gas conversion and retirement dates it modeled for Pawnee and Comanche 3?

A. No. The Company's modeling fixed the coal units' retirement or gas conversion to a select few dates which only allowed for a limited examination of the economically optimal retirement date. Table 1 shows the limited set of actions that were tested for Pawnee and Comanche 3, which leaves many avenues unexplored. In discovery responses, the Company stated that it did not conduct preliminary modeling to determine which retirement and gas conversion dates to model for

Pawnee and Comanche 3, and thus it is unclear how and why the Company selected the gas conversion and retirement dates that it presented in its direct case.[21]

Q. Did the Company model any retirement dates for Craig 2, Hayden 1, and Hayden 2 other than the retirement dates it is proposing?

A. No. All of the portfolios assumed that Hayden 2 would retire in 2027 and that Hayden 1 and Craig 2 would retire in 2028. The Company stated that these dates were agreed upon with co-owners but also that there was no modeling done to justify this decision.[22]

Q. Did the Company test the retirement dates of the Craig and Hayden units in this docket?

A. Yes, but in a very limited way and apparently after the retirement decision was made. In this docket, the Company did a side analysis comparing the already-agreed upon retirement dates to the Craig and Hayden units' original retirement dates (2039 for Craig 2, 2030 for Hayden 1, and 2036 for Hayden 2)—using the preferred plan (portfolio 7) as a basis. The Company's analysis that showed that under SCC optimization "all retirements show net benefits when the cost of carbon is included" and that under $0/ton optimization "the combination of all accelerated retirements shows net benefits when the cost of carbon is included, and near zero costs under a

[21] Hearing Exhibit 1402, Attachment TC-6 (Company's Response to Discovery Request CC 1-30).
[22] Hearing Exhibit 101, CORRECTED Attachment AKJ-2_Technical Appendix_CLEAN. p.272; *see also* Hearing Exhibit 1402, Attachment TC-7 (Company's Response to Discovery Request CC 1-9), Attachment TC-8 (Company's Response to Discovery Request CC 4-5), Attachment TC-9 (Company's Response to Discovery Request CC 4-6).

PVRR view."[23] These results show that the chosen retirement dates of Craig and Hayden were beneficial but not necessarily optimal because there were no other early retirement dates evaluated.

Q. Do you expect the Company to evaluate all possible retirement dates for all of its coal units?

A. No. Ideally, the modeling would explore all possible avenues for all units but I understand that the modeling process is time-intensive and needs to be targeted in some fashion. Given that, I still maintain that the Company could have explored more options for its coal units rather than a select few retirement dates. Moreover, the Company did not justify the selection of the dates that it chose to model. Ultimately, the Company's approach provides a narrow view of these units' economics.

B. The Company's Assumed Costs and Operations of Comanche 3 are Overly Optimistic.

Q. Are the assumptions for the operating characteristics of Comanche 3 overly optimistic?

A. Yes. The Company uses overly optimistic assumptions for the forced outage rate—and relatedly the availability factor—of Comanche 3. In addition, the Company assumes operations and maintenance (O&M) costs for Comanche 3 that are overly optimistic, which means the future performance and costs projected by the Company's modeling are unfairly favorable to keeping the unit on-line.

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[23] Hearing Exhibit 101, CORRECTED Attachment AKJ-2_Technical Appendix_CLEAN. p.274-275

Q. Are the Company's projected O&M costs for Comanche 3 reasonable?

A. [redacted]—shown in Figure 1 in real 2020 dollars. The O&M costs below includes the variable O&M (VOM) and fixed O&M (FOM) which are projected separately in the modeling but the Company does not track separately for historical data.[24] The unit's total O&M costs since its first full year of operation have averaged [redacted] ($2020), yet in its preferred plan, the Company projected an average O&M cost of [redacted] ($2020)[25]—a [redacted] decrease in real O&M costs at Comanche 3. Notably, there is a [redacted] in the actual costs incurred in 2020 [redacted]) with what the Company projected for that year ([redacted]).

[24] Attachment TC-10 (Company's Response to Discovery Request CPUC 11-6). Typically, variable O&M represents costs that vary with the level of generation while fixed O&M represents costs incurred no matter the level of generation.
[25] 21A-0141E_CONFIDENTIAL Attachment CC1-82.A1_Comanche 3 O&M; 21A-0141E_CORRECTED_Highly Confidential Workpaper_Volume 2_09_EO - SCC Base_071621. Projected values are for SCC 7 portfolio with $0/ton CO_2 dispatch.

Figure 1: Comanche 3 O&M Costs – Actual vs. Projected ($2020 mil) – HIGHLY CONFIDENTIAL[26]

[redacted]

Q. Was this issue addressed in Commission Staff's March 2021 Report, and in the Commission's request for supplemental modeling?

A. Yes. In Staff's March 2021 Report on Comanche 3, the Commission recommended that the Company conduct modeling where the unit's O&M costs based on its historical O&M costs ("Staff O&M").[27] This was a reasonable request given the Company's overly optimistic assumptions of future costs. In response to this request, the Company modeled the future fixed O&M to match the historical average total O&M and fixing the variable O&M to $0.[28]

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[26] Id.
[27] Decision No. C21-0395-I, p.4
[28] Supplemental Direct Testimony of Jon T. Landrum, p. 29, lines 4-9; Attachment TC-11 (Company's Response to Discovery Request CC 7-11).

Q. Do you agree with the way the Company conducted its supplemental modeling in response to the Commission's request to model Comanche 3 with increased O&M costs?

A. Not fully. While I broadly agree with the Commission's recommendation, the Company's modeling sets the variable O&M of the unit to $0, which decreases the unit's variable costs of operation (i.e. dispatch costs) compared to its original and corrected modeling. Variable or dispatch costs include fuel costs plus variable O&M costs, but the Company's supplemental modeling takes the latter out of the equation. All else equal, this means that the unit would appear less costly to dispatch in the model and as a result could be projected to operate more often under these falsely deflated variable costs.[29] Thus, the Company's supplemental modeling in response to the Commission would only increase or not change the unit's capacity factor. The recommended change in the availability of the unit, discussed below, would also impact the unit's capacity factor.

Q. Is the Company's projected forced outage rate for Comanche 3 reasonable?

A. No. The forced outage rate that the Company assumes for Comanche 3 in its original and corrected modeling is overly optimistic given the unit's past performance—especially given that the unit was out for almost all of 2020 because of two separate forced outages. The Company assumed a forced outage rate of [redacted] percent for the remaining life of the unit.[30] But the average forced outage rate at the unit between 2010 and 2020 was more than [redacted] percent.[31] This

[29] Id.
[30] See: 21A-0141E_Highly Confidential Attachment CC1-26.A1, Resource tab
[31] Confidential Attachment CPUC4-3c.A1

is an important modeling input because, along with the planned or maintenance outages, it determines how often the unit is available to operate. The fewer hours that Comanche 3 is assumed to be on an outage, the more potential there is for the model to operate the unit.

Q. Did the Company also address this issue in their supplemental modeling?

A. Yes, the Company followed the Commission recommendation by adjusting the equivalent availability factor (EAF) of the unit down to 71.2 percent by adjusting both the forced and planned outage rates.[32] [redacted].[33] [redacted]

C. The Company's Assumptions for New Gas Units Are Inconsistent with the Company's 2050 Zero-Carbon Goal.

Q. Does the Company's treatment of new gas units in its preferred plan sufficiently address its 2050 carbon-free goal?

A. No. The Company's approach to being carbon-free relies on speculative technology that is unproven and not all costs of going carbon-free are included. The Company's preferred plan includes approximately 1,300 MW of "firm dispatchable" capacity that is modeled as new natural gas generation.[34] Some of this new gas generation is projected to operate past 2050 when the Company has stated that it is going to be carbon-free. The Company tried to address this by modeling gas units as gradually switching to a blend of natural gas and hydrogen fuel starting in 2041, increasing to

[32] Supplemental Direct Testimony of Jon T. Landrum, p. 29, lines 9-12
[33] CONFIDENTIAL Attachment CC1-84.A1
[34] CORRECTED Attachment AKJ-1_Plan Overview_CLEAN, p.7

100 percent hydrogen by 2050.[35] The Company included a fuel cost of hydrogen but zero costs for the conversion of these units to be capable of burning 100 percent hydrogen and zero costs for transportation and storage of hydrogen.[36] The Company stated that the technology to convert its gas units to 100 percent hydrogen "is not currently technically feasible" and as a result the costs of doing so "cannot be identified at this time."[37] There is also the issue of access to hydrogen itself. The Company's modeling does not appear to assume any costs associated with transportation of hydrogen.[38]

Thus, the Company is proposing a framework for acquiring new gas and meeting its 2050 zero carbon goal that relies on conversion to 100 percent hydrogen, an untested technology that may or not be available in the future.[39] Even if it becomes technically feasible and cost-effective to convert gas turbines to burn 100 percent hydrogen, the Company is not including the full costs of hydrogen conversion in its plan, because it is accounting for only the cost of hydrogen fuel itself, and not the other conversion costs (turbine upgrades, transportation, storage, etc.).

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[35] Id. p.52; *see also* Hearing Exhibit 1402, Attachment TC-12 (Company's Response to Discovery Request CC 1-57).
[36] Hearing Exhibit 1402, Attachment TC-13 (Company's Response to Discovery Request OCC 12-4), Attachment TC-14 (Company's Response to Discovery Request CC 1-59(b)).
[37] Hearing Exhibit 1402, Attachment TC-14 (Company's Response to Discovery Request CC 1-59(b)).
[38] Hearing Exhibit 1402, Attachment TC-15 (Company's Response to Discovery Request CC 1-58).
[39] *See* Hearing Exhibit 1402, Attachment TC-16 (Company's Response to Discovery Request CC 1-19); Attachment TC-17 (Company's Response to Discovery Request CC 1-73).

Q. Are there risks to investing in new gas generation given carbon emissions goals and laws?

A. Yes. Given the Company's own carbon-free goal and the state's stringent greenhouse gas laws, there is substantial risk to building or procuring new gas units with the mere hope that they can one day run on hydrogen. One supplemental run requested by the Commission addresses this concern by asking the Company to assume that new gas units were limited to a 20-year useful life and that no power purchase agreements for natural gas generation go beyond 2050.[40] I understand the concern: if the hydrogen path does not prove feasible or economic in the future, the remaining gas units could become stranded assets—with ratepayers footing the bill.

Locking in new gas units now in the hopes of going carbon-free by converting those units to burn 100 percent hydrogen—and not including all costs associated with such operations—forecloses other options for producing carbon-free electricity in the long-term. For example, longer-duration battery storage is currently available and its costs are expected to plummet in the future.[41] The Company only modeled the 4-hour battery storage option for the analysis period (2021-2055) but longer duration batteries are likely to become a more predominant peaking capacity resource in the 2040's and 2050's.[42]

[40] Decision No. C21-0395-I, p.2

[41] Frazier, A. Will, Wesley Cole, Paul Denholm, Scott Machen, Nathaniel Gates, and Nate Blair. *Storage Futures Study: Economic Potential of Diurnal Storage in the U.S. Power Sector*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-77449. Available at: https://www.nrel.gov/docs/fy21osti/77449.pdf. Table A-3. See also: "Secretary Granholm Announces New Goal to Cut Costs of Long Duration Energy Storage by 90 Percent," available at: https://www.energy.gov/articles/secretary-granholm-announces-new-goal-cut-costs-long-duration-energy-storage-90-percent

[42] Id. p. vii.

Q. Did your team produce modeling that addressed some of your concerns to the Company's approach?

A. Yes, to an extent. My co-witness Dr. Roumpani presents modeling that addresses some of the concerns I have discussed in this section including: exploring more options for the futures Comanche 3 and Pawnee as well as more realistic O&M costs and forced outage rates at Comanche 3. In the next section, I discuss the assumptions and results from that alternative modeling and the ultimate choice of an alternative Phase I portfolio. Subsequently, I discuss steps that should be taken in Phase II to address issues I have raised.

IV. Alternative Modeling Supports 2027 Retirement of Comanche 3 and 2024 Conversion of Pawnee

Q. Did your co-witness Dr. Maria Roumpani conduct alternative modeling in this docket?

A. Yes. Dr. Roumpani conducted capacity expansion and production cost modeling using the Encompass model, broadly following the methodology of PSCO. This modeling diverged from the Company's in several key ways: 1) it tested additional retirement or gas conversion options for Comanche 3, Pawnee, and the Cherokee gas plant; 2) it incorporated updates and corrections to resource cost assumptions; 3) it updated the social cost of carbon; and 4) it used a more reasonable effective load carrying capability (ELCC) for battery storage. I provided the resource cost updates and corrections to Dr. Roumpani's modeling. My co-witness, Derek Stenclik, provided testimony on the battery ELCC assumptions. (Further detail on Dr. Roumpani's modeling assumptions is provided in her testimony.)

Q. What did Dr. Roumpani's modeling conclude regarding Comanche 3 and Pawnee?

A. This alternative modeling shows that the retirement of Comanche 3 in 2027 and the gas conversion of Pawnee in 2024 provided savings of over $1 billion in PVRR without carbon costs or $2.7 billion with carbon costs, compared to the Company's preferred plan.

Q. To use the Company's term, what "paired actions" did Dr. Roumpani evaluate for Comanche 3 and Pawnee?

A. The futures evaluated in this modeling are shown below in Table 7. This modeling replicated the preferred plan ("CC 0") as a benchmark for comparison with other combinations of retirement and gas conversion at the two units. Portfolios CC 2, 3 and 6 are combinations that were not tested by PSCO. Portfolio CC 1 has the same assumed retirement as the Company's portfolio 5. Portfolio CC 4 assumes the same retirements as the Company's portfolio 2. Portfolio CC 5 is the same as CC 1 but the former tested the retirement of Cherokee in 2027.

Table 7: Conservation Coalitions Paired Actions[43]

	Pawnee	Comanche 3	Cherokee (gas)
CC 0	Convert gas 2027	Retire 2039*	Retire 2055
CC 1	Convert gas 2027	Retire 2029	Retire 2055
CC 2	Convert gas 2027	Retire 2027	Retire 2055
CC 3	Convert gas 2024	Retire 2029	Retire 2055
CC 4	Retire 2028	Retire 2029	Retire 2055
CC 5	Convert gas 2027	Retire 2029	Retire 2027
CC 6	Convert gas 2024	Retire 2027	Retire 2055

[43] Exhibit 101, Attachment AKJ-1_Plan Overview, Table 1.5-1. The asterisk refers to where the Company assumes reduced operations for Comanche 3 in the 2030's. As a shorthand, I refer to these as "portfolios" throughout and will specify when referring to SCC or $0/ton portfolios (e.g. SCC 7).

Q. Did you recommend changes to the input assumptions that were incorporated into the alternative modeling Dr. Roumpani conducted?

A. Yes, I proposed several changes to the input assumptions related to Comanche 3 and potential replacement resources.

First, given the previously discussed concerns over the Comanche 3 O&M costs, I provided alternative assumptions that were more reasonable than those used by PSCO. My alternative O&M costs for Comanche 3 used the Company's supplemental runs (in response to Commission requests) as a basis but I backed out the variable O&M using the costs from the Company's preferred plan run (SCC 7 under $0/ton dispatch). The result is a fixed O&M that is slightly lower than what the Company modeled in the supplemental runs but with a higher variable O&M—as opposed to the $0 variable O&M assumed by the Company in its supplemental modeling run.

Second, given concerns with the overly optimistic forced outage rate assumption of Comanche 3 ([redacted] percent), I recommended that we assume a [redacted] percent forced outage rate based on the average forced outage rate of the unit from 2010 through 2019.[44] I excluded the 2020 outage from this range, treating that outage as an anomaly; although I do not take a position on whether or not it was such. The Commission's request, which includes the 2020 outage in its average, addresses a valid concern over the unit's availability given this extreme event; but I decided to not include it and remain conservative (i.e. favorable to the unit).[45]

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[44] Hearing Exhibit 1402, Attachment TC-18 (21A-0141E_Confidential Attachment CPUC4-3c.A1)
[45] Decision No. C21-0395-I, p.4

Third, I provided updated alternative solar, wind, and battery costs using the same source as the Company for these costs—forecasts from the National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB).[46] The Company used the 2020 NREL ATB but the 2021 NREL ATB was released in July of this year. I followed PSCO's methodology of calculating levelized costs of solar, wind and battery but substituted the more up-to-date 2021 ATB capital and O&M cost forecasts from NREL for these resources. I also corrected an error in the calculation of levelized costs of batteries.

Q. How do your recommended costs of solar, wind, and battery storage compare to those used by PSCO?

A. My proposed wind and battery costs are much lower—on average 16 to 17 percent lower that the Company's, respectively. The updated solar PV costs are higher given the changes to the NREL ATB—roughly 7 percent higher. Comparisons of all three resources' levelized costs are shown below:

[46] Hearing Exhibit 101, CORRECTED Attachment AKJ-2_Technical Appendix_CLEAN, p.309-310.

Figure 2: Levelized Costs of Solar PV ($/MWh)

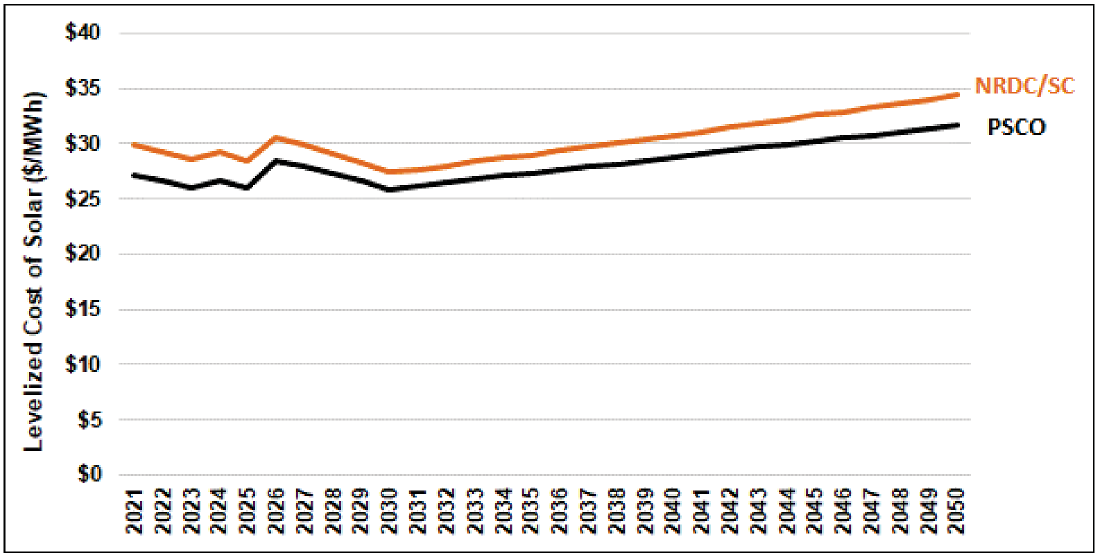


Figure 3: Levelized Costs of Wind ($/MWh)

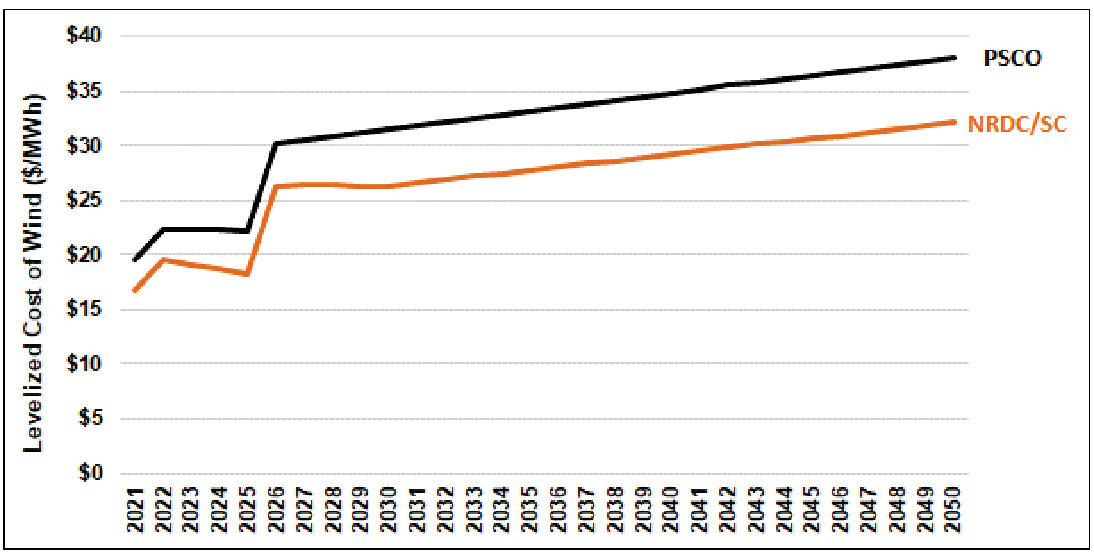
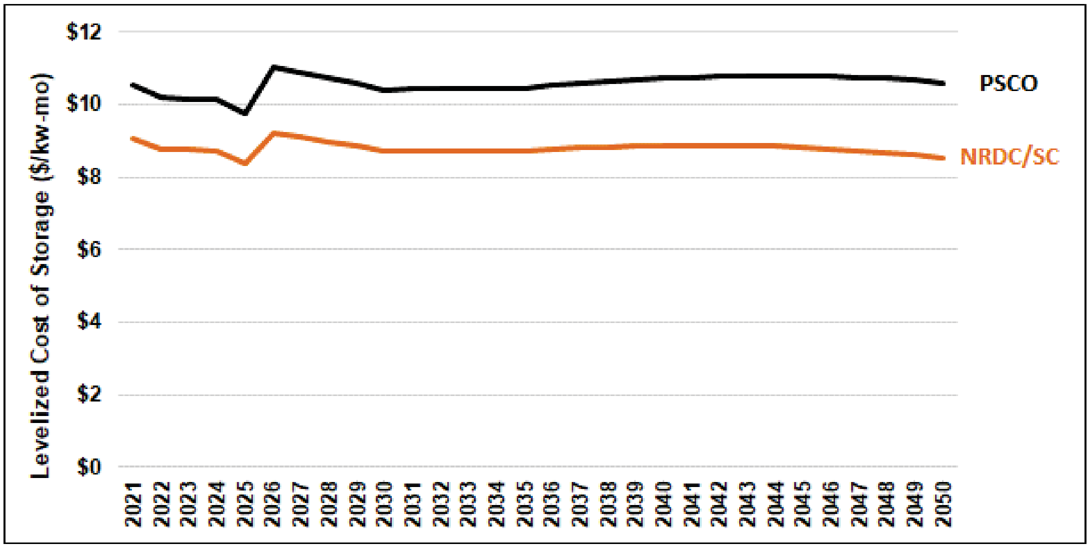


Figure 4: Levelized Costs of Battery Storage ($/kW-month)



Q. Is the decrease in costs of battery storage shown above completely due to updating NREL ATB forecasts?

A. No. I also corrected an error made by the Company in how they calculated the levelized costs of battery. The Company and I both calculated real levelized costs in 2018 dollars then later created nominal levelized costs assuming the same 2 percent rate of inflation.[47] In developing a real levelized cost (in 2018 dollars), the Company employed a nominal discount rate of its weighted average cost of capital (WACC). But this is a mismatch because a real discount rate should be used to develop a real levelized cost. This is clearly shown in NREL ATB's calculation of levelized costs of solar and wind resources in real 2018 dollars—which the

[47] 21A-0141E_Volume 2_Section 2.14_Generic Resources_Workpaper

Company used directly for those two resource types.[48] To fix this error, I recalculated the levelized cost of batteries using the Company's real discount rate.[49]

Q. Please describe how these recommended resource costs affected the modeling done by Dr. Roumpani.

A. The increase in solar costs coupled with lower wind and battery costs contributed to less solar but more wind and battery being chosen in Dr. Roumpani's modeling. (The proposed change in battery ELCC would also make it a more attractive capacity resource—as discussed by Mr. Stenclik.) Notably, however, the resource cost changes were applied to <u>all</u> portfolios, including the replication of the Company's preferred plan in portfolio CC 0. Thus, the savings that is reported with our alternative portfolios is due to that of ceasing coal at Comanche 3 and Pawnee earlier than in the Company's plan in order to provide an "apples to apples" comparison.

V. <u>RECOMMENDATIONS FOR PHASE II</u>

Q. Do you have recommendations for how to address the procurement of new resources in Phase II?

A. Yes, given my analysis of the Company's Phase I filing, I propose the following:

1. Our proposed alternative plan of retiring Comanche 3 in 2027 and converting Pawnee to gas in 2024 is clearly favorable to the Company's proposal. In Phase I, the Commission should approve retiring Comanche 3

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[48] Id, see real $2018 levelized cost calculations in "Solar-Utility PV" tab in rows 287-301 and "Land Based Wind" tab in rows 487-516.

[49] This was calculated by taking (1+WACC)/(1+inflation rate)-1 or (1.0653/1.02)-1=4.44%.

in 2027 and converting Pawnee to gas in 2024; and direct the Company to assume those actions in the Phase II procurement.

2. Phase II resources should be evaluated using the more up-to-date social cost of carbon (SCC) and the social value of methane for upstream emissions in HB 21-1238.

3. Any procurement of new natural gas resources should be evaluated assuming that the unit does not operate after 2050.

Q. Does this conclude your answer testimony?

A. Yes.

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF COLORADO

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2021 ELECTRIC RESOURCE PLAN AND CLEAN ENERGY PLAN	**PROCEEDING NO. 21A-0141E**

AFFIDAVIT OF TYLER COMINGS

I, Tyler Comings, state that the above Answer Testimony in Proceeding No. 21A-0141E was prepared by me or under my supervision and control. The testimony is true and correct to the best of my knowledge and belief. I would give the same testimony orally and would present the same attachments if asked under oath before the Commission.

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Signature of Counsel