BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

DOCKET NO. 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

SUGGESTED REQUESTS TO PSCO FOR SUPPLEMENTAL DIRECT TESTIMONY

SUBMITTED BY LESLIE GLUSTROM

May 24, 2021

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I. Introduction

Leslie Glustrom, a Public Service Company of Colorado ("PSCo" or "Xcel") customer and long-time Colorado Public Utilities Commission ("PUC" or "Commission") intervenor and participant, hereby files these suggested requests to PSCO for Supplemental Direct Testimony in the above captioned docket related to the 2021 Electric Resource Plan ("ERP") and Clean Energy Plan ("CEP") for PSCO.

This filing is made in response to the Commission discussion on May 19, 2021 of requests to make of PSCo for Supplemental Direct Testimony related to the ERP/CEP filing in this 21A-0141E proceeding.

As discussed below, there are several areas where PSCo's original filings do not fully comply with Commission rules and Colorado statutes and do not supply full and accurate information to the Commission for their review and decision.

Ms. Glustrom has devoted considerable time and effort to this filing despite the short time frame, relying on the sincerity of Commissioner Gilman's assurances on Wednesday May 19, 2021 that filings from the public are read. Given the amount of time and effort that have gone into this filing,[1] Ms. Glustrom prays that Commissioner Gilman will be true to her word and the other Commissioners will join her. At the very least, after wading through all the tables and the data, you'll get a cute picture close to the end!

[1] This filing has been prepared without the assistance of the discovery process. Ms. Glustrom has made every effort to portray information accurately, but the discovery process may disclose issues that could not be known at this early stage of the proceeding.

Ms. Glustrom respectfully disagrees with the assertion made on May 19, 2021 that coal supply and discount rate issues have been thoroughly "hashed over" by the Commission and so the Commission does not need to hear further on these issues.

Ms. Glustrom will know that the issues of coal supply and discount rate have been thoroughly considered by the Commission when she hears extensive discussion from the bench and reads well referenced decisions addressing these issues rather than hearing the issues dismissed summarily.

Given the critical nature of these decisions for our state, our planet and Xcel's customers, Ms. Glustrom thanks the Commissioners in advance for their careful reading and consideration of this filing which reflects many years of experience at the Colorado PUC and engaging on similar issues throughout the country.

II. Demonstrate that PVRR has Been Minimized as Called for in Rule 3601

Request to PSCo for Supplemental Direct Testimony: Given the requirement in PUC Rule 3601 to minimize Present Value Revenue Requirement ("PVRR"), please provide a series of portfolios including significant demand management and storage resources that demonstrate that the PVRR has actually been minimized consistent with reliability constraints and do this analysis using a discount rate of 3% or below.

Short Explanation: Xcel has provided a number of portfolios with varying cost profiles, but no apparent effort has been made to find the portfolio that <u>minimizes</u> PVRR while retaining reliability. Xcel also does not appear to have given the fullest possible consideration to demand management and storage options for lowering PVRR. Using lower discount rates to do the analysis is essential so as not to inappropriately favor fuel-dependent resources.

Longer Explanation: PUC Rule 3601 (4 CCR 723-3) states that "a primary goal of electric utility resource planning is to minimize the net present value of revenue requirements."

Rule 3601 also states "It is also the policy of the state of Colorado that the Commission gives the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies." This is consistent with CRS §40-2-123(1) which contains similar language.

The full text of Rule 3601 (4 CCR 723-3) is shown below for reference

3601. Overview and Purpose.

The purpose of these rules is to establish a process to determine the need for additional electric resources by electric utilities subject to the Commission's jurisdiction and to develop cost-effective resource portfolios to meet such need reliably. It is the policy of the state of Colorado that a primary goal of electric utility resource planning is to minimize the net present value of revenue requirements. It is also the policy of the state of Colorado that the Commission gives the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies.

The requirement to provide a wide range of portfolios with increasing amounts of renewable resources, storage and demand side options is supported in PUC rule 3604 (k) which is copied below for reference.

PUC Rule 3604 (k) (4 CCR 723-3)

(k) Descriptions of at least three alternate plans that can be used to represent the costs and benefits from increasing amounts of renewable energy resources, demand-side resources, energy storage systems, or Section 123 resources as defined in paragraph 3602(q) potentially included in a cost-effective resource plan. One of the alternate plans shall represent a baseline case that describes the costs and benefits of the new utility resources required to meet the utility's needs during the planning period that minimize the net present value of revenue requirements and that complies with the RES, 4 CCR 723-3-3650, et seq., as well as with the demand-side resource requirements under § 40-3.2-104, C.R.S. The other alternate plans shall represent alternative combinations of resources that meet the same resource needs as the baseline case but that include proportionately more renewable energy resources, demand-side resources, energy storage systems, or Section 123 resources. The utility shall propose a range of possible future scenarios and input sensitivities for the purpose of testing the robustness of the alternate plans under various parameters.

An example of the portfolios provided by Xcel is shown in the table below from Xcel witness Jim Hill's Direct Testimony, page 48.

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Figure JFH-D-3 SCC ERP and CEP Portfolio
Generic Resource Additions and CO2 Reduction

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

Notably, Xcel's suggested portfolios only provide a narrow range of options for wind and solar, no range at all for distributed solar and only a very narrow range for storage and the provisions for demand response are very conservative, as shown on line 25 on page 1 of the updated Loads and Resources table filed by Xcel on May 17, 2021 and reproduced below. In short, Xcel's portfolios largely involve trade-offs between coal and "firm dispatchable" (very likely gas combustion) resources with non-fossil fuel levels held largely constant. This is not in accordance with Rule 3601 or 3604(k).

UPDATED LOADS AND RESOURCES TABLE

	PSCo Summer L&R Table (MW)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	
1	Owned Coal	1,980	1,980	1,655	1,655	1,655	1,278	1,278	1,278	1,278	1,278	
2	Purchased Coal	150	150	-	-	-	-	-	-	-	-	
3	**Total Coal-Fired Generation**	**2,130**	**2,130**	**1,655**	**1,655**	**1,655**	**1,278**	**1,278**	**1,278**	**1,278**	**1,278**	
4	Owned Gas Steam	310	310	310	310	310	310	310	-	-	-	
5	Owned Gas Combined Cycle	1,855	1,941	1,968	1,968	1,968	1,968	1,968	1,968	1,968	1,968	
6	Purchased Gas Combined Cycle	370	302	170	51	51	-	-	-	-	-	
7	Owned Gas Combustion Turbine	805	1,067	1,067	1,067	1,067	1,067	896	896	896	896	
8	Purchased Gas Combustion Turbine	1,013	758	758	758	758	733	458	238	238	238	
9	**Total Gas-Fired Generation**	**4,352**	**4,378**	**4,273**	**4,155**	**4,155**	**4,078**	**3,632**	**3,102**	**3,102**	**3,102**	
10	Owned Storage	162	243	276	276	276	276	276	276	276	276	
11	Purchased Storage	-	-	199	199	199	199	199	199	199	199	
12	Purchased Biomass	3	3	3	-	-	-	-	-	-	-	
13	Owned Hydro	14	14	14	14	14	14	14	13	13	13	
14	Purchased Hydro	18	18	18	18	17	17	9	-	-	-	
15	Owned Solar	0.9	0.9	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	
16	Purchased Solar	202	363	673	669	666	663	659	653	650	647	
17	Purchased BTM Solar	172	195	119	119	125	130	136	144	153	164	
18	Community Solar	71	111	102	103	121	138	155	171	186	201	(1)
19	Owned Wind	131	131	147	147	147	147	147	147	147	147	
20	Purchased Wind	360	360	402	402	402	394	384	316	316	313	
21	Firm Transmission Import	47	-	-	-	-	-	-	-	-	-	
22	**Total Renewable/Other Generation**	**1,180**	**1,439**	**1,953**	**1,948**	**1,967**	**1,979**	**1,980**	**1,920**	**1,942**	**1,961**	
23	**TOTAL ACCREDITED CAPACITY**	**7,663**	**7,947**	**7,881**	**7,758**	**7,777**	**7,335**	**6,891**	**6,300**	**6,322**	**6,342**	A
24	Native Load Forecast - Spring2021	6,958	6,984	6,994	7,034	7,106	6,921	7,016	7,093	7,199	7,284	
25	Demand Response	(527)	(527)	(561)	(561)	(561)	(586)	(586)	(586)	(586)	(605)	
26	**FIRM OBLIGATION LOAD**	**6,431**	**6,457**	**6,433**	**6,473**	**6,545**	**6,335**	**6,430**	**6,507**	**6,613**	**6,679**	B
27	Target Planning Reserve Margin	1,158	1,162	1,242	1,243	1,257	1,210	1,157	1,171	1,190	1,202	
28	IREA & HCEA Backup Reserves	45	45	48	48	48	11	11	11	11	11	
29	**TOTAL PLANNING RESERVE MARGIN TARGET**	**1,203**	**1,207**	**1,290**	**1,291**	**1,305**	**1,221**	**1,168**	**1,182**	**1,201**	**1,213**	C
30	Actual Reserve Margin	1,231	1,490	1,448	1,285	1,232	1,000	461	(207)	(291)	(337)	A-B
31	**CAPACITY POSITION: LONG/(SHORT)**	**29**	**283**	**159**	**(6)**	**(72)**	**(221)**	**(707)**	**(1,389)**	**(1,492)**	**(1,550)**	A-B-C

	Announced Early Coal Retirements	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
32	Craig 2									(40)	(40)
33	Hayden 1									(135)	(135)
34	Hayden 2								(98)	(98)	(98)
35	**PREFERRED PLAN CAPACITY POSITION: LONG/(SHORT)**	**29**	**283**	**159**	**(6)**	**(72)**	**(221)**	**(707)**	**(1,487)**	**(1,765)**	**(1,823)**

(1) Includes 2.9 MW of accredited capacity for Company Owned Communtiy Solar.

As discussed in further detail below, there is every reason to believe that robust demand management and demand response programs combined with additional storage can "shave the peak" of Xcel's projected load and do it much more cost-effectively and reliably than acquiring over 1,000MW of the "firm[2] dispatchable" resources as proposed by Xcel and summarized in Table JFH-D-3 above. As discussed further below, these "firm dispatchable" (i.e. probably gas

[2] Xcel's "firm dispatchable" resources are likely to be "gas turbines" and which can be of questionable "firmness" for a variety of reasons including loss of fuel supply.

turbine) resources will sit idle for well over 90% of the year and the peak they would be acquired to meet can almost certainly be met more economically through "peak shaving" with modern demand management techniques.

Conclusion: To ensure that Xcel finds a **minimum** PVRR, the Commission should ask Xcel to present an array of options that incorporate a wider array of wind, solar, storage, distributed and demand resources and then analyze the PVRR at a discount rate of 3% or below.[3]

III. Model Shaving Peak Load with Demand Resources and Storage

Request to PSCo for Supplemental Direct Testimony: The load Xcel provided is for peak load.[4] Please prepare cases that "shave" the top 5-10% of the peak load with various combinations of demand options and storage in order to reduce reliance on peaking gas turbines and run the cost analyses at a discount rate of 3% or lower.

Short Explanation: It serves Xcel's interests to "build to the peak" because they can own additional resources that go into rate base and increase earnings under Colorado's "Cost of Service" model of utility regulation. Building to the peak is very likely an expensive way to operate a system since, by definition, the load experienced on the peak hour of the year will not be experienced for the other 8759 hours.[5] That means that capacity will sit idle for all of those hours. It is very likely that a much more cost-effective way to manage the system is to "shave"

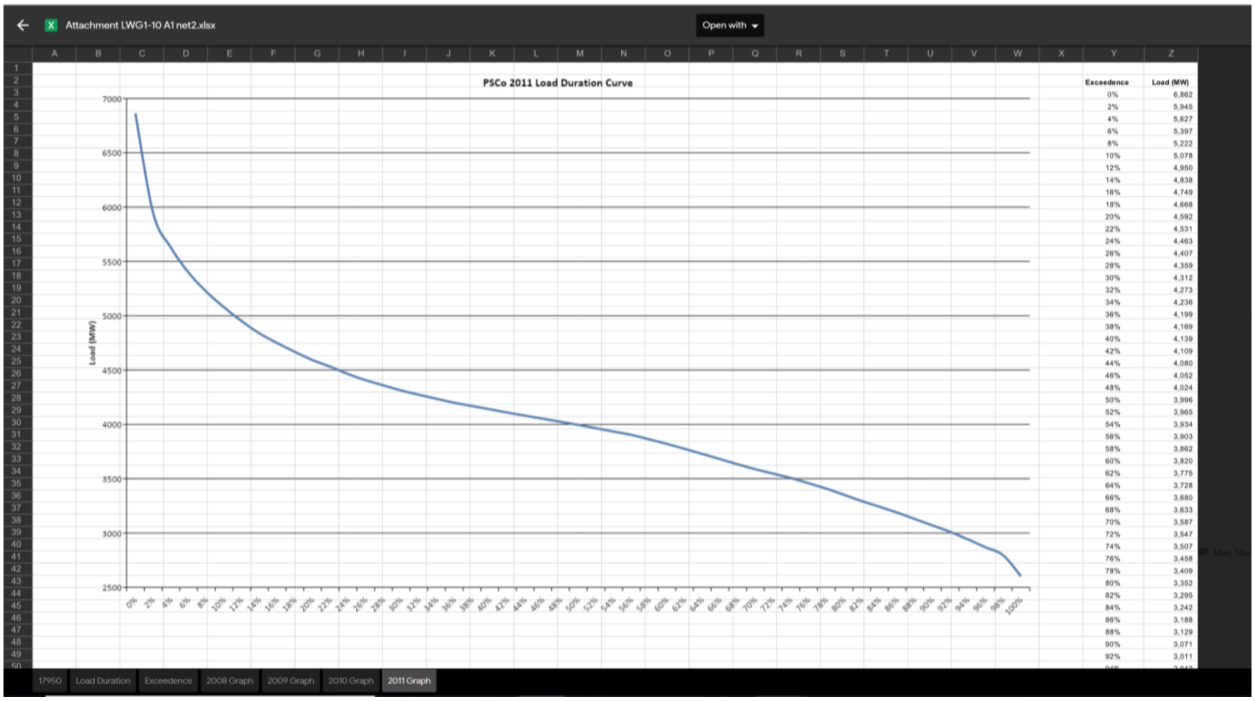
[3] For an extended discussion of Xcel's practice of discount rate at approximately 7% and why a significantly lower discount rate should be so as not to favor fuel-dependent (and CO2 producing) options, see Ms. Glustrom's Petition to Intervene in this 21A-0141E proceeding at the Colorado PUC. The Colorado PUC called for running discount rate sensitivity analyses at 3% and 0% in Xcel's 2016 ERP by PUC Decision C17-0316, ¶94.

[4] It needs to be confirmed in discovery, but there is every reason to believe that the "load" provided by Xcel on line 24 of the Loads and Resources table is for peak load and is the load that will only be experienced for one hour of the 8760 hours in a typical year.

[5] A "normal" year has 24 hours/day x 365 days/year = 8760 hours/year (with a leap year being 8784 hours)

the top part of the demand peak with storage and demand side options rather than obtaining capacity that will sit idle for over 99% of the year.

Longer Explanation: A typical load duration curve is shown below. While this curve is for 2011,[6] it is very likely that a 2020 curve obtained in discovery in this proceeding would have a substantially similar shape.



The load duration curve above shows clearly how there is a sharp peak in demand that is only experienced for a small percentage of the year.[7] For example, over 1000 MW of demand is only needed for about 2% of the year with most of that demand only experienced for one or two hours at a time (e.g. from 4-6 pm on a hot summer night). In that case 2-4 hours of storage can make a big difference.

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[6] Data for the 2011 load duration curve was obtained from Xcel in the 11A-869E proceeding in response to discovery request LWG 1-10.

[7] On top of planning for the peak demand, Xcel then adds a reserve margin of another 1100-1200 MW as shown in line 27 of the Loads and Resources table above.

While Xcel has done an extensive explanation of why we aren't ready to run their system without **any** dispatchable generation,[8] this is not an "all-or-none" situation. The question in this case is how much of the peak demand could be shaved using a few hours of storage. Preliminary analysis of past data shows it could be very substantial and the Commission would be well served to ask for this analysis from Xcel.

Similarly, demand response (e.g. aggregating responsive demand from businesses and homes)[9] to help shave the peak is also very likely a lower cost way of meeting the peak than having a lot of gas turbines standing idle for over 99% of the year to meet the peak demand. Looking at the "Demand Response" numbers in line 25 in the Loads and Resources table above, it can be seen that Xcel has only projected a very modest 78 MW increase in demand response from 527 MW in 2021 to 605 MW in 2030 with many years seeing no increase at all in demand response additions.

Modern automated demand response efforts are very likely to provide a much lower cost way to deal with peak demand events while still providing enough "firm dispatchable" capacity to meet weather events (sometimes called "dark-calms") which are not likely to happen during peak demand times (which currently occur on hot **sunny** summer days), and the Commission should ask Xcel to model increasing levels of demand response as called for in Rule 3604(k).

In short, Xcel should plan for both "dark-calm" weather and hot summer peaks. but these two events should not be conflated; there is good reason to believe that additional storage and

[8] See Volume 2 of the Resource Plan, AKJ-2, pages 231-236

[9] One leader in demand response, solar plus storage and Behind-the-Meter (BTM) applications is EnelX with many stories and resources available on their website https://www.enelx.com/n-a/en

demand response resources *can* help shave the summer peaks even if they aren't yet able to get the system through a multi-day "dark-calm."

Conclusion: To ensure the lowest cost resource plans for customers, Xcel should provide a number of portfolios that combine storage and demand-side resources to shave the peak rather than acquiring large numbers of gas turbines to meet the peak plus the reserve margin. As always, the financial analysis should be done at a discount rate of 3% or less to avoid "discounting" future fuel costs heavily and thereby favoring fuel-dependent solutions over fuel-independent solutions.[10]

IV. Request Breakdown of Cost Estimates and Explanation for Loss of the "Renewable Dividend"

Request to PSCo for Supplemental Direct Testimony: Many utilities that are shifting to higher levels of renewable generation are finding they are receiving a "renewable dividend." Please explain why Xcel is projecting steady cost increases and provide a breakdown of the source of those cost increases.

Short Explanation: Many utilities that are shifting to higher levels of renewable generation are finding they are receiving a "renewable (or green-energy) dividend" since renewable generation (typically at 3 cents/kwh and below) is now less costly than existing fossil fuel generation (at 3 cents/kwh and above) and utilities are using this "renewable dividend"[11] to

[10] For an extended discussion of Xcel's practice of discount rate at approximately 7% and why a significantly lower discount rate should be so as not to favor fuel-dependent (and CO2 producing) options, see Ms. Glustrom's Petition to Intervene in this 21A-0141E proceeding at the Colorado PUC. The Colorado PUC called for running discount rate sensitivity analyses at 3% and 0% in Xcel's 2016 ERP by PUC Decision C17-0316, ¶94.

[11] For an example of Tri State CEO Duane Highley discussing the "green energy" dividend see https://www.denverpost.com/2020/10/07/tri-state-rates-renewable-energy/.

For a description of how Holy Cross Energy has transitioned to high levels of renewables while maintaining stable rates see https://www.vaildaily.com/news/how-holy-cross-energy-plans-to-deepen-penetration-of-renewables/

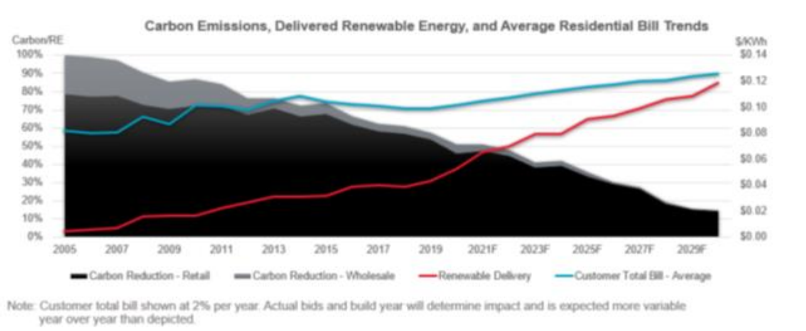
invest in customer-centric programs and/or to keep rates stable or lower. As an Investor Owned Utility ("IOU"), Xcel is typically trying to increase returns to shareholders, expressed as Earnings Per Share or "EPS." The standard way to increase EPS is to increase capital expenditures that can be added to rate base and increase the IOU's profits.

As discussed further below, Xcel had $588 million of after-tax net income in Colorado in 2020—a very generous profit and the PUC should ensure that Xcel is not spending the renewable dividend in a way that generates yet more profits for shareholders rather than benefitting customers.

To protect Xcel's Colorado customers, the Commission should request a breakdown of expected costs and an explanation of what happened to the "renewable dividend" and why Xcel's bills are expected to increase at a rate of about 2% per year as shown in the blue line in AKJ-D-1 copied below.

<u>From Xcel Witness Alice Jackson's Direct Testimony, page 17</u>

Figure AKJ-D-1



For a description of how Fountain (Colorado) Utilities is lowering costs with a shift to renewable generation, see https://gazette.com/news/city-of-fountain-strikes-electricity-deal-through-2039-to-lower-costs/article_60b4625e-994a-11ea-8b3f-bb3b9d33ce31.html

Longer Explanation: Xcel's cost and rate projections are shown in Figures JFH-D-6 and JFH-D-7 from Xcel witness Jim Hill's testimony as copied below.

<u>From Xcel witness Jim Hill's testimony Pages 51 and 53</u>

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Figure JFH-D-6: SCC ERP and CEP Portfolio Projected Costs

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

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Figure JFH-D-7: SCC ERP and CEP Portfolio Projected Rate Impacts

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

From Figures JFH-D-6 and JFH-D-7 above, it can be seen that Xcel is projecting rate increases for all the SCC (Social Cost of Carbon) portfolios. Xcel projects the highest annual rate increases occurring in the coming decade and on-going rate increases through 2055. This means that Xcel's plan is to keep charging customers more for products (i.e. wind, solar, storage and demand side options) that are likely to keep costing less. Only a monopoly could consider proposing such a scheme and the Commission should take steps to protect Xcel's customers from monopolistic practices. As discussed previously, all financial analyses should be done at a discount rate of 3% or less to avoid favoring fuel-dependent resources.

Conclusion: Renewable generation is now generally lower cost than fossil fuel generation. The Commission should ensure that Xcel customers benefit from what is being called the "renewable dividend" as we go through the coming decade.

V. Request Analysis that Involves Xcel Writing Off At Least 50% of its Stranded Assets

Request to PSCo for Supplemental Direct Testimony: Please provide cost analyses for various portfolios that include Xcel writing off at least half of the cost of undepreciated fossil fuel assets.

Short Explanation: Xcel's cost analyses appear to assume that all undepreciated fossil fuel assets will be paid for by customers with Xcel's full "return of" and "return on" for those assets—up until the time that Xcel proposes securitization for the Pueblo Unit 3 coal plant in 2040. As discussed below, Xcel's profits have been very robust in recent years and they have privatized the profits from their coal plants. Now the Commission should at least examine portfolios that call for Xcel to also privatize at least half of the risks that go with investments in fossil fuel resources that are becoming stranded. Most companies have no choice but to write off

100% of their mistakes, so only asking Xcel to write off half of its mistaken investments in fossil fuels is a generous approach. If the Commission is not willing to have Xcel privatize the risks of investments, then it should plan on reducing Xcel's Return on Equity ("ROE") in Colorado. Xcel should not be allowed to both privatize the profits and socialize the risks by having their customers pay off fossil fuel plants that are no longer used and useful *and* provide Xcel with a ROE that exceeds 9%.

Longer Explanation: It appears that Xcel is proceeding with the assumption that customers will be solely responsible for paying for its stranded fossil fuel assets and in many cases paying Xcel their full level of "return on" those assets. The Commission should investigate which part of the increased costs projected by Xcel are due to customers paying off Xcel's stranded assets and obtain new cost estimates that include Xcel writing off at least half of any undepreciated fossil fuel assets, including the Pueblo Unit 3 coal plant (aka "Comanche 3). Pueblo Unit 3 will be delivering a lot less than half of the generation that it was expected to when it was approved by the PUC so there is no reason for customers to be providing Xcel with 100% of its "return of" and "return on" a plant that will have delivered less than half of the generation it was expected to. (As currently proposed by Xcel, Pueblo Unit 3 will deliver 0% of its expected generation for the last half of its original projected life from 2040-2070 and about 33% of its expected generation from 2030-2039. In addition, the Pueblo Unit 3 coal plant has delivered less than it projected capacity factor every year since it began operation in 2010 as shown below.

From Page 71, PUC Staff Report on Pueblo Unit 3 Coal Plant in Proceeding 20I-0437E

Table 9. Modeled vs. actual capacity factors for Comanche 3, May 2010 – October 2020.

Year	Modeled CF	Actual NCF	% (Actual/Modeled)
2010	66.2	-	-
2011	69.8	52.66	75.44%
2012	80.9	68.13	84.22%
2013	72.2	70.29	97.35%
2014	66.7	50.54	75.77%
2015	76.0	64.64	85.05%
2016	87.2	75.56	86.65%
2017	75.3	71.89	95.47%
2018	80.2	79.46	99.08%
2019	72.9	69.65	95.54%
2020	63.7	2.37	3.72%

As shown in the "bottom line" below, Xcel had $588 million of after-tax net income in Colorado in 2020. It is past time that the Colorado PUC began protecting Xcel's Colorado customers from Xcel's monopoly power and in this case set the expectation that Xcel will internalize the risks—and not just the profits from its misguided decision-making.

Page 24, PSCo 2020 10-K[12]

PUBLIC SERVICE CO. OF COLORADO AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(amounts in millions)

	Year Ended Dec. 31		
	2020	2019	2018
Operating revenues			
Electric	$ 3,116	$ 3,033	$ 3,031
Natural gas	1,024	1,161	1,015
Other	43	43	40
Total operating revenues	4,183	4,237	4,086
Operating expenses			
Electric fuel and purchased power	1,132	1,083	1,157
Cost of natural gas sold and transported	374	526	428
Cost of sales — steam and other	13	17	15
Operating and maintenance expenses	811	810	788
Demand side management expenses	141	136	142
Depreciation and amortization	655	602	561
Taxes (other than income taxes)	234	206	202
Total operating expenses	3,360	3,380	3,293
Operating income	823	857	793
Other (expense) income, net	(1)	3	2
Allowance for funds used during construction — equity	35	22	56
Interest charges and financing costs			
Interest charges — includes other financing costs of $7, $7 and $7, respectively	238	235	208
Allowance for funds used during construction — debt	(14)	(11)	(22)
Total interest charges and financing costs	224	224	186
Income before income taxes	633	658	665
Income tax expense	45	80	113
Net income	$ 588	$ 578	$ 552

See Notes to Consolidated Financial Statements

Conclusion: The Commission should protect Xcel's customers from having to pay off Xcel's mistakes and ask for cost analyses of portfolios in which Xcel writes off at least half of undepreciated fossil fuel assets.

[12] Available from https://investors.xcelenergy.com/financial-documents/sec-10-k-filings/default.aspx

VI. Request that Xcel Correct the Errors in the Burnham Coal Report and Provide a Realistic View of the Future of the US Coal Industry

Request to PSCo for Supplemental Direct Testimony: Ask PSCo to revise the Burnham Coal Report (Appendix F to AKJ-2) to reflect the fact that coal in the ground is not the same as "reserves," to acknowledge that there are numerous signs of structural decline of the US coal industry including among the Powder River Basin producers and to correct the errors in the Report. Indeed, Xcel and the PUC would probably be best served by hiring a different coal analyst to prepare their coal supply reports; in particular Xcel and the Commission should look for coal analysts that recognize that the US thermal coal industry is almost certainly in a state of structural decline with very large uncertainties related to future US thermal coal production.

Short Explanation: Making an informed decision about Xcel's remaining coal plants in Colorado including the Brush coal plant (that Xcel calls "Pawnee") and the Pueblo Unit 3 coal plant (that Xcel calls "Comanche 3") requires an accurate understanding of the future of the US coal industry. The Burnham Coal Report provided by Xcel (Appendix F to AKJ-2) fails to provide that accurate understanding because it assumes that coal in the ground can be referred to as "reserves." This is a very fundamental error as "reserves" properly refers to resource deposits like coal that can be mined at a profit. While there is lots of coal left underground in the United States, the vast majority of the remaining coal is buried too deeply to be mined at a profit.

To make a wise decision about the coal options laid out by Xcel, the Commission needs a thoughtful and accurate assessment of the future of the US coal industry. The Burnham Coal Report provides neither.

Longer Explanation: As shown in Table JFH-D-2 below from the Direct Testimony of Xcel witness Jim Hill, Xcel's 8 porfolios are built around various options for its two largest coal plants, the 505 MW coal plant in Brush (which Xcel calls "Pawnee") and the 750 MW[13] Pueblo Unit 3 coal plant **(**which Xcel calls "Comanche 3").

<u>Table JFH-D-2 from Direct Testimony of Xcel Witness Jim Hill, Page 35</u>

Table JFH-D-2 Pawnee and Comanche 3 Actions

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

Xcel's preferred portfolio is #7 (See Tables JFH-D-6 and JFH-D-7 copied above) which proposes to convert the Brush coal plant to gas in 2027 and retire the Pueblo Unit 3 coal plant in 2039 after reducing its operation through the 2030s.

Implicit in Xcel's preferred portfolio #7 is that it will have a supply of coal for the Pueblo Unit 3 coal plant until 2039 and the Brush coal plant until 2027. Neither of these assumptions can be taken for granted. There is lots of coal left in the ground in the United States, but the only coal that really matters is coal that can be mined at a profit.

[13] The Pueblo Unit 3 coal plant is probably closer to an 800 MW coal plant—when it is operating….

Given that coal companies are having a hard time now making a profit and with the confluence of social, financial and geologic obstacles facing future coal mining, it can not be assumed that just because Xcel wants to burn coal at the Pueblo Unit 3 coal plant (and earn their full level of profit on the coal plant through that time), that the coal will just show up. Also, of course there are serious issues about the operation and economics of the Pueblo Unit 3 coal plant as detailed in Colorado PUC proceeding 20I-0437E.

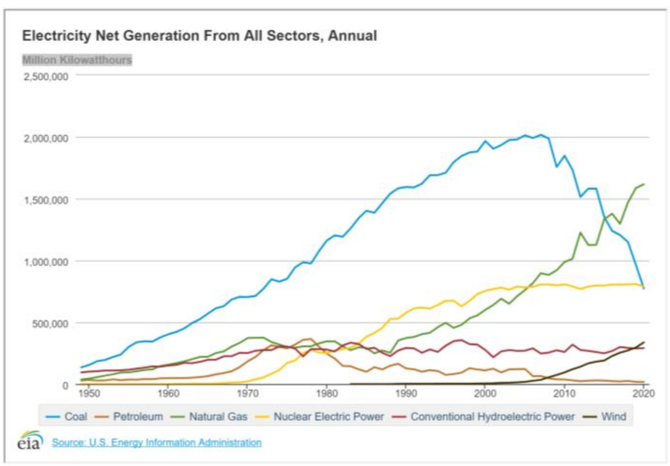
Key points for the PUC to consider include:

- **Coal in the ground should not be called "reserves" unless it can be mined at a profit.** The most fundamental issue with the Burnham Coal Report (Appendix F to AKJ-2) is that it repeatedly assumes that any remaining coal in the ground can can properly be referred to as "reserves" which is not true until the coal has been analyzed for the ability to mine it at a profit. The entire Burnham should be re-written to reflect this fact or should be withdrawn and replaced with an analysis by someone who understands the meaning of "reserves." As discussed further below, reviewing the financial and geological issues facing the Powder River Basin mines gives a strong indication that the remaining coal is buried too deeply to be mined at a profit. If coal can't be mined at a profit, not much of it is likely to be mined.
- **Coal doesn't just "fall out of the sky."** Coal has to be mined and that is a very labor and capital intensive process. After the top four US coal companies (and dozens of smaller companies) have filed for bankruptcy in recent years and with demand dropping and production costs rising, the finances of US coal companies

are generally bleak and financial markets are increasingly unwilling to finance coal mining.

- **The Burnham Coal Report repeatedly fails to adjust its analysis to reflect what is happening**. As discussed further below, the Burnham Coal Report (Appendix F to AKJ-2) contains numerous errors and repeatedly fails to give thoughtful consideration to the numerous signs that the US thermal[14] coal industry is in structural decline.[15] As a result, future projections made in the Burnham Coal Report are highly questionable.

One of the many indicators of the structural decline of the US thermal coal industry is depicted in the graph below of coal's contribution to electricity production in the United States.[16]



[14] Coal used for electricity production is referred to as thermal coal. There is also metallurgical coal which is used for making steel. Metallurgical coal is on a different trajectory and is generally more profitable than thermal coal. Since this is an electric resource planning proceeding, the focus of this filing is on thermal coal.
[15] One analysis of the Powder River Basin being in structural decline can be found at http://ieefa.org/wp-content/uploads/2019/03/Powder-River-Basin-Coal-Industry-Is-in-Long-Term-Decline_March-2019.pdf
[16] Chart of EIA data from https://www.canarymedia.com/articles/another-bad-year-for-coal/

The blue line in the graph above shows coal's contribution to US electric generation by year making the steep downward slope for coal generation very clear. While the future is always unknown, there is good reason to believe that the steep downward trend for thermal coal will continue through the 2020s with a very uncertain future by 2030—and perhaps even by 2025. As a result, Xcel's proposal to burn coal at the Pueblo Unit 3 coal plant until 2039 is very likely not a realistic one.

The EIA data above and many, many other facts indicate the strong likelihood that the US thermal coal industry is in structural decline and is not likely to remain as a significant profitable business in the coming decades. While no one can say for sure how long the US thermal coal industry will remain viable, there are many indicators that the 2020s will see very significant declines for the US coal industry; like making typewriters and buggy whips-- thermal coal mining is very likely to become largely an enterprise of the past.

In addition to failing to reflect the strong likelihood that the US thermal coal mining industry is in structural decline, the Burnham Coal Report (Appendix F to AKJ-2) contains numerous other omissions, errors and misleading statements. Examples of these can be seen by focusing on the key mines that support the Pueblo Unit 3 coal plant as discussed below.

As seen in the tables below from the Burnham Coal Report the Belle Ayr and Black Thunder are two key coal mines that provide coal to the Pueblo Unit 3 coal plant. Prior to 2006 the Belle Ayr mine was the sole supplier to the Pueblo coal plants. Starting in the last decade, an increasing amount of coal has been sourced from the Black Thunder coal mine.

PSCo Coal Deliveries from the Belle Ayr Mine (Burnham Coal Report, Page 28)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Grand Total
							(1,000 tons)							
BELLE AYR MINE														
Arapahoe	0.00	0.00	0.00	0.00	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12
Comanche	2,602.59	2,889.47	2,346.42	2,530.11	2,645.00	2,472.16	2,542.79	2,318.66	2,911.48	2,851.84	2,595.63	1,609.20	1,101.50	31,416.84
Pawnee	14.64	14.27	0.00	111.38	14.13	14.13	0.00	0.00	0.00	0.00	0.00	0.00	168.87	337.41
	2,617.23	2,903.73	2,346.42	2,641.49	2,659.25	2,486.28	2,542.79	2,318.66	2,911.48	2,851.84	2,595.63	1,609.20	1,270.37	31,754.37

PSCo Coal Deliveries from the Black Thunder Mine (Burnham Coal Report, Page 29)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Grand Total
							(1,000 tons)							
BLACK THUNDER														
Arapahoe	600.91	517.01	434.70	421.56	464.69	394.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2,833.19
Comanche	0.12	190.15	0.00	648.73	690.12	1,362.72	912.81	1,383.49	1,635.69	1,690.06	2,480.24	2,698.08	1,472.32	15,164.51
Pawnee	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.00	14.09	0.00	0.00	0.00	14.21
Valmont	75.11	197.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	272.12
	676.14	904.17	434.70	1,070.29	1,154.81	1,757.03	912.81	1,383.61	1,635.69	1,704.15	2,480.24	2,698.08	1,472.32	18,284.03

The future of the Belle Ayr mine is very questionable. While there is still coal left in the ground, it now appears that the reclamation obligations on the mine are larger than the value of the mine and remarkably, the **last two times the Belle Ayr mine has changed hands, the seller has paid the buyer to take the mine! (Yes, the seller paid the buyer.)** This is documented on pages 18 and 19 of the Burnham Coal Report, but it is buried in text that is not easy to follow. Here is a short history of the Belle Ayr mine over the last several years.

- In 2015, then owner of the Belle Ayr and Eagle Butte[17] mines, Alpha Natural Resources filed for bankruptcy.[18] As a result of the bankruptcy, the Belle Ayr and Eagle Butte mines were transferred to Contura.

[17] Until 2005 the Eagle Butte was the sole supplier of Xcel's coal plant in Brush, Colorado (which Xcel calls "Pawnee.") The Eagle Butte continues to provide significant amounts of coal to Xcel's Brush coal plant.
[1818] For a description of the 2015 Alpha Natural Resources bankruptcy, see https://www.forbes.com/sites/nathanvardi/2015/08/03/u-s-coal-company-alpha-natural-resources-files-for-bankruptcy/?sh=1249e4404379

- In 2017, Contura paid Black Jewel $21 million to take the Belle Ayr and Eagle Butte mines[19] but the permits were never transferred to Black Jewel and Black Jewel filed for bankruptcy in July 2019 leaving the mine permits with Contura.
- In October 2019, Contura once again transferred the Belle Ayr and Eagle Butte mines and once again paid the "buyer" (in this case Eagle Specialty Minerals) to take the mines.[20] The "deal" involved Contura paying Eagle Specialty Minerals a total of $90 million to take the mines.

When the seller is paying the "buyer" to take a coal mine, it is probably a strong indication that the reclamation liability for the mine is greater than the value of the coal mine itself. As a result, the Burnham Coal Report projections for the future of the Belle Ayr and Eagle Butte mines should be strongly questioned by the Colorado PUC.

With respect to the Black Thunder coal mine which is a key supplier of the Pueblo coal plants, there are several issues that the Colorado PUC should be questioning.

First, the Burnham Coal Report generally assumes that future production remains relatively constant with only minor adjustments. This fails to recognize what is the steep downward trend for the US thermal coal industry. Stated mathematically, instead of recognizing

[19] For Contura paying Black Jewel to take the Belle Ayr and Eagle Butte mines in late 2017, see https://www.coalage.com/breaking-news/contura-pays-90m-to-blackjewel-spinoff-to-take-prb-mines/
[20] For Contura paying Eagle Specialty Minerals to take the Belle Ayr and Eagle Butte mines , see https://www.coalage.com/breaking-news/contura-pays-90m-to-blackjewel-spinoff-to-take-prb-mines/

the strong negative downward slope for the US thermal coal industry, Burnham assumes that the slope magically becomes flat or close to flat.

Mr. Burnham's apparent inability to recognize the implications of what is happening in the US thermal coal industry mean that his projections are not very accurate. The inaccuracy of Mr. Burnham's coal projections is borne out by comparing Mr.Burnham's 2018 projections for the Black Thunder mine in his report filed in the 16A-0396E proceeding to his 2021 projections filed as Appendix F to AKJ-2 in this 21A-0141E. For the record Mr. Burnham's 2021 and 2018 projections are copied below.

<u>Burnham 2021 Projections for Black Thunder Coal Production</u>

Table 4 - PRB Reserve Depletion

	Market Share	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Arch Resources																						
Black Thunder																						
2017 Production		50.2	48.0	48.0	47.2	46.1	45.0	44.2	43.4	42.7	41.1	39.9	39.5	37.9	37.9	37.9	37.9	37.9	36.8	33.9	33.3	33.3
Plant Retirements																						
Allen S King	0.8	0.3									0.3											
Clay Boswell		1.4																				
Comanche (CO)	0.6	1.5			0.3			0.4										0.8				
Coronado	0.2	0.5			0.1			0.1										0.3				
Dan E Karn	0.6	0.5				0.5																
Eckert Station		0.0																				
Edgewater	0.1	0.1			0.1																	
Genoa	1.0	0.5		0.5																		
Harrington	0.2	0.4						0.4														
Labadie	0.6	6.1																	2.9			
Limestone	0.2	0.9											0.9									
Michigan City	1.0	0.8									0.8											
Prairie Creek	0.2	0.0						0.0														
R M Schahfer	0.4	0.3		0.3																		
Ray D Nixon	0.5	0.4										0.4										
Rush Island	0.0	0.0																				
Sherburne County	0.8	2.1				0.7			0.7				0.8									
Sioux	0.1	0.1									0.1											
South Oak Creek	0.4	0.7					0.7															
Tolk	0.5	0.5																		0.5		
Trenton Channel	0.8	0.1			0.1																	
W A Parish	0.3	2.1																				
Plant Retirements Transferred From Coal Creek																						
Dave Johnson	0.5	1.6								1.6												
Edgewater	0.6	0.4			0.4																	
W A Parish	0.1	0.3																				
Future Production		50.2	48.0	47.2	46.1	45.0	44.2	43.4	42.7	41.1	39.9	39.5	37.9	37.9	37.9	37.9	37.9	36.8	33.9	33.3	33.3	33.3
Reserves (EOY)		698.0	650.0	602.0	554.8	508.6	463.7	419.4	376.1	333.4	292.2	252.3	212.8	174.9	137.1	99.2	61.4	491.1	454.3	420.4	387.1	353.7
Reserve Additions		West Jacobs Ranch-956 mmt																North Hilight LBA-467.6 mmt				
Coal Creek - Transfer market and retirements to Black Thunder																						
Production		2.1	2.0																			
Plant Retirements																						
Dave Johnson	0.5	1.6																				
Edgewater	0.6	0.4																				
W A Parish	0.1	0.3																				
Future Production		2.1	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reserves (EOY)		90.0	Reserves Abandoned																			
Reserve Additions		West Coal Creek-57 mmt																				

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Burnham 2018 Projections for Black Thunder Coal Production (16A-0396E)

Table 4 - PRB Reserve Depletion

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Arch Coal																								
Black Thunder																								
2017 Production	70.5	70.5	70.5	70.5	70.5	70.5	70.5	70.5	70.5	70.5	70.5	70.5	70.5	70.5	70.5	70.5	70.5	70.5	70.5	70.5	70.5	70.5	70.5	70.5
Plant Retirements																								
Clay Boswell		0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
J T Dealy		0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
CP Crane		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
FirstEnergy W H Sammis				0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Eckert Station				0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Sherburnee County 2						1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Sherburnee County 1								0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Comanche 1						0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Comanche 2									0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Pleasant Prarie		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Edgewater		0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Future Production	70.5	69.3	69.3	69.0	69.0	67.6	67.6	67.5	67.1	67.1	67.1	67.1	67.1	67.1	67.1	67.1	67.1	67.1	67.1	67.1	67.1	67.1	67.1	67.1
Reserves (EOY)	896.4	827.1	757.8	688.8	619.8	552.2	484.6	417.1	350.1	283.0	216.0	148.9	81.8	482.4	415.3	348.3	281.2	214.2	147.1	80.0	969.0	901.9	834.9	767.8
Reserve Additions														North Hilight LBA-467.6 mmt							West Jacobs Ranch-956 mmt			
Coal Creek																								
Production	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Plant Retirements																								
Big Brown		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Monticello		0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Gibbons Creek		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Edgewater		0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Future Production	9.0	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4
Reserves (EOY)	128.4	121.0	113.6	106.1	98.7	91.3	83.9	76.4	69.0	61.6	54.2	46.7	39.3	31.9	24.5	17.1	9.6	59.2	51.8	44.4	36.9	29.5	22.1	14.7
Reserve Additions																		West Coal Creek-57 mmt						
Blackjewel																								
Belle Ayr																								
Production	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8
Plant Retirements																								
Montrose		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Comanche 1						0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Comanche 2									0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Edgewater		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Future Production	15.8	15.7	15.7	15.7	15.7	15.0	15.0	15.0	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2
Reserves (EOY)	278.4	262.7	247.1	231.4	215.7	200.8	185.8	170.9	156.7	142.5	128.3	114.1	99.9	85.7	71.5	57.3	43.1	28.9	14.7	253.6	239.4	225.2	211.0	196.8
Reserve Additions																				Belle Ayr West-253 mmt				

Since the font is small in the Burnham Coal Reports, a table comparing Mr. Burnham's 2018 and 2021 projections is provided below.

Black Thunder Annual Production
Burnham 2018 v 2021 Projections
Million Tons
(Data from tables above)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
2018 Projection	69.0	69.0	67.6	67.5	67.1	67.1	67.1	67.1	67.1	67.1
2021 Projection	48.0	47.2	46.1	45.0	44.2	43.4	42.7	41.1	39.9	39.5

Since Mr. Burnham's 2018 projections have not been borne out, and because he seems to be incapable of understanding the implications of what has been happening in the US thermal coal industry, the Colorado PUC should be asking very hard questions related to Xcel's coal projections. If Mr.Burnham can't even make reasonably accurate projections three years out, the Colorado PUC should not assume that he can make accurate projections for 10-20 years out.

While there are other coal mines in the Powder River Basin, they are all subject to the same basic geologic facts (e.g. the remaining coal beds are generally buried more deeply)[21] as well as to the economic forces of competition from lower cost renewable generation and a widespread concern about the increasingly serious impacts of climate change making financing for thermal coal mining increasingly difficult. As a result, the same issues facing the Belle Ayr and Black Thunder coal mines are also facing the other Powder River Basin mines making production through the 2020s uncertain.

Due to the press of other commitments and work, Ms.Glustrom is having to finish this filing quickly. She apologizes for the roughness of the writing and any spelling or grammar errors. Additional discussion of coal supply issues and the likely structural decline of the US thermal coal industry and the implications for the Powder River Basin mines can be found in

[21] A detailed geologic assessment of the coal beds of the Powder River Basin can be found in the United States Geologic Service ("USGS") report on the Powder River Basin at https://pubs.usgs.gov/of/2008/1202/

Ms.Glustrom's Petition to Intervene in this proceeding as well as in many of Ms. Glustrom's previous filings at the Colorado PUC.

In addition to apparently not understanding the implications of the structural decline of the US thermal coal industry, Mr. Burnham's coal report appears to have a number of errors. With respect to the Black Thunder mine, on page 19, Mr. Burnham identifies "NTEC" as the successor for the West Jacobs Ranch Lease by Application (LBA). This does not appear to be correct as the West Jacobs Ranch LBA is typically associated with the Black Thunder mine which is owned by Arch Resources. Similarly, Mr.Burnham shows the West Jacob's Ranch lease as becoming available to the Black Thunder mine in the 2020s (see the 2021 Black Thunder table above). This is highly unlikely as the West Jacob's Ranch lease application has been withdrawn and the coal is buried over 400 feet on average[22] and highly unlikely to be minable at a profit. The supporting data is below.

https://eplanning.blm.gov/public_projects/nepa/67033/127143/154790/West_Jacobs_Ranch_LBA.pdf

West Jacobs Ranch LBA

Serial Number	WYW-172685
Applicant	Kennecott Energy
Mine Name	Jacobs Ranch
Application Date	March 22, 2006
Application Tonnage	957,000,000
Application Acreage	5,944.00
Regional Coal Team Review	April 19, 2006
Scoping Meeting	July 24, 2007
EA/Draft EIS (DEIS)	June 26, 2009
FMV Hearing	July 29, 2009
FMV Hearing Transcript	N/A
EA/Final EIS	July 30, 2010
Notes on Current Status	Application Requested to be withdrawn Septemebr 19, 2014 Withdrawl and Case Closed effective January 7, 2015

[22] See page

Final EIS Wright Area EIA Coal LBAs

https://www.wrcc.osmre.gov/programs/federalLands/NEPA_NAntelopeEA.pdf

3.0 Affected Environment and Environmental Consequences

Table 3-7. Average Overburden, Interburden, and Coal Thicknesses and Approximate Postmining Surface Elevation Changes of the Six WAC LBA Tracts.

LBA Tract and Configuration	Overburden Thickness (ft)	Interburden Thickness (ft)	Total Coal Thickness (ft)	Swell Factor (percent)	Coal Recovery Factor (percent)	Postmining Elevation Change[1]
North Hilight Field						
Proposed Action	246	1	61	16	92	16.6 ft lower
Alternative 2	246	1	61	16	92	16.6 ft lower
South Hilight Field						
Proposed Action	292	94	81	16	92	12.8 ft lower
Alternative 2	292	94	81	16	92	12.8 ft lower
West Hilight Field						
Proposed Action	428	32	93	16	92	12.0 ft lower
Alternative 2	428	32	93	16	92	12.0 ft lower
Alternative 3	428	32	93	16	92	12.0 ft lower
Existing Black Thunder Mine Leases						
No Action Alternative for North, South and West Hilight Field LBA Tracts	282	Included with overburden	78	16	92	26.6 ft lower
West Jacobs Ranch						
Proposed Action	475	0	102	18	90	6.3 ft lower
Alternative 2	486	0	104	18	90	6.1 ft lower
Existing Jacobs Ranch Mine Leases						
No Action Alternative for West Jacobs Ranch LBA Tract	168	9	57	18	90	19.4 ft lower
North Porcupine						
Proposed Action	343	0	75	15.5	92	15.8 ft lower
Alternative 2	354	0	75	15.5	92	13.9 ft lower
South Porcupine						
Proposed Action	346	11	76	15.5	92	14.7 ft lower
Alternative 2	347	10	76	15.5	92	14.7 ft lower
Existing North Antelope Rochelle Mine Leases						
No Action Alternative for North and South Porcupine LBA Tracts	211	17	71	15.5	92	30.0 ft lower

[1] Reclaimed (postmining) surface elevation change calculated as: ((overburden thickness + interburden thickness) × swell factor) – (coal thickness × coal recovery factor).

3-14 *Final EIS, Wright Area Coal Lease Applications*

Conclusion: The Burnham Coal Report provided by Xcel (Appendix F to AKJ-2) fails to recognize the very likely structural decline of the US thermal coal industry and contains numerous other omissions and errors and its projections are highly unlikely to be correct. Xcel and the PUC would be best served by finding a new entity to prepare a more realistic coal supply report.

Cute Picture Time

OK—I promised you a cute picture. So here you go. I took out the picture of the ostriches with their head in the sand…but I couldn't resist this one…I even paid some $$ for it in hopes that you all get a laugh out of it—and in hopes that the Commissioners and their Staff will realize that hiding your eyes from the facts on coal will not serve the people of Colorado well.

Coal doesn't fall out of the sky and **the mines that provide coal to Xcel's Colorado coal plants are playing out—and playing out quickly.** What Mr. Burnham calls "reserves" are not really reserves. Please pay attention. Please don't hide your eyes (or let them glaze over…) PLEASE—the people of Colorado and the planet are relying on you not to do what this adorable bear is doing!!

VII. Summary

Please ask Xcel to provide Supplemental Direct Testimony that will do the following

- Demonstrate that the PVRR has actually been minimized as called for in Rule 3601
- Model shaving the peak load with storage and demand resources rather than just acquiring gas turbines to meet it.
- Provide a breakdown of the cost estimates and explain what happened to the "renewable dividend"
- Model Xcel writing off at least half of their stranded fossil fuel assets rather than assuming that customers have to pay for the Company's' errors
- Provide a coal report (preferably done by a different entity) that will provide a more realistic view of the future of the US thermal coal industry

Thank you for serving our state and doing so with attention and integrity!

Respectfully submitted this 24th Day of May 2021

/s/ Leslie Glustrom

Leslie Glustrom
4492 Burr Place
Boulder, Colorado 80303
lglustrom@gmail.com
720-341-3154