COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR APPROVAL OF ITS 2020 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	**)))))**	**CASE NO. 2020-00061**

RESPONSE OF LOUISVILLE GAS AND ELECTRIC COMPANY TO COMMISSION STAFF'S POST-HEARING REQUEST FOR INFORMATION DATED SEPTEMBER 11, 2020

FILED: SEPTEMBER 18, 2020

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates, for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Robt M. Conroy

Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 16th day of September 2020.

Notary Public

Notary Public, ID No. 603967

My Commission Expires:

7/11/2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Stuart A. Wilson**, being duly sworn, deposes and says that he is Director, Energy Planning, Analysis & Forecasting for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Stuart A. Wilson

Stuart A. Wilson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 16th day of September 2020.

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Louisville Gas and Electric Company
Response to Commission Staff's Post-Hearing Request for Information
Dated September 11, 2020

Case No. 2020-00061

Question No. 1

Witness: Robert M. Conroy

Q-1. Confirm that the settlement and final Order in LG&E's 2018 rate case[2] did not specify that the authorized return on equity is to be used for the Environmental Surcharge.

A-1. The Stipulation and Agreement entered into on March 1, 2019 and the final Order issued on April 30, 2019 in LG&E's 2018 base rate case did not reference a return on equity ("ROE") for the environmental surcharge for good reason. The Commission continued to follow its well-established policy of implementing the change in the ROE approved in the most recent base rate case when reviewing and approving the calculation of the environmental surcharge in subsequent ECR review cases.

Prior to the issuance of the final Order in LG&E's most recent base rate case, on February 13, 2019 the Commission initiated the six-month review of the environmental surcharge in Case No. 2019-00015.[3] The Company proposed the continued use of the 9.70% ROE approved in the 2016 base rate case for the purpose of the environmental surcharge mechanism going forward. On April 30, 2019 – the same day the final Order in the 2018 base rate case was issued – the Commission issued an Order in Case No. 2019-00015 stating:

> "The Commission takes administrative notice that LG&E filed a base rate application docketed as Case No. 2018-00295.[8] We also take notice that the final order was issued in the proceeding on April 30, 2019, wherein the Commission determined that a reasonable return on equity (ROE) for LG&E was 9.725 percent. Based on our determination in Case No. 2018-00295, the Commission finds that the ROE determination in that case is applicable to the instant proceeding."

In addition, ordering paragraph 3 in the April 30, 2019 Order in Case No. 2019-00015 held:

> "Beginning in the second full-billing month following the date of this Order, LG&E shall use a WACC of 7.02 percent, a tax gross-up factor of 0.75, a return-on-equity rate of 9.725 percent, and an overall grossed-up return of

[2] See Case No. 2018-00295, *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates* (Ky. PSC Apr. 30, 2019).
[3] *Electronic Examination by the Public Service Commission of the Environmental Surcharge Mechanism of Louisville Gas and Electric Company for the Six-Month Billing Period Ending October 31, 2018* (Ky. PSC Apr. 30, 2019).

Louisville Gas and Electric Company
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Question No. 2

Witness: Gary H. Revlett / R. Scott Straight / Stuart A. Wilson

Q-2. Revise the economic analysis modeling, as provided in the Direct Testimony of Stuart A. Wilson, Exhibit SAW-1, to reflect the following assumptions:

a. Under the Fuel Price Scenarios, using the existing Low Gas Price scenario as the new Base Case scenario along with a revised Low Gas Price scenario that reflects gas prices being 25 percent lower than the new Base Case scenario.

b. Reducing replacement capacity to reach an assumed reserve margin to 19 percent without factoring the predetermined retirement of Mill Creek Unit 1.

c. Under the Replacement Generation Resources assumption, the cost for the Natural Gas Combined Cycle (NGCC) capacity should reflect the NGCC capacity cost based upon the 2019 Annual Technology Baseline from the National Renewable Energy Laboratory of $887/kW.

d. Include the cost for the additional gas transmission pipeline that will be needed at the Ghent Generating Station associated with the NGCC alternative.

e. Identify the carbon price that will result in the NGCC alternative being the least cost option.

A-2. a. – e. See attached.

The Companies have updated the economic modeling that was presented in the Direct Testimony of Stuart A. Wilson, Exhibit SAW-1, to reflect the assumptions requested by the Commission at the hearing and through these data requests. In isolation, the results of the requested lower natural gas price forecast and lower construction cost for natural gas combined cycle ("NGCC") plants indicate that the Companies' recommended ELG compliance plan for the Mill Creek, Ghent, and Trimble County stations has a higher net present value of revenue requirements ("PVRR"). However, a decision to retire and replace 1,165 MW of capacity and energy at Mill Creek, 1,919 MW of capacity and energy at Ghent, and 919 MW of capacity and energy at Trimble County by 2029 is an extremely serious and risky course of action. A decision of this magnitude and consequence should not be based on one particular view of natural gas prices and NGCC construction costs at the lower range of a database that does not take into account site specifics, including installing miles of natural gas pipelines (and the attendant property acquisition difficulties) and acquiring environmental permits for new natural gas pipelines and NGCC generating facilities. Furthermore, use of the NGCC construction costs at the lower range of the suggested database is outdated. A 2020 updated database was recently published and NGCC construction costs are not materially different from the pricing the Companies assumed initially.[1]

The replacement of 4,003 MWs will need to be accomplished in only eight years because of the ELG regulatory deadlines. Permitting activities, property acquisitions, and associated challenges alone could take eight years, thus not accommodating 1-2 years that would be required for commercial activities and a 3-4 year construction period. The magnitude and potential capital costs of such an endeavor ($4.5 billion to $5.9 billion) dwarf the proposed ELG investments ($405 million) while adding significant execution risk.

As shown below, when reflecting the total costs of the replacement alternatives (e.g., transmission and gas pipeline) and clearly assessing the relatively low execution risks of the ELG compliance plans compared to the extreme risks to implement the stations' replacement alternatives, the recommended 2020 ECR compliance plans are the most reasonable, least-cost option over a broad range of possible commodity prices and CO_2 regulation futures. Furthermore, the recommended ELG compliance plans will likely reduce the future cost of generation when the Mill Creek and Ghent coal units retire because they will facilitate a phased retirement and an orderly and less risky expansion of each power station's existing infrastructure. The complete replacement of 4,000 MWs of capacity by January 1, 2029 represents an unprecedented construction and implementation goal with serious execution risks and cost impacts.

As discussed below and shown in the Applications, the Companies' recommended 2020 ECR compliance plan does not include installing enough water processing capability at Mill Creek to continue to operate Mill Creek Unit 1 ("MC1") because it is uneconomic to continue its operation

[1] See footnote 10 herein.

beyond December 31, 2024.[2] As further demonstrated below, the current stay-open costs of MC1 are approximately equal to the fuel savings associated with its operation. Hence, any major capital expense (e.g., ELG compliance, NOx reduction with an SCR, 316-b compliance, or major equipment failure) is enough to cause MC1 to be retired while allowing the Companies' summer reserve margin to remain within its target range of 17 percent to 25 percent post-retirement. In short, MC1's capacity does not need to be replaced. MC1's retirement today would not save customers money because the stay-open fixed O&M cost savings are offset by higher fuel costs while reliability risks would increase. As shown below, with MC1 and the aging secondary CTs retired by the end of 2024, the Companies' forecasted summer reserve margin is 19 percent or less from that time forward. Thus, none of the "no ELG compliance" options were based on overbuilding capacity to a reserve margin that is greater than 19 percent.

The analysis originally presented in Exhibit SAW-1 and now supplemented by the additional cases provided in this data response collectively constitute a voluminous set of data and analysis (see Appendix 1 through Appendix 15 for all cases evaluated). The uncertainty of the future is always a consideration in any planning decision. For example, the price of natural gas, changes in environmental regulations like CO_2 constraints, and the actual costs of constructing new generation and the associated permitting challenges are typical planning issues that cannot be known with absolute certainty. As the Commission has observed, "determining market conditions with absolute certainty or precision is not possible."[3] What is known with certainty is that, under the clear terms of the 2020 ELG Final Rule, the Companies must comply with the ELG requirements "as soon as possible" on or after one year from the date the Final Rule is published in the Federal Register.[4] Publication is expected to occur in early October 2020.[5] To meet this compliance obligation, the Companies must seek a modification of their existing discharge permits from the state permitting authority (which is the Kentucky Division of Water) and the Companies must seek that modification within 90 days after publication.[6] Thus, the Companies must embark on their ELG compliance plans in the immediate future.

The question presently facing the Companies and before the Commission is:

> Are the recommended ELG compliance plans in the best interest of our customers when compared to the risk and uncertainty associated with not complying and undertaking the

[2] In accordance with prudent planning, the Companies sized the proposed project at Mill Creek to treat only 600 gpm instead of the 750 gpm that would be required if all four Mill Creek units are operated simultaneously. But to maximize flexibility and options, the Companies have designed that project in a way that it can be efficiently expanded to treat 750 gpm if it becomes prudent or necessary based on ozone levels or any other reason. (Revlett Direct Testimony, 3/31/20, pp. 11-12).
[3] *An Examination by the Public Service Commission of the Application of the Fuel Adjustment Clause of Kentucky Utilities Company from May 1, 2001 to October 31, 2001*, Case No. 2000-00497-B, Order, n. 28 (Ky. PSC Jan. 28, 2003)("We concede that determining market conditions with absolute certainty or precision is not possible.").
[4] See Mr. Revlett's 9/4/20 Supplemental Direct Testimony, p. 3.
[5] September 10, 2020 Formal Hearing, Video Record at 14:07.
[6] See Mr. Revlett's 3/31/20 Direct Testimony, p. 12.

replacement of generation facilities that reliably provide approximately 80 percent of the energy needs of our customers in 8 years?

The evidence originally presented in Exhibit SAW-1 and supplemented by the analysis in this data response shows that the best decision for our customers is to proceed with the recommended ELG compliance plans. The totality of the financial analysis provided in this case, the significantly lower risk of executing the ELG compliance plans, and the unreasonably high execution risk of permitting and re-constructing the majority of the Companies' generation fleet in just eight years demonstrates that the recommended ELG compliance plans are least-cost, lowest risk, and offer the best value for reliably serving customers' energy needs. Importantly, the ELG compliance plans also preserve the option to move to natural gas, renewables, and storage in an orderly manner. The 2020 ELG compliance plan is reasonable and cost-effective for compliance with the ELG environmental requirements.

Discussion of Commission's recommend assumptions

Natural gas prices

Per the Commission's request, a new lower natural gas price forecast was created that is 25 percent less ("Low less 25%") than the Companies' Low fuel price forecast. Table 1 shows the new forecast along with the other three forecasts that were previously evaluated. For PROSYM modeling purposes, coal prices in the Low less 25% and Low fuel price scenarios are the same.

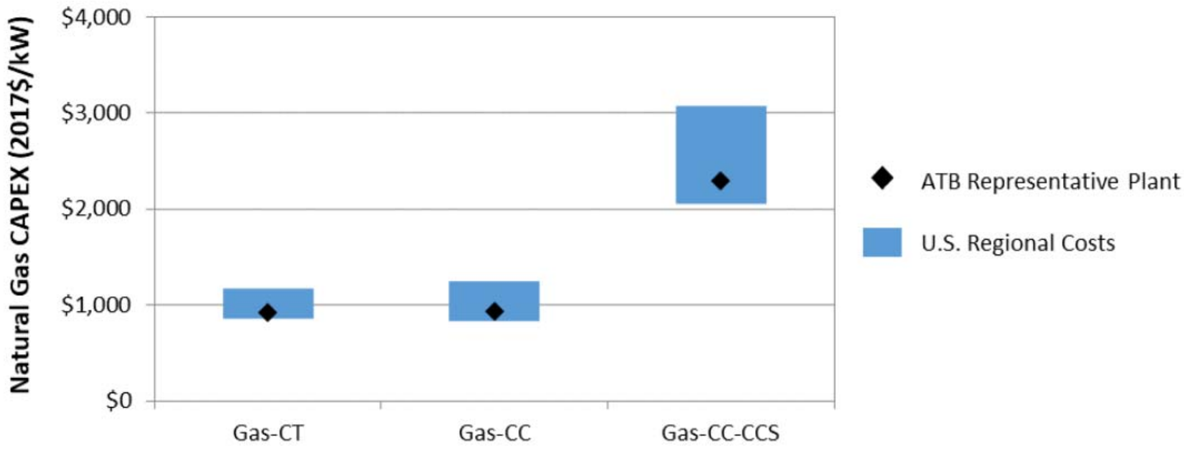
Table 1: Gas Price Forecasts ($/mmBtu)

Year	Gas Price Scenario			
	Low less 25%	Low	Mid	High
2021	1.72	2.29	2.68	3.41
2022	1.76	2.34	2.74	3.61
2023	1.84	2.46	2.87	3.80
2024	1.94	2.59	3.03	4.00
2025	2.05	2.73	3.19	4.20
2026	2.16	2.87	3.35	4.40
2027	2.26	3.02	3.52	4.60
2028	2.37	3.16	3.69	4.80
2029	2.49	3.31	3.87	5.00
2030	2.60	3.46	4.04	5.20
2031	2.64	3.52	4.16	5.39
2032	2.69	3.59	4.28	5.59
2033	2.74	3.65	4.39	5.79
2034	2.79	3.72	4.51	5.99
2035	2.84	3.79	4.63	6.19
2036	2.89	3.85	4.74	6.39
2037	2.94	3.92	4.86	6.59
2038	3.00	3.99	4.98	6.79
2039	3.05	4.07	5.10	6.98
2040	3.10	4.14	5.21	7.18
2041	3.16	4.21	5.33	7.38
2042	3.22	4.29	5.45	7.58
2043	3.27	4.37	5.57	7.78
2044	3.33	4.44	5.68	7.98
2045	3.39	4.52	5.80	8.18
2046	3.45	4.61	5.92	8.38
2047	3.52	4.69	6.04	8.57
2048	3.58	4.77	6.15	8.77
2049	3.64	4.86	6.27	8.97
2050	3.71	4.95	6.39	9.17

Replacement generation NGCC cost

The analysis that will be discussed below was updated to reflect National Renewable Energy Laboratory’s 2019 Annual Technology Baseline (“NREL’s 2019 ATB” or “2019 ATB”) estimate that a NGCC would cost $887/kW (2020 in-service; 2017 dollars).[7] Because cost of construction can vary, the chart below shows NREL's range of costs.[8] Note that the $887/kW is near the bottom of the range. It should also be noted that the capital cost assumption used in the Companies' analysis ($1,044/kW in 2017 dollars for 2020 in-service) falls within the NREL range. Finally, please note NREL recently published its 2020 ATB, which shows the overnight capital cost for NGCC capacity at $1,023/kW, which is indistinguishable from the Companies' assumption.[9] Thus use of the NGCC construction costs at the lower range of the suggested database is now outdated.

Figure 1: Range of Capital Construction Costs (Source: NREL 2019 ATB)



Ghent pipeline cost

If the Companies are able to replace Ghent's coal generation at the Ghent site with NGCC units, a pipeline of at least 20 miles would need to be constructed to reach the nearest interstate pipeline system. Absent a study of a possible route and associated geological or other issues that might impact the constructability of such a pipeline, the cost estimate must be based on a $ per mile estimate. Using the recent estimate presented by Duke Energy Kentucky, Inc. to the Commission of $8.7 million per mile, the estimated cost of a Ghent pipeline would be $175 million.[10] It should be noted that having 1,919 MW of baseload capacity and energy reliant on a single gas pipeline

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[7] NREL's cost estimates do not include interconnection costs and can understate the full cost of an NGCC construction project. Per NREL, "Regional cost variations and geographically specific grid connection costs are not included in the ATB." https://atb.nrel.gov/electricity/2019/index.html?t=cg
[8] Source: https://atb.nrel.gov/electricity/2019/index.html?t=cg.
[9] Select "DOWNLOAD 2020 ATB SPREADSHEET" at the following link: https://atb.nrel.gov/electricity/2020/data.php. Overnight capital costs for average to high capacity factor NGCC units are located in rows 241 to 246 of the Natural Gas worksheet.
[10] In Case No. 2019-00388, Duke Energy Kentucky, Inc. filed a CPCN to construct a 7.22-mile pipeline at an estimated cost of $63 million. https://psc.ky.gov/pscecf/2019-00388/e.rolfes-adkins%40duke-energy.com/11062019053031/2019-00388_Application_-_Exhibit_4.pdf

would introduce a significant "single point of failure." Therefore, it is likely that additional costs would be required to ensure reliable fuel supply to the facility.

Assume that MC1 is not retired and that replacement capacity results in a 19 percent reserve margin

In the Companies' original analysis, the retirement of MC1 was not predetermined. Instead, as a result of the analysis, retirement of MC1 was determined to be least-cost based on the analysis of MC alternatives and the assumption that the NOx limit for the MC station would remain in place. Based on Jefferson County's ozone exceedances this summer, this is a very reasonable assumption. However, even with no NOx season operating constraint, the production cost benefits for year-round MC1 operation are only roughly equal to the unit's stay-open fixed O&M costs (see Table 2). As a result, because MC1 can be retired without replacement capacity, no level of investment in ELG water processing capacity[11] is warranted for MC1; and certainly no investment in a SCR as an alternative for future NAAQS compliance is warranted. The practical reason to continue to keep MC1 available until ELG compliance is required is that it serves as a low-cost hedge against high natural gas prices, extreme winter weather, or an unanticipated material forced outage of a coal unit or Cane Run unit 7.

Table 2 – Annual Mill Creek 1 Production Cost Benefit vs. Stay-Open Costs (Mid Fuel, High Fuel)

Nominal $M	Production Cost Benefit		Stay-Open Fixed O&M
	Mid Fuel	High Fuel	
2021	3.8	8.1	13.1
2022	5.9	11.1	8.2
2023	5.6	10.4	13.1
2024	6.9	11.3	9.5

Table 3 contains reserve margins through 2050 for each of the Mill Creek alternatives evaluated. All alternatives were developed with the assumption that MC1 would be retired first and without replacement. For example, when evaluating ELG compliance for all four MC units (ELG 4; 2032/2034), MC1 is retired without replacement on 12/31/2031 at the end of its book life. When evaluating ELG compliance for fewer than four units, the analysis assumes MC1 is retired without replacement no later than 12/31/2024 when ELG station compliance is assumed to be required.

With the exception of the small-frame CTs ("secondary CTs"), the Companies have assumed that generating units would retire on a date consistent with their existing book life. Secondary CTs are

[11] As stated earlier, in accordance with prudent planning, the Companies sized the proposed project at Mill Creek to treat only 600 gpm instead of the 750 gpm that would be required if all four Mill Creek units are operated simultaneously. But to maximize flexibility and options, the Companies have designed that project in a way that it can be efficiently expanded to treat 750 gpm if it becomes prudent or necessary based on ozone levels or any other reason. (Revlett Direct Testimony, 3/31/20, pp. 11-12).

assumed to operate through 12/31/2024 based on the Companies' current business plan despite the fact that they have surpassed their book depreciation retirement dates.[12] OVEC is assumed to be retired without replacement in 2040 at the end of the OVEC contract.

With the retirement of MC1 and the secondary CTs by the end of 2024, reserve margins in all but two of the Mill Creek alternatives are approximately 19% from 2025 onward. The only exceptions are the highly unlikely cases where MC1 avoids retirement through either the end of 2028 (when the alternative assumes the entire station capacity is retired and replaced) or reaches its book depreciation retirement date in 12/31/2031. The Companies' analysis demonstrates that these alternatives are not least-cost.

Because it is economic to retire MC1 without replacement by the end of 2024 leaving a reserve margin of 19 percent or less in all cases, the megawatt for megawatt replacement assumption used to develop Exhibit SAW-1 does not result in an overbuilding of capacity or bias the results in anyway. As a result, no additional cases were produced in response to this specific data request subpart because the 19 percent reserve margin threshold was met by the cases in the original analysis.

[12] The Companies' secondary CTs are between 50 and 52 years old. Zorn 1 is planned to retire by the end of 2021. Based on current book depreciation rates, the units have already operated beyond the end of their economic lives. Haefling Unit 3 and Cane Run Unit 11 retired in 2013 and 2019, respectively, due to catastrophic failures.

Table 3: Annual Reserve Margins for Mill Creek Alternatives

Year	ELG 4; 2032/2034	ELG 3; 2025/2034	ELG 3; 2025/2029	ELG 2; 2025/2026	Early Ret; 2029/2029	Early Ret; 2025/2029	Early Ret; 2025/2026
2021	24.8%	24.8%	24.8%	24.8%	24.8%	24.8%	24.8%
2022	24.7%	24.7%	24.7%	24.7%	24.7%	24.7%	24.7%
2023	24.8%	24.8%	24.8%	24.8%	24.8%	24.8%	24.8%
2024	24.9%	24.9%	24.9%	24.9%	24.9%	24.9%	24.9%
2025	24.0%	19.2%	19.2%	19.2%	24.0%	19.2%	19.2%
2026	23.9%	19.1%	19.1%	19.1%	23.9%	19.1%	19.1%
2027	23.9%	19.1%	19.1%	19.1%	23.9%	19.1%	19.1%
2028	23.8%	19.0%	19.0%	19.0%	23.8%	19.0%	19.0%
2029	23.9%	19.1%	19.1%	19.1%	19.1%	19.1%	19.1%
2030	23.8%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%
2031	23.8%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%
2032	19.1%	19.1%	19.1%	19.1%	19.1%	19.1%	19.1%
2033	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%
2034	18.8%	18.8%	18.8%	18.8%	18.8%	18.8%	18.8%
2035	18.8%	18.8%	18.8%	18.8%	18.8%	18.8%	18.8%
2036	18.7%	18.7%	18.7%	18.7%	18.7%	18.7%	18.7%
2037	18.6%	18.6%	18.6%	18.6%	18.6%	18.6%	18.6%
2038	18.7%	18.7%	18.7%	18.7%	18.7%	18.7%	18.7%
2039	18.5%	18.5%	18.5%	18.5%	18.5%	18.5%	18.5%
2040	15.8%	15.8%	15.8%	15.8%	15.8%	15.8%	15.8%
2041	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%
2042	15.8%	15.8%	15.8%	15.8%	15.8%	15.8%	15.8%
2043	15.6%	15.6%	15.6%	15.6%	15.6%	15.6%	15.6%
2044	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%
2045	15.4%	15.4%	15.4%	15.4%	15.4%	15.4%	15.4%
2046	15.4%	15.4%	15.4%	15.4%	15.4%	15.4%	15.4%
2047	15.2%	15.2%	15.2%	15.2%	15.2%	15.2%	15.2%
2048	15.2%	15.2%	15.2%	15.2%	15.2%	15.2%	15.2%
2049	15.2%	15.2%	15.2%	15.2%	15.2%	15.2%	15.2%
2050	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%

Table 4 contains annual reserve margins for the Ghent alternatives. Based on the Mill Creek analysis discussed above, all Ghent alternatives assumed MC1 is retired in 2025 without replacement; hence as discussed above, reserve margins are at or below 19 percent beginning in 2025.

Table 4: Annual Reserve Margins for Ghent Alternatives, MC1 Retired in 2025

Year	ELG 4; 2034	ELG 4; 2029	ELG 3; 2026	Early Ret; 2029
2021	24.8%	24.8%	24.8%	24.8%
2022	24.7%	24.7%	24.7%	24.7%
2023	24.8%	24.8%	24.8%	24.8%
2024	24.9%	24.9%	24.9%	24.9%
2025	19.2%	19.2%	19.2%	19.2%
2026	19.1%	19.1%	19.1%	19.1%
2027	19.1%	19.1%	19.1%	19.1%
2028	19.0%	19.0%	19.0%	19.0%
2029	19.1%	19.1%	19.1%	19.1%
2030	19.0%	19.0%	19.0%	19.0%
2031	19.0%	19.0%	19.0%	19.0%
2032	19.1%	19.1%	19.1%	19.1%
2033	19.0%	19.0%	19.0%	19.0%
2034	18.8%	18.8%	18.8%	18.8%
2035	18.8%	18.8%	18.8%	18.8%
2036	18.7%	18.7%	18.7%	18.7%
2037	18.6%	18.6%	18.6%	18.6%
2038	18.7%	18.7%	18.7%	18.7%
2039	18.5%	18.5%	18.5%	18.5%
2040	15.8%	15.8%	15.8%	15.8%
2041	15.7%	15.7%	15.7%	15.7%
2042	15.8%	15.8%	15.8%	15.8%
2043	15.6%	15.6%	15.6%	15.6%
2044	15.5%	15.5%	15.5%	15.5%
2045	15.4%	15.4%	15.4%	15.4%
2046	15.4%	15.4%	15.4%	15.4%
2047	15.2%	15.2%	15.2%	15.2%
2048	15.2%	15.2%	15.2%	15.2%
2049	15.2%	15.2%	15.2%	15.2%
2050	15.0%	15.0%	15.0%	15.0%

Table 5 shows the annual reserve margins for the TC alternatives. Just as in the Ghent alternatives, both Trimble County alternatives assume Mill Creek 1 is retired in 2025 without replacement and, as a result, reserve margins are at or below 19 percent beginning in 2025.

Table 5: Annual Reserve Margins for Trimble County Alternatives

Year	ELG 2	Early Ret
2021	24.8%	24.8%
2022	24.7%	24.7%
2023	24.8%	24.8%
2024	24.9%	24.9%
2025	19.2%	19.2%
2026	19.1%	19.1%
2027	19.1%	19.1%
2028	19.0%	19.0%
2029	19.1%	19.1%
2030	19.0%	19.0%
2031	19.0%	19.0%
2032	19.1%	19.1%
2033	19.0%	19.0%
2034	18.8%	18.8%
2035	18.8%	18.8%
2036	18.7%	18.7%
2037	18.6%	18.6%
2038	18.7%	18.7%
2039	18.5%	18.5%
2040	15.8%	15.8%
2041	15.7%	15.7%
2042	15.8%	15.8%
2043	15.6%	15.6%
2044	15.5%	15.5%
2045	15.4%	15.4%
2046	15.4%	15.4%
2047	15.2%	15.2%
2048	15.2%	15.2%
2049	15.2%	15.2%
2050	15.0%	15.0%

Updated Analytical Results

Mill Creek

The Low less 25% fuel price scenario did not alter the lowest-cost future generation portfolio as compared to the original Low fuel price scenario. The NPVRR advantage of retiring and replacing MC2, MC3, and MC4 by the end of 2028 and replacing them with NGCC capacity moves from $37 million in the Low fuel price scenario to $214 million in the Low less 25% fuel price scenario. Assuming for the sake of the analysis proposed in the Commission's Post Hearing Data Request No. 2, that future natural gas prices are going to be in the range of the Low and Low less 25% cases, then retiring the remaining Mill Creek units (MC2, MC3, and MC4) by the end of 2028 and replacing them with NGCC capacity (and perhaps some renewables) is the course to pursue (see Appendix 1). Furthermore, using the lower 2019 ATB NGCC capital costs reduces the cost of "retire and replace" options relative to ELG compliance regardless of the fuel price scenario (see Appendix 2) because the value of deferring the cost of replacement NGCC capacity is reduced. To summarize, assuming for the sake of the Data Request analysis that both natural gas prices and the cost of using it in a NGCC plant are going to be as low as assumed in the data request, then retire and replace is preferred over the Companies' recommended ELG compliance plan. It is worth noting that the updated 2020 ATB NGCC capital costs are more in line with the Companies assumed costs as discussed above.

However, as discussed in Section 4.8 of Exhibit SAW-1, permitting activities, property constraints for siting new NGCC units, and the need to operate MC2, MC3, and MC4 up until the moment replacement generation is available make it highly impractical and unnecessarily risky to replace these units on January 1, 2029 at the Mill Creek station. Therefore, to retire the remaining Mill Creek units and move to new NGCC capacity would require the development of another location (certainly any material development of renewables would not be at Mill Creek). Of course, construction of significant amounts of new transmission facilities also would be required. As discussed in Section 4.8, the transmission capital costs associated with such a project or set of projects could easily be in the range of $650 million and could face various challenges to right-of-way acquisition, property acquisition, and other development risks. Ultimately, the actual cost and ability to execute in a timely manner would depend on the exact location of new generation, the size and type of generation, and the various route-specific acquisition costs for transmission and natural gas pipeline right-of-ways. It is not a reasonable or viable alternative.

None of the financial results presented in Exhibit SAW-1 or discussed above captured the potential impact of $650 million in new transmission costs to move 1,100 MW of generation to a new site or sites. Including this cost in the analysis (see Appendix 4) increases NPVRR of "retire and replace" in 2029 cases by approximately $700 million regardless of the future of natural gas prices. This results in the ELG compliance plan being least-cost relative to "retire and replace" in 2029 by approximately $400 - $900 million on a NPVRR basis.

After reflecting the full cost of a rapid "retire and replace" in 2029 alternative, the question of whether the Companies should install sufficient water processing capacity for MC2 remains. And that question is affected by whether gas prices in fact will follow the path of the Low less 25% scenario. As can be seen on Appendix 5, saving $9 million in capital by reducing ELG water processing capacity and retiring MC2 by the end of 2025 is least-cost only in the Low less 25% fuel price scenario.[13] However, retirement of MC2 would require replacement capacity and energy resulting in an investment of approximately $300 million or more (depending on transmission issues and physical site constraints) and cannot be assured given the timeframe (see below on development risk and timeline). In all other fuel price scenarios, installing water processing capacity for three units is least-cost – even if MC2 is retired in 2029. Thus, investing $9 million for additional ELG water processing capacity is a much lower risk than retiring and replacing MC2 by 2026.

In addition to the likely need for large investments in transmission, the "retire and replace" in 2029 cases assume that 1,100 MW of generating capacity can successfully be developed, permitted, and constructed by 2029. The Companies' experience with the Cane Run Unit 7 project confirms that full implementation of a single 640 MW NGCC at an existing company-owned site that had available real estate to site the NGCC unit and where permitting and development was relatively easy takes about five to six years. The first year would be spent issuing and evaluating a request-for-proposals ("RFP") for capacity and energy from third parties while the Companies perform preliminary development work on a self-build option. Once the best option is selected, the Companies must file a CPCN with the Commission, a process that can take up to a year. If construction of a new NGCC is selected, the actual build time is about three years after a one-two year commercial acquisition period for the technology and the engineering/construction contract. The actual total time from need identification to commercial operation depends in part on how much project development, land acquisition and permitting work takes place during the pendency of the CPCN process. For these reasons, five to six years is a very short time frame. Thus, there is good reason to question whether there is enough time to execute on the total replacement of Mill Creek station by 2029. And that replacement cannot be accomplished at the Mill Creek site because there is simply not enough real estate there to construct replacement units while keeping the existing units operational. Additionally, the current electrical substation infrastructure at Mill Creek is insufficient to handle the load that would be required to test new NGCC units while keeping the existing units operational. Thus, the Companies will need to get started in earnest no later than the middle of 2021 to begin identifying potential sites near Mill Creek and to begin the conceptual engineering for multiple NGCC units, electrical and natural gas transmission corridors, property acquisition, and permitting. This development risk and the time necessary to execute would increase substantially should the Companies also have to replace all of Ghent and Trimble county generation as well as Mill Creek.

[13] In Appendix 5 in the Low less 25% fuel price scenario, the PVRR of the ELG 2; 2025/2026 alternative is $14 million less than the ELG 3; 2025/2034 alternative.

In evaluating the totality of the Mill Creek compliance and replacement generation alternatives (see Appendices 1-5), the conclusions are as follows:

- Unless one is fully committed to and willing to wager only on a low gas price future, the recommended ELG compliance plan is the least-cost, lowest risk option for reliably serving customers' energy needs;
- Attempting to replace Mill Creek's 1,100 MW of capacity and associated energy by 2029 would likely require approximately 10 to 20 times the capital spending compared to the recommended ELG compliance plan;
- Replacing all of Mill Creek's generating capacity by 2029 would almost certainly limit the ability to utilize existing transmission and other infrastructure at the site which would only increase replacement costs and development and execution risk;
- All of the ELG compliance alternatives assume MC3 and MC4 are retired and replaced in 2038 and 2042, respectively, with NGCC capacity and energy. Thus, if the Low or Low less 25% fuel price scenarios develop beyond 2028, the least-cost option in the future may be to retire those units prior to those dates and move to natural gas. This means that the difference between the recommended ELG compliance plan and the "retire and replace" in 2029 alternative in the Low and Low less 25% scenarios is at the high end of the range because the Companies retain the ability to take action to take advantage of low natural gas prices should they emerge. Installing ELG controls today does not foreclose the ability to move to natural gas in the future. However, not installing ELG controls today means that should future gas prices be more like the Mid or High scenarios, there is no ability to move back to coal and future customers would bear the cost of that unnecessary limitation on flexibility.

Based on these conclusions, the Companies' recommended ELG compliance plan of constructing 600 GPM of processing capability for MC2, MC3, and MC4 is the least-cost, lowest risk alternative to reliably meet customers' energy needs. Not investing in ELG controls is a risky and unnecessary wager that future gas prices will be at or below the Low scenario from 2029 through 2041. That wager also assumes it is possible to acquire property, permit, engineer, and construct multiple NGCC units (including electric and natural gas transmission) to replace the Mill Creek generation. The Companies do not believe it is prudent to proceed with the "retire and replace" option based on a single assumption about the future price of natural gas because the "retire and replace" option is much more capital intensive ($1.5 to $1.9 billion for replacement versus $114 million for ELG compliance at Mill Creek) and has much greater execution risk.

Ghent

Per the Commission's data request, the Ghent analysis was updated to reflect the additional Low less 25% fuel price scenario, the 2019 ATB NGCC cost assumption, and the $175 million gas pipeline costs should all of Ghent generation be retired and replaced in close proximity to the existing Ghent station. All of these cases are shown in Appendices 6-8. Note that this updated analysis did not include any additional transmission costs as described in Section 4.8 of Exhibit SAW-1, which is consistent with the financial analysis tables shown in Exhibit SAW-1. Should replacement generation not be constructed at or near the existing Ghent station, it is estimated that approximately $900 million of capital expenses for new transmission could be required.

As with the Mill Creek analysis, the additional cases produced in response to this data request did not qualitatively change the perspective on the recommended ELG compliance plan:

- If one believes and is willing to wager only on the Low fuel price scenario, then retiring and replacing all 1,919 MW of Ghent by December 31, 2028 is the preferred option. In the Low less 25% scenario, the projected benefits of rapidly moving to NGCC generation were $291 million better than the recommended ELG compliance plan versus $64 million in the Low fuel price scenario (see Appendix 6).
- Using the lower 2019 ATB NGCC cost estimate did not change the preferred option in any of the fuel price scenarios except in the Mid fuel price scenario where the recommended ELG compliance plan went from the preferred option to the second best option (see Appendix 7). Again, it is worth noting that the updated 2020 ATB NGCC capital costs are more in line with the Companies assumed costs as discussed above.
- Appendix 8 shows the impact of including the $175 million natural gas pipeline cost. The primary impact of this change is to the Mid fuel price scenario where the recommended ELG compliance plan is slightly preferred ($2 million NPVRR) to retiring and replacing the Ghent coal units by the end of 2028.
- If the Companies' estimated NGCC capital cost is used, the recommended ELG compliance plan is clearly the preferred plan in both the Mid and High fuel price scenarios and second best in the Low and Low less 25% fuel price scenarios (see Appendix 10). Furthermore, even in the Low fuel price scenario, the recommended ELG compliance plan is just $35 million NPVRR greater than retiring and replacing all of Ghent in 2029.

Another similarity with the Mill Creek analysis is that all of the Ghent units will eventually be retired and replaced with NGCC (and perhaps some renewables). For example, Ghent 3 is assumed to retire in 2037 and Ghent 4 in 2038. Should future natural gas prices turn out to be more in line with the Low or Low less 25% fuel price scenarios, then the Companies are not forced to continue operating those stations. In other words, they can still switch to natural gas (or renewables/storage) in the future if that turns out to be a better alternative. However, just like Mill Creek, not installing ELG controls means that customers will be unnecessarily exposed to future natural gas prices regardless of their level because there is no turning back to coal.

Finally, just as in the case of Mill Creek, the execution risk profiles are not the same for the recommended ELG compliance plan versus the "retire and replace" all of Ghent alternative. Furthermore, as suggested in the Mill Creek discussion, a decision to retire and replace Mill Creek combined with a decision to do the same for Ghent by 2029 would amplify the challenges associated with executing such a monumental replacement of the generation portfolio. In addition to cost risks associated with such an endeavor, delays of any sort would almost certainly result in a high risk of generation shortfalls and potential for widespread and frequent rolling blackouts.

Based on these observations, the Companies' recommended ELG compliance plan of constructing 1,000 GPM of processing capability for all four Ghent units is the least-cost, lowest risk alternative to reliably meet customers' energy needs. Not investing in ELG controls is an unnecessary wager that future gas prices will be at or below the Low fuel price scenario from 2029 through 2037. And that wager also assumes that the same property acquisition, permitting, commercial and construction risk as Mill Creek can be implemented in the short timeframe. The Companies do not believe it is prudent to launch down the "retire and replace" path which is much more capital intensive ($2 to $3 billion for replacement v. $216 million for ELG compliance at Ghent) and has much greater execution risk based on a singular assumption about the future of natural gas prices.

Trimble County

As requested, the Trimble County analysis was updated to include the Low less 25% fuel price scenario and the 2019 ATB NGCC capital cost. The results of these additional cases show that:

- If future natural gas prices turn out to be like those in the Low less 25% fuel price scenario, then retiring and replacing Trimble County in 2029 would potentially save $93 million on a NPVRR basis. This is the only fuel price scenario in which the recommended ELG compliance plan is not preferred (see Appendix 11).
- Updating for the 2019 ATB NGCC capital cost changed the NPVRR differences in the alternative fuel scenarios but did not change the rankings of the alternatives meaning that the recommended ELG compliance plan is preferred in all fuel scenarios except the Low less 25% fuel price scenario.

Just as in the Mill Creek and Ghent evaluations, it should be noted that the perceived cost benefit of the "retire and replace" by 2029 in the Low less 25% fuel price scenario is likely overstated because ELG compliance does not lock the Companies into coal operations at Trimble County through each unit's book depreciation life (2050 for TC1 and 2066 for TC2). In effect, the results of the Low less 25% fuel price scenario were computed with the assumption that the Companies take no future action to move away from coal to natural gas from 2029 through 2050 despite 15 to 20 years of experience with relatively low natural gas prices reflected in the Low less 25% fuel price scenario.

Just as in the Mill Creek and Ghent evaluations, the execution risk profiles are not the same for the recommended ELG compliance plan versus the "retire and replace" all of Trimble Country alternative. Furthermore, a decision to retire Trimble County in addition to Mill Creek and Ghent in 2029 would only further complicate what would already be an extremely risky future resource plan and would likely be unprecedented for any utility in the industry – namely replacing approximately 80 percent of its energy in an eight-year period. Such a massive overhaul of the

Companies' generation system in such a short period of time certainly escalates the risks of numerous permitting, development, and construction activities while creating a high risk of generation shortfalls and the potential for widespread and frequent rolling blackouts.

Based on these observations, the Companies' recommended ELG compliance plan of constructing 600 GPM of processing capability for both Trimble County coal units is the least-cost, lowest risk alternative to reliably meet customers' energy needs. Again, not investing in ELG controls is an unnecessary wager that future gas prices will be at or below the Low less 25% fuel price scenario from 2029 through 2049. The Companies do not believe it is prudent to proceed with the "retire and replace" option based on a single assumption about the future of natural gas prices. The "retire and replace" option is much more capital intensive ($1 billion replacement v. $75 million for ELG compliance at Trimble County) and has much greater execution risk.

Future CO2 costs

This data request asked that the Companies "…identify the carbon price that will result in the NGCC alternative being the least-cost option." Because of the large number of alternatives and scenarios that have been evaluated, there is no one carbon price that is responsive to this request. To attempt to address this request, the Companies calculated a "break-even" CO_2 price by comparing the differences in the present value revenue requirements and CO_2 emissions between the recommended ELG compliance plans and the "retire and replace" with NGCC capacity by 2029 alternative (see Table 6). This allows for the calculation of a levelized price of CO_2 that, if in effect beginning in 2029 and continuing for the totality of the analysis period, would set the NPVRR of the two cases equal to each other. Note that the break-even prices will increase every year in the future that a CO_2 price is not actually in effect. Also, since all Low less 25% fuel price scenarios have a lower NPVRR, there is no break-even price calculated.

Table 6: Break-Even Carbon Prices ($/ton)

	Fuel Price Scenario			
Station	Low less 25%	Low	Mid	High
Mill Creek	N/A	N/A	0.30	11.40
Ghent	N/A	N/A	0.29	10.12
Trimble County	N/A	1.48	8.73	23.94

It should be noted that, while the calculated levelized price per ton of CO_2 is not very large in some cases, none of the alternatives evaluated were optimized for potential future CO_2 costs. Also, the nature of future CO_2 regulations would likely have an impact on fossil fuel prices, technology costs, and perhaps even the availability of future generation technology. For example, legislation in the future could materially impact the future price of natural gas (e.g., ban on fracking) or the ability to use fossil fuels of any type in the future (e.g., 100 percent zero carbon power by 2035). Therefore, regardless of one's view on a particular future cost of CO_2 emissions, proceeding with the recommended ELG compliance plans provides the most optionality to address future CO_2 legislation, regulations or both at the lowest cost rather than embarking on a multi-billion generation replacement with natural gas that could be banned or become technically obsolete (e.g., major break-through in storage performance and cost) just as it is being completed.[14]

Conclusion

Updating the analysis presented in Exhibit SAW-1 with the new data in the data request did not qualitatively change the analyses and conclusions that were previously presented in this case nor the Companies' recommended ELG compliance plans for the Mill Creek, Ghent, and Trimble County stations.

The timing and cost of complying with the ELG regulation present the Companies and the Commission with a stark choice:

- spend approximately $405 million to comply with the ELG regulations while maintaining the ability to transition the coal fleet to natural gas, renewables, and storage at a future date in an orderly fashion that will allow the opportunity to take advantage of existing transmission assets and other site-specific infrastructure, acquire properties for the new NGCC units or both;

Or

- launch on a multi-billion dollar project to retire and replace 80 percent of our customers' energy supply in eight years.

The Companies believe the evidence presented in this case demonstrates the prudent course is to proceed with the Companies' recommended ELG compliance plans. The recommended ELG compliance plans also provide the most optionality to manage the future. The proposed ELG compliance plans are reasonable and cost-effective for compliance with the ELG regulations.

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[14] "*A Bridge Backward? The Risky Economics of New Natural Gas Infrastructure in the United States*," Rocky Mountain Institute, September 9, 2019. See https://rmi.org/a-bridge-backward-the-risky-economics-of-new-natural-gas-infrastructure-in-the-united-states/.

Appendix 1: Original Assumptions

Mill Creek Station

Updated Table 22: Mill Creek Analysis Results ($M, PVRR 2020-2041, Excluding Transmission System Costs)

Fuel Price	Alternative	Replacement Generation Portfolio			Least-Cost Replacement Generation Portfolio	PVRR Diff from Least-Cost Alternative
		NGCC	NGCC + Renew	Peak + Renew		
Mid	ELG 4; 2032/2034	15,017	15,002	15,508	NGCC + Renew	58
	ELG 3; 2025/2034	14,959	14,944	15,450	NGCC + Renew	0
	ELG 3; 2025/2029	15,001	14,998	15,533	NGCC + Renew	54
	ELG 2; 2025/2026	15,014	15,040	15,615	NGCC	69
	Early Ret; 2029/2029	15,056	15,041	16,059	NGCC + Renew	97
	Early Ret; 2025/2029	15,030	15,014	16,032	NGCC + Renew	70
	Early Ret; 2025/2026	15,054	15,067	16,126	NGCC	109
Low	ELG 4; 2032/2034	14,288	14,290	14,912	NGCC	102
	ELG 3; 2025/2034	14,223	14,226	14,848	NGCC	37
	ELG 3; 2025/2029	14,254	14,277	14,935	NGCC	68
	ELG 2; 2025/2026	14,258	14,315	15,019	NGCC	72
	Early Ret; 2029/2029	14,216	14,228	15,452	NGCC	30
	Early Ret; 2025/2029	14,186	14,198	15,421	NGCC	0
	Early Ret; 2025/2026	14,201	14,247	15,517	NGCC	15
High	ELG 4; 2032/2034	16,322	16,274	16,590	NGCC + Renew	43
	ELG 3; 2025/2034	16,279	16,231	16,547	NGCC + Renew	0
	ELG 3; 2025/2029	16,341	16,290	16,625	NGCC + Renew	59
	ELG 2; 2025/2026	16,367	16,334	16,703	NGCC + Renew	103
	Early Ret; 2029/2029	16,580	16,512	17,184	NGCC + Renew	280
	Early Ret; 2025/2029	16,562	16,493	17,166	NGCC + Renew	262
	Early Ret; 2025/2026	16,600	16,549	17,256	NGCC + Renew	317
Low less 25%	ELG 4; 2032/2034	13,550	13,569	14,281	NGCC	290
	ELG 3; 2025/2034	13,474	13,494	14,205	NGCC	214
	ELG 3; 2025/2029	13,476	13,526	14,288	NGCC	216
	ELG 2; 2025/2026	13,459	13,553	14,367	NGCC	199
	Early Ret; 2029/2029	13,302	13,345	14,750	NGCC	42
	Early Ret; 2025/2029	13,265	13,307	14,713	NGCC	5
	Early Ret; 2025/2026	13,260	13,345	14,804	NGCC	0

Appendix 2: 2019 ATB NGCC Cost

Mill Creek Station

Updated Table 22: Mill Creek Analysis Results ($M, PVRR 2020-2041, Excluding Transmission System Costs)

Fuel Price	Alternative	Replacement Generation Portfolio			Least-Cost Replacement Generation Portfolio	PVRR Diff from Least-Cost Alternative
		NGCC	NGCC + Renew	Peak + Renew		
Mid	ELG 4; 2032/2034	14,930	14,918	15,508	NGCC + Renew	58
	ELG 3; 2025/2034	14,873	14,860	15,450	NGCC + Renew	0
	ELG 3; 2025/2029	14,905	14,905	15,533	NGCC	45
	ELG 2; 2025/2026	14,910	14,940	15,615	NGCC	50
	Early Ret; 2029/2029	14,905	14,894	16,059	NGCC + Renew	34
	Early Ret; 2025/2029	14,879	14,868	16,032	NGCC + Renew	7
	Early Ret; 2025/2026	14,896	14,914	16,126	NGCC	35
Low	ELG 4; 2032/2034	14,201	14,206	14,912	NGCC	166
	ELG 3; 2025/2034	14,136	14,142	14,848	NGCC	102
	ELG 3; 2025/2029	14,158	14,184	14,935	NGCC	123
	ELG 2; 2025/2026	14,154	14,215	15,019	NGCC	120
	Early Ret; 2029/2029	14,065	14,082	15,452	NGCC	30
	Early Ret; 2025/2029	14,035	14,051	15,421	NGCC	0
	Early Ret; 2025/2026	14,043	14,094	15,517	NGCC	8
High	ELG 4; 2032/2034	16,235	16,190	16,590	NGCC + Renew	43
	ELG 3; 2025/2034	16,192	16,147	16,547	NGCC + Renew	0
	ELG 3; 2025/2029	16,244	16,197	16,625	NGCC + Renew	50
	ELG 2; 2025/2026	16,264	16,234	16,703	NGCC + Renew	87
	Early Ret; 2029/2029	16,429	16,365	17,184	NGCC + Renew	218
	Early Ret; 2025/2029	16,411	16,347	17,166	NGCC + Renew	200
	Early Ret; 2025/2026	16,442	16,395	17,256	NGCC + Renew	248
Low less 25%	ELG 4; 2032/2034	13,463	13,485	14,281	NGCC	361
	ELG 3; 2025/2034	13,387	13,409	14,205	NGCC	285
	ELG 3; 2025/2029	13,379	13,433	14,288	NGCC	277
	ELG 2; 2025/2026	13,356	13,453	14,367	NGCC	254
	Early Ret; 2029/2029	13,151	13,198	14,750	NGCC	49
	Early Ret; 2025/2029	13,114	13,161	14,713	NGCC	12
	Early Ret; 2025/2026	13,102	13,192	14,804	NGCC	0

Appendix 3: 2019 ATB NGCC Cost + Ghent Pipeline Cost

Mill Creek Station

Updated Table 22: Mill Creek Analysis Results ($M, PVRR 2020-2041, Excluding Transmission System Costs)

Fuel Price	Alternative	Replacement Generation Portfolio			Least-Cost Replacement Generation Portfolio	PVRR Diff from Least-Cost Alternative
		NGCC	NGCC + Renew	Peak + Renew		
Mid	ELG 4; 2032/2034	15,045	15,033	15,623	NGCC + Renew	58
	ELG 3; 2025/2034	14,988	14,975	15,565	NGCC + Renew	0
	ELG 3; 2025/2029	15,020	15,020	15,648	NGCC	45
	ELG 2; 2025/2026	15,025	15,055	15,730	NGCC	50
	Early Ret; 2029/2029	15,021	15,009	16,174	NGCC + Renew	34
	Early Ret; 2025/2029	14,994	14,983	16,147	NGCC + Renew	7
	Early Ret; 2025/2026	15,011	15,029	16,241	NGCC	35
Low	ELG 4; 2032/2034	14,316	14,321	15,027	NGCC	166
	ELG 3; 2025/2034	14,251	14,257	14,963	NGCC	102
	ELG 3; 2025/2029	14,273	14,299	15,050	NGCC	123
	ELG 2; 2025/2026	14,269	14,330	15,134	NGCC	120
	Early Ret; 2029/2029	14,180	14,197	15,567	NGCC	30
	Early Ret; 2025/2029	14,150	14,166	15,536	NGCC	0
	Early Ret; 2025/2026	14,158	14,209	15,632	NGCC	8
High	ELG 4; 2032/2034	16,350	16,305	16,706	NGCC + Renew	43
	ELG 3; 2025/2034	16,307	16,262	16,662	NGCC + Renew	0
	ELG 3; 2025/2029	16,359	16,312	16,740	NGCC + Renew	50
	ELG 2; 2025/2026	16,379	16,349	16,818	NGCC + Renew	87
	Early Ret; 2029/2029	16,544	16,480	17,299	NGCC + Renew	218
	Early Ret; 2025/2029	16,526	16,462	17,281	NGCC + Renew	200
	Early Ret; 2025/2026	16,557	16,510	17,371	NGCC + Renew	248
Low less 25%	ELG 4; 2032/2034	13,578	13,600	14,396	NGCC	361
	ELG 3; 2025/2034	13,502	13,525	14,320	NGCC	285
	ELG 3; 2025/2029	13,494	13,548	14,403	NGCC	277
	ELG 2; 2025/2026	13,471	13,568	14,482	NGCC	254
	Early Ret; 2029/2029	13,266	13,313	14,866	NGCC	49
	Early Ret; 2025/2029	13,229	13,276	14,828	NGCC	12
	Early Ret; 2025/2026	13,217	13,307	14,919	NGCC	0

Note: The Ghent pipeline cost increases the PVRR for all Mill Creek alternatives by the same amount. Therefore, the PVRR differences in the last column are unchanged from the values in Appendix 2.

Appendix 4: 2019 ATB NGCC Cost + Ghent Pipeline Cost + Transmission System Costs

Mill Creek Station

Updated Table 22: Mill Creek Analysis Results ($M, PVRR 2020-2041, Including Transmission System Costs)

Fuel Price	Alternative	Replacement Generation Portfolio			Least-Cost Replacement Generation Portfolio	PVRR Diff from Least-Cost Alternative
		NGCC	NGCC + Renew	Peak + Renew		
Mid	ELG 4; 2032/2034	15,045	15,033	15,623	NGCC + Renew	58
	ELG 3; 2025/2034	14,988	14,975	15,565	NGCC + Renew	0
	ELG 3; 2025/2029	15,020	15,020	15,648	NGCC	45
	ELG 2; 2025/2026	15,025	15,055	15,730	NGCC	50
	Early Ret; 2029/2029	15,717	15,706	16,870	NGCC + Renew	730
	Early Ret; 2025/2029	15,690	15,679	16,843	NGCC + Renew	704
	Early Ret; 2025/2026	15,707	15,725	16,937	NGCC	732
Low	ELG 4; 2032/2034	14,316	14,321	15,027	NGCC	64
	ELG 3; 2025/2034	14,251	14,257	14,963	NGCC	0
	ELG 3; 2025/2029	14,273	14,299	15,050	NGCC	21
	ELG 2; 2025/2026	14,269	14,330	15,134	NGCC	18
	Early Ret; 2029/2029	14,876	14,893	16,263	NGCC	625
	Early Ret; 2025/2029	14,846	14,863	16,232	NGCC	595
	Early Ret; 2025/2026	14,854	14,905	16,328	NGCC	603
High	ELG 4; 2032/2034	16,350	16,305	16,706	NGCC + Renew	43
	ELG 3; 2025/2034	16,307	16,262	16,662	NGCC + Renew	0
	ELG 3; 2025/2029	16,359	16,312	16,740	NGCC + Renew	50
	ELG 2; 2025/2026	16,379	16,349	16,818	NGCC + Renew	87
	Early Ret; 2029/2029	17,240	17,176	17,995	NGCC + Renew	914
	Early Ret; 2025/2029	17,222	17,158	17,977	NGCC + Renew	896
	Early Ret; 2025/2026	17,253	17,207	18,067	NGCC + Renew	944
Low less 25%	ELG 4; 2032/2034	13,578	13,600	14,396	NGCC	107
	ELG 3; 2025/2034	13,502	13,525	14,320	NGCC	31
	ELG 3; 2025/2029	13,494	13,548	14,403	NGCC	23
	ELG 2; 2025/2026	13,471	13,568	14,482	NGCC	0
	Early Ret; 2029/2029	13,963	14,009	15,562	NGCC	492
	Early Ret; 2025/2029	13,925	13,972	15,524	NGCC	454
	Early Ret; 2025/2026	13,913	14,003	15,615	NGCC	442

Appendix 5: LKE NGCC Cost + Ghent Pipeline Cost + Transmission System Costs

Mill Creek Station

Updated Table 22: Mill Creek Analysis Results ($M, PVRR 2020-2041, Including Transmission System Costs)

Fuel Price	Alternative	Replacement Generation Portfolio			Least-Cost Replacement Generation Portfolio	PVRR Diff from Least-Cost Alternative
		NGCC	NGCC + Renew	Peak + Renew		
Mid	ELG 4; 2032/2034	15,132	15,117	15,623	NGCC + Renew	58
	ELG 3; 2025/2034	15,075	15,059	15,565	NGCC + Renew	0
	ELG 3; 2025/2029	15,117	15,113	15,648	NGCC + Renew	54
	ELG 2; 2025/2026	15,129	15,155	15,730	NGCC	69
	Early Ret; 2029/2029	15,868	15,852	16,870	NGCC + Renew	793
	Early Ret; 2025/2029	15,841	15,826	16,843	NGCC + Renew	766
	Early Ret; 2025/2026	15,865	15,878	16,937	NGCC	806
Low	ELG 4; 2032/2034	14,403	14,405	15,027	NGCC	64
	ELG 3; 2025/2034	14,338	14,341	14,963	NGCC	0
	ELG 3; 2025/2029	14,369	14,392	15,050	NGCC	31
	ELG 2; 2025/2026	14,373	14,430	15,134	NGCC	35
	Early Ret; 2029/2029	15,027	15,040	16,263	NGCC	689
	Early Ret; 2025/2029	14,997	15,009	16,232	NGCC	659
	Early Ret; 2025/2026	15,012	15,058	16,328	NGCC	674
High	ELG 4; 2032/2034	16,437	16,390	16,706	NGCC + Renew	43
	ELG 3; 2025/2034	16,394	16,346	16,662	NGCC + Renew	0
	ELG 3; 2025/2029	16,456	16,405	16,740	NGCC + Renew	59
	ELG 2; 2025/2026	16,482	16,449	16,818	NGCC + Renew	103
	Early Ret; 2029/2029	17,391	17,323	17,995	NGCC + Renew	977
	Early Ret; 2025/2029	17,373	17,305	17,977	NGCC + Renew	958
	Early Ret; 2025/2026	17,411	17,360	18,067	NGCC + Renew	1,014
Low less 25%	ELG 4; 2032/2034	13,665	13,684	14,396	NGCC	91
	ELG 3; 2025/2034	13,589	13,609	14,320	NGCC	15
	ELG 3; 2025/2029	13,591	13,642	14,403	NGCC	16
	ELG 2; 2025/2026	13,575	13,668	14,482	NGCC	0
	Early Ret; 2029/2029	14,114	14,156	15,562	NGCC	539
	Early Ret; 2025/2029	14,076	14,119	15,524	NGCC	502
	Early Ret; 2025/2026	14,071	14,157	15,615	NGCC	497

Appendix 6: Original Assumptions

Ghent Station

Updated Table 29: Ghent Analysis Results ($M, PVRR 2020-2037, Excluding Transmission System Costs and Gas Pipeline Costs)

Fuel Price	Alternative	Replacement Generation Portfolio			Least-Cost Replacement Generation Portfolio	PVRR Diff from Least-Cost Alternative
		NGCC	NGCC + Renew	Peak + Renew		
Mid	ELG 4; 2034	12,903	12,900	13,092	NGCC + Renew	0
	ELG 4; 2029	12,988	12,994	13,253	NGCC	88
	ELG 3; 2026	13,018	13,053	13,405	NGCC	118
	Early Ret; 2029	12,959	12,950	13,681	NGCC + Renew	50
Low	ELG 4; 2034	12,369	12,375	12,615	NGCC	64
	ELG 4; 2029	12,433	12,456	12,781	NGCC	128
	ELG 3; 2026	12,446	12,505	12,933	NGCC	142
	Early Ret; 2029	12,305	12,318	13,190	NGCC	0
High	ELG 4; 2034	13,858	13,839	13,958	NGCC + Renew	0
	ELG 4; 2029	13,980	13,952	14,112	NGCC + Renew	112
	ELG 3; 2026	14,037	14,027	14,258	NGCC + Renew	187
	Early Ret; 2029	14,152	14,108	14,606	NGCC + Renew	269
Low less 25%	ELG 4; 2034	11,829	11,843	12,128	NGCC	291
	ELG 4; 2029	11,846	11,889	12,287	NGCC	308
	ELG 3; 2026	11,825	11,912	12,426	NGCC	287
	Early Ret; 2029	11,538	11,575	12,593	NGCC	0

Appendix 7: 2019 ATB NGCC Cost

Ghent Station

Updated Table 29: Ghent Analysis Results ($M, PVRR 2020-2037, Excluding Transmission System Costs and Gas Pipeline Costs)

Fuel Price	Alternative	Replacement Generation Portfolio			Least-Cost Replacement Generation Portfolio	PVRR Diff from Least-Cost Alternative
		NGCC	NGCC + Renew	Peak + Renew		
Mid	ELG 4; 2034	12,868	12,866	13,092	NGCC + Renew	27
	ELG 4; 2029	12,938	12,945	13,253	NGCC	98
	ELG 3; 2026	12,956	12,993	13,405	NGCC	116
	Early Ret; 2029	12,845	12,840	13,681	NGCC + Renew	0
Low	ELG 4; 2034	12,334	12,341	12,615	NGCC	144
	ELG 4; 2029	12,382	12,407	12,781	NGCC	192
	ELG 3; 2026	12,384	12,445	12,933	NGCC	194
	Early Ret; 2029	12,190	12,207	13,190	NGCC	0
High	ELG 4; 2034	13,823	13,806	13,958	NGCC + Renew	0
	ELG 4; 2029	13,930	13,903	14,112	NGCC + Renew	97
	ELG 3; 2026	13,975	13,967	14,258	NGCC + Renew	161
	Early Ret; 2029	14,037	13,998	14,606	NGCC + Renew	192
Low less 25%	ELG 4; 2034	11,794	11,809	12,128	NGCC	371
	ELG 4; 2029	11,795	11,840	12,287	NGCC	372
	ELG 3; 2026	11,763	11,852	12,426	NGCC	340
	Early Ret; 2029	11,423	11,464	12,593	NGCC	0

Appendix 8: 2019 ATB NGCC Cost + Ghent Pipeline Cost

Ghent Station

Updated Table 29: Ghent Analysis Results ($M, PVRR 2020-2037, Excluding Transmission System Costs)

Fuel Price	Alternative	Replacement Generation Portfolio			Least-Cost Replacement Generation Portfolio	PVRR Diff from Least-Cost Alternative
		NGCC	NGCC + Renew	Peak + Renew		
Mid	ELG 4; 2034	12,983	12,982	13,207	NGCC + Renew	0
	ELG 4; 2029	13,082	13,088	13,397	NGCC	100
	ELG 3; 2026	13,120	13,157	13,569	NGCC	139
	Early Ret; 2029	12,988	12,983	13,825	NGCC + Renew	2
Low	ELG 4; 2034	12,449	12,456	12,731	NGCC	115
	ELG 4; 2029	12,526	12,551	12,925	NGCC	192
	ELG 3; 2026	12,549	12,609	13,098	NGCC	215
	Early Ret; 2029	12,334	12,351	13,333	NGCC	0
High	ELG 4; 2034	13,938	13,921	14,073	NGCC + Renew	0
	ELG 4; 2029	14,074	14,047	14,256	NGCC + Renew	126
	ELG 3; 2026	14,140	14,131	14,422	NGCC + Renew	211
	Early Ret; 2029	14,181	14,141	14,750	NGCC + Renew	221
Low less 25%	ELG 4; 2034	11,909	11,924	12,243	NGCC	342
	ELG 4; 2029	11,939	11,984	12,431	NGCC	372
	ELG 3; 2026	11,927	12,016	12,591	NGCC	360
	Early Ret; 2029	11,567	11,608	12,737	NGCC	0

Appendix 9: 2019 ATB NGCC Cost + Ghent Pipeline Cost + Transmission System Costs

Ghent Station

Updated Table 29: Ghent Analysis Results ($M, PVRR 2020-2037, Including Transmission System Costs)

Fuel Price	Alternative	Replacement Generation Portfolio: NGCC	Replacement Generation Portfolio: NGCC + Renew	Replacement Generation Portfolio: Peak + Renew	Least-Cost Replacement Generation Portfolio	PVRR Diff from Least-Cost Alternative
Mid	ELG 4; 2034	12,983	12,982	13,207	NGCC + Renew	0
	ELG 4; 2029	13,082	13,088	13,397	NGCC	100
	ELG 3; 2026	13,120	13,157	13,569	NGCC	139
	Early Ret; 2029	12,988	12,983	13,825	NGCC + Renew	2
Low	ELG 4; 2034	12,449	12,456	12,731	NGCC	115
	ELG 4; 2029	12,526	12,551	12,925	NGCC	192
	ELG 3; 2026	12,549	12,609	13,098	NGCC	215
	Early Ret; 2029	12,334	12,351	13,333	NGCC	0
High	ELG 4; 2034	13,938	13,921	14,073	NGCC + Renew	0
	ELG 4; 2029	14,074	14,047	14,256	NGCC + Renew	126
	ELG 3; 2026	14,140	14,131	14,422	NGCC + Renew	211
	Early Ret; 2029	14,181	14,141	14,750	NGCC + Renew	221
Low less 25%	ELG 4; 2034	11,909	11,924	12,243	NGCC	342
	ELG 4; 2029	11,939	11,984	12,431	NGCC	372
	ELG 3; 2026	11,927	12,016	12,591	NGCC	360
	Early Ret; 2029	11,567	11,608	12,737	NGCC	0

Note: The consideration of transmission system costs has no impact on the analysis of Ghent alternatives. The results in Appendices 8 and 9 are the same. The analysis assumes a Ghent pipeline and the phased replacement of the Mill Creek units will enable the Companies to avoid significant transmission system costs.

Appendix 10: LKE NGCC Cost + Ghent Pipeline Cost + Transmission System Costs

Ghent Station

Updated Table 29: Ghent Analysis Results ($M, PVRR 2020-2037, Including Transmission System Costs)

Fuel Price	Alternative	Replacement Generation Portfolio			Least-Cost Replacement Generation Portfolio	PVRR Diff from Least-Cost Alternative
		NGCC	NGCC + Renew	Peak + Renew		
Mid	ELG 4; 2034	13,018	13,015	13,207	NGCC + Renew	0
	ELG 4; 2029	13,132	13,137	13,397	NGCC	117
	ELG 3; 2026	13,182	13,217	13,569	NGCC	167
	Early Ret; 2029	13,103	13,094	13,825	NGCC + Renew	79
Low	ELG 4; 2034	12,484	12,490	12,731	NGCC	35
	ELG 4; 2029	12,577	12,600	12,925	NGCC	128
	ELG 3; 2026	12,611	12,669	13,098	NGCC	162
	Early Ret; 2029	12,448	12,462	13,333	NGCC	0
High	ELG 4; 2034	13,973	13,954	14,073	NGCC + Renew	0
	ELG 4; 2029	14,124	14,095	14,256	NGCC + Renew	141
	ELG 3; 2026	14,202	14,191	14,422	NGCC + Renew	237
	Early Ret; 2029	14,296	14,252	14,750	NGCC + Renew	298
Low less 25%	ELG 4; 2034	11,944	11,958	12,243	NGCC	262
	ELG 4; 2029	11,989	12,033	12,431	NGCC	308
	ELG 3; 2026	11,989	12,076	12,591	NGCC	308
	Early Ret; 2029	11,682	11,718	12,737	NGCC	0

Note: The consideration of transmission system costs has no impact on the analysis of Ghent alternatives. The analysis assumes a Ghent pipeline and the phased replacement of the Mill Creek units will enable the Companies to avoid significant transmission system costs.

Appendix 11: Original Assumptions

Trimble County Station

Updated Table 36: Trimble County Analysis Results ($M, PVRR 2020-2050)

Fuel Price	Alternative	Replacement Generation Portfolio: NGCC	Replacement Generation Portfolio: NGCC + Renew	Replacement Generation Portfolio: Peak + Renew	Least-Cost Replacement Generation Portfolio	PVRR Diff from Least-Cost Alternative
Mid	ELG 2	18,539	18,496	19,659	NGCC + Renew	0
	Early Ret	18,842	18,806	20,776	NGCC + Renew	310
Low	ELG 2	17,378	17,369	18,780	NGCC + Renew	0
	Early Ret	17,503	17,510	19,861	NGCC	134
High	ELG 2	20,649	20,543	21,267	NGCC + Renew	0
	Early Ret	21,299	21,183	22,462	NGCC + Renew	639
Low less 25%	ELG 2	16,240	16,262	17,844	NGCC	93
	Early Ret	16,147	16,197	18,842	NGCC	0

Appendix 12: 2019 ATB NGCC Cost

Trimble County Station

Updated Table 36: Trimble County Analysis Results ($M, PVRR 2020-2050)

Fuel Price	Alternative	Replacement Generation Portfolio			Least-Cost Replacement Generation Portfolio	PVRR Diff from Least-Cost Alternative
		NGCC	NGCC + Renew	Peak + Renew		
Mid	ELG 2	18,351	18,314	19,659	NGCC + Renew	0
	Early Ret	18,564	18,535	20,776	NGCC + Renew	221
Low	ELG 2	17,190	17,187	18,780	NGCC + Renew	0
	Early Ret	17,225	17,239	19,861	NGCC	38
High	ELG 2	20,461	20,362	21,267	NGCC + Renew	0
	Early Ret	21,021	20,912	22,462	NGCC + Renew	550
Low less 25%	ELG 2	16,052	16,080	17,844	NGCC	183
	Early Ret	15,869	15,926	18,842	NGCC	0

Appendix 13: 2019 ATB NGCC Cost + Ghent Pipeline Cost

Trimble County Station

Updated Table 36: Trimble County Analysis Results ($M, PVRR 2020-2050)

Fuel Price	Alternative	Replacement Generation Portfolio			Least-Cost Replacement Generation Portfolio	PVRR Diff from Least-Cost Alternative
		NGCC	NGCC + Renew	Peak + Renew		
Mid	ELG 2	18,466	18,429	19,774	NGCC + Renew	0
	Early Ret	18,679	18,650	20,891	NGCC + Renew	221
Low	ELG 2	17,305	17,302	18,895	NGCC + Renew	0
	Early Ret	17,340	17,354	19,977	NGCC	38
High	ELG 2	20,576	20,477	21,382	NGCC + Renew	0
	Early Ret	21,136	21,027	22,577	NGCC + Renew	550
Low less 25%	ELG 2	16,167	16,195	17,959	NGCC	183
	Early Ret	15,984	16,041	18,957	NGCC	0

Note: The Ghent pipeline cost increases the PVRR for both Trimble County alternatives by the same amount. Therefore, the PVRR differences in the last column are unchanged from the values in Appendix 12.

Appendix 14: 2019 ATB NGCC Cost + Ghent Pipeline Cost + Transmission System Cost

Trimble County Station

Updated Table 36: Trimble County Analysis Results ($M, PVRR 2020-2050)

Fuel Price	Alternative	Replacement Generation Portfolio			Least-Cost Replacement Generation Portfolio	PVRR Diff from Least-Cost Alternative
		NGCC	NGCC + Renew	Peak + Renew		
Mid	ELG 2	18,466	18,429	19,774	NGCC + Renew	0
	Early Ret	18,679	18,650	20,891	NGCC + Renew	221
Low	ELG 2	17,305	17,302	18,895	NGCC + Renew	0
	Early Ret	17,340	17,354	19,977	NGCC	38
High	ELG 2	20,576	20,477	21,382	NGCC + Renew	0
	Early Ret	21,136	21,027	22,577	NGCC + Renew	550
Low less 25%	ELG 2	16,167	16,195	17,959	NGCC	183
	Early Ret	15,984	16,041	18,957	NGCC	0

Note: The consideration of transmission system costs has no impact on the analysis of Trimble County alternatives. The results in Appendices 13 and 14 are the same. The analysis assumes a Ghent pipeline and the phased replacement of the Mill Creek units will enable the Companies to avoid significant transmission system costs.

Appendix 15: LKE NGCC Cost + Ghent Pipeline Cost + Transmission System Cost

Trimble County Station

Updated Table 36: Trimble County Analysis Results ($M, PVRR 2020-2050)

Fuel Price	Alternative	Replacement Generation Portfolio: NGCC	NGCC + Renew	Peak + Renew	Least-Cost Replacement Generation Portfolio	PVRR Diff from Least-Cost Alternative
Mid	ELG 2	18,654	18,611	19,774	NGCC + Renew	0
	Early Ret	18,957	18,921	20,891	NGCC + Renew	310
Low	ELG 2	17,493	17,484	18,895	NGCC + Renew	0
	Early Ret	17,618	17,625	19,977	NGCC	134
High	ELG 2	20,764	20,659	21,382	NGCC + Renew	0
	Early Ret	21,414	21,298	22,577	NGCC + Renew	639
Low less 25%	ELG 2	16,355	16,377	17,959	NGCC	93
	Early Ret	16,262	16,312	18,957	NGCC	0

Note: The consideration of transmission system costs has no impact on the analysis of Trimble County alternatives. The analysis assumes a Ghent pipeline and the phased replacement of the Mill Creek units will enable the Companies to avoid significant transmission system costs.