2024

WDEP Shared Governance Committee Final Report

FINAL DOCUMENTATION

CLIMATE ACTION SHARED GOVERNANCE COMMITTEE

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Executive Summary

In late-2023, the Board of Regents, upon the recommendation of campus administration, approved a $43 million project to upgrade steam and electricity generating equipment in the University's West District Energy Plant (WDEP). WDEP is a fossil fuel plant that produces energy using natural gas. Following the University's announcement of the plan, community members, including faculty, students, and staff, expressed concerns that this plan would lock-in fossil fuel emissions and is therefore inconsistent with the University's climate commitments.

On February 29, 2023, the University's Chief Operating Officer (COO) and Chair of the Boulder Faculty Assembly, appointed the WDEP Shared-Governance Committee (the Committee). The Committee was tasked with examining alternatives to the University's WDEP plan. The Committee was given a short timeline of three weeks to make a preliminary recommendation. This short timeline was due to the University's claim that a $7 million non-refundable deposit was due by April 1, 2024 to secure a tax credit if the University were to follow its original upgrade plan.

During March 2023, the Committee met with faculty, staff, consultants, and subject matter experts at the Department of Public Health and Environment. Based on those meetings, documentation research, and University policy review, the Committee was able to come up with a viable recommendation for the University regarding WDEP upgrades. The Committee's preliminary recommendation was determined based on several requirements: regulatory compliance, engineering feasibility, resilience, climate impacts, and cost. The Committee's Preliminary Report was submitted to the COO on March 21, 2024 (see here).

While Option A1 developed by the Committee still requires the use of natural gas for heating, its lifecycle GHG emissions (Scopes 1-2) are 8-10% lower than the originally proposed Option 2E between the present and 2045. In in absolute terms, the lifecycle difference comes to 100,000-110,000 tCO_2, or an average of 5,000 tCO_2 per year (= 100,000 tCO_2/20 years). For reference, the average of 5,000 tCO_2e per year of excess emissions by Option 2E is equivalent to the annual emissions from driving 1,190 gasoline-powered vehicles (for calculation, see discussion below). For further reference, the 100,000-110,000 tCO_2 in excess emissions of Option 2E over the lifecycle represents about 16-18% of the Scope 1-2 emissions reduction projects that the University plans to pursue under its new Climate Action Plan (CAP) during 2025-2045. In addition to the difference in Scope 1-2 emissions, the Committee also found that Option A1 would have lower Scope 3 emissions relative to Option 2E.

Following this option, the Committee recommended the University withhold the $7 million deposit for turbine upgrades. The Committee also submitted to the University a request for relevant information and data to support the Committee's continued work to develop additional alternatives. The Committee highlighted that Option A1 was not the final option recommended by the Committee. Rather, Option A1 was a demonstration that a preferrable option existed to the University's Option 2E, and therefore, that it was inadvisable for the University to make the non-refundable deposit on April 1. According to the Committee's position, there was no urgency to finalize the University's decision without having considered all the available alternatives. Therefore, the Committee believed that the Committee and the University should spend the following months reviewing all the relevant data and considering additional alternatives.

The April 1, 2024 deposit deadline passed, and the University apparently did not make the deposit. The COO met with the Committee on April 8, 2024. In that meeting, the COO seemed receptive to the Committee's recommendation, if the University was able to confirm the regulatory flexibility identified by the Committee under the relevant regulation. The existence of that regulatory flexibility was necessary for the Committee's Option A1 to be viable. Earlier that day, the Colorado Department of Public Health and the Environment (CDPHE) provided the Committee and the University with a written confirmation regarding the regulatory flexibility discussed in the Committee's Preliminary Report. That confirmation provided the Committee with high confidence that Option A1 was viable.

During the remainder of April and May 2024, the University largely stopped outwardly cooperating with the Committee. During that period, the University did not share with the Committee the data and information that the Committee requested to inform its continued work. The University also did not share with the Committee internal documents the University was developing regarding the WDEP upgrade. The University's lack of communication hindered the Committee's continued work toward a final reporting and recommendations.

On June 5, 2024, the University COO notified the Committee's chairs by email of the intention to proceed with the University's original WDEP plan (Option 2E), against the Committee's recommendation. The COO attached a memorandum to his email, explaining the considerations for this decision ("University's the June 5 memo" can be found here). As discussed in this Final Report, the Committee finds that the claims in the University's June 5 memo largely ignore the analysis in the Committee's Preliminary Report (March 2024), and are, in important respects, self-contradictory. The University's memo repeats claims that the University made to explain its adoption of Option 2E in Fall 2023, months before the Committee was formed. Those claims were carefully assessed by the Committee based on available data and were found to be incorrect.

Note: The Committee highlights that it did not receive all relevant data and analysis it requested from the University. The Committee's findings of certain claims by the University as incorrect or unsupported are made "based on available data", i.e., based on those materials that were available to the Committee. It is possible that the University has additional data or analysis which supports its claims but were not shared with the Committee. If the University believes it possess such materials, the Committee recommends that the University publicly disclose those materials as soon as possible so they can be reviewed.

On July 8 the Committee contacted Dr. Justin Schwartz, the new Chancellor (who entered his position on July 1, 2024). In its email, the Committee raised its concern regarding the decision and asked for a meeting with the Chancellor. The Committee attached the Preliminary Report to its email. The Chancellor did not agree to meet with the Committee. On July 23, the Chancellor decided to uphold the COO's decision. In explaining his decision to the Committee, the Chancellor made the same claims regarding the WDEP project that were addressed in the Preliminary Report. The correspondence between the Committee and the Chancellor is included here. Those are the claims the Committee had already found to be incorrect based on available data.

In this Final Report, the Committee provides a record regarding the WDEP decision and process. This record documents important shortcomings in the University's planning process. Those include the following:

1. The University's original program plan for the WDEP project was written without adequate alternatives analysis, which is essential to adequate environmental decision making.
2. The University's original WDEP plan (Option 2E) was developed with a lack of understanding of the regulatory flexibility offered by the explicit language of Reg 7. The University's perception that Option 2E was required to ensure campus resilience likely resulted from that misunderstanding.
3. In its Preliminary Report, the Committee found that Option A1 provides similar resilience benefits to the University's Option 2E. The University continued to claim that compelling resilience needs required the adoption of Option 2E despite detailed analysis by the Committee to the contrary when considering the regulatory flexibility in Reg 7. The University did not provide the Committee with any data or analysis supporting its claim.
4. The University claims Option 2E is required to protect continuity of mission critical research. Under the University's own Energy Master Plan, that goal is supposed to be achieved by other means, which the University has not yet implemented.[1]
5. In the program plan it submitted to the CU Board of Regents (Fall 2023, see here), the University did not take into consideration the additional greenhouse gas emissions that would result from Option 2E relative to the business-as-usual assumptions in its 2024 climate action planning. In this program plan, the University also highlighted carbon reduction benefits of the plan that are "...likely [to] hold true until at least 2030."[2] According to the Committee's review of the University's models, those emissions reductions are small and short-lived. Meanwhile, the University did not alert the Board of Regents to more substantial increases in carbon emissions that the plan would represent relative to the business-as-usual scenario in the long-term.
6. The University's program plan included several additional claims that were incorrect and/or incomplete based on available data. It is possible that if the Regents had received more accurate and complete information, they would have invested greater resources in finding an alternative to the University's plan. For example:
    a. The University claimed that Option 2E will replace "existing 30-year-old combustion turbines" (p. 3), without mentioning the turbines have been rebuilt in 2013, and had very little depreciation on them given minimal use since 2013;
    b. The University claimed (p.4) that Option 2E aligns with the University's 2021 Energy Master Plan (EMP), despite the fact that the EMP explicitly planned to avoid base loaded cogeneration starting 2027, given GHG considerations (see here, p. 52; note that at the time the EMP was finalized, Reg 7 which the University claims precipitated the need for Option 2E was already in force);
    c. Under the heading "Sustainable Design", the University highlighted the possibility of reconfiguring the new turbines "to operate on alternative fuels like hydrogen or other cleaner

[1] See, Energy Master Plan, p. 70; Preliminary Report, p. 10.

[2] WDEP 2023 Program Plan, p. 5 "This project has some immediate decarbonization benefits because producing power on campus with natural gas is currently cleaner than purchasing power from the grid. This will likely hold true until at least 2030 as Xcel continues to execute its Colorado Clean Energy Plan. The project also contributes to the long-term goals to decarbonize and implement the 2050 vision."; and on p. 10 "By replacing the WDEP equipment, the campus is reducing the amount of GHG emissions produced while enhancing the campus mission of education and research with redundancy and resilience."

burning fuel sources" (p. 4), even though it is widely accepted that hydrogen does not provide a feasible source of energy for heating for environmental, economic, and other reasons.

7. Concerns regarding the University's recent planning to upgrade WDEP should also be understood in the context of WDEP's role in the University's failure to achieve its 2020 climate targets. As the Committee noted in its preliminary report (p. 9): "*The minimal use of cogen throughout the 2010s substantially contributed to the University's miss of its 2020 climate target. With the grid expected to become cleaner than cogen by 2029, there is a risk that once again the University will find itself using the less climate friendly option for energy generation. In other words, the University that did not baseload cogeneration when it was climate friendly to do so will shift to baseloaded cogeneration just when it is no longer climate friendly to do so*." The University did not provide the community with adequate transparency regarding the minimal use of cogeneration during the 2010s. That minimal use ran counter to the University's planning under the 2009 Conceptual Plan for Carbon Neutrality (see Preliminary Report, pp. 4-5).

8. The desire to obtain federal tax credits under the Inflation Reduction Act (IRA) was, according to the University, an important factor in its decision to pursue Option 2E, as well as the timing for its decision. Nevertheless, the University did not carry out the necessary analysis regarding eligibility requirement for the credit. To the Committee's understanding, the University lacked such analysis as late as June 2024, even though concerns were flagged by the Committee in March 2024.

9. The University used contradictory assumptions in its financial analysis and its climate analysis. The contradictory assumptions created a biased impression regarding the financial benefits of the University's Option 2E. On the one hand, the University claimed its intention to reduce the excess emissions of Option 2E over Option A1 through an early phase-out of baseloaded cogeneration. On the other hand, for its lifecycle cost analysis, the University assumed that baseloaded cogeneration would continue in the long run, resulting in financial benefits to the University over Option A1. The University should not use two contradictory sets of assumptions, one to claim financial advantages (assuming long-term base-loading), then another to try to limit the increase in emissions (assuming a shift away from baseload generation, presumably as early as 2029).

10. The University did not share with the Committee a campus load-curve, which is essential for energy planning. Despite repeated Committee requests, the University did not corroborate its claim regarding peak-load of 200 kpph steam needs.

11. While the University's Climate Action Plan assumes a 30% decline in campus energy consumption, the University planning for WDEP assumed peak demand would remain constant long into the future. The University was not willing to engage with the Committee regarding options to reduce peak-load through demand-side management.

12. The University's claims that Option 2E will reduce campus NO_x emissions by 50% relative to current emissions has not been supported by data. While the turbines the University plans to install under Option 2E have lower NO_x emissions intensity than the existing turbines, the existing turbines are only operated by the University on rare occasions. In distinction, under the University plan, the new turbines will be used continuously for base-loaded cogeneration. The University did not present an analysis of the absolute levels of NO_x emissions that would result from its plan to support the claim of 50% reduction.

13. While claiming to be committed to shared-governance principles, the University essentially ignored the Committee's Preliminary Report, instead repeating claims (including publicly) that were found and documented by the Committee to be incorrect based on available data. The University refused to share relevant planning documents, or to engage the Committee in a meaningful review of the materials that the University developed in April-May 2024.
14. The University's lack of cooperation with the Committee during April-May 2024, hindered the work of the Committee, and, among other things, hindered the development of additional alternatives to the University's Option 2E, which may have been even more favorable than Option A1.
15. There was no urgency for the University to finalize its decision by the original April 1 deadline, or by July 2024, as later claimed by the University. Given the regulatory flexibility identified by the Committee, the University's resiliency needs were met at all times and there was no threat that they would be unmet in the coming years. Further, as discussed in the Preliminary Report, eligibility for tax credits did not present a consideration justifying expediting the decision without appropriate analysis and consideration of alternatives. At the end, the University delayed its decision beyond its original April 1 deadline, but also failed to cooperate with the Committee to develop additional alternatives after April 1.

This Final Report is submitted to the CU community to document the Committee's work and its findings, to be read in conjunction with the Preliminary Report.

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Note: An archive of the WDEP Committee's work will be posted on the Gethches-Wilkinson Center website, https://www.colorado.edu/center/gwc/

Background

In late-2023, the Board of Regents, upon the recommendation of campus administration, approved a $43 million project to upgrade steam and electricity generating equipment in the University's West District Energy Plant (WDEP) located on main campus. WDEP is a fossil fuel plant that produces energy using natural gas.

The University's decision was first made public on the CU Boulder Today website on Nov. 8, 2023, under the title *Regent-approved energy plant upgrades represent Bridge to Carbon Neutrality* (see here[3]). According to the University, the WDEP upgrade plan was precipitated by the state Air Quality Control Commission's Regulation Number 7, which places CU Boulder campus in a severe non-attainment zone for NO_x and Ozone emissions. Additional considerations cited by the University included deferred maintenance, aging equipment, and potential for an Inflation Reduction Act credit on new equipment. In the Nov. 8 article, the University characterized the upgrade as a "...key milestone on CU Boulder's path to carbon neutrality." The University further noted that "Generating power on campus with a CHP [combined heat and power] approach is currently cleaner than buying power from the grid."

Since learning about the proposed upgrades concerned faculty, students, and staff have raised concerns about whether the proposed upgrades to the WDEP are consistent with the best interests of the campus, particularly whether the proposal is consistent with the climate commitments of the campus and whether the investment in this infrastructure equipment is aligned with institutional priorities. Community members have also raised concerns about the accuracy of the University's characterization of the WDEP upgrade and whether the upgrade would achieve emissions reductions as claimed by the University. For example, in November 2024, a student organization wrote the CU Boulder Today to request a number of corrections in the Nov. 8 article (See here for the student letter, and here for the University's later correction of the Nov. 8 article). In December, 2024, an open letter by CU Boulder community members expressing concern with the WDEP decision received 460 signatures from faculty, students, staff, alums, and donors (see here).

On February 29, 2024, the University's Chief Operating Officer (COO) and the Chair of the Boulder Faculty Assembly formed a team of faculty and staff with experience in this field to address the WDEP proposal. A student was later added to the team by the co-chairs. This team was given a timeline of three weeks to make a preliminary recommendation based on the stated necessity for a deposit due by April 1 to secure long lead time equipment within the proposed project schedule.

The team met with faculty, staff, consultants, and subject matter experts at the Department of Public Health and Environment and public utility providers. Based on those meetings, documentation research, and University policy review the Committee was able to come up with a viable recommendation for the University regarding WDEP upgrades. On March 21, 2024, the Committee submitted that recommendation to the University's COO as part of its Preliminary Report (see here).

In its Preliminary Report (page ii), the Committee recommended that the COO not follow the University's original WDEP plan (Option 2E):

[3] The University later issued a correction of the Nov. 8 piece. See discussion below.

> *"Since learning about the proposed upgrades concerned faculty, students, and staff have raised questions about whether the proposed upgrades to the WDEP are consistent with the best interests of the campus, particularly whether the proposal is consistent with the climate commitments of the campus and whether the investment in this infrastructure equipment is aligned with institutional priorities.*
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> …
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> *The Committee developed an alternative option, coined Option A1, to the option previously chosen by the University in its 2023 program plan (Option 2E). The Committee finds that Option A1 is consistent with the University's climate and energy resiliency goals. While this recommendation is preliminary, the Committee finds that Option A1 is preferable to Option 2E in its GHG emissions profile and upfront cost and is comparable to Option 2E in terms of its resiliency benefits."*

While Option A1 developed by the Committee still requires the use of natural gas for heating, its lifecycle GHG emissions (Scopes 1-2) are 8-10% lower than Option 2E between the present and 2045. In in absolute terms, the lifecycle difference comes to 100,000-110,000 tCO_2, or an average of 5,000 tCO_2 per year (= 100,000 tCO_2/20 years). For reference, the average of 5,000 tCO_2e per year of excess emissions by Option 2E is equivalent to the annual emissions of 1,190 gasoline-powered vehicles.[4] For further reference, the 100,000-110,000 tCO_2 in excess emissions of Option 2E over the lifecycle represents about 16-18% of the Scope 1-2 emissions reduction projects that the University plans to pursue under its new climate action plan during 2025-2045. In addition to the difference in Scope 1-2 emissions, the Committee also found that Option A1 would have lower Scope 3 emissions relative to Option 2E.

The short timeline for the Committee's Preliminary Report was set considering the University's claim that a $7 million non-refundable deposit had to be made by April 1, 2024 for the University to qualify for a tax credit under the Inflation Reduction Act. The Committee developed Option A1 to demonstrate to the University that there was a viable alternative to Option 2E, and therefore, that the COO did not need to make the nonrefundable deposit on that option. Under the original Committee charge by the COO, the Committee was supposed to submit its Final Report by May 31, 2024. The Committee highlighted (p. 17) that its continued work may produce additional alternatives that are even more desirable than Option A1. For this and other purposes, the Committee requested additional data and information in an accompanying document (see "Additional Questions" document, here). According to the Committee's position, there was no urgency to finalize the University's decision without having considered all the available alternatives. Therefore, the Committee believed that the Committee and the University should spend the following months reviewing all the relevant data and considering additional alternatives.

The April 1, 2024 deposit deadline passed, and the University apparently did not make the deposit. The COO met the Committee on April 8, 2024. In that meeting, the COO seemed receptive to the Committee's recommendation, if the University was able to confirm the regulatory flexibility identified by the Committee under Reg 7. Earlier that day, the Colorado Department of Public Health

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[4] See EPA, GHG Equivalencies Calculator, here. Note that 5,000 tCO_2 refers to the average annual difference. As discussed below, the year-to-year difference varies considerably, starting at a low level and increasing with time.

and the Environment (CDPHE) provided the Committee with a written confirmation regarding the regulatory flexibility discussed in the Preliminary Report. The Committee shared that document with the COO by email that same day (the CDHPE confirmation is available here).

During the months of April and May 2024, the University did not provide the Committee with the data and information requested in its March Preliminary Report, thereby hindering the Committee's continued work toward a final report and recommendations.

On June 5, 2024, the University COO notified the Committee's chairs by email of the intention to proceed with the University's original WDEP plan (Option 2E), against the Committee's recommendation. The COO attached a memorandum to his email, explaining the considerations for this decision ("University's the June 5 memo" can be found here).

The Committee finds that the claims in the University's June 5 memo largely ignore the analysis in the Committee's Preliminary Report (March 2024). The University's memo repeats claims that the University made to explain its adoption of Option 2E in Fall 2023, months before the Committee was formed. Those claims were carefully assessed by the Committee and were found to be incorrect *based on available data*. In its report to the COO, the Committee made explicit findings regarding these claims. Committee findings were accompanied by data sources and engineering and legal analysis. The University's June 5 memo repeated claims without acknowledging they were found to be potentially in error by the Committee, and without explaining or supporting how it has reached opposite conclusions on the relevant issues.

Note: The Committee highlights that it did not receive all the relevant data and analysis it requested from the University. The Committee's findings of certain claims by the University as incorrect or unsupported are made "based on available data", i.e., based on those materials that were available to the Committee. It is possible that the University has additional data or analysis which supports its claims but were not shared with the Committee. If the University believes it possess such materials, the Committee recommends that the University publicly discloses those materials as soon as possible so they can be reviewed.

On June 28, 2024, the Committee met with the COO and Vice Chancellor for Infrastructure & Sustainability. In the meeting, the Committee expressed its disagreement with claims made in the COO's June 5 memo. The Committee requested the COO to reconsider his decision regarding WDEP.

On July 8, 2024 the University's COO shared with the Committee chairs a file titled Supplemental Information Document (the "Supplemental Document" can be found here). The COO noted that the document was received from Infrastructure & Sustainability, apparently in response to the Committee's Preliminary Report. The Supplemental Document provides certain comparative analyses between Option 2E and the Committee-recommended Option A1. The Committee notes that the University did not share the Supplemental Document with the Committee prior to making its decision and did not provide an opportunity for the Committee to comment on or query the Supplemental Document. The University also did not share with the Committee much of the underlying data and assumptions used to generate the Supplemental Document. As with the June 5 memo, the Committee finds that claims in the Supplemental Document repeat incorrect claims (*based on available data*) and largely ignore the analysis in the Committee's Preliminary Report.

On July 8, 2024 the Committee also contacted Dr. Justin Schwartz, the new Chancellor (who entered his position on July 1, 2024). In its email, the Committee raised its concern regarding the decision and asked for a meeting with the Chancellor. The Committee attached the Preliminary Report to its email. The Chancellor did not agree to meet with the Committee. On July 23, the Chancellor decided to uphold the COO's decision. In explaining his decision to the Committee, the Chancellor made the same claims regarding the WDEP project that were addressed in the Preliminary Report. The correspondence between the Committee and the Chancellor is included here. Those are the claims the Committee had already found to be incorrect based on available data.

The University has since repeated similar claims in the media (see here for reporting by the Colorado Sun, Aug 21, 2024).

Findings

In this Final Report, the Committee provides a record regarding the WDEP decision and process. This record documents important shortcomings in the University's planning process. Those include the following:

1. The University's original program plan for the WDEP project was written without adequate alternatives analysis, which is essential to adequate environmental decision making.
2. The University's original WDEP plan (Option 2E) was developed with a lack of understanding of the regulatory flexibility offered by the explicit language of Reg 7. The University's perception that Option 2E was required to ensure campus resilience likely resulted from that misunderstanding.
3. In its Preliminary Report, the Committee found that Option A1 provides similar resilience benefits to the University's Option 2E. The University continued to claim that compelling resilience needs required the adoption of Option 2E despite detailed analysis by the Committee to the contrary when considering the regulatory flexibility in Reg 7. The University did not provide the Committee with any data or analysis supporting its claim.
4. The University claims Option 2E is required to protect continuity of mission critical research. Under the University's own Energy Master Plan, that goal is supposed to be achieved by other means, which the University has not yet implemented.[5]
5. In the program plan it submitted to the CU Regents (Fall 2023, see here), the University did not take into consideration the additional greenhouse gas emissions that would result from Option 2E relative to the business-as-usual assumptions in its 2024 climate action planning. In this program plan (page 5), the University also highlighted carbon reduction benefits of the plan that are "…likely [to] hold true until at least 2030."[6] According to the Committee's review of the University's models, those emissions reductions are very small and short-lived. Meanwhile, the

[5] See, Energy Master Plan, p. 70; Preliminary Report, p. 10.

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University did not alert the Board of Regents to more substantial increases in carbon emissions that the plan would represent relative to the business-as-usual scenario in the long-term.

6. The University's program plan included several additional claims that were incorrect and/or incomplete based on available data. It is possible that if the Regents had received more accurate and complete information, they would have invested greater resources in finding an alternative to the University's plan. For example:
   a. The University claimed that Option 2E will replace "existing 30-year-old combustion turbines" (p. 3), without mentioning the turbines have been rebuilt in 2013, and had very little depreciation on them given minimal use since 2013;
   b. The University claimed (p.4) that Option 2E aligns with the University's 2021 Energy Master Plan (EMP), despite the fact that the EMP explicitly planned to avoid base loaded cogeneration starting 2027, given GHG considerations (see here, p. 52; note that at the time the EMP was finalized, Reg 7 which the University claims precipitated the need for Option 2E was already in force);
   c. Under the heading "Sustainable Design", the University highlighted the possibility of reconfiguring the new turbines "to operate on alternative fuels like hydrogen or other cleaner burning fuel sources" (p. 4), even though it is widely accepted that hydrogen does not provide a feasible source of energy for heating for environmental, economic, and other reasons.
7. Concerns regarding the University's recent planning to upgrade WDEP should also be understood in the context of WDEP's role in the University's failure to achieve its 2020 climate targets. As the Committee noted in its preliminary report (p. 9): *"The minimal use of cogen throughout the 2010s substantially contributed to the University's miss of its 2020 climate target. With the grid expected to become cleaner than cogen by 2029, there is a risk that once again the University will find itself using the less climate friendly option for energy generation. In other words, the University that did not baseload cogeneration when it was climate friendly to do so will shift to baseloaded cogeneration just when it is no longer climate friendly to do so."* The University did not provide the community with adequate transparency regarding the minimal use of cogeneration during the 2010s. That minimal use ran counter to the University's planning under the 2009 Conceptual Plan for Carbon Neutrality (see Preliminary Report, pp. 4-5).
8. The desire to obtain federal tax credits under the Inflation Reduction Act (IRA) was, according to the University, an important factor in its decision to pursue Option 2E, as well as the timing for its decision. Nevertheless, the University did not carry out the necessary analysis regarding eligibility requirement for the credit. To the Committee's understanding, the University lacked such analysis as late as June 2024, even though concerns were flagged by the Committee in March 2024.
9. The University used contradictory assumptions in its financial modelling and its climate modeling. The contradictory assumptions created a biased impression regarding the financial benefits of the University's Option 2E. The contradictory assumptions created a biased impression regarding the financial benefits of the University's Option 2E. On the one hand, the University claimed its intention to reduce the excess emissions of Option 2E over Option A1 through an early phase-out of baseloaded cogeneration. On the other hand, for its lifecycle cost

analysis, the University assumed that baseloaded cogeneration would continue in the long run, resulting in financial benefits to the University over Option A1. The University should not use two contradictory sets of assumptions, one to claim financial advantages (assuming long-term base-loading), then another to try to limit the increase in emissions (assuming a shift away from baseload generation, presumably as early as 2029).

10. The University did not share with the Committee a campus load-curve, which is essential for energy planning. Despite repeated Committee requests, the University did not corroborate its claim regarding peak-load of 200 kpph steam needs.
11. While the University's Climate Action Plan assumes a 30% decline in campus energy consumption, the University planning for WDEP assumed peak demand would remain constant long into the future. The University was not willing to engage with the Committee regarding options to reduce peak-load through demand-side management.
12. The University's claims that Option 2E will reduce campus NO_x emissions by 50% relative to current emissions has not been supported by data. While the turbines the University plans to install under Option 2E have lower NO_x emissions intensity than the existing turbines, the existing turbines are only operated by the University on rare occasions. In distinction, under the University plan, the new turbines will be used continuously for base-loaded cogeneration. The University did not present an analysis of the absolute levels of NO_x emissions that would result from its plan to support the claim of 50% reduction.
13. While claiming to be committed to shared-governance principles, the University essentially ignored the Committee's Preliminary Report, instead repeating claims (including publicly) that were found and documented by the Committee to be incorrect based on available data. The University refused to share relevant planning documents, or to engage the Committee in a meaningful review of the materials that the University developed in April-May 2024.
14. The University's lack of cooperation with the Committee during April-May 2024, hindered the work of the Committee, and, among other things, hindered the development of additional alternatives to the University's Option 2E, which may have been even more favorable than Option A1.
15. There was no urgency for the University to finalize its decision by the original April 1 deadline, or by July, 2024, as later claimed by the University. Given the regulatory flexibility identified by the Committee, the University's resiliency needs of the University were met at all times and there was no threat that they would be unmet in the coming years. Further, as discussed in the Preliminary Report, eligibility for tax credits did not present a consideration justifying expediting the decision without appropriate analysis and consideration of alternatives. At the end, the University delayed its decision beyond its original April 1 deadline, but also failed to cooperate with the Committee to develop additional alternatives after April 1.

The remainder of this Final Report provides detailed responses by the Committee to claims made in the University's June 5 memo and related documents. The discussion addresses claims regarding resilience, emissions, cost analysis, and additional regulatory aspects.

A. Resilience

A.1. The Committee Found Option 2E Does Not Have Resilience Benefits Claimed by the University Relative to Option A1

The June 5 memo (p. 2) claims that Option 2E will provide the University with resilience benefits relative to the Committee's Option A1 (pages 2-3):

> "*The turbine upgrades provide more flexibility of operation, as well as increased reliability and resiliency to ensure the campus teaching and research mission is protected at all times. While it is likely that in most years Option A1 would allow the campus to operate within the requirements of Regulation 26, I am concerned that we would exceed that capacity in the event of significant demand upon campus to provide electricity independently of Xcel, an equipment failure at EDEP [East District Energy Plant], or major upgrades at the EDEP facility that would require the campus to rely solely upon WDEP for heating capacity.*"

The University's claim that Option 2E is necessary for campus energy resilience has been subject to extensive analysis in the Preliminary Report and rejected explicitly. In large part, the University's original claim that Option 2E was necessary for resilience was based on an incorrect understanding of the regulatory treatment of the turbines under Reg 7 (later relabeled as Reg 26, as it appears in the University's June 5 memo).

As discussed in the Preliminary Report (p. 5), Reg 7, which entered into force in Dec 2020, required a stricter standard of performance for the WDEP cogeneration turbines (the CTGs) and Boilers 3-4. However, that regulation included a 10% capacity factor for turbines and 20% for the boilers. The University's understanding, as relayed by Facilities staff at a March 11 meeting, was that compliance with capacity factor exemptions was assessed on a monthly basis. For example, the Director of Utility and Energy Services noted that if the CTGs were turned on, they would have to be "dead" for an extended period of time.[7] The University's understanding was inconsistent with the language of Reg 7. That language plainly notes that the capacity factor exemption is calculated over a 3-year averaging period. The Committee was able to confirm that understanding with a letter from the CDPHE, the relevant regulator (Colorado Department of Public Health & Environment, here). The letter was shared with the University on April 8, 2024, nearly two months before the University communicated its decision to the Committee in the June 5 memo (here).

The Committee's finding regarding the far-longer averaging period is significant. It opened the possibility that the University could use the CTGs for resilience purposes while staying in compliance with Reg 7. Accordingly, in its preliminary report, the Committee assessed the resilience needs of campus for electricity and heat, and examined whether the Committee proposed Option A1 can provide for those needs under the correct understanding of Reg 7. Based on quantitative and engineering analysis, the Committee made explicit findings that all resilience concerns the University shared with the Committee will be met under Option A1 (pages 2-3). The Committee summarized its analysis as follows:

[7] Apparently, the understanding of the Director of Utility and Energy Services were that an exceedance of the capacity factor over a one-month period would prevent use of the turbines for a 3-year period.

> *"From a resiliency and redundancy perspective, the Committee finds that the 10% capacity factor exemption under Reg 7 offers the University substantial flexibility and is more than sufficient to meet the University's needs. While a 10% capacity factor may sound intuitively small, the relevant legal rules allow for the existing CTGs to be used at 100% capacity, as long as the 10% capacity factor average is not exceeded over extended periods of time (three years). The Committee compared the available capacity under the 10% exemption to the University's resiliency needs under scenarios specified by the University. The Committee finds that under the proposed Option A1, and based on the available historical data provided, the 10% capacity factor for the CTGs meets all anticipated campus resiliency and redundancy needs for both electric power and heating.*
>
> *The Committee has not identified any resiliency benefits or scenarios in which increasing the CTGs' capacity factor from 10% (Option A1) to 100% (Option 2E) improves outcomes for the University…"*

The University's June 5 memo (p.2) acknowledged that "…the campus has additional regulatory flexibility under Regulation 26 than what we initially understood." However, this acknowledgement was missing in two key respects. First, the memo only acknowledged one of the two aspects of regulatory flexibility, and by far the less relevant one of the two.[8] Second, the University's June 5 memo seemingly missed the implications of the regulatory flexibility that the Committee identified, and its analysis regarding how the way in which regulatory flexibility supports Option A1.

The specific concerns mentioned in The University's June 5 memo pertain to three issues: (1) "significant demand upon campus to provide electricity independently of Xcel"; (2) "an equipment failure at EDEP", and (3) "major upgrades at the EDEP facility that would require the campus to rely solely upon WDEP for heating capacity." The first two have been discussed extensively in the Preliminary Report and found incorrect based on available data (pages 9-10, 14-16). The third issue did not previously emerge as a major University concern from staff and is implausible. The Committee also considered, and found uncompelling, other resilience benefits the University claimed regarding Option 2E. These issues are discussed in the following sections.

A.2. The Committee Found Option A1 to Provide Necessary Electric Resiliency

Regarding Xcel, the Preliminary Report found (p. 10) that maximum potential uses to meet Xcel peaks under its agreement with the University reflects a capacity factor of under 1.5% per year. Further, even in the extreme event of a weeklong power outage, the University will be able to run the CTGs at maximum capacity, 24-7, for a full week, with the ensuing capacity factor being below 2% for the calendar year. These 1.5% and 2% (total of 3.5%) per year are well below the regulatory requirement of a capacity factor of 10% averaged over a 3-year period. The Committee's analysis was based on

[8] As explained in the Preliminary Report, the flexibility afforded under the Reg 7 exemption has two aspects. First, the University is allowed to average capacity factors over a 3-year period. Second, even in the event the 3-year average exceeds the relevant capacity factor, the University would have a 3-year period starting from the exceedance to meet its stricter license. The University's memo only refers to the second aspect, while omitting the first (p.2): "I concur that the campus would have a three-year compliance window to conduct upgrades if WDEP became noncompliant." That omission is significant insofar as it may lead the University to ignore the fact that with three-year averaging, there is no reason to assume the University would be non-compliant in the first place.

conservative assumptions (For example, in fact, University demand on a 24-hour basis is significantly below maximum capacity of both turbines).

This analysis was not addressed in the University's June 5 memo.

The Committee's analysis was also not addressed in the University's more technical Supplemental Document. In the Supplemental Document (p.3), the University explicitly reiterated the notion of "firm capacity" that was found to be inadequate by the Committee.[9] The Supplemental document further claims (p. 4) that: "The annual capacity limits also restrict the availability of the stationary combustion turbines which directly impacts campus back-up power generation and electric demand response [reduction]."[10] As noted above, this claim is inconsistent with the Committee's finding that under conservative assumptions, the back-up power generation and demand response needs of the university will consume at most 3.5% out of the 10% available capacity factor.

In the Supplemental Document (p. 5), the University further mentions the existence of a "permit exemption example scenario spreadsheet". According to the Supplemental Document, examples in that spreadsheet "...show that that a unit [i.e., a CTG or boiler] can quickly reach the capacity limit." The University did not share that spreadsheet with the Committee or provide an opportunity for the Committee to comment on the spreadsheet (Indeed, the Supplemental Document itself was only shared with the Committee on July 8, after the decision had already been made). Given the analysis in the Committee's Preliminary Report, the claim made in the Supplemental Document seems highly dubious

A.3. The Committee Found Option A1 to Provide Necessary Heating Resilience

With regards to a potential failure in EDEP boilers, the Committee provided a 2-page analysis (pages 14-15), demonstrating that Option A1 satisfies the University's N+1 requirement. This analysis was also not addressed by the University in the June 5 memo. "N+1" refers to the University's need to meet campus peak-demand for steam (assumed by the University at 200 thousand pounds per hour, "kpph") in the event of failure of the largest steam asset, EDEP Boiler 1 (capacity of 100 kpph). As in the case of electric resilience, the University's misinterpretation of the Reg 7 exemption led to an under-appreciation of the flexibility afforded by that regulation to meet resilience needs. Specifically, the University focused on a notion of "firm capacity," where a steam asset can only serve as a backup up to its capacity factor. Thus, if the CTGs can provide 160 kpph at 10% capacity factor, the University would only count them as 16 kpph (= 10%*160 kpph) firm capacity for N+1 purposes. This notion of firm capacity seems to have been premised on a simple misunderstanding, i.e., the University assumed that exceedance of the capacity factor over a period of a single month would prevent further use for extended periods.

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[9] "Firm Capacity: Refers to the requirement that the utility must have available and operate multiple boilers at a capacity level that allows for immediate loading (ramp up) if the largest boiler in operation should fail (and still maintain system pressure). *Meaning, boiler capacity that meets system demand at all times*. Heating buildings is critical to the operation of the campus and the availability of our heat generating equipment *cannot be conditional. Our plans should adhere to the firm capacity requirements under any scenario, or the campus is accepting unnecessary risk*." (Emphasis added)

[10] See also Supplemental Document, p. 12.

The Committee found that with flexibility afforded by the Reg 7 exemption, an asset can serve for resilience purposes if the capacity factor required for the resilience purpose does not exceed the average capacity factor over the averaging period (3-years). Thus, the CTGs can provide up to 160 kpph (their maximum capacity) when called on, if the average capacity factor does not exceed the 16 kpph over the averaging period. The Committee provided quantitative analysis to examine whether that condition is met.

The Committee found that even in the event of failure of EDEP Boiler 1 (100 kpph), the University would have 150 kpph available through other boilers at up to 100% capacity factor (those are EDEP Boiler 2, and the newly installed WDEP Boiler 3 under Option A1). Therefore, to meet peak demand of 200 kpph, the University would only be required to satisfy the area of the load curve between 150 kpph and 200 kpph. The Committee consulted a figure from the University's steam load profile (See Figure 1 below). This figure demonstrates the relevant area is smaller "by orders of magnitude" relative to the capacity afforded by the CTG's at 10% capacity factor (p. 15).

Figure 1: Campus Steam Load Profile from Consultant Model

Note accompanying Figure 1 in the Preliminary Report: The Committee's understanding of plant-side load is based on a scaling of the building model to peak demand reported from the plant. As discussed below, the Committee would be interested in reviewing plant side data

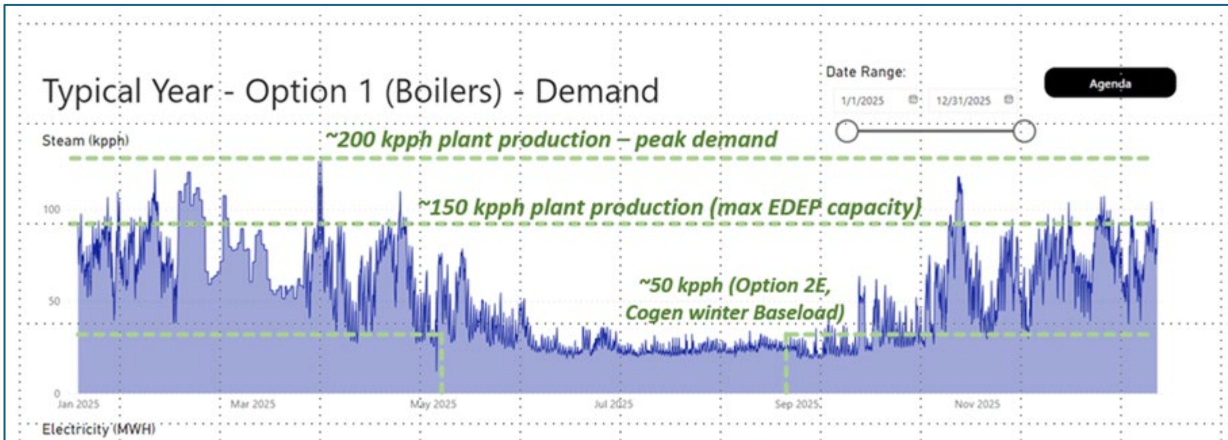

Figure 1: Campus Steam Load Profile (Source: Consultant Dashboard, slide 20, with additions in green by the Committee)

The Committee also noted that Option A1 provides even greater resilience given the availability of the refurbished WDEP Boiler 4 (100 kpph at 20% capacity factor). In the event of a failure in EDEP Boiler 1, WDEP Boiler 4 can be turned on before the CTGs, providing a second layer of redundancy. The Committee summarized the results of its analysis as follows (p. 15):

> *"To summarize, the Committee finds that an N+1 framework requires capacity to meet peak load with the failure of the largest unit. N+1 does not require that the backup assets themselves have a capacity factor of 100%, only that their available capacity and capacity factor would be adequate to meet the relevant demand in the resiliency scenario. The Committee finds that this condition is clearly satisfied for Option A1, with multiple redundancies (CTG and WDEP Boiler 4)."*

As with the June 5 memo, the University's more technical Supplemental Document largely did not directly address the Committee's analysis. In the Supplemental Document, the University maintained its focus on the notion of "firm capacity" which the Committee already found to be inadequate in its Preliminary Report (see Section A.3. above). The Supplemental Document then claims (p. 11) that Option A1 has a firm capacity shortfall of 14 out of 200 kpph (assumed Winter Peak). As noted, the Committee finds that firm capacity is not the only relevant metric to assess. However, even according to the University's notion of firm capacity, the Committee finds that the University has not demonstrated a firm capacity gap.

- First, the University has not provided any documentation to back up its claim for 200 kpph peak Winter demand. The figures presented to the Committee by the University used a building-demand model developed by the University's consultant. That model demonstrated peak demand of only 126 kpph (Mar. 25, 2025).[11] The Committee recognized that due to transmission losses, building demand (the model figure) is lower than peak generation required at the plant, which is the relevant figure for resilience analysis. However, the University has never presented the Committee with any documentation regarding its claim for plant-side peak demand of 200 kpph. The Committee flagged the lack of documentation in its Preliminary Report (p. 18) and made a formal request for documentation. See WDEP Shared Governance Committee, Additional Questions, p. 1 (here). The University did not respond to that or future requests.
- Second, the Committee highlighted that the 200 kpph figure ignores the University's plans to reduce energy demand by 30% by 2030. See Additional Questions, p. 2.
- Third, the Committee highlighted that simple demand-side measures could be used to reduce the 200 kpph load, like recalibrating thermostat set-points or turning off non-essential demand in the unusual circumstances of an N+1 event coinciding with a peak-demand day. The Committee made formal requests for information on future energy demand and thermostat set point data. See Additional Questions Document. The University did not respond to those requests.
- The University's failure to provide the necessary figures and documents is of special significance because the firm capacity gap the University claims is quite small relative to peak demand (only 7%, i.e., 14 kpph out of 200 kpph).

As with electric resilience, the University's later Supplemental Document refers to a permit exemption example scenario spreadsheet which is reported to analyze heating resilience considering the capacity factor exemption. The University claims the spreadsheet shows that regulatory exemption factors can be exceeded due to heating resilience demands. As noted above, this spreadsheet was not shared with Committee, and the University's claim seems implausible considering the Committee's quantitative analysis. To address the Committee's concerns, the University would need to quantify the area of the load curve between 150 kpph and 200 kpph ("150-200 kpph demand"). It would then need to demonstrate that annual capacity provided by the Reg 7 exemption is lower than 150-200 kpph demand. Given the University's choice to not share the load curve, the Committee was not able to perform that analysis for the University. However, from the other data it has, the Committee can demonstrate with a high level of confidence that the capacity

[11] As noted in the caption, Figure 1 in the Preliminary Report scales the consultant's building-side model from 126 kpph to 200 kpph as a means of approximating plant-side demand.

exemption factor provides for annual capacity that exceed 150-200 kpph demand, and therefore, that Option A1 provides appropriate heating resiliency.

The annual capacity provided by the Reg 7 exemption amounts to 175,200 thousand pounds per year (kppy) for Boiler 4 and 141,760 kppy for the CTGs.[12] These figures assume the units are used at 100% capacity, which is a conservative assumption. For the CTGs, the Committee further adjusted the figure down to 92,144 kppy to reflect the fact that 3.5% of the 10% exempted capacity factor can be reserved to meet electric resiliency needs (see Section A.2. above).[13] Therefore, the Committee's annual capacity figure for the CTGs is already net of electric resiliency needs.

Under Option A1, in the event of an N+1 scenario (failure of EDEP Boiler 1), the University would have heating capacity of 150 kpph available from EDEP Boiler 2 (50 kpph), and the new WDEP Boiler 3 (100 kpph). Therefore, to meet an assumed peak of 200 kpph, the University would only need an additional 50 kpph from either Boiler 4 or the CTGs. That demand amounts to 1,200 (= 24 hours*50 kpph) thousand pounds per day (kppd) for any days where the University must meet peak capacity. Note that in this case as well the Committee is making the conservative assumption that the relevant unit is used at 100% capacity for a full 24 hours (i.e., that peak demand persists for 24 hours a day). With demand of 1,200 kppd, Boiler 4 and the CTGs can be used to meet N+1 requirements for a total of 146 and 77 days a year, respectively. See Table 1 below.

Table 1: Number of days where Reg 7 exemptions allow the University to meet heating resilience needs under Option A1

	Available annual capacity (kppy) under Reg 7 exemption	Required daily capacity (kppd) to meet 150-200 kpph demand (assuming 100% capacity)	Number of days where 150-200kpph steam demand can be met by unit
Boiler 4	175,200	1,200	146
CTGs (net of electric resiliency needs)	92,144	1,200	77

The Committee finds the University's claim regarding unmet heating resilience needs under Option A1 is inconsistent with these figures. For the claim to be correct, the University would need to face a total of 195 days a year (i.e., a total of 7.5 months) of peak demand. However, as Figure 1 above demonstrates, days where demand exceeds 150 kpph are rare. The Committee finds that even when ignoring Boiler 4, the 77 days of peak demand capacity (24 hours a day) provided by the CTGs alone would be highly sufficient to meet heating resiliency needs, and the University's claim is unfounded. For this reason, the Committee finds that the University did not demonstrate a heating resilience need for Option 2E that is unmet by Option A1. The Committee notes that the University, that (in all

[12] For Boiler 4, exempted capacity factor of 20%*8,760 hours per year*100 kpph capacity equals total permissible annual capacity of 175,200 kpph. For the CTGs, exempted capacity of 10%*8,860 hours per year*160 kpph equals total permissible annual capacity of 141,760 kpph.

[13] 92,144 kppy = (10%-3.5%)*141,760 kppy.

likelihood) has the most direct load curve figures, could have easily presented to the Committee an analysis explaining its claims regarding heating resiliency. The University chose not to do so.

A.4. EDEP Upgrades Do Not Represent a Resiliency Concern Under Option A1

The University's June 5 memo expresses concern that "we would exceed that capacity in the event of… major upgrades at the EDEP facility that would require the campus to rely solely upon WDEP for heating capacity." Unlike the event of an unexpected failure in equipment, which may occur at any time during the year, when major upgrades are performed, the timing is planned. As the University's heat load curve demonstrates, the University demand for power is low (below 100 kpph, and often below 50 kpph) between May and September (even into October; see Figure 1 above). Under Option 1A, major upgrades can be scheduled during that period where the reinstalled WDEP Boiler 3 would be more than adequate to meet the demand. In addition, the refurbished WDEP Boiler 4 and the CTGs would provide additional resiliency as discussed above. The Committee finds that no information was shared by University staff that suggests that future EDEP upgrades would lead to resiliency concerns that would necessitate Option 2E.

A.5. Other Findings Regarding Resilience by the Committee

While not the focus of the University's June 5 memo, Facilities staff raised several additional resiliency concerns. Those were also considered by the Committee and found to be met by Option A1.

- One critical concern expressed by University staff was ensuring continuity of operations, e.g., that University research can never be interrupted in the face of short-term disruptions to the University's electric supply. The Committee considered the issue and found that goal did not require baseloaded cogeneration by the CTG turbines as envisioned by Option 2E. Rather, the Committee recommended the University follow the detailed roadmap laid out in the University's own 2021 Energy Master Plan for that specific purpose (see Preliminary Report, p. 10; Energy Master Plan, pp. 62-63, available here).
- Another consideration mentioned by University staff in support of Option 2E was providing resilience during and after the planned conversion of the University's heating system to low-temperature hot water. The Preliminary Report (p. 19-20) provides an engineering analysis showing that Option A1 is consistent with that transition.

Resilience Summary

As a general matter, the Committee extended an open invitation to the Facilities staff to share with it in writing any resiliency scenario for consideration in the Preliminary Report (See, e.g., March 12, 2024, Next Steps document, Item 7, available here). The Committee did not receive any additional scenarios to those that Facilities raised in meetings. Therefore, the Committee believes that its Preliminary Report fully addressed the University's resiliency concerns.

B. Emissions

B.1. Option 2E Will Lead to an Increase, Not a Decrease, in University Emissions

The University's June 5 memo claims that Option 2E will reduce the University's greenhouse gas (GHG) emissions (p.3):

> *"The upgraded turbines would emit lower greenhouse gas emissions when operating until Xcel achieves its carbon reduction goals, resulting in immediate greenhouse gas savings. While it is possible that Xcel will meet its emissions goals, the carbon reduction savings to the campus in the interim years advance the campus's goal of reducing emissions."*

The University's claim that Option 2E will reduce the University's GHG emissions has been examined by the Committee and rejected explicitly. In the first page of its report, the Committee summarized its findings as follows:

> *"The option labeled as 2E for the purchase of two new CTGs assumes that the upgraded cogeneration plant will be operated for baseload (10 MW and 50 kpph steam) during eight months of the year. The Committee finds that operating a cogeneration plant for baseload will jeopardize the University's ability to meet its climate goals under the 2024 draft Climate Action Plan (CAP). Expanded use of the cogeneration plant would markedly increase the University's greenhouse gas (GHG) emissions over the alternative of procuring power from Xcel Energy given Xcel's 2030-2050 decarbonization pledges. As early as 2029, procuring power from Xcel and using gas-fired steam boilers exclusively for heat will have lower GHG emissions than the alternative of baseload cogeneration with supplemental steam boilers."*

Later in the Preliminary Report, the Committee cites specific figures. These figures were provided to the Committee by the University's engineering consultant (the "consultant") who advised the University on the WDEP upgrade and met with the Committee on March 11, 2024. The consultant's carbon analysis demonstrates that Option 2E will not lead to any substantial short-term reduction in emissions but will lead to significant long-term increases in emissions. The Committee's analysis compared Option 2E to Option 1 assessed by the consultant. That Option 1 (which was originally under consideration by the University) has a similar emissions profile to Option A1 proposed by the Committee, as well as to the business-as-usual (BAU) scenario in the University's 2024 Climate Action Plan. The Committee made the following findings (emphasis added):

> *"<u>Carbon analysis performed by the consultant demonstrates that Option 2E will result in excess cumulative Scope 1-2 emissions of about 100,000-110,000 tCO2e over Option 1 in the 2025-2045 period</u>[14] (see Consultant Dashboard, slide 26, Pledged; the bottom and top of the range pertain to situations where CTG installation is completed by 2025 and 2026 respectively). The Committee found that Option 1 resembles GHG emission assumptions in the University's business-as-usual (BAU) scenario under the 2024 draft Climate Action Plan that takes into account 2030-2050 emission reductions from Xcel (see draft CAP here, page 48). <u>Conversely, the adoption of Option 2E is expected to raise Scope 1-2 emissions in the 2024 CAP BAU scenario by the same 100,000- 110,000 tCO2e amount of excess emissions relative to Option 1 that was modeled by the consultant</u>.*

[14] In the later Supplemental Document (p. 19), the University revised its figure of the cumulative GHG emissions difference between Option 2E and Options A1 and 1 to 86,000 tCO_2e for the period 2025-2045 (=1,157 tCO_2 for Option 2 Unaccelerated – 1,071 tCO_2e for Options A1 and 1, both unaccelerated). The document does not provide an explanation as to why the figure was revised downwards.

> *The Committee finds that the 100,000-110,000 tCO2e difference is significant in the context of the 2024 CAP. In annual terms, Option 1 will have equal annual emissions to Option 2 as early as 2028. This transition reflects the rapidly rising share of renewable generation in the grid, that outperforms cogeneration of heat and power. In the consultant's dashboard, near-parity in GHG emission factors between Option 1 and Option 2E occurs as early as 2026. The only year for which Option 2E represents a significant reduction in emissions over Option 1 is 2026 [sic—should be 2025] (the University will only benefit from that reduction if installation is completed before 2025). If Option 2E is adopted, the University's Scope 1-2 BAU emissions in the year 2040 will be 8,000 tCO2e higher than the BAU scenario currently modeled in the 2024 CAP. That is a change of about 10% relative to the CAP BAU, which is highly significant (see CAP draft here, p. 17). By baseloading the new CTGs under Option 2E, the University will essentially lock-in a substantial portion of its power supply at the 41 lbs. CO2e/kWh emissions factor for 2028 and will not benefit from further declines in that emissions factor in the future (see Consultant Dashboard, slide 25, Pledged scenario)."*

In an August, 2024 statement to the Colorado Sun (here), the University claimed that the GHG difference between the two options was small:

> *"CU officials calculated the extra greenhouse gas savings from the faculty's preferred alternative were only about 5% above what the chosen plan would accomplish."*

In addition to being inaccurate –*the savings are on the range of 8-10%*–[15] the University's claims ignore the significance of 100,000-110,000 tCO_2e in the context of the University's past and future climate action. In 2009, the University adopted its first climate target for a 20% reduction in Scope 1-2 emissions by 2020, using a 2005 baseline. Under a linear reduction pathway, the target required the University to cut its emissions by a cumulative amount of 232,473 tCO_2 over the decade and a half period (this and subsequent calculations and data are available in Appendix A). In practice, by 2020, the University had emitted an excess of 306,683 tCO_2 relative to the linear target pathway. Namely, instead of cutting its cumulative emissions by about 232,000 tCO_2, the University's cumulative emissions actually increased by about 74,000 tCO_2 relative to a hypothetical where it maintained its baseline emissions. Put in this context, GHG savings of 100,000-110,000 tCO_2 from Option A1 could go about one third of the way in remedying the University's carbon deficit from the 2005-2020 target period.

The Committee has also considered the significance of 100,000-110,000 tCO_2e in the context of the University's 2024 Climate Action Plan. In the period between 2024-2040, the University plans to pursue projects with cumulative GHG savings in Scope 1-2 emissions of about 625 tCO_2 (For data,

[15] Rounded to the next full percentage point. Source: Consultant dashboard, Appendix A below.

S1-2 Emissions (tCO_2)	O1 (and A1)	Option 2E	O1 (and A1) savings	Savings/2E
2025-2045	1,104,105	1,200,698	96,593	8%
2026-2045	1,020,574	1,128,930	108,356	10%

see Appendix A below).[16] Therefore, the GHG savings from the Committee recommended Option 1 amount to about 16%-18% (= 100,000-110,000 tCO_2 divided by 625,000 tCO_2) of total emissions reductions planned by the CAP. The Committee finds this amount to be substantial in the context of campus climate action.[17]

So far, the analysis has focused on the difference in Scope 1-2 emissions between the different options. In its Preliminary Report, the Committee further noted (p. 13) that the carbon analysis performed by the consultant pertained to Scope 1-2 emissions but did not include Scope 3 FERA (Fuel and Energy Related Activities) emissions. As noted there, the consultant agreed with the Committee that those FERA emissions would be higher in Option 2E relative to BAU. FERA emissions are subject to targets under the University's 2024 Climate Action Plan (see pages 44, 79, here). From a climate point of view, the Committee highlighted that the high short-term warming impacts of methane from leaked natural gas makes FERA emissions especially concerning (see, e.g., Abernethy and Jackson (2022), here). To the best of the Committee's knowledge, the University did not use the months between March 21 (the submission of the Preliminary Report) and June 5 (when the COO's decision was finalized) to complete a Scope 3 assessment.[18] The University's June 5 memo includes several additional claims regarding GHG emissions that require discussion.

B.2. The Possibility that Xcel Will Fail to Meet Climate Targets is Remote and Does Not Support Option 2E

In the June 5 memo, the University tried to support the decision to adopt Option 2E by highlighting the risk that Xcel would fail to meet its carbon emission targets (p. 3):

> *"After Xcel's upgrades allow them to achieve their carbon emissions targets (hopefully on a timeline that will be consistent with its 2030 goals, but that is not certain, as Xcel significantly missed its emissions goals for 2024 under its agreement with the City of Boulder), we will manage operation of the plant to meet or exceed our emissions reduction goals outlined in the CAP [Climate Action Plan]."*

The statement conflates Xcel's climate targets under its Clean Energy Plan and separate targets under its agreement with the City of Boulder. It implies that Xcel's miss of the 2024 benchmark in the agreement with the City of Boulder is a warning that it will fail its 2030 Clean Energy Plan target (thereby delaying the year where Option 2E leads to excess emissions).

Xcel's carbon emissions targets under its Clean Energy Plan are mandated by state legislation that requires utilities to cut emissions 80% by 2030 and 100% by 2050 (2005 baseline). These binding targets underlie the business-as-usual scenario the University's adopted in its 2024 Climate Action

[16] The University also plans to pursue projects with additional savings of about 462,928 tCO_2 in the 2040-2050 period. These reductions were excluded from the text because according to Figure 2 in the CU Boulder 2024 Climate Action Plan (p. 17) the lion's share of cumulative savings will accrue after 2045 (the end of the period for which the comparison is drawn). See screenshot in the Appendix.

[17] Further, in the March 11 meeting, the Committee heard conflicting views from senior Facilities staff regarding the feasibility of the University's timeline for some of the measures included under the CAP. If the University where to delay on some of its plans, the proportion would be even greater.

[18] The University's Supplemental Information Document includes a number of references to Scope 3 emissions (p. 20); however, it does not include a comparative GHG analysis of Scope 3 emissions under Option 2E and Option A1.

Plan (see, here, pp. 49-50). To the best of the Committee's understanding, these are also the targets that were modeled by the University's consultant in his carbon analysis.[19] The Committee finds no indication that Xcel will miss or fail these binding targets.[20]

In distinction, the targets that the University's June 5 memo refers to are included in a settlement agreement between Xcel and the City of Boulder. As part of that agreement, Xcel and the City of Boulder formulated benchmarks that set interim targets ('22, '24, '27) for Xcel to meet before its 2030 target (see, here, pdf. p. 24). Importantly, these benchmarks are not required by Colorado state legislation or by the Colorado Public Utility Commission. Even under Xcel's agreement with the City of Boulder, missed benchmarks do not give the City of Boulder any significant remedies against Xcel.[21]

While the University is correct to note that Xcel missed its 2024 City of Boulder benchmark, that miss is not indicative of Xcel's inability to meet its statutory 2030 target. Utilities' progress towards targets is not linear, especially over short horizons. Meanwhile, the University seemingly missed encouraging indications regarding Xcel's progress. Earlier this year (2024), Xcel provided a forecast indicating that it will significantly outperform the 2027 City of Boulder benchmark, as well as its statutory 2030 Clean Energy Plan target (see here, around 40:00). That recent Xcel forecast is of special significance because it incorporates the Colorado PUC's approval of Phase II of Xcel's Clean Energy Plan (that plan approves new renewable capacity). Xcel's forecasts translate to achieving 80% emissions reduction target as early as 2027 (3 years ahead of the 2030 target), and nearly 90% reduction by 2030.[22] A screenshot of the forecast is included as Figure 2 below. The green line represents the Boulder agreement benchmarks, and the blue line represents Xcel's performance (including 2027 and 2030 forecast). The large area where the blue is below the green line represents the forecast for target overperformance by Xcel.

To summarize, the Committee finds that the risk of Xcel failing its 2030 targets is, according to available information, remote. This remote risk should have only received a very low weight in the University's analysis of the pathway of future GHG emissions. Conversely, the University should have assigned a high weight to the highly likely scenario where Xcel complies (and potentially overperforms) its statutory targets and Option 2E leads to an increase in emissions relative to Option A1.

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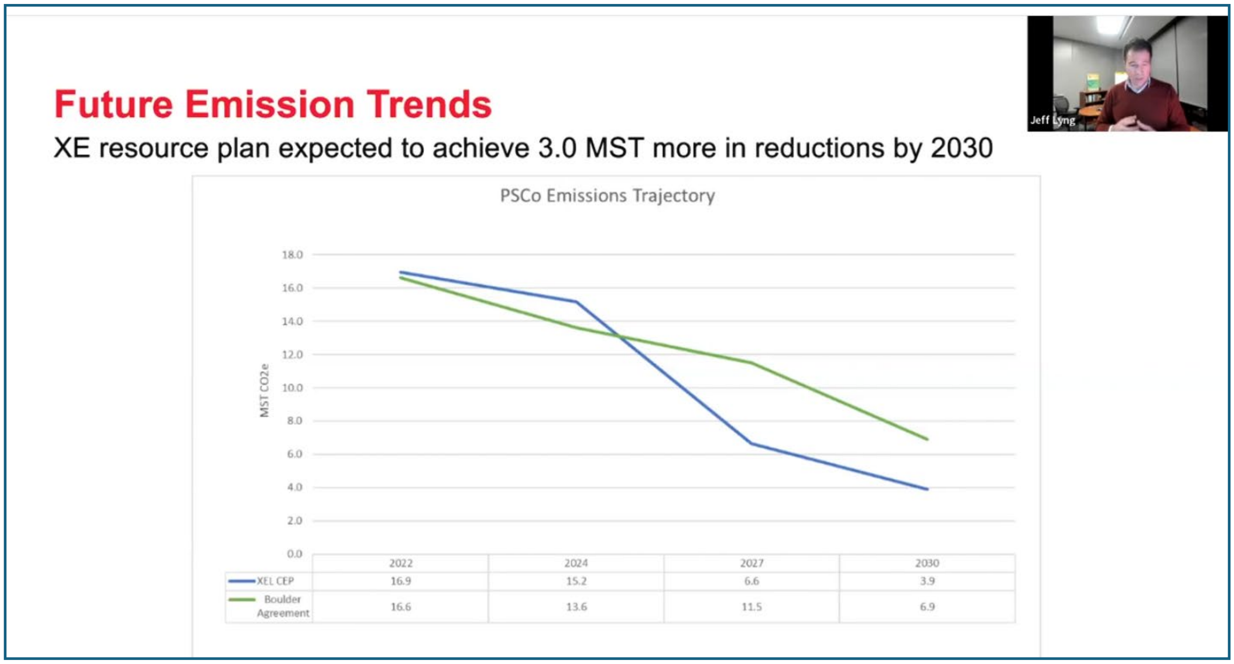
[19] See Consultant Dashboard, Slide 25. Screenshot in Appendix below. "Pledged" option.

[20] Indeed, the majority of the emissions reductions under CU Boulder's Climate Action plan will derive from the reduction in Scope 2 emissions of power purchased from Xcel. See Appendix A below. Compare the area between the 2019 baseline and the BAU curve, to the area between the BAU curve Scenario 3). If the University's planning assumption were that Xcel will fail to meet its 2030 target, the 2024 Climate Action Plan needs to be reworked entirely.

[21] Under the settlement agreement, the City of Boulder is already entitled to terminate Xcel's franchise at its sole discretion every 5 years, if it obtains a two-third majority vote from City Council or the passage of a ballot initiative (see here, pp. 25-25).

[22] Calculations based on Figure 1. As noted in the Xcel presentation (39:00), 2005 baseline emissions of 33.9 MST CO_2. For 2027, the forecast is 6.6 MST. This translates to 81% reduction = 1-(6.6/33.9). For 2030, the forecast is 3.9 MST CO_2. This translates to 89% reduction = 1-(3.9/33.9). Note that the Xcel figures in Figure 2 are absolute carbon figures, while the consultant's model is (appropriately) based on projected carbon intensities (CO_2/kWh).

Figure 2: Xcel Emission Forecast Relative to City of Boulder Benchmarks[23]



B.3. The University is Using Contradictory Assumptions in Emissions and Financial Models

The next issue that requires discussion is the University's claim regarding the future phase-down of higher-emitting base-loaded generation. The University claimed that excess emissions of Option 2E relative to Option A1 can be reduced by decreasing usage of the WDEP cogen plant for baseload generation (p. 3):

> *"The turbines at WDEP do not have to operate for eight months at base load annually between now and 2050 as assumed in the modeling Option 2 referenced in the Shared Governance Team's proposal... Meaning, once the Xcel electric grid becomes cleaner than operating the combined heat and power plant for baseload, the campus can decrease usage and shift to as-needed operations. Managing plant operations in this way can reduce the emissions gap between Options A1 and 2."*

This claim is problematic for two reasons. First, as discussed above, the moment where the grid is cleaner than baseloaded cogeneration will take place in 2029, almost immediately after Option 2E is implemented (as discussed above, parity is virtually achieved as early as 2026). That is not a remote date in the future, but the condition that would prevail for virtually the entire 20–to-30-year lifetime of the new turbines. Second, the assumption that the use of the plant would be decreased is inconsistent with the University's own financial analysis. The Committee alerted staff to this concern during the March 11, 2024 meeting, and included its concern prominently in its Preliminary Report (p.15, 11):

> *"... the University noted that under Option 2E, it may switch away from baseloading cogen in the later period to avoid some of the increase in GHG emissions relative to the*

[23] See presentation available here, 41:00.

> *BAU [business-as-usual] scenario. The Committee finds that such a switch would raise the lifecycle cost of Option 2E…"*
>
> *"… the Committee finds that the lifecycle cost in favor of Option 2E inherently requires the University to operate the cogen for baseload. As the consultant's dashboard demonstrates, savings under Option 2E accrue from lower utility bills from Xcel thanks to baseloaded cogeneration (these savings exceed simultaneous increases in the University's gas bill). As noted above, the Committee recommends that the University avoid baseloaded cogeneration due to its higher GHG emissions profile starting 2029. The financial modeling choice to assume baseloaded cogeneration in Option 2E is therefore inconsistent with that recommendation and leads to an underestimation of lifecycle cost for Option 2E relative to Option 1."*

In other words, the savings in life-cycle cost that the University hopes to gain from Option 2E are dependent on precisely the same modeling assumptions that, according to the University, will be abandoned to contain the increase in emissions from Option 2E. The University should not use two contradictory sets of assumptions, one to claim financial advantages (assuming long-term base-loading), the another to try to limit the increase in emissions (assuming a shift away from baseload generation, presumably as early as 2029).

B.4. The University's Claim Regarding NO_x Emissions is Unsupported

The University claims that Option 2E would reduce NO_x emissions on campus:

> *"…importantly, the turbine upgrades will significantly reduce nitrogen oxide emissions, which have significant public health impacts."*

The University made a similar comment to the Colorado Sun in August, 2024 (here):

> *"The new turbines will come with emissions control equipment that cut the west plant's nitrogen oxide emissions by 50%."*

This claim is not supported by analysis and does not address important facts highlighted in the Preliminary Report. The University is correct that under Option 2E, the new cogeneration turbines will have lower NO_x emissions intensity (16 ppm) relative to the existing turbines in Option A1 (65-70ppm, p. 12). However, the University does not seem to include in their statements the activity levels that (when multiplied by emissions intensity) will determine *absolute* emissions levels. As highlighted in the Preliminary Report, since 2009, use of the existing turbines has been minimal, and reserved only to meet rare resilience needs (p. 6). The Committee highlights that in absolute terms, a plant that is minimally active, has near-zero emissions irrespective of its emissions intensity. On the other hand, while the emissions intensity of the new turbines (Option 2E) is about one fourth of the existing turbines, the use of these turbines for generation is expected to increase by a factor of about 10 (from average capacity factor of 1.5% to about 20%). The Committee noted this point when discussing the potential for adverse regulatory implications of Option 2E (p. 12):

> *That risk of the University exceeding current NOx emissions by more than 25 tpy under Option 2E arises even though emissions intensity of the new CTGs (16 ppm) will be considerably lower than those of the existing Mitsubishi CTGs (65-70ppm). The reason is that while the emissions intensity of the new turbines will decline by a factor of about*

> *four, the usage of the CTGs is expected to rise by a factor of 10 or more due to the baseloading of the turbines, e.g., from average capacity factor (2009-2020) of 1.5% to more than 20% (see calculation above).*

Further complicating the picture is the fact that baseloaded cogeneration could dramatically increase absolute NO_x emissions from the WDEP, but also reduce some NO_x emissions from the University's boilers. It cannot be claimed based on first principles which of these factors will prevail. The question which of the options, Option 2E or Option A1, has lower overall NO_x emissions, is therefore a question that requires quantitative analysis. The Committee recommended that the University perform such analysis to better assess the regulatory implications of Option 2E (p. 12). To the best of the Committee's knowledge, the University has not performed such analysis to date.

While the NO_x performance of Option 2E is uncertain, the Committee finds that Option A1 will not reflect an increase in NO_x emissions relative to current (2024) levels. Indeed, Option A1 will provide a new WDEP Boiler 3 with state-of-the-art NO_x control technology. Insofar as the University currently uses the old WDEP Boilers 3 and 4 for peak heat, the upgrade of Boiler 3 is likely to decrease NO_x emissions relative to current levels (and the updated Boiler 4 will ideally have better NO_x mitigation technology). The Committee also finds that the NO_x emissions profile of Option A1 is similar to the NO_x emissions profile of Option 1. Under both options, the University's heating load is met with modern boilers with efficient NO_x mitigation technology.

Despite the lack of quantitative analysis, in the Supplemental Document (p. 9) the University noted that Option A1 has the "Highest NOx Emissions Potential." As noted above, the University's reference to "emissions *potential*" is inapposite, since a plant that is only used for back-up purposes has virtually zero emissions in *absolute* terms. Based on the discussion above, the Committee finds that Option A1 should have received the same NO_x emissions score as Option 1. The Committee finds that in scoring NO_x emissions, the University should have quantified absolute emissions, which it apparently did not do.

The University's claim regarding lower NO_x emissions under Option 2E also led to inadequate ranking of the options in the Supplemental Document. In its ranking of different options, the University provided a single score to a "Lowest Emissions" item, which apparently combines both GHG and NO_x emissions. Options A1 and 2E received the same emissions score of 8/10, while Option 1 received a 10/10 (perfect) emissions score. The Committee finds that the University's scoring is inconsistent. Since Option A1 and Option 1 have similar emissions profiles (both with respect to GHGs and NO_x) they should have received the same 10/10 score (unless the University had quantitative analysis indicating otherwise).

The Committee finds that the ranking of the Lowest Emissions item inappropriately removed GHG emissions as a factor in the decision. Namely, the inadequate scoring made it seem as if there is no sacrifice or tradeoff in choosing the higher GHG emissions Option 2E.

C. Upfront Cost and the IRA Credit

The University's June 5 memo (p. 4) recognized that "[t]he initial investment cost in Option A1 is lower than the initial investment in the turbine upgrades…". The memo, however, does not discuss the size of the upfront cost advantage in favor of Option A1.[24] In its Preliminary Report (p. 16), the Committee found that the:

> *"The upfront cost of Option A1 is estimated to be $15 million, which is $10-12 million lower than replacing the two CTG turbines at $25-27 million [Option 2E]."*

The Committee also noted that the $10-$12 million difference in upfront cost, favoring Option A1, could be smaller depending on whether the University qualifies for the IRA federal tax credit. In the original 2023 program plan, the University claimed the tax credit would have maximum value of $9 million. The June 5 memo does not include an estimate for the value of the credit. In a more recent announcement, The University has provided an estimate of $5-7 million (CU Boulder Today, Jul 23, 2024, here). Therefore, even if the University were eligible for the tax credit, the difference in upfront cost favoring Option A1 would be $3-$7 million.[25]

In its Preliminary Report (pages 10-11), the Committee found that there was considerable uncertainty regarding the eligibility of Option 2E for the federal tax credit, and that, even if the project were eligible, the amount of the credit is likely to be low. The Committee's concerns regarding eligibility for the credit involved the "new property" requirement under the Inflation Reduction Act (IRA). According to this requirement, for Option 2E to qualify for the credit the upgraded components need to represent at least 80% of the project's total fair market value. Given the existence of substantial legacy components (two heat recovery steam generators and one steam generator) it is unclear whether the new property requirement can be met. The Committee further noted that even if the University met the new property requirement, the tax credit is likely to be partial. The reason is that Option 2E exceeds the "applicable capacity limit" of 15 MW for the cogeneration tax credit. The Committee found that the applicable capacity limit would reduce the tax credit from $9 million (the University's previous estimate for the maximum credit) to only $4 million.

Given the smaller amount of the credit, and uncertainty regarding any eligibility, the Committee noted that the "expected value [of the tax credit] is likely to be low" (p. 16). The Committee's findings were significant given the weight that the University assigned to tax credit eligibility and the apparent urgency of the application. The University communicated to the Committee a sense of urgency to make a non-refundable deposit on the turbines by April 1, 2024 to meet eligibility requirements. A similar notion of urgency around the tax credit was included in the June 5 memo (p.6), regarding the alleged need to proceed rapidly with Option 2E.

Considering its findings, the Committee made an explicit recommendation in the Executive Summary of its Preliminary Report, that:

> *" … the University should not rely on eligibility for a $9 million, or even a $4 million credit, before completing a legal analysis regarding eligibility concerns identified below."*

To the best of the Committee's knowledge, the University did not carry out the recommended analysis prior to its decision to adopt Option 2E in June 2024. The June 5 memo refers to the tax credit

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[24] See below for discussion of Figures in the Supplemental Document.

[25] This range is a product of the Committee's $10-12 million range in cost advantage for Option A1 and the University's $5-7 million estimate for the IRA tax credit. The top of the range $7 million assumes a $12 million difference and $5 million tax credit; the bottom of the range assumes a $10 million difference and a $7 million tax credit.

eligibility in tentative terms ("…if we qualify", p. 6). Further, in a meeting with the COO and Vice Chancellor for Infrastructure & Sustainability on June 27, 2024, the Committee highlighted the uncertainty around the tax credit and shared its impression that the analysis it recommended regarding eligibility has not been produced by the University (June 27, 2024 meeting, Minutes, p. 4). The University did not indicate the contrary. The Committee finds that the lack of appropriate research regarding eligibility by the University (as recommended by the Committee on March 21, 2024) during the months of April and May is inconsistent with the weight that the University assigned to the tax credit as a consideration for accelerating its decision.

The Committee is unaware as to how the University came to its later July 2024 estimate of the tax credit figure at $5-$7 million, and whether this estimate is based on the analysis recommended by the Committee. If the University did in fact pursue such analysis, it is unclear why the bottom of the range in that estimate ($5 million) is still higher than maximum eligibility estimated by the Committee ($4 million).

To summarize, the Committee found that Option A1 has an advantage of $10-12 million in upfront cost relative to Option 2E. As noted in the Committee's report, in the absence of necessary legal research, this is the figure that should have been used in the University's decision-making. Further, according to the committee's analysis, even in the uncertain event where the University were eligible for the tax credit, there would still be a $6-8 million advantage in favor of Option A1.

To complete the picture, the Supplemental Document the University shared with the Committee after the University's decision, provides a different set of upfront cost figures (p. 9, Figure 3 below). The items included in these cost figures make it challenging to understand how these cost estimates compare to those originally provided to the Committee by the consultant. The figure presents a $11.6 million cost advantage to Option A1 relative to Option 2E. That difference is consistent with the one found by the Committee.

As can be seen in Figure 3 below, the Supplemental Document also included a cost item for nearly $10 million to replace Boiler 4 in 2030 (when it will turn 65). The item is clearly not an "upfront cost" and was not included in the University's upfront cost total. However, it is likely that the University did include the cost item in its lifecycle cost analysis (see discussion below). The Committee finds that the University incorrectly added the $10 million Boiler 4 cost item to Option A1. As discussed above (Section A.3.), even in the absence of the refurbished Boiler 4, the CTGs provide 77 full days (1,848 hours) where they can meet the segment of the load curve between 150-200 kpph under conservative assumptions. Further, with the University intending to reduce its energy demand 30% by 2030, the Committee finds it unreasonable that the same 200 kpph peak demand assumption is used in 2030.

The Committee also finds that in replacing Boiler 4, the University essentially changed the resiliency specifications for Option A1 from an N+1 to an N+2 standard.[26] The University's Option 2E only meets

[26] Under the University's variation of Option A1, 150 kpph boiler capacity in EDEP will be supplemented by 200 kpph in WDEP (all 100% capacity factor), and the CTGs (160,000 kpph under the 10% exemption factor). Therefore, two 100 kpph boilers can fail, with the remaining 150 kpph in boiler capacity, and the CTGs still meeting assumed peak demand of 200 kpph.

an N+1 standard after 2030.[27] In this way, the University's cost analysis required the Committee to meet a far higher resilience standard than the University option. That higher resilience standard added the $10 million cost to Option A1, but not to Option 2E. As a result, the University's Option 2E appears more financially attractive than it actually is.

Figure 3: Upfront Costs from the University's Supplemental Document

	Ideal System	Boilers Option 1	CHP Option 2	CASGC Option A1
Capital Project [First Cost]		*$35,852,000*	*$40,534,000*	*$28,913,000*
Direct Costs (Design / CM / CA / Admin)		$7,110,737	$7,785,985	$4,962,230
Construction Costs		$16,647,086	$13,165,702	$9,882,509
Equipment Cost (Boilers or CTG)		$12,094,177	$19,582,313	$6,161,054
CHP Maint Costs (CTG-2 Overhaul & Ctrls)				$7,907,207
				BLR-4 Rplmt $9,700,435 @ 2% escalation *Includes BLR-4 Rplmt in 2030 [Age 65]

D. Life-Cycle Cost Analysis (LCCA)

D.1. The Committee's Findings Regarding LCCA

The University's June 5 memo (p. 4) claims that

> *"...the life cycle costs of the turbines upgrades [Option 2E] is lower than the life cycle costs of Option A1..."*

In contrast, in its Preliminary Report (p. 17), the Committee found that "...there is no significant difference in lifecycle cost between Options A1 and 2E that factors into the Committee's recommendation." The Committee cited the following considerations for its finding (p. 16):

> *"The consultant's analysis did not include Option A1 and did not quantify its lifecycle cost. As discussed above, the consultant's 20-year lifecycle cost analysis found a $58 lifecycle cost advantage for Option 2E over Option 1 (2025-2045), but the Committee finds that the difference is over-estimated.*
>
> *Further, Option A1 will have a considerably lower lifecycle cost than Option 1 (e.g., lower by $15 million in upfront cost, and another $15 million in the modeled risk management premium).*
>
> *Lastly, the University noted that under Option 2E, it may switch away from base loading cogen in the later period to avoid some of the increase in GHG emissions relative to the draft 2024 CAP BAU scenario [Note: this latter point is discussed in Section B.2. above]."*

The University's June 5 memo seems to have missed the Committee's analysis regarding life-cycle cost. The University explained the claim that Option 2E has lower lifecycle costs with two bullets (p. 4):

> *"--The costs of Option A1 did not include a refurbishment of one of the turbines that will need to occur by 2027 at a cost of $5.25 million or the $2.7 million in required distributed control system upgrades.*

[27] Under the University's Option 2E, 150 kpph boiler capacity in EDEP will be supplemented by 160 kpph in WDEP CTGs (all 100% capacity factor). Therefore, if the two large assets –100 kpph boiler, and one 80,000 kpph turbine—fail, the remaining 130 kpph will not be able to meet assumed peak demand of 200 kpph.

> *-- Option A1 has a total life cycle cost of $723 million as compared to total life cycle costs for the planned upgrade of $689 million. These costs are based on the analysis of 30-year net present value of capital cost, interest, utility cost, rate of inflation, existing debt, discount rate, operating and maintenance cost, and social cost of carbon."*

The Committee disagrees with the University's claims, both with regards to the additional cost items (Bullet 1) and the lifecycle cost analysis (Bullet 2). These are discussed in turn.

D.2. The University's Claims Regarding Additional Cost Items

To the best of the Committee's knowledge, the University's claim regarding the need for a $5.25 million refurbishment of one of the existing turbines by 2027 has not been previously raised. In the March 11, 2024 meeting with Facilities staff and the consultant, the Committee was assured by the consultant that the existing turbines are in good technical condition. Indeed, considering the minimal use of these turbines since their rebuilding (as documented above) it is unclear why a turbine would need to be refurbished. A document shared with Committee in July 2024 attributes the $5.25 million cost item to a 100,000-hour maintenance overhaul" (Supplemental Information Document, p. 22). The Committee notes that in general, hour marks requiring maintenance overhauls in electrical systems (e.g., the 100,000-hour mark) should be read in relationship to the actual use of the turbines, not to their calendar age. If the University claims otherwise, appropriate documentation should be provided from the CTG manufacturer.

The Committee finds it highly unlikely that the CTGs will reach their 100,000-hour mark in 2027 as assumed in the University's financial analysis. In the Preliminary Report (p. 6), the Committee included data demonstrating that between 2013 (when the turbines were last rebuilt), and 2020 (the last year for which the Committee had available data[28]), the two turbines produced only 32,119 MW. Under the assumption that a turbine runs at full capacity, this figure corresponds to about 2,072 operating hours (= 32,119 MW / 15.5 MWh), or an average of only 260 hours per year (= 2,072/8 years).[29] Therefore, for the 100,000 maintenance hour limit to be reached, the University would need to increase its usage of the turbines in the 2020-2027 period by a factor of 47 (97,928 hours / 2,072 hours) relative to the 2013-2020 period. Option A1 is clearly not designed to increase usage in this fashion (indeed, it is designed to avoid baseloading of the turbines). For this reason, the Committee finds that the University's claim regarding the $5.25 million cost items seems unsupported.

The second cost item mentioned in the University's memo is the $2.7 million in distributed system upgrades. To the Committee's understanding, the distributed control system upgrades are part of a broader set of about $15 million in deferred maintenance items. These items were not included in the consultant's original cost comparison between Option 2E and Option 1 (see Preliminary Report, p. 16; Consultant Dashboard, Slide 17, screenshot in Appendix A). The Committee did not receive a detailed accounting of these items and cannot comment on the appropriateness of the inclusion of the $2.7 million item.

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[28] The Committee's requests for updated data (2021-2023) were not met by the University.

[29] The Committee acknowledges that a turbine might be used at less than full capacity, but there are also two turbines, that could divide operating hours. Therefore, if a turbine is used at half its capacity, but operating hours are divided equally between turbines, the same analysis holds.

Lastly, even in the highly unlikely event that Option A1 involved the full additional lifecycle costs claimed by the University, the total of these costs ($8 million) still does not create a substantial lifecycle cost advantage for Option 2E (given a $10-12 million advantage in upfront cost to Option A1, or $6-8 million in the uncertain event of tax credit eligibility).

D.3. The University's Claims Regarding Lifecycle Cost Difference are Unsupported

With regards to the University's claim of a $34 million life cycle cost advantage to Option 2E (= $723 million for Option A1 - $689 million for Option 2E), the Committee finds the claim to be unsupported and implausible.

The University's figure for Option A1 ($723 million) seems to be based on an analysis that the University performed after the Committee's Preliminary Report. That analysis (and the underlying documentation) has not been shared with the Committee, despite repeated requests to the University. The Committee finds that in the absence of sharing of the relevant documentation the University's claim regarding the lifecycle advantage of Option 2E remains unsupported. This finding is of special significance considering the important concerns identified by the Committee with respect to the University's previous lifecycle cost analysis of Option 2E.

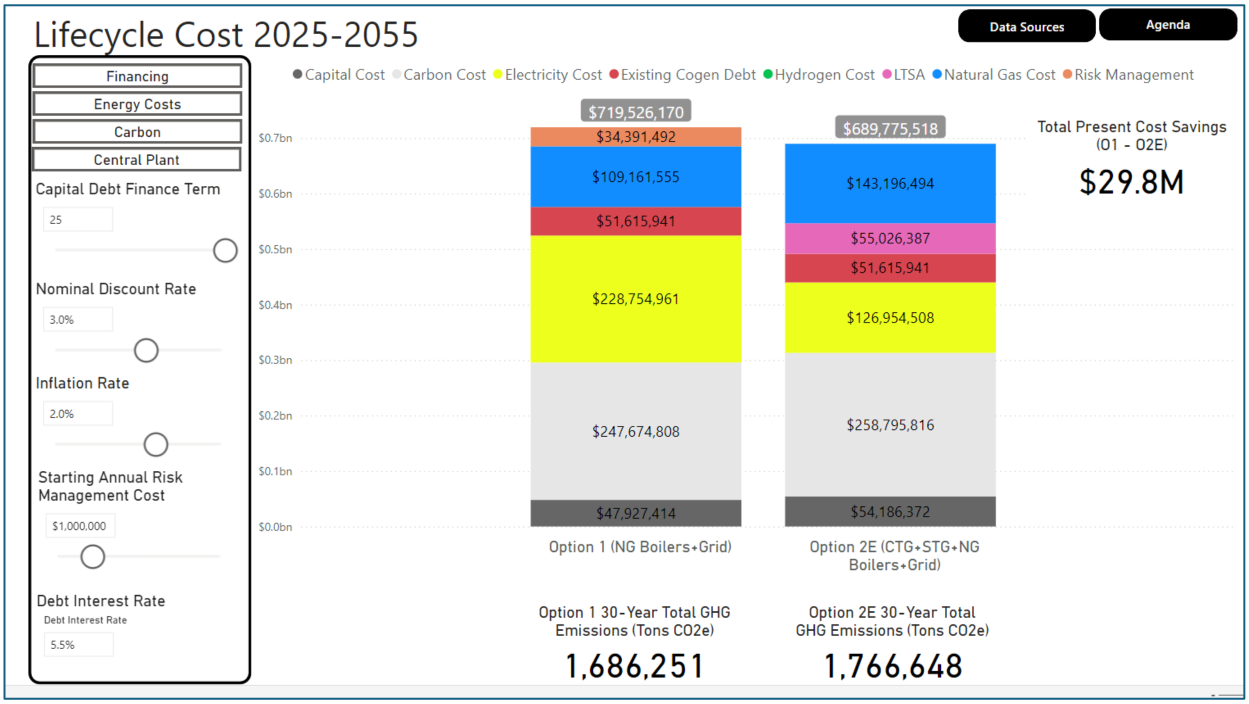
The Committee finds that even if one accepts the University's lifecycle difference figure for the sake of argument, that figure cannot justify Option 2E. The difference of $34 million should be considered in the context of total lifecycle costs of about $700 million over the next 30 years for both options. The difference of 5% is based on highly uncertain assumptions, for example, with respect to the path of future electric and gas costs. In its Preliminary Report (p. 11), the Committee made a similar observation with respect to the University's previous lifecycle model: "The modeled lifecycle cost differential is also sensitive to relatively small changes in several parameters." The Committee's observation is based on prevailing engineering practice with respect to margins of error in long-term cost models.

The Committee also finds the University's $34 million lifecycle cost advantage figure to be implausible. The University's $689 million figure for Option 2E is identical to the figure presented to the Committee originally in the Consultant Dashboard (Slide 34, screenshot in Appendix A below). The Consultant Dashboard did not include a lifecycle cost analysis for Option A1, which was developed by the Committee at a later point. However, Option A1 has a lower upfront cost than Option 1 (because only one instead of two boilers need to be purchased). Option A1 has a similar operating cost relative to Option 1 (because both options use the grid and boilers to meet electric and heating needs). As a result, logically, the life-cycle cost of Option A1 should be lower than the lifecycle cost of Option 1. Instead, the University's June 5 memo estimate of $723 million for Option A1 is slightly greater than the Consultant's estimate of Option 1.

One key concern highlighted in the Committee's Preliminary report was the use of contradictory assumptions regarding baseloading of the new turbines under Option 2E (see discussion in Section B.2. above). From an emissions standpoint, the University claims that it will phase-out its use of cogen for baseloading to limit the increase in emissions of Option 2E relative to BAU. Meanwhile, from a financial standpoint, the University's analysis of Option 2E runs until 2055 (see screenshot below).

Figure 4: The University's LCCA for Option 1 and Option 2E (2025-2055)

Source: Consultant Dashboard, Slide 34 (last accessed August 22, 2024)



These contradictory assumptions are problematic because the savings in lifecycle cost identified in the consultant's model derived precisely from the operation of the cogen (and corresponding savings in Xcel utility bills). Graphically, this can be seen in the fact that the yellow and blue boxes (electricity and gas cost respectively) are higher for Option 1 (and hence, 1A) than they are for Option 2E (about $337 million to $269 million, i.e., $68 million difference). The University faces a tradeoff between increasing its emissions and trying to reduce its utility bill. As discussed in the Preliminary Report (p. 1), Under the University's Energy Master Plan ("EMP", 2021), the University intended to refrain from baseloaded cogeneration once the emissions factor of the grid and boiler heat is lower than cogeneration. According to the University's own model, that point is expected to be reached as early as 2029. The only lifecycle cost advantages that Option 2E can have after 2029 are a direct result of departing from the EMP and increasing emissions relative to BAU. Thus, if the University abided by the EMP, there should no meaningful lifecycle cost advantage to Option 2E after 2029. The Committee finds that the lower upfront cost of Option A1 (especially when considering uncertainty over the tax credit) would likely lead to an overall lifecycle cost for Option A1 that is similar or lower than Option 2E.

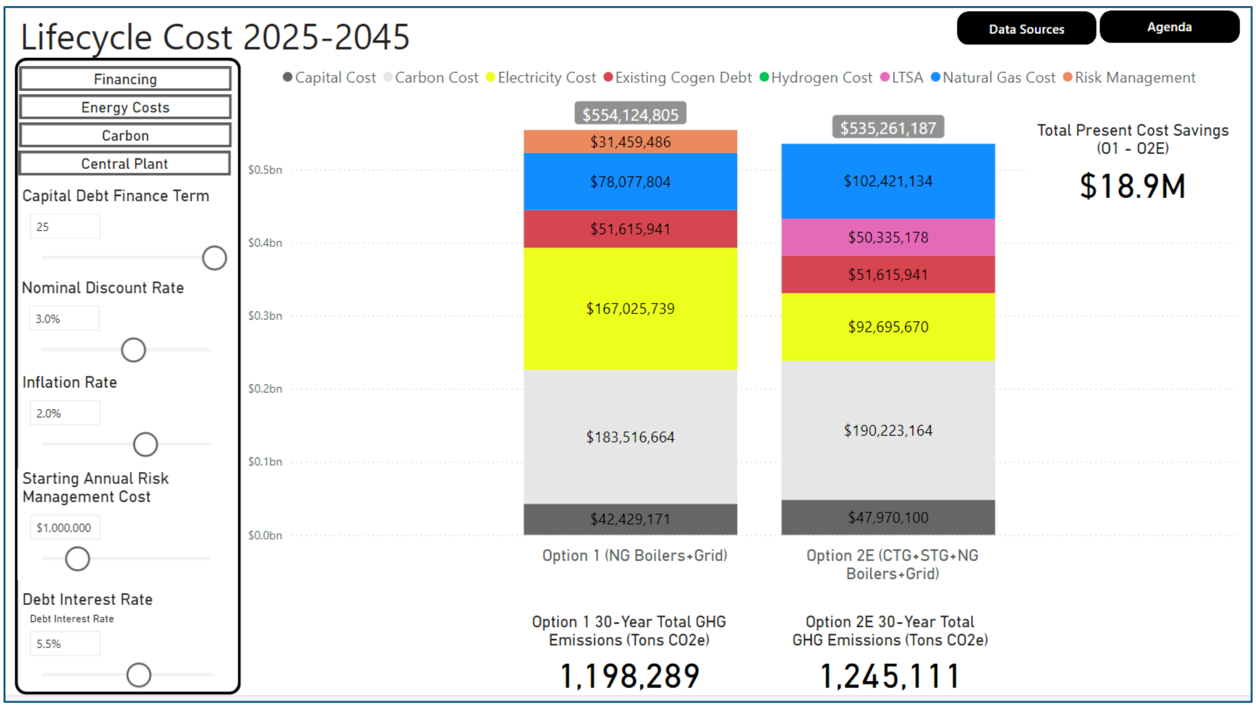
The Committee further notes that the University's choice of 2055 as the end-year for lifecycle cost analysis is unwarranted. The University's climate action plan intends to complete heating electrification by 2045 (see Appendix A). Therefore, use of cogeneration turbines for baseload appears inconsistent with the Climate Action Plan.[30]

[30] GHG analysis by the consultant demonstrates that if Option 2E were actually to be run until 2055, the GHG savings from Option 1 (and hence, A1) about double to 200,000 tCO_2 (12% difference between the options). See Consultant Dashboard, Slide 26. Screenshot in Appendix A below.

The consultant also performed a 20-year lifecycle cost-analysis for 2025-2045. This analysis found a smaller cost advantage to Option 2E over option A1, only $19 million rather than $30 million. Consistent with the Committee's analysis, the 2025-2045 analysis has a smaller utility bill difference: electric and natural gas cost (sum of yellow and blue boxes) equals $245 million for Option 1 and $194 million for Option 2E. That $51 million cost difference (2025-2045 analysis) is $17 million smaller than the $68 million difference in the 2025-2055 analysis. That $17 million amount accounts for nearly the entire difference between the shorter-term and longer-term analysis ($19 million). Using the same logic, if the University chose to phase-out the baseloading of cogen prior to 2045, it would reduce the cost saving it claims even further.

Figure 5: The University's LCCA for Option 1 and Option 2E (2025-2045)

Source: Consultant Dashboard, Slide 33 (last accessed August 22, 2024)



To summarize, the Committee finds that in the absence of transparency regarding assumptions, and given the concerns discussed, the $34 million figure should not have been relied on in the University's decision-making.

E. Additional Regulatory Aspects

In its Preliminary Report (p. 12), the Committee found that Option 2E could subject WDEP to the New Source Review (NSR) program. Under 42 USC Sec. 7602(j) a "major stationary source" is defined as any source that emits, or has the potential to emit, more than 100 tons per year of any pollutant in any single year.[31] To the best of the Committee's information WDEP would easily exceed that

[31] In the Preliminary Report (p. 12), the Committee originally noted that NSR could result if WDEP increases its actual NO_x emissions by 25 tons per year (tpy), but that threshold only applies to VOCs. See 42 USC Sec. 7511a(d).

threshold. NSR applies to any "new" or "modified"[32] major stationary source in a non-attainment area (42 USC 7502(c)(5)). To the best of the Committee's understanding, WDEP would meet the definition of a new or modified major stationary source.

The EPA had designated Denver and the northern Front Range of Colorado as a severe nonattainment area for ozone.[33] On July 24, 2024, the northern Front Range was redesignated as a serious nonattainment area. While the standards for such areas are not as strict as for severe areas, they remain problematic for the proposed facility. Specifically, a new source in a serious non-attainment area must achieve offsets of 1.2-to-1 for NO_x and VOCs and must install the technology that achieves the lowest achievable emission rate standard (LAR). See 42 USC Sec. 7502(3). This is generally acknowledged to be the best technology available. See 42 USC 7503(c)- (d). The Committee met with Colorado Department of Public Health and the Environment (CDPHE) staff who have indicated that at this point, there are no available NO_x emissions credits in Colorado.

In the Preliminary Report, the Committee also noted that if an increase in CTG NO_x emissions of the relevant threshold[34] occurred, it is possible that the University would be able to net those higher NO_x emissions against lower NO_x emissions from reduced use of WDEP Boilers 3-4. However, that possibility depends on legal and data assumptions. In the Preliminary Report, the Committee recommended that the University obtain the necessary data and complete regulatory analysis regarding NSR prior to making the WDEP decision. The University did not provide the Committee with any such analysis, thus frustrating the Committee's ability to complete the regulatory analysis in this Final Report.

In the June 5 memo (p. 6), the University claimed that Option 2E will not subject the University to NSR under existing regulations:

> *"In relation to the new EPA rules you have noted, we have confirmed with our Environmental Health and Safety compliance team, as well as our turbine vendor, that the new rules apply only to equipment of 25 megawatts and above, not turbines of the size we will be replacing…".*

The Committee is not familiar with the CDPHE Air Quality Division rules that the University referenced, and has not carried independent research on this issue. However, it is noteworthy that the University's claim regarding a below-25-megawatt threshold seems to be inconsistent with the provisions of the federal Clean Air Act, as described above. Accordingly, the Committee asks that the University share documentation for its claim, so it can be reviewed by the Committee.

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[32] 42 USC Sec. 7411(a)(4) defines modification to mean "…any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted."

[33] During the period when the Committee was considering these issues, the Front Range was designated a "severe" nonattainment area for ozone. On July 24, 2024, the northern Front Range was redesignated as a "serious" nonattainment area for ozone. 89 Fed. Reg. 59832 (2024). See also https://cdphe.colorado.gov/nonattainment-federal-ozone-pollution-standards. Ozone is formed in the atmosphere from a combination of NO_x and volatile organic compounds (VOCs) in sunlight.

[34] According to the analysis above, the relevant threshold should be 100 tpy, rather than 25 tpy. See discussion in note 31 above.

F. Process Concerns

In the spirit of ongoing assessment and continuous improvement, the Committee would like to address a few of the issues (some of which have been alluded to in the report above) that have been found surrounding initiation, management, and close-out of this project. These issues are not unique to the University, as managing complex projects that are staffed with multidisciplinary teams always present challenges. These will be discussed briefly below.

Many of the issues mentioned here likely stem from the specific timing of Committee formation and involvement. The University began the WDEP emissions compliance program a year before the formation of the Committee, and WDEP upgrade planning was likely underway well in advance of adoption of Reg 7. Committee formation happened several months after Regent approval of the Program Plan, and the Committee was given a short timeline (three weeks during the spring semester) to complete a complex analysis and audit of the proposal and present a viable alternatives analysis. Obviously, this created a daunting technical and regulatory task for the Committee; however, the project and personnel management issues that injecting a “Tiger Team” of subject matter experts into a mature multi-year project likely caused greater hurdles on the University side. Often in these cases, when an outside team of auditors is charged with a performing critical analysis of an existing team’s work, friction between the existing team and the new parties arise. Although there is some level of inevitability to this, frictions could have been mitigated by having a member of the Committee involved from the outset, or by making sure all members of the original team understand that any work being done on a project will be audited by subject matter experts near the end of the project. It should never be the prevailing opinion that any collaborative project analysis is a zero-sum game with winners and losers. Both teams have the utmost sincerity for the best interests of the university in mind. Fostering an environment of collaboration and developing effective strategies for resolving conflicts that arise from this is essential to the success of any project.

Although having a multidisciplinary team is critical to the mission of inclusive excellence, there are some project management concerns that stem from this. Communication barriers do exist between individuals with diverse backgrounds. Faculty and staff from different disciplines may work with varying terminologies, industries, and communication styles which can lead to misunderstandings. Information overload can also occur. Managing the flow of information to ensure all team members are adequately informed without being overwhelmed can be challenging. Throughout this project the Committee attempted to understand and empathize with the priorities (or at lease stated priorities) of the University. Although faculty may prioritize theoretical and research aspects as part of daily work, the Committee attempted to focus on practical implementation and operational efficiency to match the needs of plant operators. However, the communications gap mentioned above made this task difficult. Without having a big picture of operational finance and future projects, determining actual priorities in this instance was difficult. For this project it was especially important since the technical integration of the proposed solution needed to be compatible with existing systems and future technologies, and this could only happen with careful coordination between the University and the Committee.

It is also worth mentioning that the differences in work culture between academic and operational staff can lead to friction, affect team cohesion, and lead to communication breakdown. All the above were observed on this project, and, although management on both sides effectively used their own strategies and techniques to mitigate these issues, there appears to be a cultural divide between faculty and staff at all levels of magnification at the university – at the very least there is a perception of that divide. The solutions to this are manifold and not necessarily unique to this university, so they will not be mentioned here.

Time management on a project with this short of a timeline is a concern as well. On the most optimistic of timelines coordinating schedules of faculty (who have teaching, service, and research commitments) with staff (who have operational and service duties), can be difficult. Coupling that with a compressed schedule and communication issues on this project has led to confusion, mistrust, and unnecessary rework.

Addressing these issues requires a proactive approach, strong leadership, and effective project management strategies to ensure the success of future collaboration projects. Several effective strategies to address these issues that were used to varying degrees of success on this project include, but are not limited to:

- Early identification and resolution of issues: It is important to recognize conflicts and issues early to prevent them from escalating. Regular Committee meetings helped identify potential problems before they become major roadblocks.
- Open channels of communication: The Committee encouraged a culture of transparent and open communication. Team members were encouraged to voice their concerns and provide feedback without fear of retribution or reprisal. Unfortunately, the direction and pace of information flow between the Committee and the University proved to be an ongoing issue.
- Creating an environment of collaborative problem-solving: The Committee was continuously engaged in collaborative investigative analysis. This not only helped in finding optimal solutions but also boosted team morale, cohesion, and purpose.
- Clear goals and expectations: Although this Committee was formed ad hoc, initial project goals and expectations were clearly defined and communicated to all team members at the outset. This helped in aligning the team’s efforts and avoiding (most) misunderstandings.
- Regular check-in meetings: Regular check-ins and one-on-one meetings were performed throughout the project to address any issues promptly and keep the project on track given the short timeline.
- Effective and efficient documentation: Documentation of Committee processes, decisions, and changes through email, meeting agendas, meeting minutes, and reports facilitated transparency, ensured all Committee members had up-to-date information, and provides a reference for future projects.

It is the sincere hope of this Committee that future collaborations such as these build upon the relationships and learning opportunities posed on this project for the betterment of the university as a whole.

Appendix A

Figure 6: GHG Emissions Comparison

Source: Dashboard consultant, Slide 26 (Screenshots from Aug. 22, 2024)

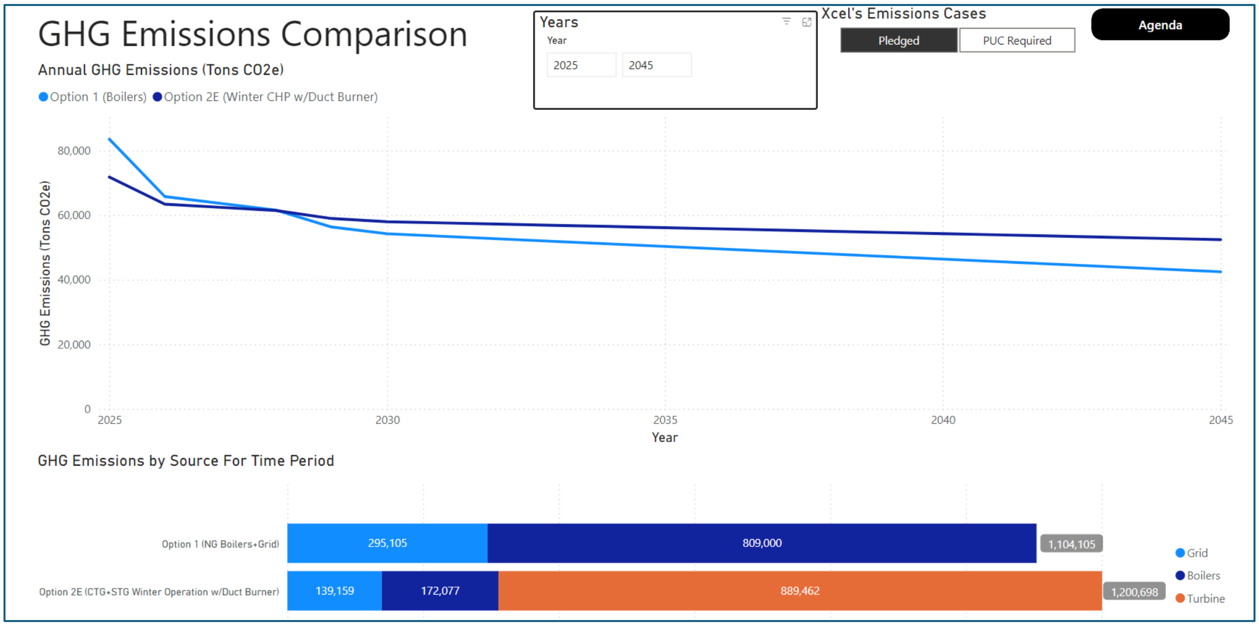


Figure 7: GHG Emissions Comparison

Source: Dashboard consultant, Slide 26 (Screenshots from Aug. 22, 2024)

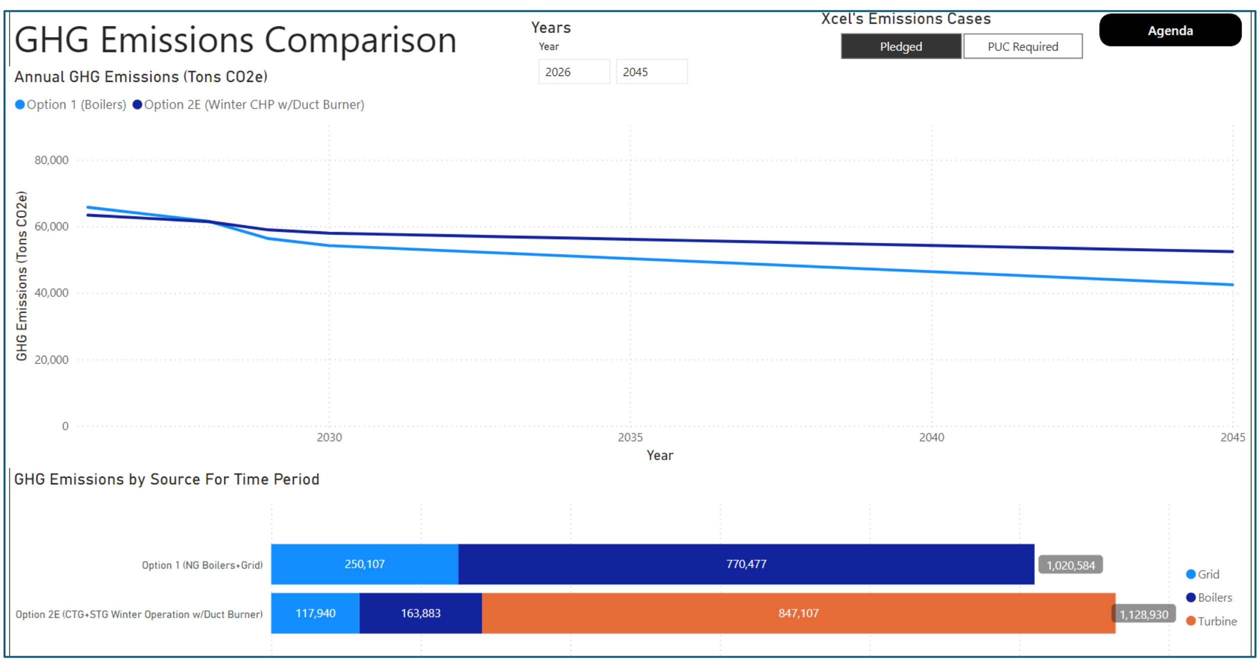


Table 2: Cumulative Performance of the 2020 Target

Source: Graduate Student and Faculty Suggested language to acknowledge CU Boulder's miss of the 2020 target (Available here)

The table is based on data from Column D in University of Colorado Boulder (UCB), S1-2 emissions spreadsheet (on file with authors). Remainder based on authors' calculations.

A. Year	B. Target year	C. 20% by 2020 linear reduction (tCO2e)	D. Gross S1+2 GHG Emissions (Metric Tons CO2e)	E. Required annual reduction from baseline (tCO2e)	F. Annual difference btw actual emissions and target (=D-C)	G. Cumulative target performance for each year (based on F)
2005	0	135,609	135,609	0	0	0
2006	1	133,672	146,889	1,937	13,217	13,217
2007	2	131,735	144,968	3,875	13,233	26,450
2008	3	129,798	140,858	5,812	11,061	37,511
2009	4	127,860	142,971	7,749	15,111	52,622
2010	5	125,923	143,492	9,686	17,569	70,191
2011	6	123,986	151,277	11,624	27,291	97,482
2012	7	122,048	150,768	13,561	28,719	126,201
2013	8	120,111	155,996	15,498	35,885	162,086
2014	9	118,174	144,752	17,435	26,578	188,663
2015	10	116,237	144,535	19,373	28,299	216,962
2016	11	114,299	136,130	21,310	21,831	238,793
2017	12	112,362	135,992	23,247	23,630	262,422
2018	13	110,425	128,807	25,185	18,382	280,805
2019	14	108,488	126,442	27,122	17,955	298,759
2020	15	106,550	114,474	29,059	7,924	306,683
Cumulative				232,473	**306,683**	

Figure 8: CU Boulder's C Miss of the 2020 Target (Figures in tCO2e, source: Table 1 above)

Source: Graduate Students and Faculty suggested language to acknowledge CU Boulder's miss of the 2020 target, see above.

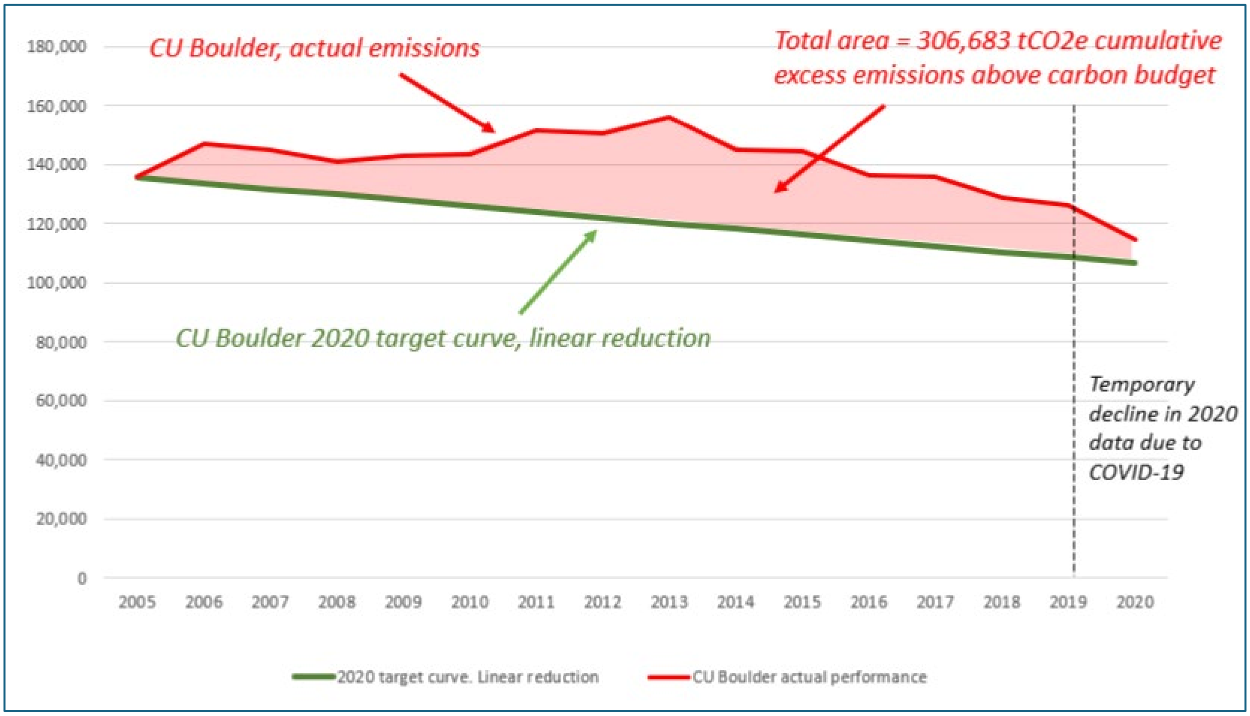


Figure 9: Implementation Timeline

Source: CU Boulder, 2024 Climate Action Plan, p. 17

STRATEGY / DECADE	YEARS 2024–2030	2031–2040	2041–2050
Building Efficiency	197,629 MTCO2e	2,781 MTCO2e	No projects
Renewable Energy	20,066 MTCO2e	No projects	No projects
Fleet Replacement	5,273 MTCO2e	5,434 MTCO2e	2,825 MTCO2e
Heating System Upgrades	138,348 MTCO2e	256,118 MTCO2e	462,928 MTCO2e

Figure 10: Key Assumptions

Source: Consultant Dashboard, Slide 17, accessed on Aug 22, 2024

Capital Costs

Option 1: CTG Capital Cost *(assume $25Mil in year 2025 – Report noted $23.4Mil)*

Option 2: Boiler replacement cost based on 80kpph, 9ppm boilers to meet emissions regulations
-Replace boilers 3 and 4 at year 2025 with 99 MMBTU input, *(assume $15Mil each to replace within the WDEP).*

-Design contingency and soft costs already covered in capital cost

-Each option has a unique capital cost schedule with debt financed on a 25-year term at the current (July 2022) municipal bond rate

-No major steam infrastructure improvement projects planned during the 30-year life cycle.

-Capital cost finance payments that run past the end of the LCCA study period are not shown in the cash flow diagrams, but are accounted for in the LCCA calculations and total present cost results.

Operations, Load Model and Fuel Costs

-CU provided natural gas consumption data for the East and West District Energy Plants as well as electricity consumption data from mid-2019 to 2021. AEI developed a typical mean year consumption model from this dataset filtering out data omissions and times when the combustion turbine operated. This provides a good baseline model for operating the packaged boilers to produce steam and electricity consumption without on-site generation.

Figure 11: GHG Emissions Comparison

Source: Consultant Dashboard, Slide 26

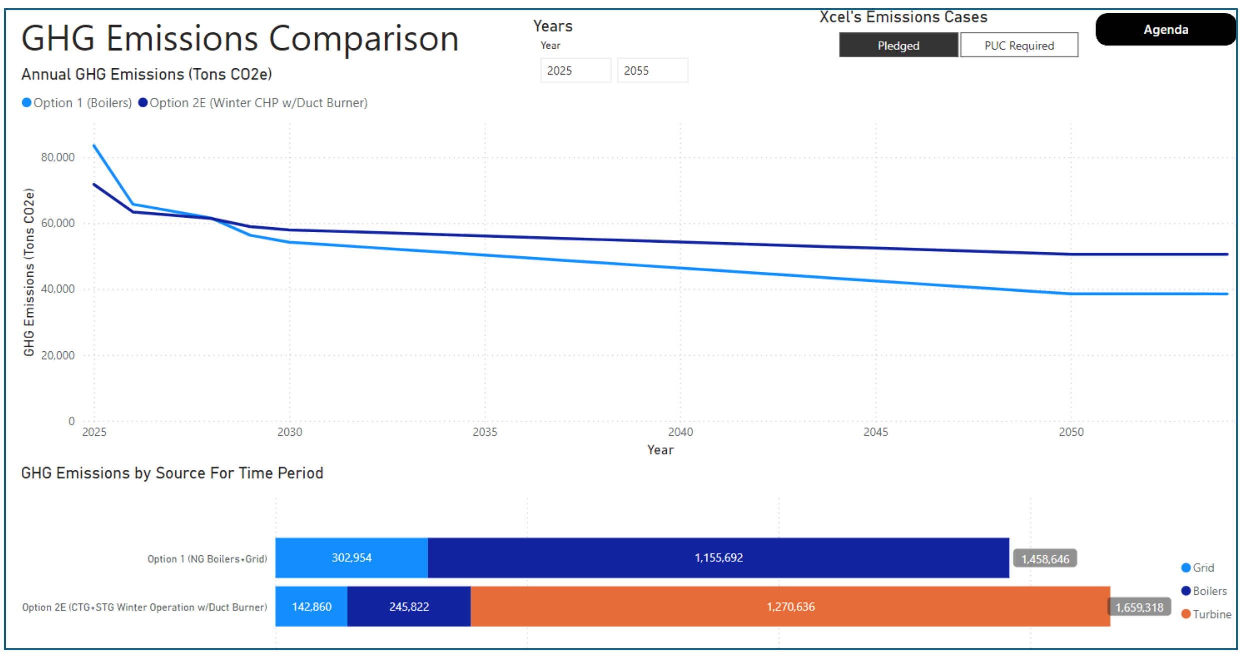


Figure 12: Decarb Pathway

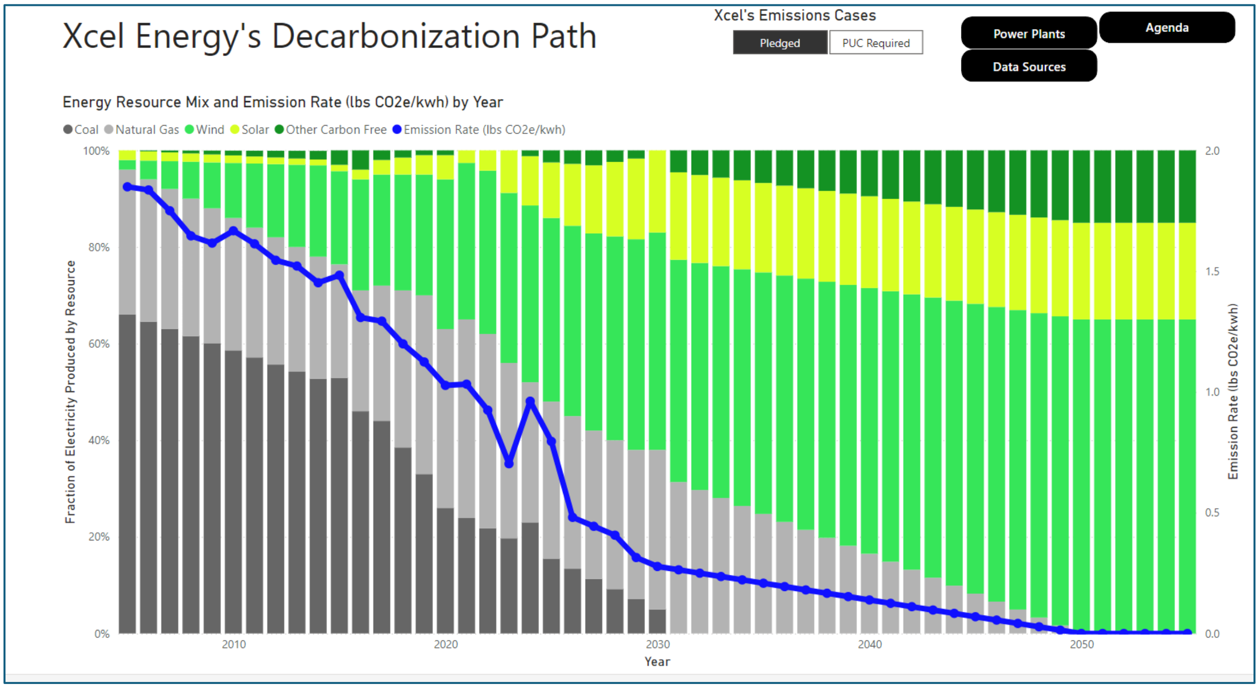
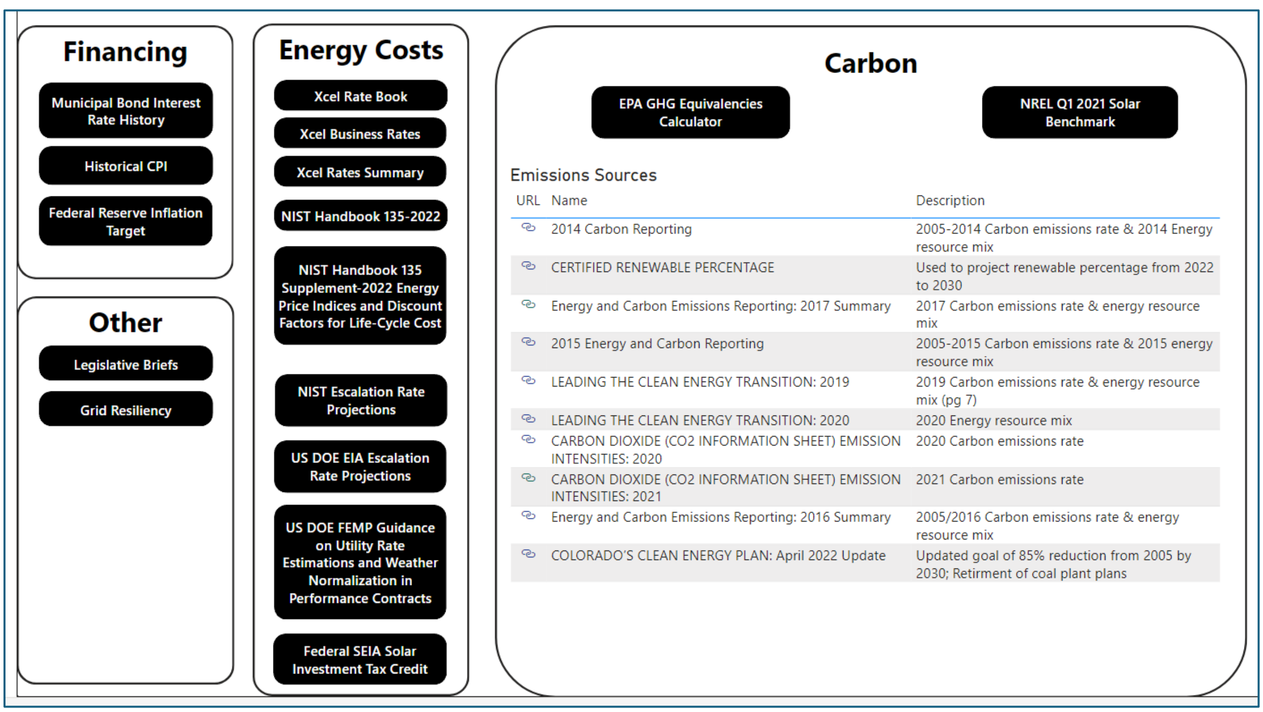


Figure 13: Some Data Sources from Dashboard

Consultant Dashboard, Slide 51



Appendix B

Attachments (linked in the body of the report)

1. wdep_shared_governance_committee_preliminary_recommendation_report.pdf
2. WDEP Memo to BFA Subcommittee.pdf
3. UCB_WDEP Emissions Compliance Program Plan.pdf
4. WDEP Committee Correspondence with Chancellor.pdf
5. cub-empappendices_2022-0214.pdf
6. original article.jpg
7. student letter (link pg8)
8. WDEP Nov.8 article. Correction.png
9. CU Boulder is Lagging Behind Colorado Peers in the Climate Transition (Google Form)
10. WDEP Shared Governance Committee Additional Questions.pdf
11. CDPHE Responses to Reg 7 Questions from 4_08_24 email.pdf
12. WDEP Compliance Project – Supplemental Information Document35.pdf
13. Colorado Sun article.html
14. Committee foreward of CDPHE confirmation to COO.msg
15. Next Steps. Mar. 12, 2024.pdf
16. CU Boulder. Climate Action Plan. 2024.pdf
17. Settlementagreementfullyexecuted9220200.pdf