University of California, Berkeley

Campus Energy Plan

Final Report

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Executive Summary

The University of California, Berkeley (UCB) receives steam and power from a cogeneration plant. Motivated by aging and inefficient equipment, leaking distribution, air quality issues, high carbon emissions, and insufficient capacity, UCB commissioned a study in 2015 to analyze options to improve or replace the cogeneration plant. This study builds upon the 2015 study by:

- Investigating all-electric systems for the 2025 carbon neutrality mandate
- Defining phasing to provide insight into cashflow and campus disruption
- Evaluating upgrades to electrical infrastructure required for each system
- Incorporating changes in technology cost and feasibility since 2015
- Accounting for addition of comfort cooling to existing campus buildings
- Considering the cost of financing

Options

Ten holistic and unique strategies that could improve or replace the cogeneration plant, termed "core options," were investigated. Where the core options triggered onerous electrical upgrades, "enhancement strategies" such as thermal storage and solar photovoltaic (PV) were added to reduce the amount of infrastructure upgrade required (Figure 1).

Electrical Infrastructure

Due to increased campus demand from new buildings and cooling systems, some level of electrical infrastructure upgrade was required for every option. Due to onerous electrical infrastructure upgrade requirements that could not be mitigated with enhancements, the electric boiler options (1b, 8a, 11b) were deemed unfeasible and were removed from consideration.

Siting and Phasing

For new central options (2, 8b, 11a, 11c), a new central utility plant is proposed to be located in the new construction of Evans Hall anticipated in 2030. For new nodal options (1a and 1c), new plants are proposed to be located in the following sites: Tolman, Evans, Edwards, and Piedmont Houses.

A 15-year transfer timeline was developed that balanced alignment with planned construction and renovation projects, risk, physical adjacencies, available surge space, and minimum capacity of the existing cogeneration plant.

Core Options							Enhancements				
#	Description	Heating Layout	Heating Distribution	Heating Generation	Cooling	Electricity	Thermal storage	Solar hot water	Battery storage	Carbon capture & storage	Solar PV
0	BAU – Upgrade existing central cogeneration plant, in-building cooling									✓	
1a	Nodal heat recovery chillers and gas boiler heating									✓	
1b	Nodal heat recovery chillers and electric boiler heating						✓	✓	✓		✓
1c	Nodal heat recovery chillers and heat pump heating						✓	✓	✓		✓
2	New central cogeneration plant, in-building cooling									✓	
8a	Central electric boiler heating, in-building cooling						✓	✓	✓		✓
8b	Central heat pump heating, in-building cooling						✓	✓	✓		✓
11a	Central heat recovery chillers and gas boiler heating									✓	
11b	Central heat recovery chillers and electric boiler heating						✓	✓	✓		✓
11c	Central heat recovery chillers and heat pump heating						✓	✓	✓		✓

LEGEND

Layout
- Central
- Nodal
- Building

Heat Distribution
- Steam
- Hot water

Heat Generation
- Cogeneration
- Gas boiler
- Electric boiler
- Heat pump

Electricity Source
- Cogeneration
- PG&E

Figure 1 Ten core options were considered to provide heating to the UCB campus (left). Each core option was considered with and without "enhancements" that improved performance (right).

Life Cycle Cost

Thirty-year life cycle costs were developed for each core option with and without enhancements as shown in Figure 2. Life cycle costs included:

- Capital cost for new buildings, mechanical equipment, electrical infrastructure upgrade, distribution piping, and in-building equipment related to campus systems (e.g. heat exchangers)
- Electricity, natural gas, water, and carbon emissions
- Operations and maintenance
- Equipment replacement

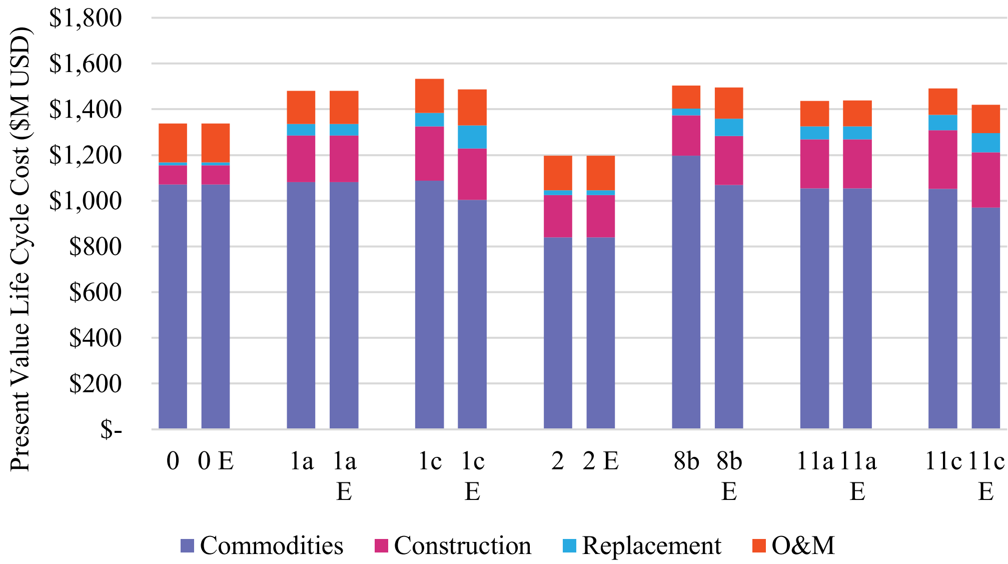

Figure 2 Life cycle cost for each core option with and without enhancements.

Financing

By financing the estimated capital costs either through tax exempt debt or through a project financing with taxable debt and equity, the University should expect to have an average annual nominal payment for the total cost of ownership that falls between $97.6M and $127.4M starting in 2030.

Recommendations

The recommended system from this study varies depending on UCB's priorities as shown in Figure 3.

Variable	Unit	Best Solution per Variable		Best Carbon Neutral Solution per Variable	
		Option	*Amount*	*Option*	*Amount*
Lowest capital cost	NPV first cost	Option 0 (upgrade existing cogeneration plant)*	$87M	Option 8b (central heat pumps with HHW distribution) with enhancements	$247M
Lowest life cycle cost	NPV 30-year life cycle cost	Option 2 (new cogeneration with HHW distribution)*	$1.2B	Option 11c (central heat recovery chillers and heat pump heating) with enhancements	$1.4B
Lowest annual commodities cost	NPV annual commodities cost after project completion	Option 2 (new cogeneration with HHW distribution)*	$77M	Option 11c (central heat recovery chillers and heat pump heating) with enhancements	$104M
Lowest carbon emissions	Annual CO_2-eq after project completion	All-electric options (1c, 8b, and 11c)	0 tons CO_2 per year	All-electric options (1c, 8b, and 11c)	0 tons CO_2 per year

* Options violates the UCOP carbon neutrality mandate.

Figure 3 Recommended system by UCB priority. Best solution is listed for each variable in leftmost column. The best solution of all options studied is shown in the column titled "Best Solution per Variable." The best solution of only the carbon neutral options (1c, 8b, 11c) is shown in the column titled "Best Carbon Neutral Solution per Variable."

Key Takeaways

Key takeaways from this study are:

- The accuracy range of the capital cost estimate of each option overlaps significantly so that no one option stands out as an obvious choice. The exception is option 0 (upgrade existing cogeneration plant), which has a lower capital cost because a new plant building and distribution piping are not required.
- The accuracy range of the life cycle cost estimate of each option overlaps significantly so that no one option stands out as an obvious choice. This indicates that an all-electric system is not prohibitively more cost intensive than a system with natural gas heating or continued operation of the existing

cogeneration plant. While there is still some overlap in accuracy range, Option 2 shows the lowest life cycle cost due to the low cost of natural gas compared to electricity.

- The difference between each option is leveled by the phasing schedule, which requires partial operation of both the existing cogeneration plant and the new system for the first 15 years of the 30-year study period. A shorter phasing schedule reduces the amount of time that UCB pays to operate two plants simultaneously and therefore reduces costs and commodities use considerably.
- Thermal storage is a key component of any electrified strategy to reduce peak loads. Thermal storage and solar PV can also be applied to all options to further reduce operating cost.

Next Steps

Based on these findings, we recommend the following items for further study:

- High-level life cycle cost analysis of "minimum viable options" that have some commodities and carbon reduction benefits and require fewer infrastructure upgrades:
  - Gas boilers and steam distribution
  - Gas boilers and hot water distribution
  - Electric heat pump and heat recovery chiller plants for biosciences and engineering, physics and chemistry nodes only
- Opportunities to condense construction and phasing schedule and reduce the amount of time that the old and new systems must be operated simultaneously.
- Detailed solar PV and battery storage optimization for electrical infrastructure and resilience.
- Detailed operational cost optimization for solar PV and thermal storage.
- Evaluation of delivery methods over the life cycle period such as design-build-operate-maintain (DBOM), design-build-finance-maintain (DBFM), design-build-finance-operate-maintain (DBFOM) as compared to a traditional approach to determine the best value solution (i.e. Value for Money). This will go beyond technical and total cost considerations to consider factors the University and/or Board of Visitors might want to see such as affordability, risk transfer over the asset life cycle, deal attractiveness to investors/philanthropists, market precedents for similar transactions.
- Detailed O&M study for the current central cogeneration plant to understand potential operational cost savings from implementing proposed options.
- Future technologies that may become more feasible, such as hydrogen-based fuel cells. While this study indicates that heat pumps are the most effective carbon-free technology today, other technologies may become viable before the project is built.

1 Introduction

The University of California, Berkeley (UCB) receives steam and power from a cogeneration plant. The plant requires substantial upgrade or replacement:

- Equipment is old and past its end of useful life
- Significant deferred maintenance must be addressed, including replacing major plant equipment and seismic upgrade to the plant building.
- The auxiliary boilers are not in compliance with air quality standards and can only be run 10% of the year.
- Inefficient equipment consumes natural resources. Newer equipment can operate more efficiently and substantially reduce operating costs.
- Steam distribution infrastructure is leaking, leading to 37% thermal losses.
- The system is unable to meet current campus needs. During peak conditions, excess electricity must be purchased from PG&E at a high rate. This issue will be exacerbated as the campus grows and comfort cooling is expanded.
- The system is responsible for 90% of the UCB's carbon emissions.

Motivated by these factors, UCB commissioned a study in 2015 to analyze different options to improve or replace the cogeneration plant to serve the campus's energy needs. That study recommended three systems for further analysis:

1. Nodal heat recovery
2. Centralized cogeneration
3. Centralized electric boilers

This study builds upon the 2015 energy delivery options study in several ways:

- Investigates all-electric systems to align with the 2025 carbon neutrality mandate issued by the University of California Office of the President (UCOP)
- Defines phasing for each system to provide insight into cash flow and campus disruption
- Evaluates electrical upgrades that will be required for each system
- Incorporates changes in technology cost and feasibility since 2015
- Accounts for addition of comfort cooling to existing campus buildings

This report summarizes the methodology and assumptions used for analysis and presents the results for each system. Results include:

- Mechanical and electrical equipment upgrades required
- Central utility plant siting and pipe routing
- Construction phasing
- Electricity, natural gas, and water usage
- Carbon emissions
- Capital and life cycle costs
- Financing options assessment

2 Methodology

2.1 Campus Energy Systems

The systems studied fell into two categories: holistic and unique strategies that could replace the cogeneration plant, termed "core options," as well as "enhancement" strategies that could be added to improve the performance of the various core options.

2.1.1 Core Options

The core options deemed for further study are shown in Figure 4. These core options were derived from the systems recommended for further study in the 2015 analysis, as well as low-carbon technologies like heat pumps that have since become more feasible. They also accounted for future expansion of comfort cooling to existing buildings throughout the campus.

Each core option consists of different combinations of a menu of systems that provide heating, cooling, and electricity.

- Heating- heat pumps, electric boilers, gas boilers, or cogeneration. Central or nodal configuration. Hot water or steam distribution.
- Cooling- electric chillers, heat recovery chillers, packaged units. Central, nodal, or distributed at the individual building level.
- Electricity- cogeneration or PG&E grid electricity. Central configuration.

These systems can follow three configurations:

- Central- one system serves the whole campus
- Nodal- campus is divided into 4 quadrants, each served by its own system
- Distributed- each building has its own system

2.1.2 Enhancements

The enhancements considered for further study are also shown in Figure 4. These enhancements were derived from the 2015 study, as well as low-carbon technologies like solar hot water and carbon capture and storage that may have since become more feasible.

Core Options							Enhancements				
#	*Description*	*Heating Layout*	*Heating Distribution*	*Heating Generation*	*Cooling*	*Electricity*	*Thermal storage*	*Solar hot water*	*Battery storage*	*Carbon capture & storage*	*Solar PV*
0	BAU – Upgrade existing central cogeneration plant, in-building cooling	Central	Steam	Cogeneration	Building	Cogeneration				✓	
1a	Nodal heat recovery chillers and gas boiler heating	Nodal	Hot water	Gas boiler	Nodal	PG&E				✓	
1b	Nodal heat recovery chillers and electric boiler heating	Nodal	Hot water	Electric boiler	Nodal	PG&E	✓	✓	✓		✓
1c	Nodal heat recovery chillers and heat pump heating	Nodal	Hot water	Heat pump	Nodal	PG&E	✓	✓	✓		✓
2	New central cogeneration plant, in-building cooling	Central	Hot water	Cogeneration	Building	Cogeneration				✓	
8a	Central electric boiler heating, in-building cooling	Central	Hot water	Electric boiler	Building	PG&E	✓	✓	✓		✓
8b	Central heat pump heating, in-building cooling	Central	Hot water	Heat pump	Building	PG&E	✓	✓	✓		✓
11a	Central heat recovery chillers and gas boiler heating	Central	Hot water	Gas boiler	Central	PG&E				✓	
11b	Central heat recovery chillers and electric boiler heating	Central	Hot water	Electric boiler	Central	PG&E	✓	✓	✓		✓
11c	Central heat recovery chillers and heat pump heating	Central	Hot water	Heat pump	Central	PG&E	✓	✓	✓		✓

LEGEND

Layout
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Heat Distribution
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Heat Generation
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- Gas boiler
- Electric boiler
- Heat pump

Electricity Source
- Cogeneration
- PG&E

Figure 4 Ten core options were considered to provide heating to the UCB campus (left). Each core option was considered with and without "enhancements" that improved performance (right).

Originally, carbon capture and sequestration was applied only to options that consumed natural gas and all other enhancements were applied only to the all-electric options. As analysis progressed, four items became clear:

- Carbon capture and sequestration systems are not currently available at the campus equipment scale
- Solar photovoltaic (PV) and solar hot water compete for roof space, and solar PV is a superior technology for this application in terms of first cost, usability, integration with wider campus systems, and impact on infrastructure resilience
- The all-electric core options exceed the maximum capacity of the sole substation that serves campus electricity (Hill Substation), triggering expensive and disruptive upgrades
- Thermal storage presents an excellent opportunity to reduce campus loads, reduce size of mechanical and electrical equipment, reduce electrical rate through peak demand shaving, and increase heat recovery potential

With this information in mind, the approach to enhancements was modified: thermal storage was applied to all electric options (1b, 1c, 8a, 8b, 11b, 11c), and solar PV was added to the options as needed to reduce the peak load below the maximum capacity of the Hill Substation (8a, 8b). While this method was applied for this study, it is important to note that thermal storage and/or up to 700,000 sqft of solar PV could be applied to any option, and costs vs. benefits should be studied in more detail as part of a deeper optimization analysis.

These core options, with and without enhancements, were carried forward for life cycle cost analysis.

2.2 Campus Loads

To estimate sizes for mechanical and electrical equipment and distribution infrastructure for the options studied, peak heating, cooling, and electrical demand was calculated for the campus. To calculate the annual electricity, natural gas, and water usage of each core option with and without enhancements, annual load projections were calculated for the campus.

For existing buildings connected to the cogeneration plant, peak and annual loads were sourced from the 2015 energy delivery options study. These loads were adjusted to account for addition of comfort cooling to all existing buildings. Annual loads were projected into the future assuming baseline energy conservation measures (ECMs) as defined in the 2015 study. Buildings planned for demolition were removed from the load projections in their estimated year of demolition.

For new buildings, UCB provided building area, building type, and estimated construction year. Annual and peak loads were derived for these new buildings by applying the appropriate area-normalized factors from the UCOP Whole-Building Energy Performance Targets.

Load assumptions are listed in Appendix A1.

2.3 Commodities

Electricity, natural gas, and water usage for each core option with and without enhancements was calculated using the equipment efficiency assumptions listed in Appendix A3.1.

Carbon emissions were calculated from electricity and natural gas use. Carbon emissions for natural gas were assumed to remain constant across the 30-year study period. Current carbon emissions for electricity were sourced from PG&E and projected into the future according to California's renewable portfolio standards. Emissions factors are listed in Appendix A3.2.

2.4 Siting and Phasing

Siting and phasing opportunities, constraints, and priorities were brainstormed during an interactive workshop with UCB staff from the planning, asset management, utilities engineering, and energy management departments. The Arup team used the workshop outputs as a starting point and factored in:

- Previously planned new construction and renovation projects that could be leveraged to reduce cost and disruption, such as seismic upgrades and chiller replacements
- Physical location and adjacency of buildings
- Minimum capacity at which the cogeneration plant can be operated during switchover from an old to a new system

The team's first siting and phasing plan spanned 25-30 years due to the constraint that surge space could accommodate only 10% of the campus at any given time. However, as buildings were transferred off of the existing cogeneration plant and onto the new system, the plant reached its minimum operating capacity threshold at year 15 (meaning all remaining buildings must be transferred in that year). The original siting and phasing plan was therefore compressed into a 15-year schedule.

More information on siting and phasing inputs can be found in Appendix D.

2.5 Electrical Infrastructure

This study also examined the upgrades that would be required to existing campus electrical infrastructure under each core option with and without enhancements.

First, the existing capacity of campus electrical infrastructure was determined as described in Appendix C2. Next, the load impact of each core options was assessed. To calculate electrical peak loads in the future scenarios, a 25% growth factor was applied to current campus non-heating and non-cooling electricity use and added to new mechanical load estimates for each option. Attention was given to capacities of electrical components directly impacted by proximity (e.g.

switching station nearest to a proposed node), as well as the ability of upstream components in the distribution system to support that load. See Appendix C2 for further illustration.

The key priorities identified through this study were to:

- Maintain redundancy in campus electrical distribution and capacity
- Prevent a major Hill Substation upgrade

To maintain resilience and redundancy and prevent a major upgrade to the Hill Substation, energy storage in the form of lithium-ion batteries was considered to shave peak demand for core options with load that exceeded campus infrastructure capacity.

See Appendix C for assumptions and calculations.

2.6 Cost Estimation

All net present value costs are presented in 2025 USD unless otherwise noted.

2.6.1 Capital Cost

Capital cost was estimated for each core option with and without enhancements based on equipment quantities and capacities produced by the electrical and mechanical analysis. Costs reflect the phasing schedules for each option, which give a 10-year construction period for Option 0 and a 15-year construction period for all other options. Capital costs are listed in US dollars and escalated to 2025 with an annual rate of 3%. A design-bid-build procurement method was assumed. Costs are a Class 5 estimate according to Arup's estimate classification matrix, which was developed using AACE International Estimate recommended practices and are accurate from -40% to +50%.

The capital cost estimate includes direct costs, indirect costs, soft costs, and contingencies. Further explanation of the assumptions, exclusions and methodology is listed in Appendix B1.

2.6.2 Life cycle Cost

Life cycle cost was also estimated for each core option with and without enhancements. In addition to the capital cost, life cycle cost also includes costs for equipment replacement, operations and maintenance, commodities (electricity, natural gas, and water), and carbon emissions over a 30-year period.

Major assumptions for the life cycle cost include:

- 30-year period starting in 2025
- Phased construction packages

- Phased commodities usage as buildings are transferred from the existing cogeneration plant to the new system
- Annual escalation for operations and maintenance, utilities, and replacement
- Annual discount rate of 5% for calculation of net present value

Further explanation of the assumptions, exclusions and methodology is listed in Appendix B2.

2.7 Financing

Financial analysis was performed for the following two options that are meant to represent simplified “bookends” of a range of possible financing costs and their commensurate risk profile:

- Option 2 (new cogeneration) - lowest life cycle cost of all options
- Option 11c with enhancements (central heat recovery chillers and heat pump heating with thermal storage) - lowest life cycle cost of all carbon neutral options

For each option, Arup estimated the financing costs under two scenarios for the up-front capital investment:

- Tax-exempt (“T-E”) alternative - assumes a financing strategy consistent with UCB’s traditional financing approach of using tax-exempt bonds, which represents the lowest cost of capital with minimal transfer risk.
- Private financing (“P.F.”) alternative - assumes a financing strategy that combines private equity and long-term taxable debt, which increases the cost of capital in return for transferring capital delivery and asset preservation risks.

These financing costs replaced the capital costs within the life cycle cost estimates to determine the potential range of “total cost of ownership” for UCB, expressed in nominal and net present value terms.

Financing assumptions are listed in Appendix E1.

3 Results

3.1 Siting and Phasing

The siting options developed below are representative rather than absolute. Using an alternative site that is also located along the major distribution path should not substantially impact cost analyses.

3.1.1 Plants and Piping

After factoring in planned construction and renovation projects, risk, adjacencies, available surge space, and minimum cogeneration capacity, a 15-year phasing schedule was derived for each core option. Three siting and phasing plans were developed:

1. Option 0 (upgrade existing cogeneration)
2. Options 1a and 1c (nodal heating with heat recovery chillers)
3. Options 2, 8b, 11a, and 11c (central systems replacing cogeneration)

Plant siting and pipe routing are shown in Figure 5 for new central options and in Figure 6 for new nodal options. Phasing and constructions schedules are shown in Figure 73, Figure 74, Figure 75, and Figure 76 in Appendix D1.

3.1.2 Solar PV

Since many buildings on the UCB campus are historic and feature terra cotta roof tiles, the potential to install solar PV on existing buildings is limited. Based on experience designing solar PV systems for other projects, the team assumed that solar PV could be installed on 70% of the roof area of newly constructed buildings, which equates to about 700,000 sqft in total.

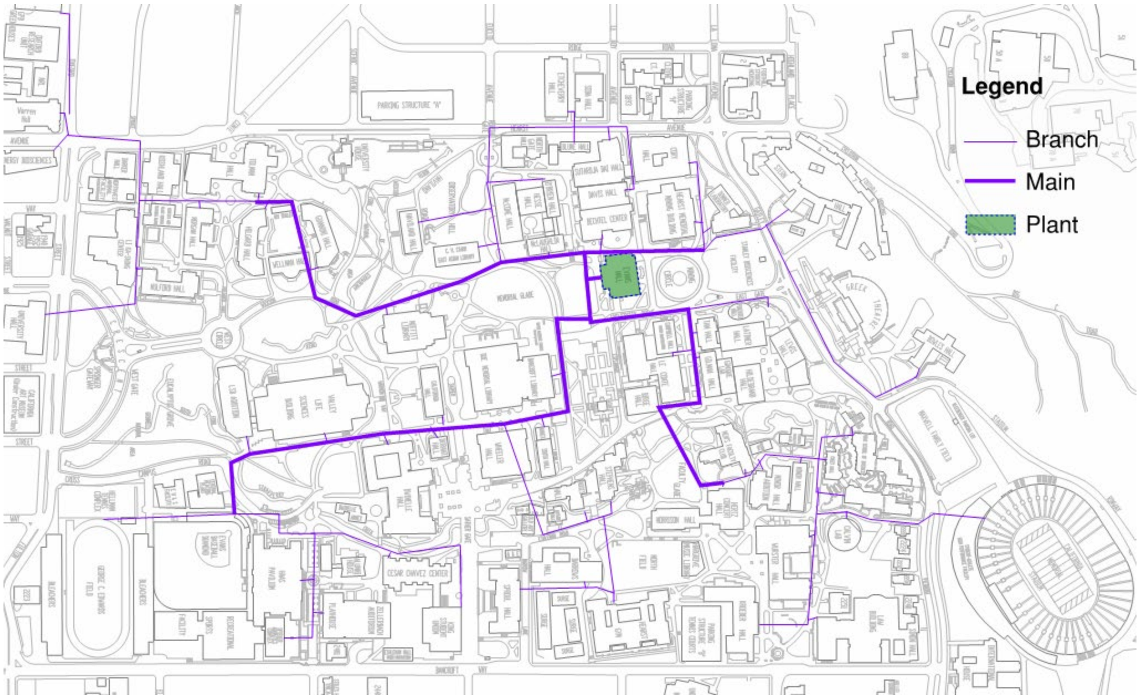


Figure 5 Plant sites and pipe routing for central options (2, 8b, 11a, 11c). Options 2 and 8b have heating hot water piping only; in addition, options 11a and 11c also have chilled water piping along the same layout.

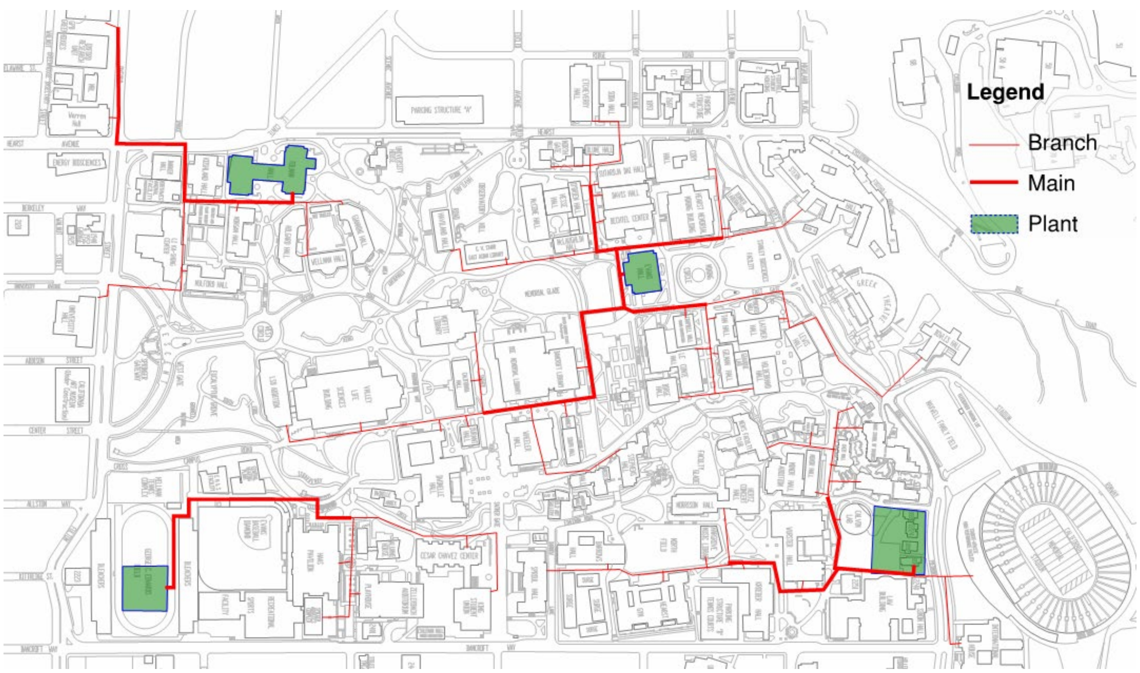


Figure 6 Plant sites and pipe routing for nodal options (1a, 1c). Pipe layout is the same for both heating hot water and chilled water piping.

3.1.3 Thermal Storage

Three options were identified for locating thermal storage tanks:

1. Next to plant
2. Underground
3. On hillside

There are benefits and drawbacks to each option, as shown in Figure 7. Locating tanks next to plant integrates well with the system but requires aesthetic mitigation and takes up valuable land in the center of campus. Locating tanks underground reduces aesthetic impact but is prohibitively expensive due to excavation and structural requirements. Locating tanks on the hillside has moderate aesthetic impact but introduces delay in response time to the system. For the central options, we recommend locating thermal storage tanks on the hillside (Figure 8); delay can be mitigated through controls, and intelligent site selection reduces aesthetic impact and high-value land take. For nodal options, we recommend locating the tanks adjacent to the plant (Figure 9) as they are smaller and interfere less aesthetically.

	Next to Plant	Underground	On hillside
Cost			
Delay			
Integration			
Aesthetics			
Land Value			

Figure 7 Thermal storage tanks can be located directly adjacent to the utility plant, underground, or on the hillside above campus. The low, moderate, and high impacts of each option are shown in red, amber, and green, respectively.

Figure 8 Thermal storage tank size and location for all-electric campus options (8b and 11c). Option 8b has a heating hot water tank only; in addition, option 11c also has a chilled water tank.

Figure 9 Thermal storage tank size and location for all-electric nodal options (1c).

3.2 Campus Energy Options

3.2.1 Equipment Sizes

Equipment sizes for each core option are summarized in Appendix A2.1. While Option 0 shows the lowest space take of all options, note that space will be required within a mechanical room or on the roof of every building for cooling equipment (chillers or packaged units).

Equipment sizes for each core option with enhancements are summarized in Appendix A1.1. Where the sizes are identical between the core options only and the core options with enhancements, no enhancements were applied.

While thermal storage and solar PV sizes may appear large, they are reasonable at a campus scale. The largest thermal storage tank proposed is 3.75M gallons; for comparison, Stanford SESI has two chilled water storage tanks that are 4.75M gallons each. Similarly, the largest solar PV array proposed takes up 70% of available roof space on buildings planned for new construction.

3.2.2 Commodities Usage

Annual commodities usage is shown in Figure 10. Carbon emissions are lowest for the all-electric options (1c, 8b, 11c) and highest for Option 0 (upgrade existing cogeneration plant).

Commodity	0	1a	1c	1c E	2	8b	8b E	11a	11c	11c E
Electricity (MWh/y x1000)	55	208	296	296	-	333	319	180	268	268
Natural gas (therms/y x1000)	20,949	7,125	-	-	12,386	-	-	7,125	-	-
Water (CCF/y x1000)	291	164	164	164	234	234	234	164	164	164
Carbon (tons CO_2-eq/y x1000)	141	48	-	-	83	-	-	48	-	-

Figure 10 Annual commodities (electricity, natural gas, water, and carbon) for each option with and without enhancement (denoted with "E") after construction is completed on the new system in 2045. Where core option only is shown, enhancements were not applied.

3.3 Electrical Infrastructure

Peak demand for each core option is summarized in Figure 11.

The natural gas options (0, 1a, 2, 11a) fall below the Hill Substation capacity of 3,000 amps and do not require enhancements. The heat pump options (1c, 8b, 11c) exceed the Hill Substation capacity but can be mitigated using enhancements (thermal storage, solar PV, and battery storage). Without enhancements, these options would require either addition of a third 115-kV from PG&E or a loss of redundancy.

The electric boiler options (1b, 8a, 11b)8 exceed the Hill Substation capacity and cannot be mitigated using enhancements. As such, they were removed from further consideration.

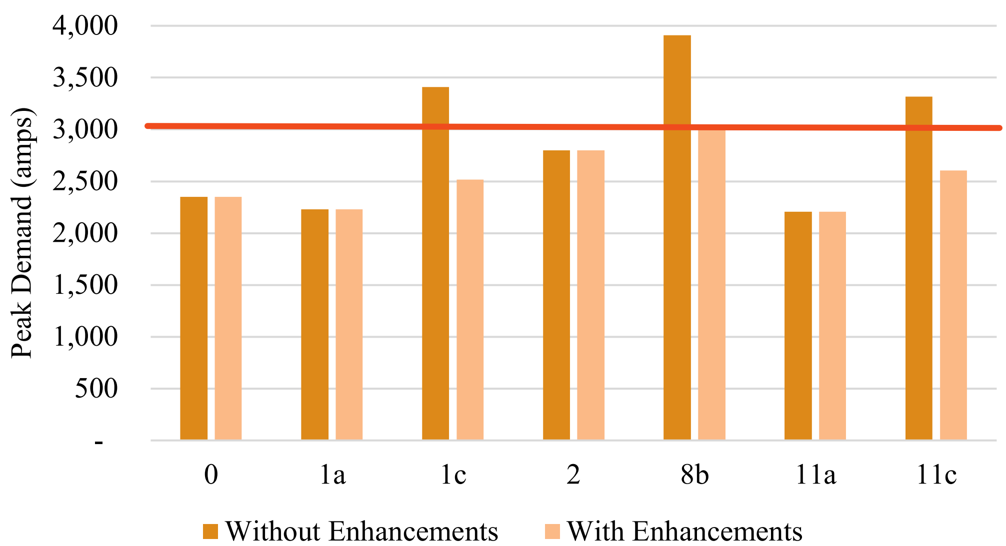


Figure 11 Peak electrical demand for each core option with and without enhancements.

Even for the business as usual case, Option 0, the peak load increases 158% based on projected growth in building area and cooling demand. To accommodate this growth, all options require some electrical upgrades. In all future options under consideration, higher electrical demands require upgrades to many segments along the electrical distribution system, and existing HV utility transformers to run at higher fan-assisted output ratings to maintain a similar operating arrangement to the existing system.

3.4 Cost Estimation

3.4.1 Capital Cost

Capital cost for each core option with and without enhancements is shown in Figure 12. Capital cost ranges from $87M to $306M across all options. Option 0 (upgrade existing cogeneration plant) has the lowest capital cost of all options at $87M. Option 8b (central heat pumps with HHW distribution) with enhancements has the lowest capital cost of the all-electric options (without upgrading the Hill Substation) at $247M. The accuracy range of the capital cost estimate of each option overlaps significantly so that no one option stands out as an obvious choice. The exception is option 0 (upgrade existing cogeneration plant), which has a lower capital cost because a new plant building and distribution piping are not required.

Direct cost breakdown is shown in Figure 13. Tabular capital costs are shown in Appendix B1.

3.4.2 Life Cycle Cost

Life cycle cost for each core option with and without enhancements is shown in Figure 14. Life cycle cost includes first cost, operations and maintenance costs, replacement costs, and commodity costs attributable to electricity use, gas use, water use, and carbon emissions. The difference in life cycle cost between Option 0 (BAU) and all other options is shown in Figure 15.

Life cycle cost ranges from $1.2B to $1.5B across the options. Option 2 (new cogeneration with HHW distribution) has the lowest life cycle cost of all options at $1.2B. Option 11c (central heat recovery chillers and heat pump heating) with enhancements has the lowest life cycle cost of the all-electric options at $1.4B.

The margin of error on the life cycle cost of each option overlaps significantly so that no one option stands out as an obvious choice. This indicates that an all-electric system is not prohibitively more cost intensive than a system with natural gas heating or continued operation of the existing cogeneration plant. While there is still some overlap in margin of error, Option 2 shows the lowest life cycle cost due to the low cost of natural gas compared to electricity.

Life cycle cost for all options is driven by commodities usage. Thirty-year commodities cost for each core option with and without enhancements is summarized in Figure 16. Life cycle commodities cost ranges from $840M to $1.2B across all options.

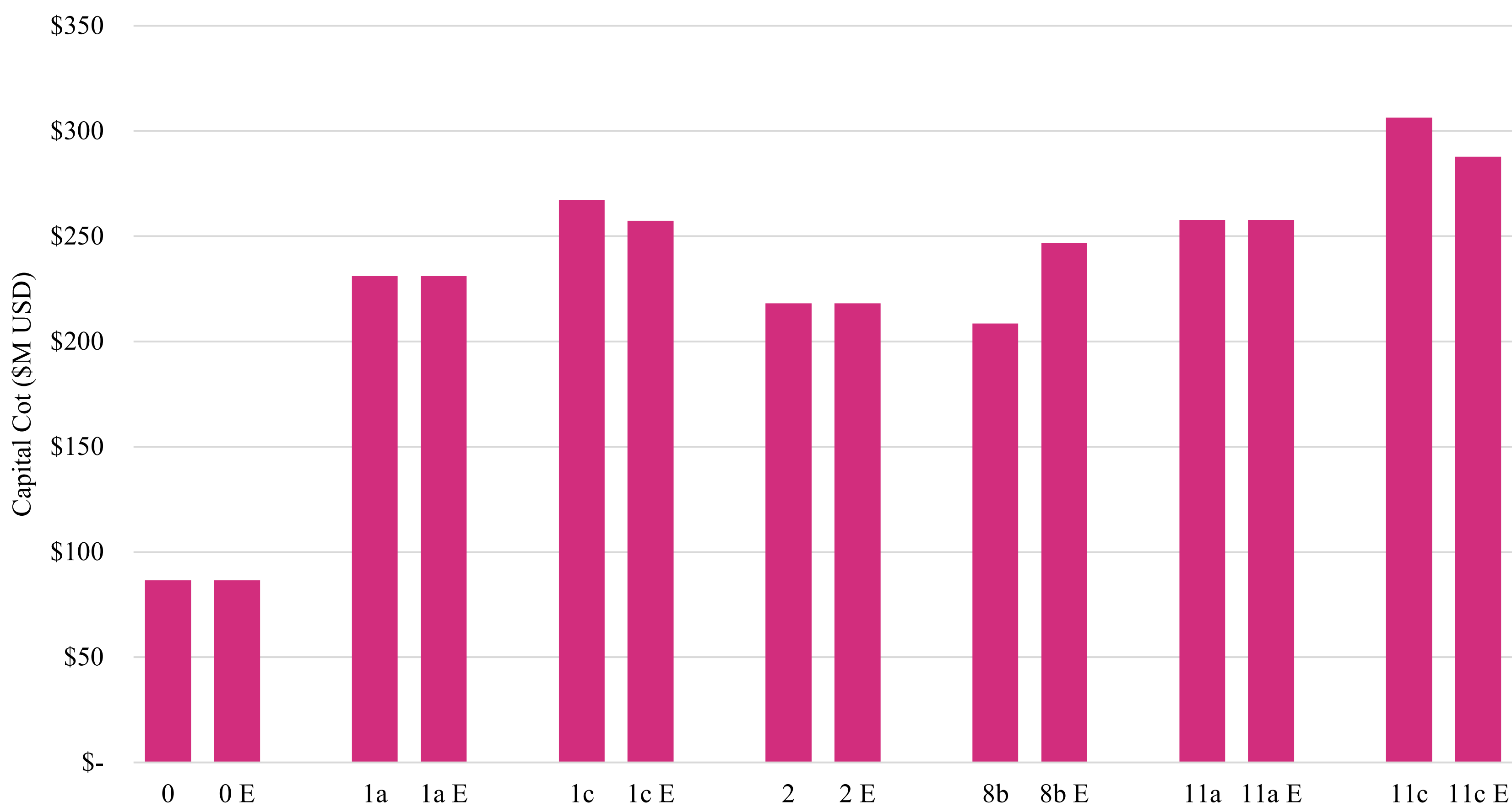


Figure 12 Capital cost for each core option with and without enhancements (noted with “E”). Note that all of the electric-only options without enhancements (1c, 8b, and 11c) would require either addition of a third 115-kV from PG&E (cost unknown) or a loss of redundancy.

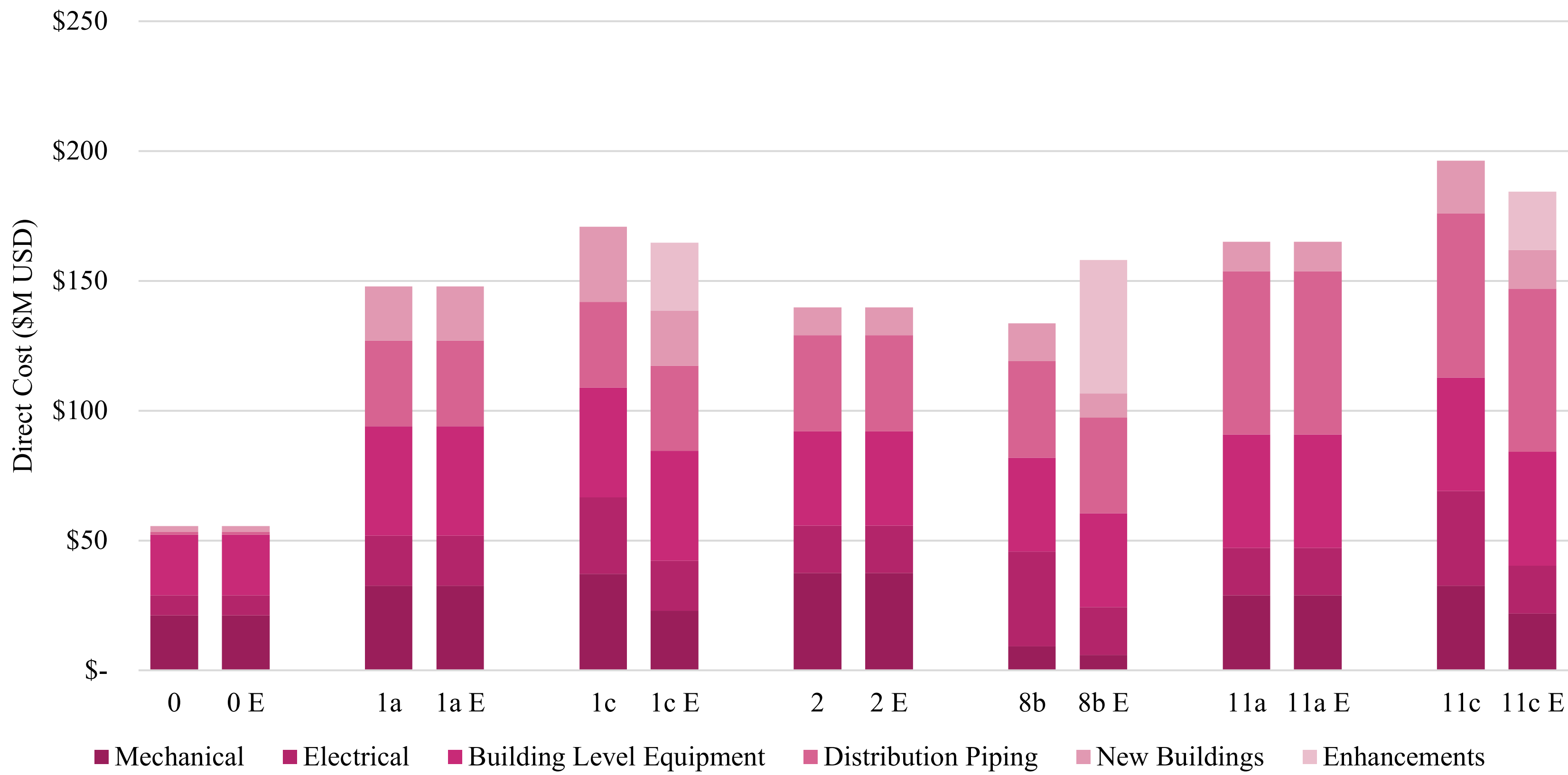


Figure 13 Direct cost breakdown for each core option with and without enhancements (noted with "E"). Note that all of the electric-only options without enhancements (1c, 8b, and 11c) would require either addition of a third 115-kV from PG&E (cost unknown) or a loss of redundancy.

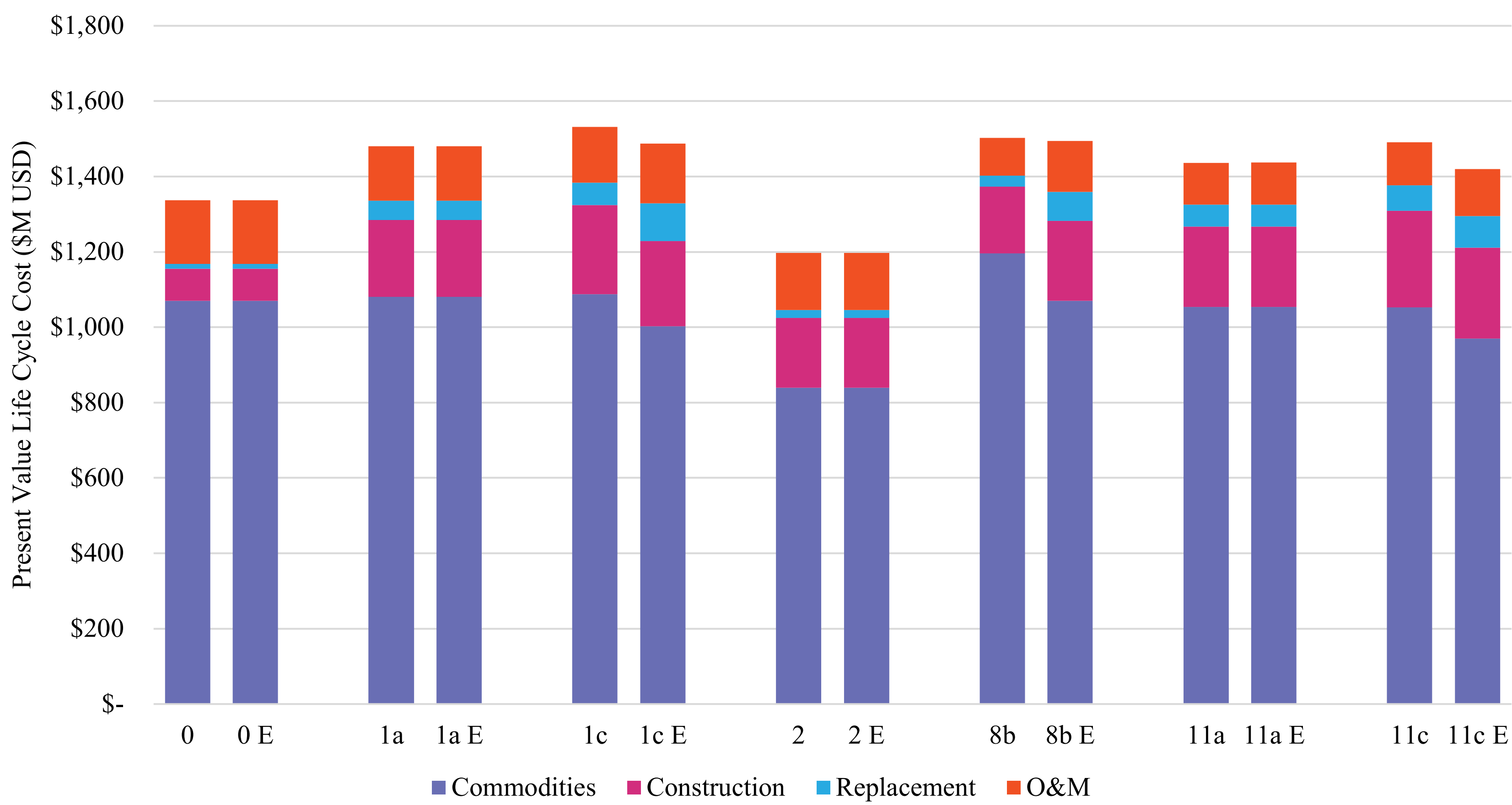


Figure 14 Life cycle cost for each core option with and without enhancements (noted with “E”). Note that all of the electric-only options without enhancements (1c, 8b, and 11c) would require either addition of a third 115-kV from PG&E (cost unknown) or a loss of redundancy.

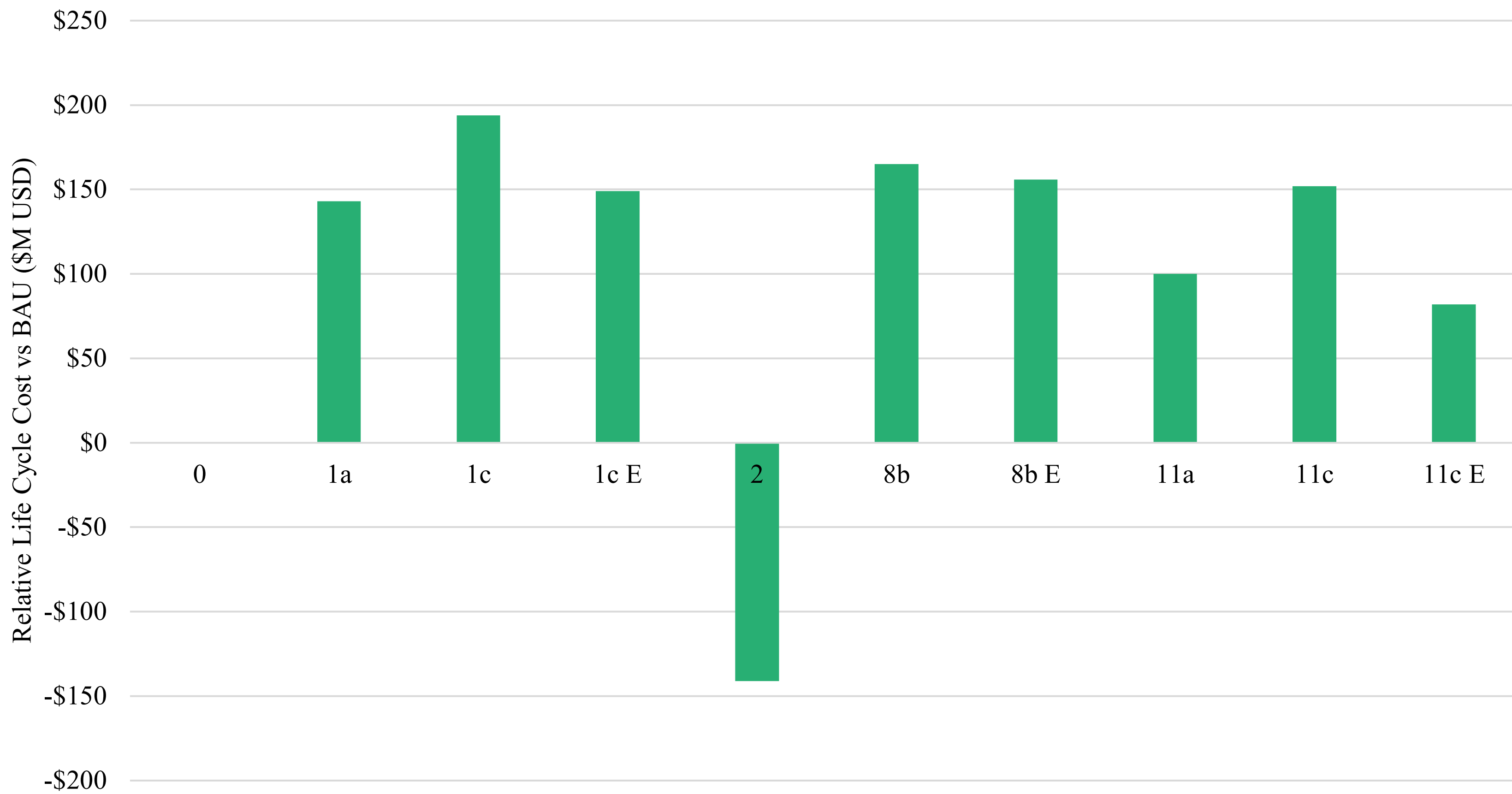


Figure 15 Difference in life cycle cost between each option and business-as-usual (Option 0). Negative values indicate life cycle cost savings vs. BAU. Enhancements noted with “E”.

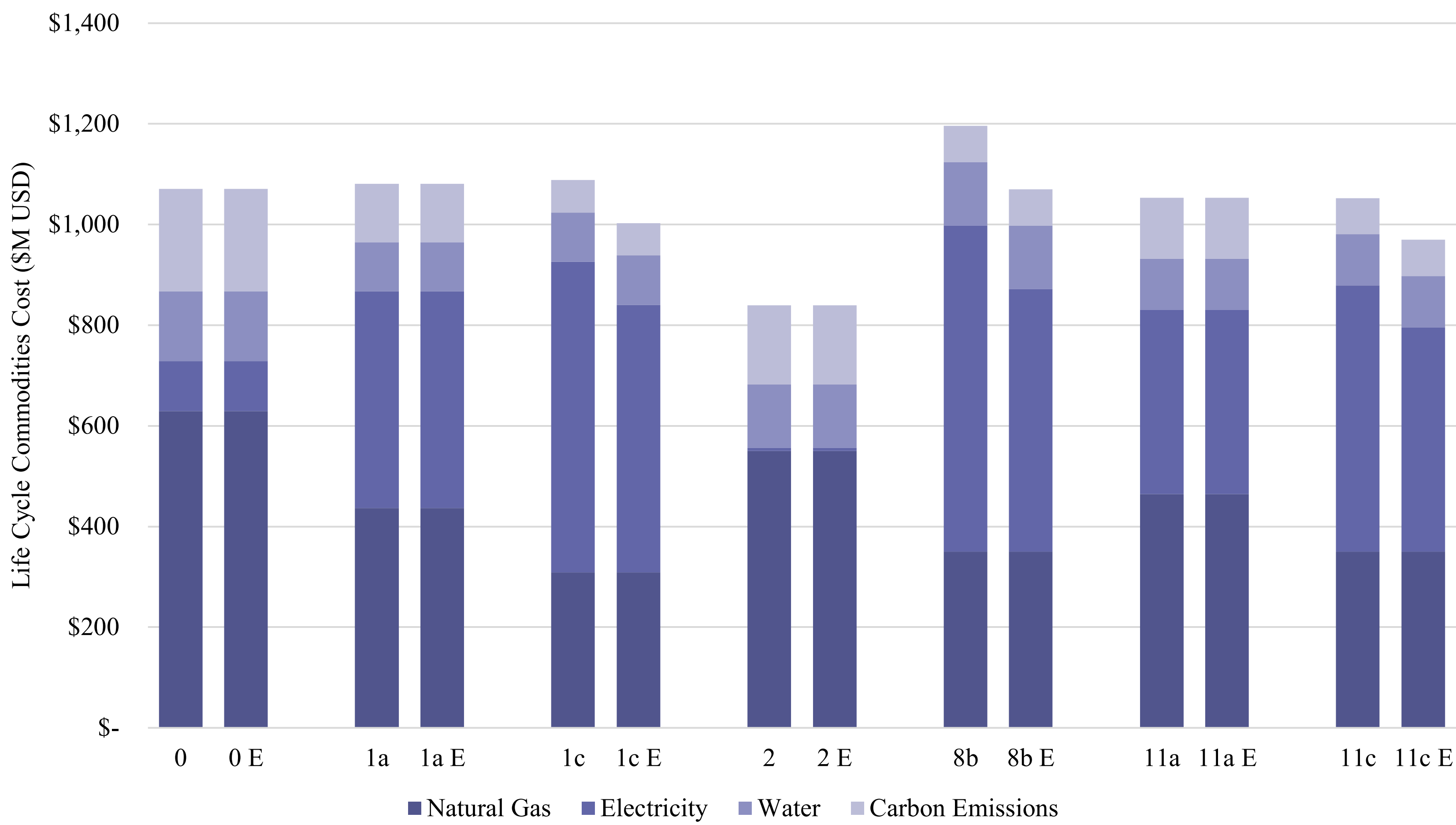


Figure 16 Life cycle commodities cost for each core option with and without enhancements (noted with "E").

3.4.3 Annual Cost Upon Project Completion

The difference between life cycle cost of each option is leveled by the phasing schedule, which gradually migrates loads from the old to new system over 15 years. As a result, both the existing cogeneration plant and the new plant must be operated (with corresponding efficiencies and costs) for the first half of the 30-year study period. A shorter phasing schedule would reduce the amount of time that UCB pays to operate two plants simultaneously and increase the difference in life cycle costs between options.

By looking at operating costs (commodities and O&M) after the new system is fully constructed in 2045, the difference between options becomes clearer (Figure 17). Once complete, Option 2 (new cogeneration with HHW distribution) has the lowest operating cost of all options at $98M/y (USD 2045). Option 11c (central heat recovery chillers and heat pump heating) with enhancements has the lowest operating cost of the carbon neutral options at $121M/y (USD 2045).

The difference in annual operating cost between Option 0 (BAU) and all other options is shown in Figure 18.

Cash flow for each option with and without enhancements is shown in Appendix B3.

Tabular life cycle costs are shown in Appendix B2.

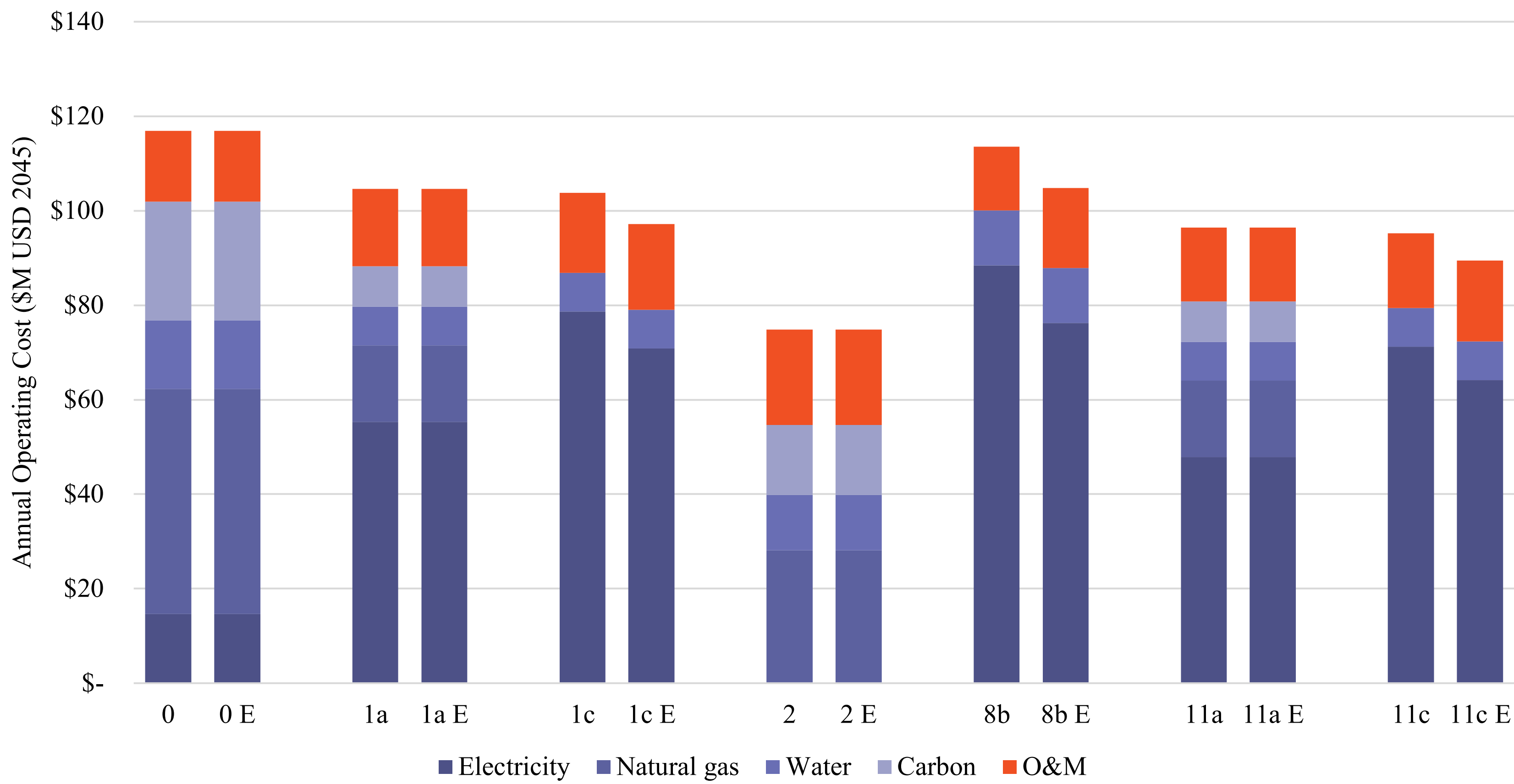


Figure 17 Annual operating cost (commodities and O&M) for each option with and without enhancements (noted with “E”) after the new system is fully operational in 2045 ($M USD, 2045).

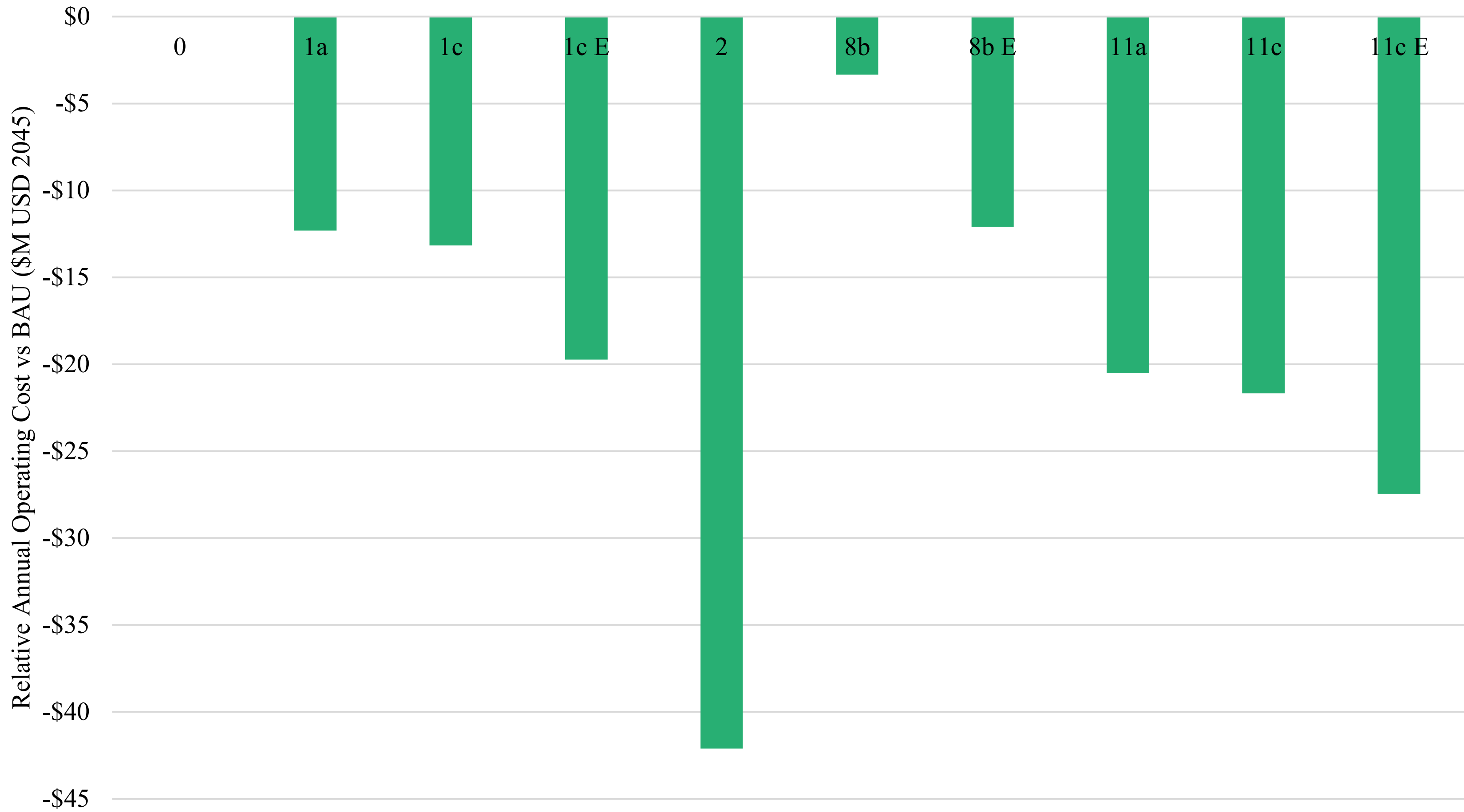


Figure 18 Difference in annual operating cost (commodities and O&M) between each option and business-as-usual (Option 0), after the new system is fully operational in 2045 ($M USD, 2045). Negative values indicate operational cost savings vs. BAU. Enhancements noted with "E".

3.5 Financing

3.5.1 Capital Cost

The range of financing costs are shown in Figure 19 below. Capital cost indicates how much it will cost to build the project, while the tax-exempt and private financing show how much it will cost the University to fund the capital project under public and private financing scenarios, respectively. The 18-20% premium paid for Project Financing over the Tax-exempt financing is entirely attributable to the assumed difference in interest rates.

Option	Capital Cost	Tax-exempt Financing	Private Financing	Financing Delta
Option 2	$185.2	$213.5	$252.9	$39.5
Option 11c E	$241.7	$278.0	$332.4	$54.4

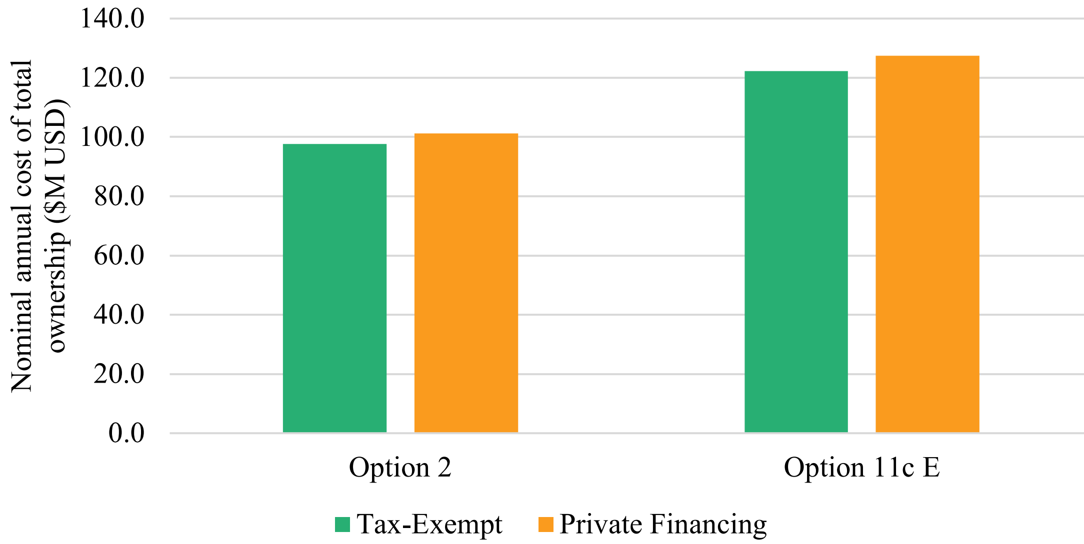
Figure 19 Total capital cost compared to total financing costs for each option on net present value basis. Values in million USD.

When the total cost of ownership is viewed as a range of average annual total cost of ownership, the possible impact on UCB budget and project affordability is more tangible. Figure 20 summarizes the potential average annual payments for the total cost of ownership in nominal dollars over the 25-year operation period, between 2030 and 2055. The University should expect and budget to have an average annual nominal payment for the total cost of ownership of the new system that falls between $97.6M and $127.4M starting in 2030.

Note that these averages include the operating costs of both the existing cogeneration plant and the new system over the 15-year construction period and are not indicative of the eventual annual total cost of ownership once the existing cogeneration plant is decommissioned.

Private financing yields a higher annual payment, ranging from $3.6-$5.2 million USD annual, over the tax-exempt ("T-E") alternative. However, the Private financing alternative should enable the transfer of engineering; procurement; financing; construction; and long-term operations, maintenance and replacement risks to a private developer. For a project this complex, the value added by transferring risk may outweigh the premium for private financing.

To examine this more closely, please see recommended next steps in Section 4.1.



Option	Tax-exempt	Private Financing	Delta
Option 2	$97.6	$101.2	$3.6
Option 11c E	$122.3	$127.4	$5.2

Figure 20 Potential average annual payments for the total cost of ownership in nominal dollars over the 25-year operation period, between 2030 and 2055. Values in million USD. Please note that these averages include the operating costs of two systems over the 15-year period construction period 2030 -2045 and are not indicative of the eventual annual total cost of ownership once the old system is decommissioned.

3.5.2 Operations, Maintenance, and Commodities

To provide an idea of annual O&M and commodities budget after project completion, Arup compared the O&M with commodities annual nominal costs after all loads have been transferred to the new system (years 2045-2055). Costs were compared for Option 0 (upgrade existing cogeneration plant), Option 2 (new central cogeneration plant, in-building cooling) and Option 11c (central heat recovery chillers and heat pump heating) with enhancements. As a reference point these three options were compared to a hypothetical "do nothing" scenario in which no upgrades are made to the current system, based on the current energy facilities budget (pink line in Figure 21). According to the data provided by UC Berkeley, the preliminary energy facilities operating budget, which accounts for O&M and commodities costs, for 2019-2020 is $30.8M; escalated at 3% per year to 2045, this equals $66.4M.

Note that the hypothetical "do nothing" scenario is not a viable option due to equipment condition and is provided for comparison only. It also excludes the cost of carbon and increased O&M and commodities for new cooling demand:

- Carbon is not a cost item in the current budget since the UCOP carbon neutrality mandate will be implemented starting in 2025
- Comfort cooling is not accounted for in the current budget because UCB does not currently allow for comfort cooling on campus. This policy will likely change soon to adapt to impacts of a warming climate.

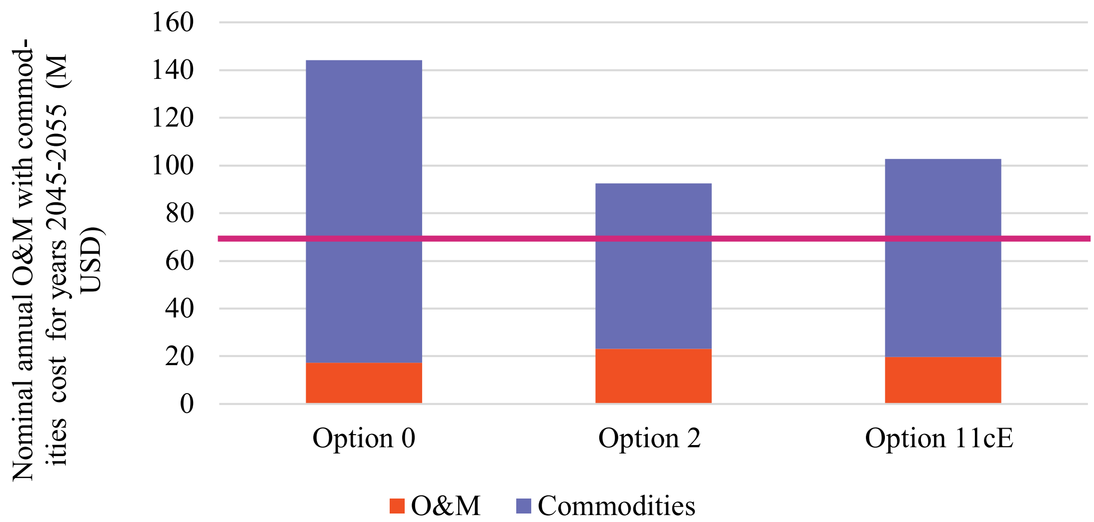


Figure 21 Nominal annual O&M with commodities cost annualized over the last 10 year of operations. Values in million USD.

4 Conclusions and Recommendations

The key performance aspects of each system, with and without enhancements, are summarized in Figure 22.

Variable	0	1a	1c	1c E	2	8b	8b E	11a	11c	11c E
Capital cost ($M USD)	$87	$231	$267	$257	$218	$209	$247	$258	$306	$288
Life cycle cost ($M USD)	$1,338	$1,481	$1,532	$1,487	$1,197	$1,503	$1,494	$1,438	$1,490	$1,420
Annual commodities cost ($M USD, 2045)	$142	$123	$124	$113	$78	$144	$127	$113	$113	$104
Annual O&M cost ($M USD, 2045)	$15	$16	$17	$18	$20	$13	$17	$16	$16	$17
Carbon (1,000 tons CO2-eq/y)	141	48	-	-	83	-	-	48	-	-

Figure 22 Summary of key performance aspects of each system with and without enhancements (denoted with “E”). Options where no enhancements were applied are listed as the core option only. Red, amber, and green indicate poor, moderate, and good performance in each category, respectively.

Based on this study, the recommended system varies depending on UCB's priorities as shown in Figure 23.

Variable	Unit	Best Solution per Variable		Best Carbon Neutral Solution per Variable	
		Option	*Amount*	*Option*	*Amount*
Lowest capital cost	NPV first cost	Option 0 (upgrade existing cogeneration plant)*	\$87M	Option 8b (central heat pumps with HHW distribution) with enhancements	\$247M
Lowest life cycle cost	NPV 30-year life cycle cost	Option 2 (new cogeneration with HHW distribution)*	\$1.2B	Option 11c (central heat recovery chillers and heat pump heating) with enhancements	\$1.4B
Lowest annual commodities cost	NPV annual commodities cost after project completion	Option 2 (new cogeneration with HHW distribution)*	\$77M	Option 11c (central heat recovery chillers and heat pump heating) with enhancements	\$104M
Lowest carbon emissions	Annual CO_2-eq after project completion	All-electric options (1c, 8b, and 11c)	0 tons CO_2 per year	All-electric options (1c, 8b, and 11c)	0 tons CO_2 per year

* Options violates the UCOP carbon neutrality mandate.

Figure 23 Recommended system by UCB priority. Best solution is listed for each variable in leftmost column. The best solution of all options studied is shown in the column titled "Best Solution per Variable." The best solution of only the carbon neutral options (1c, 8b, 11c) is shown in the column titled "Best Carbon Neutral Solution per Variable."

4.1 Key Takeaways

Key takeaways from this study are:

- The accuracy range of the capital cost estimate of each option overlaps significantly so that no one option stands out as an obvious choice. The exception is option 0 (upgrade existing cogeneration plant), which has a lower capital cost because a new plant building and distribution piping are not required.
- The accuracy range of the life cycle cost estimate of each option overlaps significantly so that no one option stands out as an obvious choice. This indicates that an all-electric system is not prohibitively more cost intensive than a system with natural gas heating or continued operation of the existing cogeneration plant. While there is still some overlap in accuracy range, Option

2 shows the lowest life cycle cost due to the low cost of natural gas compared to electricity.

- The difference between each option is leveled by the phasing schedule, which requires partial operation of both the existing cogeneration plant and the new system for the first 15 years of the 30-year study period. A shorter phasing schedule reduces the amount of time that UCB pays to operate two plants simultaneously and therefore reduces costs and commodities use considerably.
- Thermal storage is a key component of any electrified strategy to reduce peak loads. Thermal storage and solar PV can also be applied to all options to further reduce operating cost.

4.2 Next steps

Based on these findings, we recommend the following items for further study:

- High-level life cycle cost analysis of "minimum viable options" that have some commodities and carbon reduction benefits and require fewer infrastructure upgrades:
    - Gas boilers and steam distribution
    - Gas boilers and hot water distribution
    - Electric heat pump and heat recovery chiller plants for biosciences and engineering, physics and chemistry nodes only
- Investigation of opportunities to condense construction and phasing schedule and reduce the amount of time that the old and new systems must be operated simultaneously.
- Detailed solar PV and battery storage optimization for electrical infrastructure and resilience.
- Detailed operational cost optimization for solar PV and thermal storage.
- Evaluation of delivery methods over the life cycle period such as design-build-operate-maintain (DBOM), design-build-finance-maintain (DBFM), design-build-finance-operate-maintain (DBFOM) as compared to a traditional approach to determine the best value solution (i.e. Value for Money). This will go beyond technical and total cost considerations to consider factors the University and/or Board of Visitors might want to see such as affordability, risk transfer over the asset life cycle, deal attractiveness to investors/philanthropists, market precedents for similar transactions.
- Detailed O&M study for the current central cogeneration plant to understand potential operational cost savings from implementing proposed options.
- Future technologies that may become more feasible, such as hydrogen-based fuel cells. While this study indicates that heat pumps are the most effective carbon-free technology today, other technologies may become viable before the project is built.