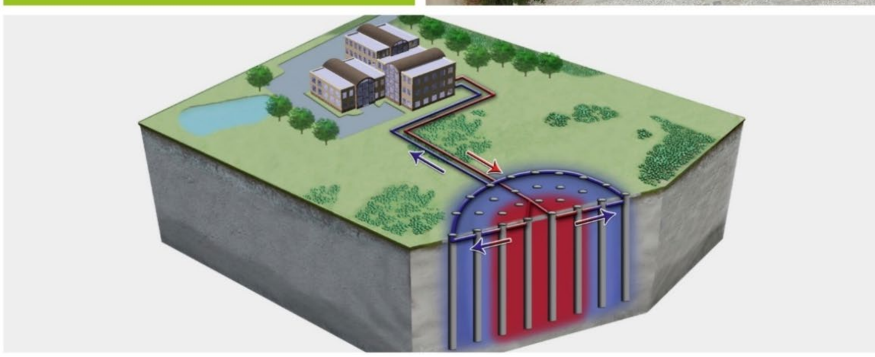
Applicability of Large Thermal Energy Storage for Public Communities Located in Different Climate Zones – Guidelines

June 2024

PIT THERMAL ENERGY STORAGE

TANK THERMAL ENERGY STORAGE



BOREHOLE THERMAL ENERGY STORAGE

THIS PAGE INTENTIONALLY LEFT BLANK

Applicability of Large Thermal Energy Storage for Public Communities Located in Different Climate Zones – Guidelines

Authors

Dr. Alexander Zhivov, U.S. Army Research & Development Center

Morten Vang Bobach & Rasmus Junker, Aalborg CSP

Contributors:

Dr. Michael Case, U.S. Army Research & Development Center

Jon Boergesen, Aalborg CSP

Anthony Latino & Matthew Talaber, SC-B Consulting Inc.

Gearoid Foley, Integrated CHP Systems Corp.

Richard Sweetser, EXERGY Partners Corp.

June 2024

THIS PAGE INTENTIONALLY LEFT BLANK

Executive Summary

Thermal energy storage (TES) is a critical tool in the overarching energy system architecture in that it allows the use of intermittingly generated energy, the energy available during certain periods (e.g., wind, solar), or energy waste streams from industrial processes, when needed for air-conditioning or process needs. TES can be designed to charge, store, and discharge energy daily, weekly, or seasonally. Examples of daily cycling of TES include hot water storage in the domestic hot water system and chilled water storage designed for load shifting to reduce the peak demand and the size of cooling equipment. Seasonal TES is typically used to store heat in the months with high solar radiation to be used for heating needs in the colder months. TES can be designed to be used in heating or cooling system configurations with a several-day or several-month capacity based on the user load profile. It can be charged using waste heat, e.g., generated by Combined Heat and Power (CHP), by cooling equipment, or by collecting heat from solar receivers. Interest in large-scale and long-term thermal energy storage is growing, with new plants being planned and built in Denmark and Germany; the number of countries interested in this technology is growing as indicated by a recently completed International Energy Agency (IEA) "Energy Storage Technology Collaboration Programme" Task 39 that brought together researchers and practitioners from Austria, Denmark, France, Germany, the Netherlands, Sweden, and the USA to analyze the use of Large Thermal Energy Storages for District Heating. Most of the large TES built to date have been considered pilot or demonstration projects and have been subsidized as such. The analysis presented in the current report has been performed in IEA Task 39 ~~is~~ to determine under which circumstances large-scale TES improves energy supply systems' resilience, reduces CO_2 emissions and is cost effective in different climates and at different energy prices and economic incentives. This analysis was conducted by an international team of researchers and practitioners led by the U.S. Army Engineer Research and Development Center, Construction Engineering Research Laboratory (ERDC-CERL) and was sponsored by the office of the Deputy Assistant Secretary of the Army for Energy and Sustainability.

Chapter 1 introduces this project. Chapter 2, "Thermal Energy Storage," discusses general TES applications and specific case studies. This chapter presents the construction, storage medium characteristics, working principles, and real-world applications of TES. Specific types of TES included in the analysis are Tank Thermal Energy Storage (TTES), Pit Thermal Energy Storage (PTES), and Borehole Thermal Energy Storage (BTES). Aquifer Thermal Energy Storage (ATES) requires very specific geological conditions. The allowable temperatures in ATES are typically very limited compared to other TES types. Due to these limitations ATES is not included in this report.

Chapter 3, "Methodology," delineates the parameters, system architectures, and demand profiles used for the simulations. The demand profiles are based on a representative U.S. Army Brigade Combat Team (BCT) complex of buildings, which include a variety of buildings with different uses. The demand profiles for these buildings have been generated using Energy Plus modeling for representative U.S. public/military locations in the 18 U.S. Department of Energy (DoE) climate zones (section 3.3). Section 3.3 also includes the TMY3 weather data that form the basis for the temperatures, solar radiation, wind speed, humidity, and precipitation ranges used in this analysis. Section 3.4 outlines the system architectures of the simulated alternative energy systems. Although these architectures are divided into cold/moderate climate zones and hot climate zones, they share the same baseline system architectures that form the basis for the criteria used to compare the results. The baseline system architecture is comprised of a boiler to satisfy demand for heating and domestic hot water needs, an electric chiller to satisfy cooling demand, and sourcing electricity from the public grid to satisfy overall electricity demand, encompassing the usage of the electric chiller. The seven cold/moderate climate system architecture scenarios include the ones used to demonstrate the advantage of TES use in combination with different

sizes and architectures of systems with Combined Heat and Power (CHP) plants and a Solar Water Heating field. In these scenarios, CHP plants generate all or a fraction of electrical and heat loads with the grid and a boiler providing the remaining fractions of loads, when necessary, in each cold/moderate climate zone. While the hot climate system architecture is similar to the one used for cold/moderate climates, it differs with the addition of absorption chiller(s) for cooling energy production and TES for storing cooling energy. The simulations for the hot climate zones are also structured differently in that they include eight simulation scenarios in which elements of the system architecture were gradually added and replaced.

Chapter 4, "Input Data and Boundary Conditions," details the parameters and data used in the simulation framework. This section encompasses various elements such as energy prices, heating values, emission rates for imported electricity, equipment maintenance costs, equipment efficiencies, and Capital Expenses (CAPEX) associated with equipment and TES capacities (Foley 2022). Additionally, it provides graphical representations of CAPEX for different TES technologies across varying capacities. These insights are derived from thorough research and informed industry expertise contributed by the involved stakeholders, with proper references cited for each category. The energy prices are divided into three categories for both the import of electricity and purchase of natural gas, except for Fairbanks, which was assigned a fourth category "extra high (Alaska) prices" denoted to accommodate the higher energy prices in Fairbanks given to the less integrated gas infrastructure and higher electricity transmission costs. The emission rates for the imported electricity were similarly divided into three categories that denote the potential emissions levels associated with the imported electricity (MWh). Due to the legal complexity of exporting electricity, the simulations do not include the export of electricity. The feasibility of the CAPEX and operational expenses (OPEX) associated with the alternative energy systems rely solely on the savings that these system solutions yield. Different coefficients of performance (COPs) were used for electric chillers and absorption chillers because different cooling technologies are used in the system architectures for the cold/moderate and the hot climate zones.

Chapter 5, "Results," presents and explains the results of the simulation performed for different climate zones, starting with the results for the coldest climate zone (c.z.) 8 (Fairbanks) and proceeding to the hottest climate zone 0A (Guam) along with general recommendations regarding the practical implementation of TES technologies.

In cold to moderate climate zones, simulation results consistently demonstrate that TES used in combination with CHP results in the lowest total energy costs, indicating significant total cost savings. This application proves to be most beneficial in scenarios with high winter heat demand and lower heat demand in summer. Without TES, CHP systems often cease electricity production during summer months once heat demand is met, leading to reliance on imported electricity to meet remaining demands. However, with TES integration, excess heat produced by CHP during summer can be stored for later use in winter when CHP alone may not suffice, increasing resilience and reducing reliance on supplementary heating sources like boilers. Consequently, this leads to decreased natural gas consumption, enhanced energy efficiency, and overall larger savings. This effect is particularly pronounced in Minneapolis (c.z. 6A) and Chicago (c.z. 5A), where integrating TES enables the same CHP capacities to effectively double both electricity and heat production. In contrast, in climate zones with high winter heat demand but moderate summer demand, such as Duluth (c.z. 7), Helena (c.z. 6B), Vancouver (c.z. 5C), Denver (c.z. 5B), Seattle (c.z. 4C), Albuquerque (c.z. 4B), and Baltimore (c.z. 4A), the impact of TES is less pronounced. In these climate conditions, TES increases heat production from the same CHP capacity by only a third, indicating that surplus heat production is more effectively used in summer months. Conversely, in regions like San Francisco (c.z. 3C), where heat demand remains consistent year-round, TES has minimal impact on heat production.

Across all cold/moderate climate zones, the integration of TES along with CHP, and a solar water heating (SWH) plant consistently results in the lowest overall emissions at every emission rate with a grid power generation. Despite the varying emission rates, these zones generally maintain a reduction in total energy costs. Notably, heat generated from the SWH plant is prioritized over that from the CHP due to its emissions-free nature. As the size of the SWH field and TES capacity gradually increases in the scenarios, the load generated by CHP and boiler decreases, leading to reduced local emissions but a higher reliance on imported electricity. For scenarios with low emission rates, overall emissions steadily decline as the SWH field and TES used to meet a larger portion of the heating demand, eventually fulfilling the entire demand in the final scenario. However, as the electricity demand must increasingly be met with imported electricity, medium and high emission rate scenarios experience an uptick in overall emissions. This trend indicates that scenarios where the entire heat demand is satisfied by a SWH plant and TES result in higher overall emissions at higher emission rates. Consequently, scenarios with the lowest overall emissions at every emission rate feature a combination of CHP, TES, and a SWH plant. The solar field supplements heat production sufficiently to eliminate the need for the boiler but does not render the CHP redundant, thereby minimizing reliance on imported electricity.

TES plays a crucial role in enhancing the resilience of solar energy systems by enabling the storage of excess heat generated from solar fields during periods of ample sunlight. This stored heat can then be used during periods of low or no sunlight, ensuring continuous heat supply even when solar energy production is limited. Essentially, TES acts as a buffer, allowing the surplus heat captured on sunny days to be efficiently stored and later deployed to meet heating demands when sunlight is not available. This capability enhances the reliability and resilience of solar energy systems, contributing to their overall effectiveness and viability as sustainable energy solutions.

Hot climate zones are characterized by low heat demand, even during the winter months, and significant cooling needs in the summer. Given that solar radiation peaks during the summer when heat demand is minimal, it is more beneficial to use solar energy for cooling purposes, typically through absorption chillers (ABS). In these regions, most simulated scenarios incorporating CHP, ABS, and TES demonstrate the lowest total energy costs. However, unlike in moderate climate zones, the implementation of TES in hot climates has a lesser impact on heat production from the CHP. Instead, it often results in a modest increase in heat production from the same capacity CHP, typically by about a tenth.

In hot climate zones like Las Vegas (c.z. 3B), Atlanta (c.z. 3A), and Phoenix (c.z. 2B), the simulation results consistently trend towards gradually expanding the SWH fields and increasing the capacity of absorption chillers. This approach serves to bolster cooling capabilities while reducing reliance on electric chillers and their associated electricity consumption. Notably, scenarios featuring CHP, ABS and TES lead to a significant reduction in overall emissions, particularly at higher emission rates. This reduction is attributed to decreased usage of electric chillers and boilers, with the CHP fulfilling a larger portion of the electricity demand. As SWH field sizes, TES and absorption chiller capacities are incrementally increased, emissions continue to diminish. This decline is facilitated by the use of solar heat in absorption chillers to meet cooling demands, enabling the CHP to meet electricity needs and resulting in the lowest overall emissions.

In Miami (c.z. 1A) and Guam (c.z. 0A), where heating demands are minimal but cooling demands are substantial year-round, the introduction of CHP and TES initially leads to an increase in emissions at low emission rates. This uptick is primarily due to heightened fuel consumption, resulting in emissions surpassing those of the baseline scenario, where only a boiler, an electric chiller, and imported electricity are used. However, at higher emission rates, the electricity generated by the CHP replaces imported electricity, resulting in lower emissions compared to the baseline. The most effective emission reduction strategies in these climates involve the integration of CHP, ABS, TES, and SWH fields. In these scenarios, overall emissions are minimized as electricity import is minimized, electric chillers are underused, and TES effectively stores surplus heat generated by the solar field.

The simulation results underscore the pivotal role of CHP and TES in optimizing energy systems across diverse climate zones. In moderate climates with pronounced seasonal variations, TES emerges as a game-changer, allowing surplus heat to be stored during periods of low demand and then used during peak demand seasons. This dynamic helps alleviate strain on heat-producing systems, leading to significant economic benefits by reducing the need for additional natural gas purchases and imported electricity.

Additionally, scenarios incorporating CHP, TES, and SWH plants consistently exhibit the lowest overall emissions across different emission rates. This strategic combination minimizes reliance on external electricity sources, leverages solar energy to meet heating and cooling needs, and enhances system resilience by enabling the storage of excess energy for future use. By harnessing the synergy between CHP and TES alongside renewable energy sources like solar heating, these scenarios not only optimize energy use but also contribute to environmental sustainability by mitigating emissions. However, the drawback of implementing these technologies is often an increased total energy cost due to higher CAPEX and maintenance costs, which consequently leads to longer payback periods.

The analysis also investigates how variations in energy prices, and the availability of tax credits influence the economic viability of different scenarios, providing comprehensive insights into the interplay between financial incentives and energy economics across diverse climate zones.

In Chapter 6, “Discussion,” the analysis delves into several critical aspects of energy system viability and resilience. It underscores the importance of assessing the payback savings generated by alternative energy systems, emphasizing that large equipment investments must yield subsequent savings or income to be feasible over the equipment's lifetime. The study's focus on savings-driven economics, omitting energy export considerations, highlights the significance of energy prices in shaping investment incentives. Particularly, lower energy prices diminish the economic appeal of alternative energy sources, impacting the feasibility of TES implementation. Additionally, the chapter sheds light on the surprising disparity between greenhouse gas emissions associated with imported electricity and those locally produced by CHP. Despite the perceived intricacies of modern power plants, CHP systems typically emit fewer greenhouse gases per unit of energy compared to electricity imported through the grid.

A key aspect explored in the discussion is the role of TES in enhancing system resilience by decoupling energy generation and consumption. TES systems facilitate flexible energy supply by storing excess thermal energy during off-peak periods or when renewable generation exceeds demand, ensuring continuous energy availability during fluctuating demand or renewable source intermittency. Furthermore, the discussion addresses the technical nuances of TES systems, including optimal temperature settings and efficiency considerations. Comparisons with Danish PTES systems highlight the potential for higher overall efficiency and reduced total energy costs by adopting alternative temperature settings. In hot climate zones like Guam, the inefficiency of using solar fields for cooling prompts exploration of alternative solutions, such as leveraging photovoltaics to assist CHP systems in supplying electricity to electric chillers. This approach offers a less complex and potentially more cost-effective means of meeting cooling demand. Moreover, the section explores the potential of BTES in scenarios requiring extensive TES. BTES is noted for its space efficiency, making it a viable solution where space constraints exist. The discussion underscores the advantages of BTES in energy efficiency for seasonal heating and cooling, its extended operational life of 100 years, and minimal maintenance requirements, which enhance overall system economy compared to PTES. However, successful BTES implementation is contingent upon favorable geological conditions, necessitating meticulous planning to overcome terrain and drilling supply challenges. Effective management of drill-related factors, such as noise mitigation and rigorous quality control, is deemed essential for successful vertical borehole construction.

Chapter 7, “Conclusion,” outlines the methodological process which generated the results, together with the key findings from every simulated climate zone. Key findings from each simulated climate zone are distilled into actionable recommendations, delineating optimal technology combinations and capacities that either drive favorable economics or achieve significant emission reductions. Furthermore, the technology recommendations regarding TES, given the simulated capacities, are summarized together with geological and hydrological considerations in relation to potential BTES use.

A pivotal component at the end of the conclusion is the presentation of a summarizing table that encapsulates technology combinations used in the analysis that either excel in economic performance or emission reduction outcomes. This visual aid summarizes the findings in more easily digestible insights that help stakeholders to make better informed decisions involved in energy system planning and implementation.

Table of Contents

Acknowledgments

The "Analysis of Large Thermal Energy Storage Application for Public/Military Communities Located in Different Climate Zones" development was funded by the Office of the Deputy Assistant Secretary of the Army for Energy and Sustainability. The authors express their appreciation to the many international contributors and organizations whose volunteer efforts made the development of this practical guide possible.

Special gratitude is owed to ASHRAE and its Technical Committees TC 6.2 "District Heating" and TC 6.9 "Thermal Storage," and the International Energy Agency "Energy Storage Technology Collaboration Programme" (ES TCP) Task 39 "Large Thermal Energy Storages for District Heating" (Task Manager Wim van Helden, AEE - Institute for Sustainable Technologies Austria) for providing a platform for discussion of the project's progress and for the review of the document by its members.

The authors would like to personally thank Paul Volkman, Office of the Deputy Assistant Secretary of the Army for Energy and Sustainability for providing direction, guidance, and support to the project and review of this document.

Sincere gratitude is given to Mark A. Worthington for his valuable contribution, providing critical information and parameters regarding Borehole Thermal Energy Storages.

Special appreciation is owed to the following reviewers, who provided their valuable comments and suggested improvements.

Geoffroy Gauthier, PlanEnergi
Daniel R. Pyewell, Tanco Engineering, Inc.
Pierre Delmas, newHeat
Maria Moser, SOLID
Abdulrahman Dahash, AIT
Adib Kalantar, Muovitech
Hendrik Wetzel, PlanEnergi

The authors gratefully acknowledge William J. Wolfe, Writer-Editor, SC-B Consulting, Inc., for his help in the preparation of this document.

Abbreviation List

Abbreviations	Full Term
ABS	Absorption Chiller
BCT	Brigade Combat Team
CAPEX	Capital Expenses
CHP	Combined Heat and Power
COP	Coefficient Of Performance
CZ	Climate Zone
DoE	Department of Energy
GHG	Greenhouse Gas
GWHP	Ground Water Heat Pump
HTF	Heat Transfer Fluid
HVAC	Heating, Ventilation, and Air-Conditioning
OPEX	Operational Expenses
TSP	Thermal Solar Plant
TES	Thermal Energy Storage
SWH	Solar Water Heating
ATES	Aquifer Thermal Energy Storage
BTES	Borehole Thermal Energy Storage
PTES	Pit Thermal Energy Storage
TTES	Tank Thermal Energy Storage

THIS PAGE INTENTIONALLY LEFT BLANK

CHAPTER 1. INTRODUCTION

1.1. Background

This report presents the analysis of the possibilities of transitioning traditional energy supply systems to more environmentally friendly alternatives, with a particular emphasis on exploring thermal energy storage (TES) as a resource conservation and resilience measure. The study aims to investigate various energy system architectures capable of meeting facilities' energy demands, leveraging TES implementation across 18 U.S. Department of Energy (DoE) climate zones.

For the fair comparison of TES, the report establishes a baseline for simulations, assumptions, boundary conditions, technical and economic characteristics of components, and other parameters used in the analysis. Subsequently, it identifies variations within each climate zone and conducts simulations of each scenario accordingly. The outcomes inform recommendations for alternative energy solutions and technologies, including tailored equipment combinations for each climate zone.

Conclusions drawn from the simulations allow formulating recommendations for TES and technical scenarios of its application in the studied climate zones. The study endeavors to explore the conditions under which TES contributes to viable, beneficial, and sustainable energy solutions. By examining various factors influencing TES environmental and cost effectiveness, the goal is to uncover practical applications and identify optimal implementation scenarios, crucial for maximizing energy efficiency and advancing sustainable energy systems.

Analysis of key technological aspects such as system integration, scalability, cost effectiveness, and environmental impact provides valuable insights for decision-making and evaluating TES technologies across different applications. Ultimately, the findings contribute to a better understanding of TES and its role in optimizing energy management for sustainability goals, without endorsing a specific "best" TES technology.

1.2. Supporting Data

Note that Appendices A and B are included in a full version of this document, available through URL http://www.SomeWebsite.com

CHAPTER 2. THERMAL ENERGY STORAGE

2.1. TES Types and Applications

TES facilitates the storage of heating or cooling energy for subsequent use in HVAC systems or various industrial processes. These adaptable TES systems can be designed for daily, weekly, or seasonal energy charging, storage, and discharge. Daily cycling applications include, e.g., hot water storage in domestic systems and ice storage for air-conditioning in commercial buildings. TES is also integral in district heating networks, optimizing heat distribution throughout the day, and ensuring a steady supply for industrial processes. Furthermore, TES enhances the efficiency of solar thermal systems by storing excess heat during daylight hours for later use in heating or power generation. Overall, TES serves as a versatile solution for load shifting, reducing peak demand, and optimizing the size and capacity of energy-producing equipment. For extended storage needs, seasonal TES is typically coupled with solar heating, addressing higher heating demands during months with fewer sunlight hours. Additionally, TES can be charged using waste heat from, e.g., CHP, cooling equipment, sewage, data centers, biogas reactors, industrial heat waste, etc.

The medium used in TES can be hot water, chilled water or another chilled fluid, ice or another phase change material, thermal oil, and molten salt. Other types of TES use sensible heat to store thermal energy in a medium such as stone, concrete, and air but will not be further elaborated upon due to their currently limited use cases.

Commonly used TES configurations include:

- **TTES**: Steel, concrete, or plastic tanks (Figures 2-1, 2-2, 2-3, 2-4)
- **PTES**: Pit thermal energy storage (Figure 2-5)
- **BTES**: Borehole thermal energy storage (Figure 2-6)
- **ATES**: Aquifer thermal energy storage (Figure 2-7).

Compared to the other TES types, ATES requires very specific geological circumstances due to its characteristic working principle. The allowable temperatures in ATES are typically also limited compared to other TES types. Due to these limitations, this type of TES has been omitted from consideration.

The most common TES consists of hot and chilled water tanks. District heating and district cooling systems commonly use a pressureless steel tank. The water level in the tank maintains the pressure in the network, where nitrogen (N_2) is occasionally used as a top layer to protect the tank against corrosion. The largest tanks can have volumes up to 30,000 m^3 (1,059,440 cu ft), and the smallest prefabricated tanks (used for small systems) can have volumes as small as 200 m^3 (7,063 cu ft). Pressurized tanks are designed to hold water at a temperature up to 165°C (329°F); these tanks have smaller sizes with a smaller diameter due to their expensive steel construction, especially if the tanks are pressurized. When the temperature of the stored water is below 125°C (257°F), the additional cost for a larger steel tank is modest.

TES operating strategies may be classified as either partial or full storage. Partial storage systems can be sized for load-leveling or demand-limiting operations. These terms refer to the amount of on-peak heating or cooling load that is shifted to off-peak. Full storage systems are sized to meet entire heat demands, in which heating/cooling equipment is deactivated during peak demand periods. In addition, daily and seasonal storage strategies can be used. Seasonal storage is when the storage gets filled during long periods of low demand. When the demand rises during a high-demand period, the storage supplements the demand during these periods (Mangold D. et at.). Daily storage refers to the daily cycling of the storage, where the storage gets charged and discharged on a daily basis.

TTES is the most common type of TES; it uses above-ground tanks that contain the storage medium. This type of TES must be insulated by either ROCKWOOL® mineral wool batt insulation or some other kind of insulating material, such as polyisocyanurate. Depending on the temperature range and medium, the tanks can be pressurized to prevent the medium from evaporating at the storage temperature. There are two methods of storing thermal energy in TTES. The first method is a two-tank system, also called "empty tank method," where one tank contains the cold medium and one tank contains the heated medium. When the TTES system charges, the medium flows from the cold tank through the heating entity and when heated, is stored in the hot tank. When the heat is needed, the heated medium flows from the hot tank, delivers its stored heat to where it is needed, and is then stored in the cold tank again, completing the cycle. The other storage method uses thermocline where both the hot and cold mediums are stored in the same tank. Some storage mediums decrease in density when heated and will therefore flow to the top of the tank where it can be drawn out when needed and when the cool medium returns to the tank, its higher density will keep it at the bottom.

PTES is an in-ground storage method that allows for large quantities of storage medium to be stored for long periods of time, which is why it is often referred to as seasonal storage. This type of TES does not need insulation, other than on top, due to the surrounding soil acting as insulation. The insulating layer on top floats on the storage medium and consists of several layers of different types of insulating foam. Current PTES systems use only the principle of thermocline and water as the storage medium.

BTES is a large in-ground structure with many boreholes that reach far into the ground. In this type of storage, the hot storage medium heats the structure and soil around the boreholes. When the heat is needed, the medium collects the stored heat from the structure and soil and delivers it where it is needed. In this sense, the BTES acts as both a TES and a heat exchanger. The storage medium is usually water-based ethanol and glycol solutions, for antifreeze protection. The heat is commonly stored and extracted from the storage using a heat pump in a closed loop configuration. Because BTES reaches far into the ground, it can store large amounts of heat in a relatively small surface area so that the remaining surface area can be used for other purposes (Sibbitt et al.).

ATES uses naturally occurring aquifers as storage tanks and only uses the two-tank method. This means that ATES needs two aquifers to work. The size and feasibility of this type of TES is yet undetermined and will require geological surveys and environmental evaluations to determine if aquifers are present and if they can be used. Also, ATES can only use water as the storage medium and temperatures are typically not allowed to rise higher than 25-30°C (77-86°F).

2.2. TES Sites

Source: Ramboll. Private communications for Anders Dyrelund. September 2021.

Figure 2-1. 70,000 m³ plus (529,720 cu ft) tanks at Fynsværket in Odense Denmark (Ramboll).

Source: Ramboll. Private communications for Anders Dyrelund. September 2021.

Figure 2-2. 2000 m³ (70,629 cu ft) chilled water tank, Taarnby Forsyning, Denmark (Ramboll).

Source: Ramboll. Private communications for Anders Dyrelund. September 2021.

Figure 2-3. 3,000 m³ (105,944 cu ft) chilled water tank in Frederiksberg Forsyning, Carlsberg City, Denmark (Ramboll).

Source: Ramboll. Private communications for Anders Dyrelund. September 2021.

Figure 2-4. 2 x 24,000 m³ (847,552 cu ft) pressurized tanks in Copenhagen, Denmark, up to 125°C (257°F) sectioned from network by 10 Bar (Ramboll).

Figure 2-5. 60,000 m³ (2,118,880 cu ft) “SUNSTORE 3” pit storage in Dronninglund, Denmark, 2013. (SHC Task 45).

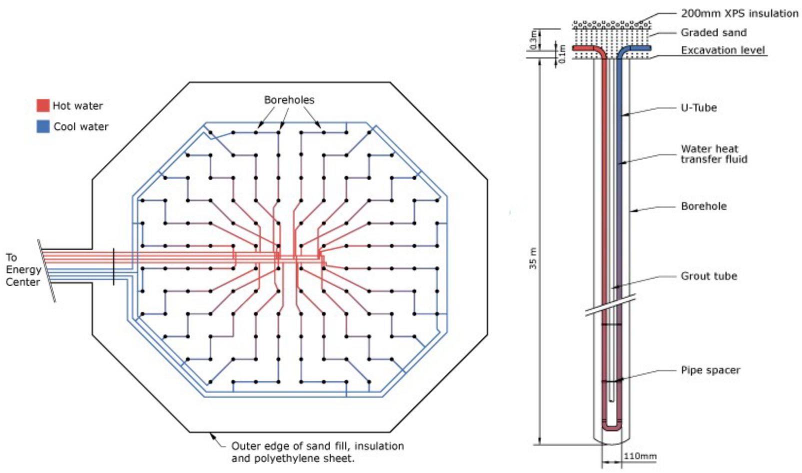


Figure 2-6. Borehole Thermal Energy Storage (BTES) installed at Drake Landing Solar Community, Okotoks, Alberta, Canada. 144–150mm (~6 in.) dia x 35m (115 ft) deep boreholes spaced 2.25m (7 ft) of center used for storing heat collected in summer for use later in winter.

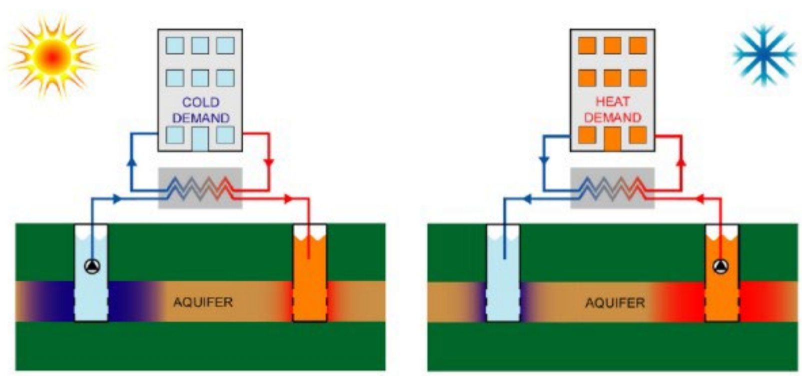


Figure 2-7. Open loop ATES system scheme with seasonable reversible operation. In summer, aquifer water is extracted from the cold well (left) and injected into the warm well (right). Free cooling (through heat exchanger) or additional ground water heat pump (GWHP, cooling mode) is used for cooling. In the winter period, the operation is reversed using GWHP for heating (Drijvert et al. 2001).

CHAPTER 3. METHODOLOGY

This chapter presents the overall methodology for the analysis of TES in all DoE climate zones. Representative U.S. locations/cities have been selected for each climate zone. For the uniformity of the analysis, a military building complex has been used with its thermal characteristics adjusted to individual climate conditions and heating, cooling and power demand profiles have been developed through building energy modeling using local weather conditions.

TES has been analyzed for two typical applications supporting excess energy production from (1) Combined Heat and Power (CHP) generation and (2) large-scale Solar Water Heating (SWH) plants.

The baseline scenario used for all analyzed scenarios comparison included a system architecture comprised of a building cluster/district system using a boiler to produce heat, an electric chiller to produce cooling, and the import of electricity from the public grid to meet the electricity demand of the building complex and the electric chiller.

CHP by its own (without using TES) has some advantages compared to the baseline scenario. To single out the advantage of TES in this application, scenarios using varying CHP sizes without TES have been developed, i.e., CHP sized to meet the electricity baseload, CHP sized to meet the entire electricity load and lastly the addition of TES to showcase how this enhances the output of the CHP by storing heat that is not immediately needed. All of these scenarios are compared to the baseline.

Solar Water Heating (SWH) system can reduce the use of the building cluster boilers when heat generated by the sun can be used at the time of its generation. TES allows to increase the use of SWH by easing the size of the solar field and extending the time of heat use. Therefore, scenarios using a combination of CHP and SWH have been analyzed, with varying SWH field and TES sizes and compared to the baseline.

Finally, a scenario with the exclusion of CHP has been developed where all of the heat is supplied by SWH with TES, necessitating all electricity to be imported by the public grid similar to the baseline. This is done to give insights into the necessary size of SWH field and TES to cover the heat demand and to compare the subsequent emissions and economics with the baseline.

The analysis included variations of the scenarios described above for cold and moderate climates (where heat was used for heating and domestic hot water generation) and for hot climates, where heat was used for heating (where needed), domestic hot water generation and for cooling supported by absorption chillers.

Sizes of the energy conversion and thermal storage equipment are varied in each scenario to match the demand profiles for each simulated climate zone and to provide the necessary resilience, respectively.

All scenarios were evaluated within their respective categories by benchmarking against the baseline, considering key parameters such as emission levels with a grid power generation and economic factors, encompassing investment costs, operational expenses (Aalborg CSP 2022), total energy costs, savings, and payback time. The improved energy systems resilience of compared scenarios is achieved by increased on-site power generation (using CHP units) and thermal energy storage allowing for thermal energy system redundancy.

The analysis adopted a “no heat loss from TES approach,” where heat losses from TES were disregarded. This simplification was implemented to streamline the generic analysis of the various TES technologies, considering that the efficiency of each technology differs. It was also assumed that the TES technologies can provide sufficient temperature and effect for the operation of the district heating, cooling grids, and the absorption chiller operation.

These assumptions are reasonable when large-scale water-based TES are used. Large-scale water-based TES (TTES and PTES) generally have lower thermal losses and offer the largest flexibility when it comes to storage temperature differences and charge/discharge power. However, PTES can require significant space and are not applicable for all situations. BTES offers potentially less flexible operation due to the charge/discharge rate being dictated by the technical heat transfer between the Heat Transfer Fluid (HTF) in the boreholes and the surrounding soil. BTES also requires a slightly different system architecture to include a heat pump due to lower storage temperature but offers advantages when it comes to space requirements and land usage, as the space on top of the storage can be used for other purposes. Therefore, the results for TTES and PTES cannot be directly applied to BTES.

The subsequent subsections delineate various topics of the methodology in greater depth.

3.1. Building Complex

An economic analysis of TES has been conducted for an example scenario of a public community comprised of a mix of building types that represents a generic Brigade Combat Team (BCT) complex (Zhivov et al. 2010). This complex has been built to meet EPACT 2005 energy requirements based on the ASHRAE Standard 90.1 (2004). Figure 3-1 shows the cluster of buildings included in this analysis. From the North to the South the BCT consists of Barracks (light blue) with a Dining Facility (purple) in the middle. Then the Headquarters Building (orange) is close to the through street. South of the street and parking spaces the Company Operation Facility (green) and Tactical Equipment Maintenance Facilities (red) are shown. The total building floor space is about 1,402k square feet (sq ft), which is divided into Barracks with 567k sq ft, Dining Facility with 31k sq ft, Tactical Equipment Maintenance with 229k sq ft, Company Operation Facilities with 447k sq ft, and 129k sq ft for the Headquarters.

Table 3-1 lists the average square footage of each building type:

Table 3-1. Square footage of each building type.

Building	Average floor space [sq ft]
Barracks	51,503
Dining	30,624
Tactical Eq. Maint.	44,204
Company Operation	51,253
Headquarter	129,237
Total	1,402,021

Figure 3-1. Layout of typical BCT complex.

3.2. Climates

The analysis was conducted for the representative U.S. public/military locations in 18 U.S. DoE climate zones listed in Table 3-2.

Table 3-2. Summary of the climate zones to be simulated.

Zone	Thermal Criteria	Representative U.S. City
0A	$6000 < CDD10^{\circ}C$	Guam
0B	$6000 < CDD10^{\circ}C$	NA
1A	$5000 < CDD10^{\circ}C$	Miami
1B	$5000 < CDD10^{\circ}C$	NA
2A	$3500 < CDD10^{\circ}C \leq 5000$	Houston
2B	$3500 < CDD10^{\circ}C \leq 5000$	Phoenix
3A	$2500 < CDD10^{\circ}C \leq 3500$	Atlanta
3B Coast	$2500 < CDD10^{\circ}C \leq 3500$	Los Angeles
3B Other	$2500 < CDD10^{\circ}C \leq 3500$	Las Vegas
3C	$HDD18^{\circ}C \leq 2000$	San Francisco
4A	$CDD10^{\circ}C \leq 2500$ and $HDD18^{\circ}C \leq 3000$	Baltimore
4B	$CDD10^{\circ}C \leq 2500$ and $HDD18^{\circ}C \leq 3000$	Albuquerque
4C	$2000 \leq HDD18^{\circ}C \leq 3000$	Seattle
5A	$3000 \leq HDD18^{\circ}C \leq 4000$	Chicago
5B	$3000 \leq HDD18^{\circ}C \leq 4000$	Denver
5C[2]	$3000 \leq HDD18^{\circ}C \leq 4000$	Vancouver
6A	$4000 \leq HDD18^{\circ}C \leq 5000$	Minneapolis
6B	$4000 \leq HDD18^{\circ}C \leq 5000$	Helena
7	$5000 \leq HDD18^{\circ}C \leq 7000$	Duluth
8	$7000 < HDD18^{\circ}C$	Fairbanks

The weather data for each of the climate zones were obtained from the Typical Meteorological Year 3 (TMY3) datasets. These datasets provide detailed information on weather parameters such as temperature, solar radiation, wind speed, humidity, and precipitation. By incorporating TMY3 data specific to each simulated location within a climate zone, the simulations can accurately capture the climatic variations experienced by the facilities under investigation.

3.3. Demand Profiles

Energy load profiles were developed for this project using the System Master Planner (SMPL) tool (Case, M.P., A. Zhivov, R.L. Liesen, and M. Zhivov. 2016. A Parametric Study of Energy Efficiency Measures Used in Deep Energy Retrofits for Two Building Types and U.S. Climate Zones. ASHRAE Transactions. 2016 ASHRAE Transactions Volume 1), which in turn uses the Modelkit/Params Framework (https://bigladdersoftware.com/projects/modelkit/), a parametric template and scripting engine that uses the U.S. Department of Energy tool EnergyPlus to perform whole-building energy simulations. Using a library of standard building models from SMPL corresponding to the Brigade Combat Team building types described in section 3.1, a model set was instantiated for each of the locations/climate zones shown in Table 3-2. Essentially, this approach is equivalent to placing a copy of the Brigade Combat Team complex in different locations, selecting the appropriate weather file, and using the Modelkit functionality to parametrically adjust the EnergyPlus building models for the climate zone (e.g., insulation, glazing, etc.).

Using SMPL, EnergyPlus simulations were run for each building in the complex for each location/climate zone. Building annual hourly load (8760 hours) profiles were extracted from the Energy Plus output for heating, cooling, and electrical power. Heating and cooling loads were calculated using coil loads. Domestic hot water loads were included in the heating loads. Energy loads were then aggregated for the entire BCT for each location.

Figures 3-2, 3-3, and 3-4 show the load profiles as the hourly energy demands in kWh, resulting in a load profile for the heating, cooling and electricity demands for each of represented climate zones. Heating profiles characteristically show higher demand in winter and lower in summer.

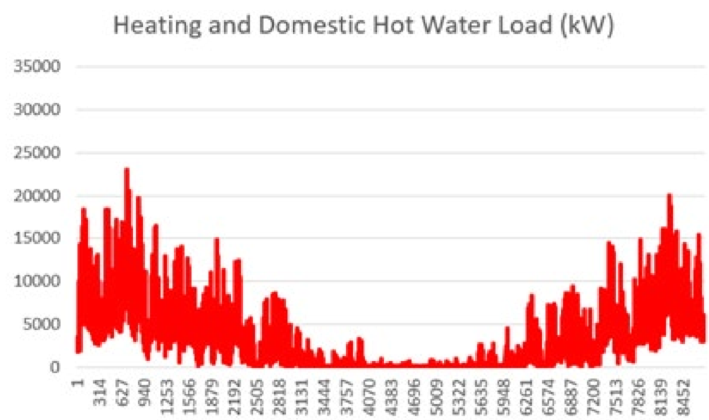


Figure 3-2. Visualized heating demand for Minneapolis.

The opposite tendency can be seen in the cooling demand, where the cooling demand is low in the winter and high in the summer.

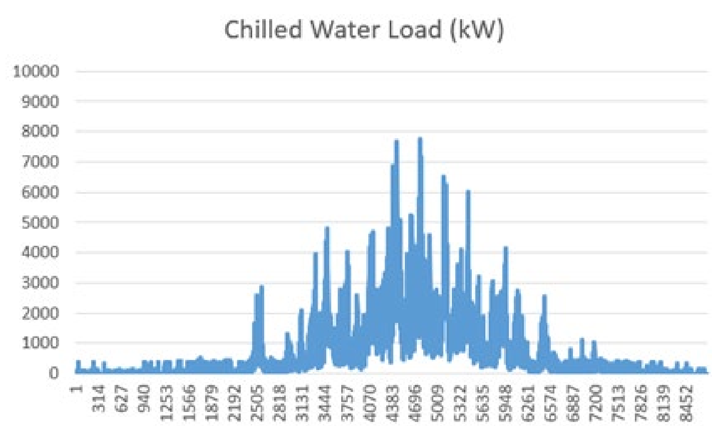


Figure 3-3. Visualized cooling demand for Minneapolis.

Lastly, the electricity demand does not illustrate the same seasonal trends as much, as this demand stays relatively consistent throughout the year. The variation is mainly on a daily and weekly basis with a baseload (in the night) of approximately 850 kW and a peak load of approximately 3 times the baseload (2,500 kW).

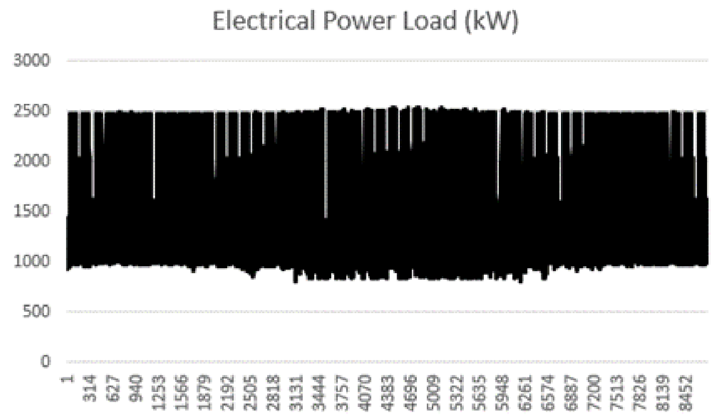


Figure 3-4. Visualized electricity demand for Minneapolis.

These characteristic tendencies can be seen in almost every climate zone, with some exceptions in either the exceptionally cold or hot climate zones.

Electric and thermal load profiles developed for all climate zones are presented in Appendix A.

3.4. System Architectures

Figure 3-5 shows the baseline system architecture representing the baseline scenario, which is the same for all climate zones. Heat is supplied by a boiler, cooling demand is supplied by an electric chiller, and electricity demand is imported from public grid. The only technological difference between the architecture for cold/moderate climate zones and hot climate zones is that in cold and moderate climate zones an electric chiller is used for cooling, whereas in hot climate zones absorption chiller is used instead; the two cooling technologies yield different efficiencies (Foley 2022).

Figure 3-6 shows the energy supply system architecture used for analysis of scenarios with CHP units and SWH plants in moderate and cold climate zones and Figure 3-7 in hot climate zones. The difference between the two architectures is the presence of an absorption chiller in Figure 3-7 (Foley 2022). The absorption chiller is driven by heat from the CHP unit and/or from solar collectors directly or through a hot TES. For hot climate zones, where the heat demand is relatively small and the cooling demand is relatively large, an absorption chiller is a sensible choice because it uses surplus heat from the CHP unit or a solar plant to produce cooling. This effectively increases the potential electricity production by the CHP unit and at the same time decreases the electricity demand for the electric chiller. For cold climate zones where the heat demand is relatively large and the cooling demand is relatively small, an absorption chiller is less feasible. Moderate climate zones are generally modeled with the cold/moderate climate architecture although some of the moderate climate zones with lowest heat demand benefit from the hot climate architecture.

Baseline Architecture

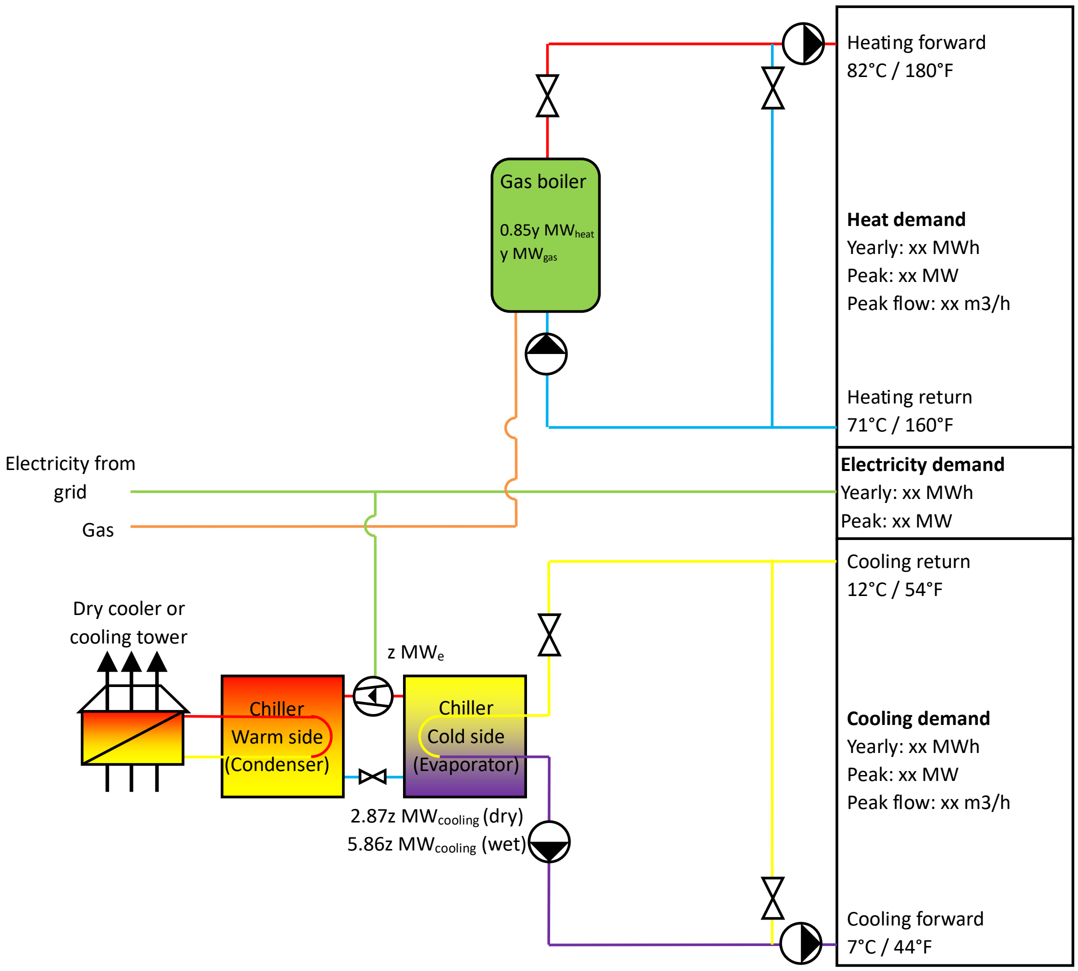


Figure 3-5. Baseline system architecture. Heat demand is supplied by a boiler. Cooling demand is supplied by an electric chiller with dry cooler (cold and moderate climate zones) or cooling tower (hot climate zones). Electricity demand for the building cluster and electricity consumption for the chiller is supplied by electricity from the public grid. Equipment efficiencies and supply and return temperatures are based on input and discussions with Gearoid Foley and Richard Sweetser.

Extended Architecture for cold and moderate climates

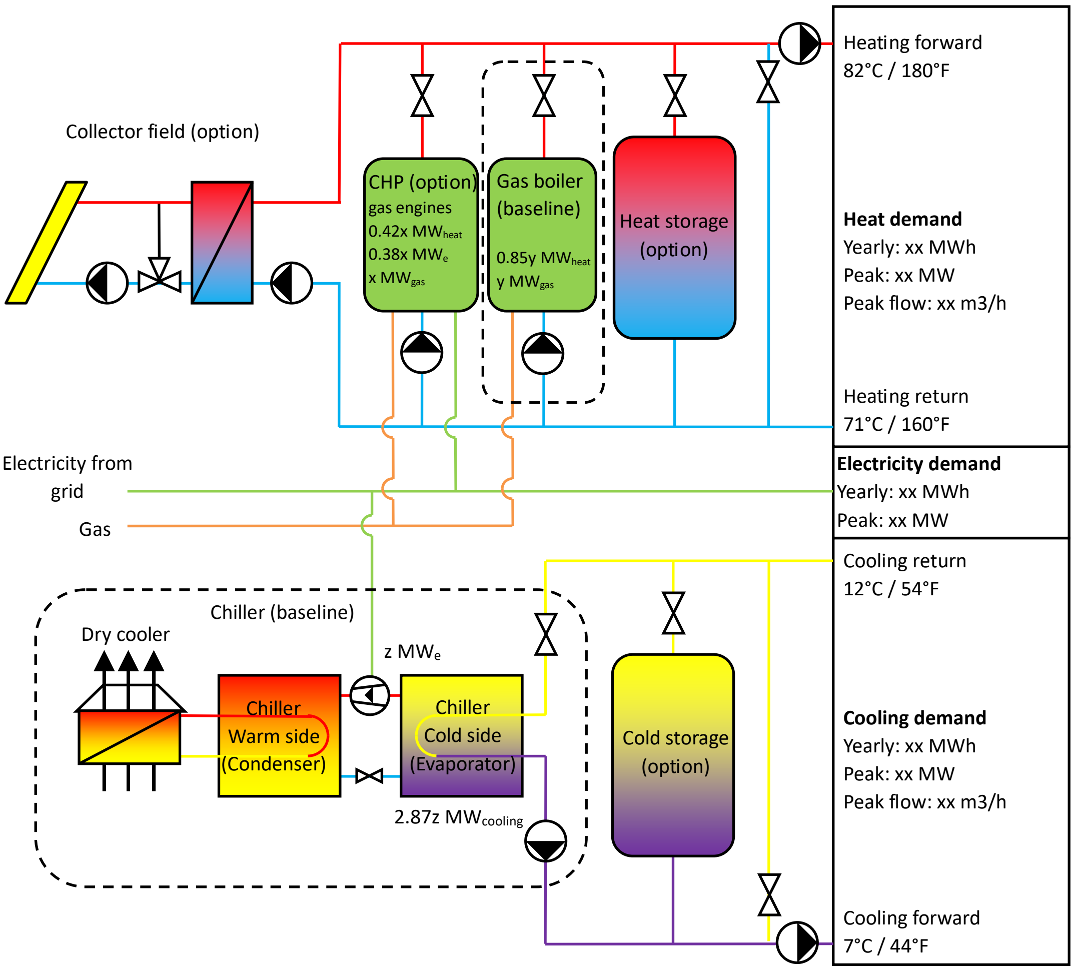


Figure 3-6. Extended architecture for cold and moderate climates. Optional production units and TES are added to the baseline units to represent different extended scenarios. Equipment efficiencies and supply and return temperatures are based on input and discussions with Gearoid Foley and Richard Sweetser.

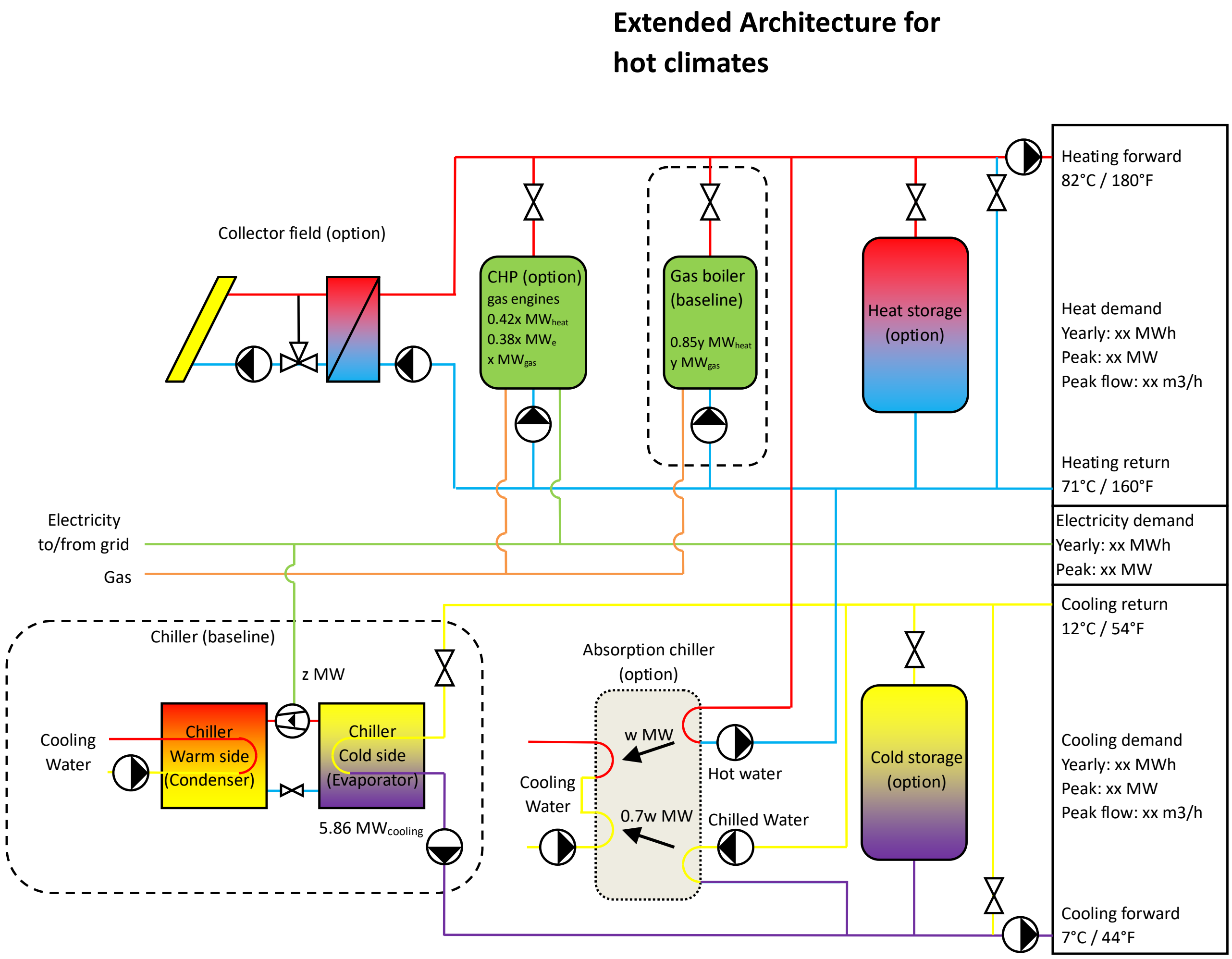


Figure 3-7. Extended architecture for hot climates. Optional production units and TES are added to the baseline units to represent different extended scenarios. Equipment efficiencies and supply and return temperatures are based on input and discussions with Gearoid Foley and Richard Sweetser.

3.5. Model Scenarios

This section outlines the scenarios used to analyze alternative energy systems and TES. These scenarios are categorized into two groups based on the classification of climate zones: cold/moderate and hot.

3.5.1. Model Scenarios, Cold/Moderate Climate Zones

In total, seven different scenarios are modeled for each cold climate zone as well as most moderate climate zones.

Baseline

<u>Scenario 0. Boiler only</u>

In this scenario all heat demand is produced by a boiler, all cooling demand is produced by an electric chiller and all electricity demand is bought from the public grid.

CHP + TES

1. Scenario 1. CHP baseload

   In addition to the baseline technologies, this scenario includes a CHP unit sized for the electricity baseload demand. Heat from the CHP unit is used partly to meet heat demand for the building cluster.

2. Scenario 2. 3x CHP

   Scenario 2 is similar to scenario 1 but has a 3X larger CHP that allows an increased share of on-site electricity generation for the building cluster and electric chiller.

3. Scenario 3. 3x CHP with TES

   This scenario has the same system architecture as scenario 2, but also includes TES. The objective of this scenario is to have TES sized to allow 100% of its own production of electricity to meet both the campus electricity demand and the electricity demand of the electrical chiller.

CHP + SWH + TES

4. Scenario 4. 3x CHP with small SWH and TES

   Includes three CHP units with a small SWH plant and TES. The SWH plant collectors' area is reduced to 25% of the area required for 100% solar water heating needs (see scenario 6). CHP unit is sized to meet required electricity capacity.

5. Scenario 5. 2x CHP with medium SWH and TES

   Includes two CHP units with a medium SWH plant and TES. The SWH plant collectors' area is reduced to 50% of the area required for 100% solar water heating needs (see scenario 6). CHP units are scaled down due to the heat production from the SWH plant rendering additional CHP capacity unnecessary. Consequently, a portion of the electricity demand must be met through imports from the public grid.

SWH + TES

6. Scenario 6. Large SWH and TES

   This scenario generates 100% of heating demand using SWH plant. It does not include on-site electricity generation. That means that 100% of electricity must be bought from the public grid (as in scenario 0).

3.5.2. Model Scenarios, Hot Climate Zones

In total, eight different scenarios are modeled for each hot climate zone and for some moderate climate zones.

Baseline

Scenario 0. Boiler only

In the baseline scenario all heat demand is produced by a boiler, all cooling demand is produced by an electric chiller, and all electricity demand is bought from the public grid.

CHP / ABS + TES

1. Scenario 1. CHP baseload and ABS

This scenario adds a CHP unit and an absorption chiller. The CHP unit is sized to meet the baseload electricity demand. The heat generated by the CHP unit is used to fulfill the heat demand for the building cluster and contribute to the heat input for the absorption chiller.

2. Scenario 2. 3x CHP and 3x ABS

Same as scenario 1 but with 3 times the CHP and absorption chiller capacity. Scenario 2 provides an increased share of its own production of electricity and an increased share of cooling produced by the absorption chiller.

3. Scenario 3. 3x CHP and 3x ABS with TES

Same as scenario 2, but also includes cold and hot TES. The objective of this scenario is to have TES sized to allow 100% of its own production of electricity (to meet both the campus electricity demand and the electricity demand of the electrical chiller).

CHP / ABS + SWH + TES

4. Scenario 4. 3x CHP and 3x ABS with small SWH and TES

Same as scenario 2 but adds a small SWH plant. TES were sized to collect and use all excess heating and cooling energy.

5. Scenario 5. 3x CHP and 3x ABS with medium SWH and TES

Same scenario as scenario 4 but with an increased size of the SWH plant allowing to eliminate the need of heat production by the boiler and all cooling production by the electric chiller (or alternatively uses the absorption chiller 100%).

6. Scenario 6. 3x CHP and 6x ABS with medium SWH and TES

Same scenario as scenario 5 but has a double absorption chiller capacity. This scenario potentially requires a smaller TES storage capacity, which in turn requires smaller investments.

ABS + SWH + TES

7. Scenario 7. 6x ABS with large SWH and TES

‘Similar to scenario 6, but without CHP unit, and generates 100% of heating and cooling demand using the SWH plant. SWH plant and TES capacity are sized to provide 100% of the heating and the cooling demands. It does not include on-site electricity generation. That means that 100% of electricity must be bought from the public grid (as in scenario 0).

CHAPTER 4. INPUT DATA AND BOUNDARY CONDITIONS

4.1. Energy Prices

All fuel is assumed to be natural gas, which was simulated at four different prices, low, medium, high, and "extra high" for Fairbanks, Alaska, where natural gas prices are exceptionally high (Table 4-1). The prices for purchase of electricity were also simulated at four different prices, low, medium, high, and "extra high" for Fairbanks, Alaska (Table 4-2). Note that the sale/export of locally produced electricity was omitted from the simulations due to the complexity of the export tariffs and laws regarding this subject in all the different locations.

Table 4-1. Natural gas prices.

Price point (Natural Gas)	USD/MWh	USD/MMBTU	USD/Nm^3
Low	15	4.5	0.16
Medium	19	5.6	0.21
High	27	8	0.30
Extra high (Alaska prices)	59	18	0.633

Table 4-2. Electricity prices.

Price point (Electricity Purchase)	cents/kWh	USD/MWh
Low	7	70
Medium	12	120
High	20	200
Extra high (Alaska prices)	40	400

4.2. Heating Value

The heating value of natural gas can vary drastically depending on composition. Table 4-3 summarizes the chosen heating values for the simulations (EPA 2021).

Table 4-3. Chosen heating value for the simulations.

MMBTU/Nm^3	kWh/Nm^3	MJ/Nm^3
0.036271	10.63	38.268

4.3. Different Emission Rates with Power Generation

Source energy (also called primary energy) represents and accounts for the raw fuel (energy) that is consumed to create heat or generate electricity for the end user or building (see ASHRAE Standard 105 N15 for additional information). This is an important consideration because as much as three units of raw fuel (energy) may be required to generate a single unit of energy for the end user or building, such as for electricity supplied by the grid or heat received from a district heating system. The percentage and type of fuel used for power generation differs from location to location in the USA even in the same climate zone.

Table 4-4 gives an overview of the U.S. source energy and greenhouse gas emissions conversion factor from ASHRAE.

Table 4-4. U.S. Source Energy and Greenhouse Gas Emissions Conversion Factors (ASHRAE Std 100-2024)

Energy Form		Source Energy Conversion Factor	Greenhouse Gas Emissions Factor, GWP_{100} (lb CO_2e/kBtu)	Greenhouse Gas Emissions Factor, GWP_{100} (kg CO_2e/MJ)
Grid electricity		2.74	0.326	0.140
Grid natural gas		1.09	0.147	0.063
Grid fuel oil		1.19	0.196	0.084
Grid liquified petroleum gas (LPG) or propane		1.15	0.169	0.073
Coal		1.10	0.104	0.242
Other		Note a	Note a	Note a
Purchased district energy	Hot water	1.35	0.234	0.234
	Steam	1.45	0.247	0.247
	Chilled Water	1.04	0.083	0.083

The emission rate for natural gas combustion is 181.1 g/kWh (399.2 lb/MWh). To cover the variations of emission rates from power generation between U.S. states, the emission rates for imported electricity are divided into three different emission rates, all including +5% grid loss. Table 4-5 lists these emission rates.

Table 4-5. Emission rates for imported electricity.

Emission rate (Imported electricity)*	lb/MWh	g/kWh
Low	751	341
Medium	1338	607
High	1762	799

* Source: Emission rates and grid loss percentages determined from e-grid data provided in an email from R. Sweetser dated 2023-03-13.

4.4. Maintenance Cost of Equipment

The maintenance costs of the equipment were determined by Aalborg CSP based on previous experience and calculations (Table 4-6).

Table 4-6. Equipment maintenance costs.

Maintained Equipment	USD/MMBTU	$USD/MWh_{electric}$	$USD/MWh_{thermal}$
CHP	—	8	—
Boiler	4.6	—	1.35
Electric Chiller	—	3	—
Absorption Chiller (Cooling output)	7.47	—	2.19
Solar Field (Including electricity consumption)	6.14	—	1.8

Based on experience by Underground Energy, the maintenance cost of a BTES installation located in NE USA, can range from 50-150 $USD/MWh_{thermal}$.

The maintenance cost of both TTES and PTES are considered negligible.

4.5. Efficiency – Equipment

The efficiencies of the equipment used were determined by Aalborg CSP based on previous experience and calculations (Table 4-7).

Table 4-7. Efficiencies of the equipment used.

Equipment	Efficiency*
CHP	38% El / 42% Heat
Boiler	85%
Electric Chiller (COP Cooling)	Cold / moderate CZ: 2.87 (dry cooling) Hot CZ: 5.86 (wet cooling)
Absorption Chiller (COP Cooling)	0.7
*Efficiencies are provided by Gearoid Foley in an email dated 21-09-2022.	

The efficiency of BTES is estimated from <20% in fast-flowing aquifers up to 80% in unfractured, impermeable rock. Efficiency increases with the scale of the BTES installation and can be maximized by optimizing the surface area-to-volume ratio. The heat pump in the BTES systems usually have COP values of 3.0-3.5 and above, depending on the temperature supply requirements of the thermal load.

The efficiency of both TTES and PTES are generally considered to be above 80%. In the simulations, all storage types are considered to operate at 100% efficiency for simplification purposes.

4.6. CAPEX

The capital expenses of the simulated equipment and technologies were estimated by Aalborg CSP based on previous projects using equipment of similar type and size. Table 4-8 summarizes the capital expenses for the equipment and technology used in the simulations.

Table 4-8. Capital expenses for the equipment and technology used in the simulations.

Equipment	Pricing (USD)
CHP	1,100,000.0 (per $MW_{thermal}$)
Absorption chiller	1,460,000 (per $MW_{thermal, cooling}$)
Solar field	293.0 (per m^2)

4.6.1. TTES and PTES

The pricing of PTES varies depending on the chosen size. The graph shown in Figure 4-1 summarizes the prices applicable to both TTES and PTES. Please note that the minimum TTES size is around 1,000 m^3 (1.3k cu yd) and the threshold for the transition from TTES to PTES is 30,000 m^3 (40 cu yd).

Figure 4-1. Price of PTES as a function of size (USD/m³).

The graph shown in Figure 4-1 shows how relatively high costs per m^3 of smaller capacities decrease exponentially as capacities increase. Additionally, the Department of Energy (DoE) has indicated that projects <1MW may receive a 30% tax credit reduction, which if granted could apply to every simulated scenario. This was considered in the calculations of the CAPEX for each combination of equipment and technology in each climate zone and was summarized in a separate calculation showing the impact of this potential subsidy.

4.6.2. TES Technology Price Comparison

Like PTES, BTES pricing fluctuates based on size. However, determining precise BTES costs is challenging due to the variable volumetric storage capacity and CAPEX influenced by geological and hydrogeological conditions. As a result, a range between minimum and maximum BTES prices, directly compared to the TTES and PTES pricing is shown in Figure 4-2.

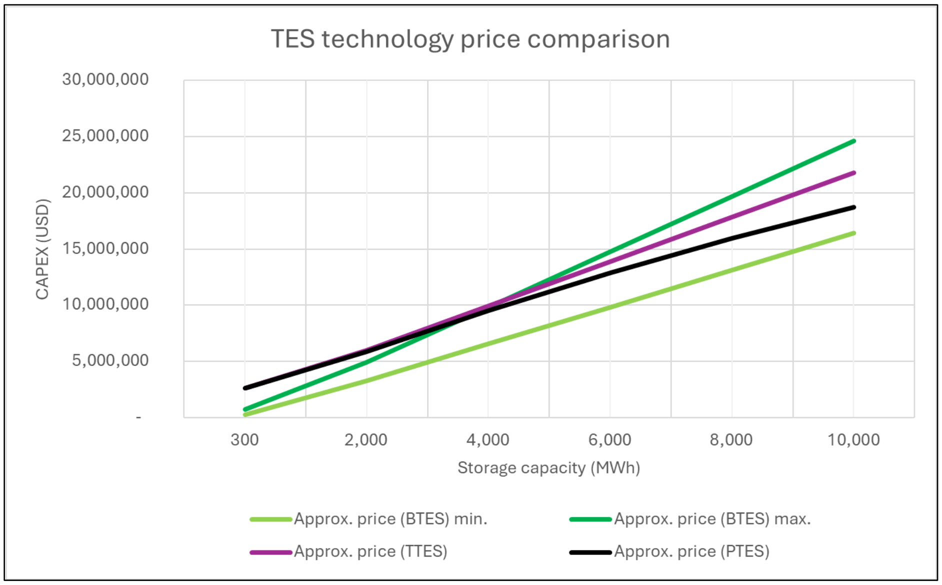


Figure 4-2. Price comparison between TES technologies.

Figure 4-2 shows TTES, PTES and BTES pricing per MWh stored, for comparison. In optimal conditions, BTES has the lowest investment cost. However, less favorable conditions may increase BTES costs, surpassing TTES and PTES at specific thresholds. This emphasizes the importance of understanding subsurface conditions to determine the most economical technology. In addition, incompatible conditions may render BTES unsuitable as a storage solution altogether.

4.7. Total Energy Cost

To ensure a meaningful and easily interpretable comparison between the economics of each simulated technology combination, total energy cost is used as a key metric for measuring overall costs and is calculated over a one-year operational period. Total energy costs are calculated by adding both CAPEX and OPEX together and dividing it by the total produced energy in MWh, both as heating and cooling. This gives a total cost in USD per produced MWh energy. The simplified formula for total energy cost can be illustrated as follows:

$$Total\ Energy\ Cost = \frac{(CAPEX + OPEX)}{(Energy\ production)}$$

The CAPEX is determined as an annualized cost, equivalent to 7% of the initial investment. This figure aligns with a 20-year annuity loan structure, assuming an interest rate of approximately 3% per annum.

The OPEX is the accumulated cost relating to the operation of the energy-producing entities, including fuel consumption, electricity purchase and maintenance of equipment with predetermined rates based on prior experience.

CHAPTER 5. RESULTS

This chapter details the overall observations, tendencies, and results gathered throughout the simulations with a focus on the correlation between overall emissions and total energy costs.

To simulate a common year of service, the TES are simulated at half-full capacity in the beginning of all the simulations. This is done to avoid simulating only start-up scenarios and to ensure that it is possible for scenarios to use the solar field to satisfy the entire heat demand, as the solar field cannot meet the heat demand from day one.

To emphasize optimal economic insights while maintaining a balanced presentation of information, only results under the highest energy prices are showcased. This highlights the considerable potential savings offered by the presented technology combinations. All results for various energy price levels can be found in Appendix A to this report.

Please note that Appendix B contains all simulation results for all climate zones. They include variations in energy prices, both with and without tax credit reduction, detailed contributions from energy-producing entities, in-depth economic analyses, and graphical representations illustrating interactions between energy-producing and consuming entities, along with TES levels throughout a simulated year of operation.

For easier reference to simulation scenarios, the naming conventions used in this section may differ from those in the Appendices. However, the number of scenarios, technologies, and capacities remains consistent.

5.1. Cold/Moderate Climate Zones

5.1.1. CZ 8 – Fairbanks

Overall Observations

Fairbanks is the coldest of the simulated climate zones. It has a distinctive high heat demand in the winter and low cooling demand in the summer, as illustrated in Figure 5-1. In winter, when heat demand is high, the short daytime duration and relatively low solar radiation results in a comparatively low yield from solar fields.

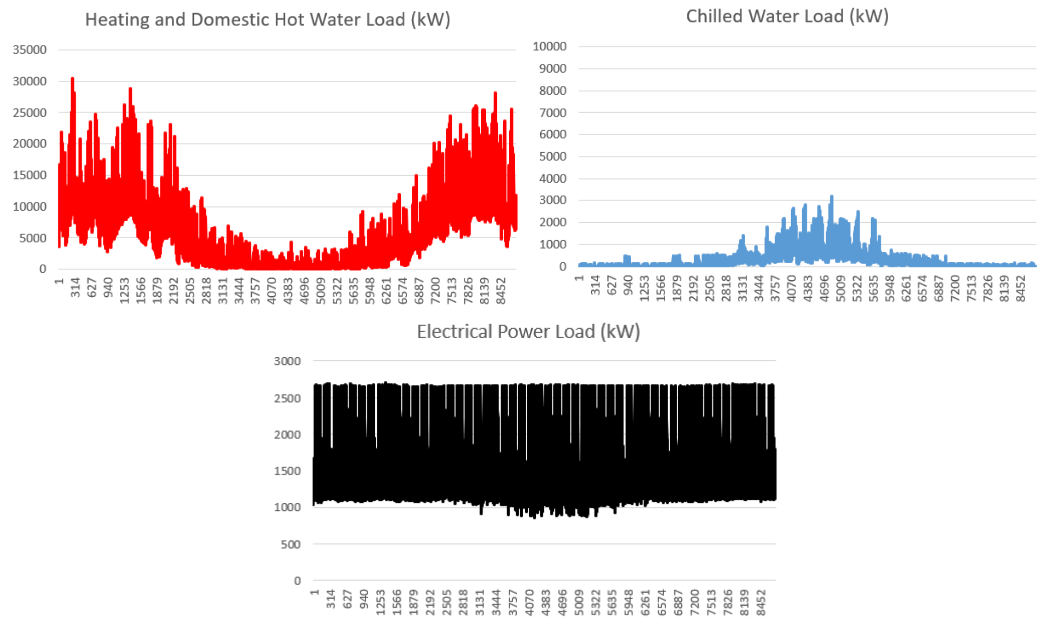


Figure 5-1. Load profiles of the heating, cooling, and electricity demands for Fairbanks.

Besides the standard energy rates, economics for Fairbanks was simulated using the special conditions with extra high energy price (Alaska price) for both natural gas and electricity. This decision was made due to the absence of natural gas infrastructure and the relatively higher electricity transmission prices in Alaska compared to similar climate zones.

In the baseline scenario, named “0. Boiler only,” heat demand is met by a gas boiler, cooling is provided by an electric chiller powered by imported electricity, and electricity demand is met with imported electricity. This baseline facilitates the comparison of subsequent technology combinations in terms of emissions and economics.

CHP + TES

In scenario “1. CHP Baseload,” a CHP gas engine provides both electricity and heating. The CHP has been sized to meet the baseload electricity demand, necessitating the remaining electricity and heating demand to be met with the gas boiler and imported electricity. However, with CHP gas engines, the production of electricity and heat goes together, meaning that if no more electricity is needed, it also stops producing heat and vice versa. The cooling demand is met by an electric chiller, similar to the baseline scenario.

In scenario “2. 3x CHP,” the CHP has been sized to be three times the size it was in the first scenario. This is done because the demand profile shows that the peak electricity demand is approximately three times higher than the baseload, as described in Section 3.3 of this report. The CHP is capable of meeting the electricity demand but given the large heating demand and periods of low electricity demand, the gas boiler still needs to contribute during these periods.

Scenario “3. 3x CHP with TES” has similar sized CHP as scenario 2, but with the addition of a 200,000 m^3 TES. This provides an improved energy system resilience since TES allows the CHP gas engines to generate more heat than is immediately needed and thereby produce electricity more consistently. Additionally, the TES allows the stored heat to be used in periods of low heat production due to low electricity demand. The type of TES used in this scenario is PTES as the size is larger than what can be achieved by TTES, as described in section 4.6.1.

CHP + SWH + TES

With the showcased resilience of TES, the further use of TES can now be demonstrated through the addition of two scenarios with the implementation of SWH plants.

In scenario "4. 3x CHP with small SWH and TES," the TES capacity has been increased to 500,000 m^3 and a SWH plant of 45,000 m^2 has been added. The SWH plant provides the remaining heat that the gas boiler used to provide in the previous scenarios. Due to the SWH plant not producing heat during night or cloudy days, the TES capacity has been increased as well to collect the overproduced heat.

Scenario "5. 2x CHP with medium SWH and TES" is made to demonstrate the effect of SWH replacing a share of heat production from the CHP. The SWH plant has been doubled to 90,000 m^2 to achieve this and the TES capacity has been further increased to 1 million m^3 to provide the necessary resilience. Since some of the heat production has been replaced from the CHP, its capacity has been reduced to two times the electricity baseload capacity. This means that some of the electricity must be imported, since it cannot be met entirely be the CHP anymore.

SWH + TES

In the last scenario "6. Large SWH and TES," the entire heat production is met with the SWH plant, and the CHP has therefore been eliminated. To achieve this, the SWH plant has been doubled again to 180,000 m^2 and the TES capacity has been doubled to 2 million m^3 to provide the necessary resilience. Since the CHP is no longer present, the entire electricity demand is met by importing electricity. This, however, shifts the emission tendency by reducing emissions savings with increasing emission rates due to all the electricity being imported. This results in higher emission rates now increases the overall emissions.

Summary

Table 5-1 provides a comprehensive list of simulated scenarios for Fairbanks, detailing TES capacities, SWH field sizes, and CHP capacities. It further includes a summary of total heating and cooling production, a breakdown of CAPEX for various technology and equipment, the overall CAPEX, the CAPEX after a potential 30% tax credit reduction, and the potential savings resulting from the tax credit reduction.

Table 5-1. Simulation parameters and economics for the Fairbanks simulation scenarios.

		0. Boiler only	1. CHP baseload	2. 3x CHP	3. 3x CHP w/TES	4. 3x CHP w/small SWH and TES	5. 2x CHP w/medium SWH and TES	6. Large SWH and TES
Component size								
TES	m^3	-	-	-	200,000.00	500,000.00	1,000,000.00	2,000,000.00
Solar plant	m^2	-	-	-	-	45,000.00	90,000.00	180,000.00
CHP	MW_{heat}	-	0.85	2.55	2.55	2.55	1.70	-
Energy production								
Heat production	MWh	45,394	45,394	45,394	45,394	45,394	45,394	46,547
Cooling production	MWh	2,440	2,440	2,440	2,440	2,440	2,440	2,440
Investment								
TES	USD	-	-	-	10,600,000	18,800,000	29,000,000	44,800,000
Solar plant	USD	-	-	-	-	13,185,000	26,370,000	52,740,000
CHP added capacity	USD	-	935,000	2,805,000	2,805,000	2,805,000	1,870,000	-
Sum	**USD**	-	**935,000**	**2,805,000**	**13,405,000**	**34,790,000**	**57,240,000**	**97,540,000**
Reduction due to tax credits	30%	-	280,500	841,500	4,021,500	10,437,000	17,172,000	29,262,000
Investment after tax credits	**USD**	-	**654,500**	**1,963,500**	**9,383,500**	**24,353,000**	**40,068,000**	**68,278,000**

A summary of the emissions at the different emission rates and the total energy costs for each simulation scenario are presented in Figure 5-2 (Sweetser 2023). All of the total energy costs are presented in percents compared to the baseline Scenario, which is why the total energy cost is denoted as "100%" at this scenario.

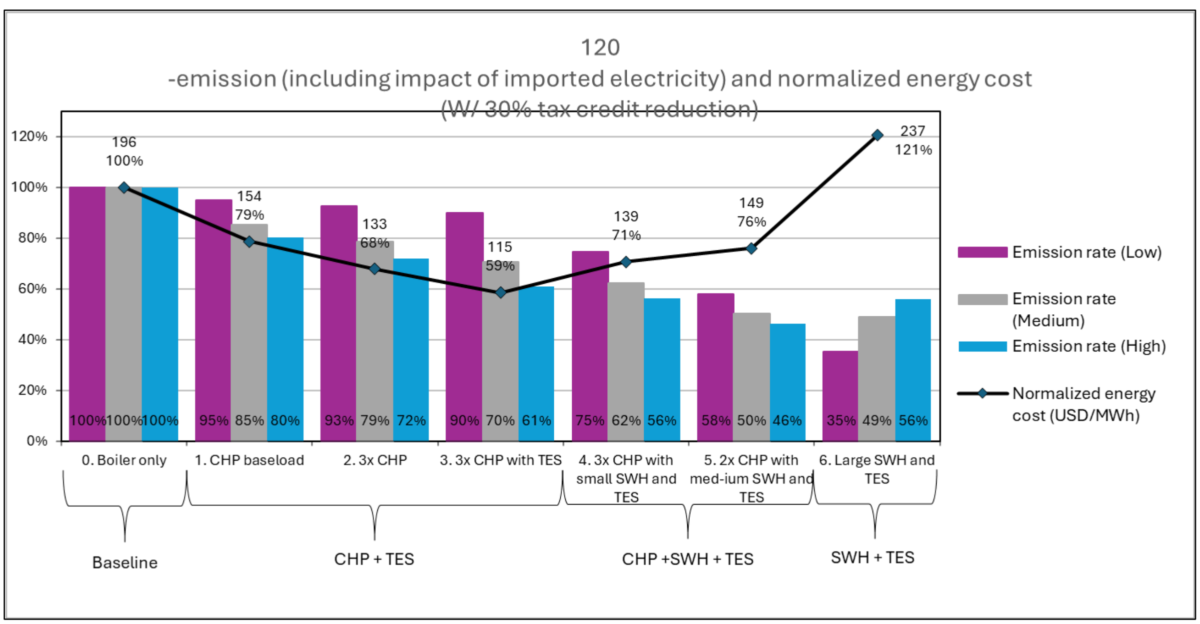


Figure 5-2. Combined graph of the CO_2 emissions at each emission rate and the total energy costs with 30% tax credit reduction for Fairbanks.

Figure 5-3 shows the distribution of electricity demand met by imported electricity and CHP. The campus and electric chiller maintain constant electricity consumption throughout all scenarios, as no other entities provide cooling.

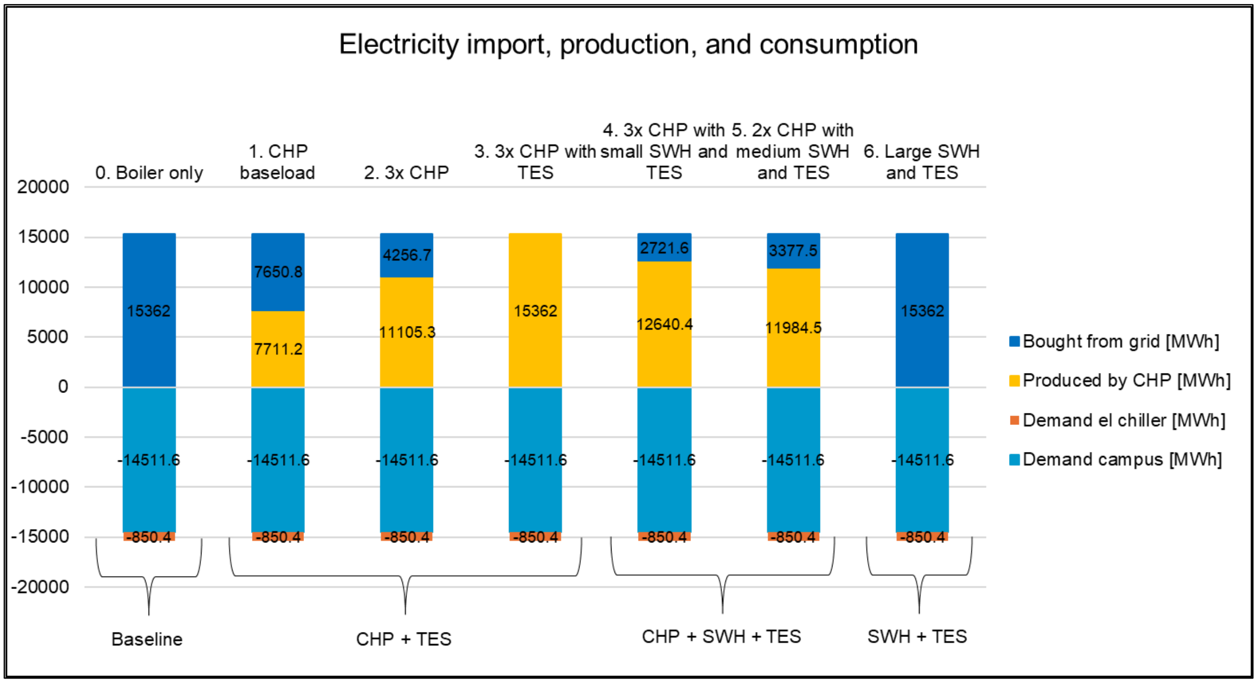


Figure 5-3. Electricity import, production and consumption for the Fairbanks scenarios.

Table 5-2 provides a breakdown of the economics for all scenarios, including initial investments, OPEX, simple payback period, CAPEX in terms of repayment of loans, and annual savings compared to the baseline scenario.

Table 5-2. Breakdown of economics relating to CZ 8 – Fairbanks simulations at extra high energy price (Alaska price).

Base calculation		0. Boiler only	1. CHP baseload	2. 3x CHP	3. 3x CHP w/TES	4. 3x CHP w/small SWH and TES	5. 2x CHP w/medium SWH and TES	6. Large SWH and TES
Investment	USD	-	654,500	1,963,500	9,383,500	24,353,000	40,068,000	68,278,000
OPEX*	USD/year	9,388,877	6,965,460	5,898,772	4,561,021	4,588,064	3,965,418	6,231,135
OPEX savings	USD/year	-	2,423,417	3,490,105	4,827,856	4,800,813	5,423,459	3,157,742
Simple payback period	Years	-	0.3	0.6	1.9	5.1	7.4	21.6
CAPEX**	USD/year	-	45,815	137,445	656,845	1,704,710	2,804,760	4,779,460
Total Cost Savings	**USD/year**	**-**	**2,377,602**	**3,352,660**	**4,171,011**	**3,096,103**	**2,618,699**	**-1,621,718**
Production cost	USD/MWh	196	154	133	115	139	149	237
Reduction		100%	79%	68%	59%	71%	76%	121%

* OPEX calculated in energyPRO.

** Calculated as 7%/year of investment, corresponding to 20-year annuity loan with an interest of app. 3% p.a.

As was expected, the use of CHP only in scenario 1 and 2, results in a reduction of emissions at all emission rates between 5% and 18% and a total energy cost reduction between 21% and 32%. Adding TES to CHP in scenario 3 results in further emission reduction ranging between 10% and 39%, compared to the baseline scenario, with a total energy cost reduction of 41%. On-site power and heat generation and thermal storage increases energy system resilience by decoupling electricity and heat demand in the CHP. This allows the CHP to produce more heat than immediately needed and thereby cover the entire electricity demand.

The presented data shows that the use of CHP in all analyzed scenarios is cost effective, resulting in reduced emissions and total energy costs. Adding TES improves these characteristics and results in further improvement of energy systems resilience with a payback ranging between 0.3 and 1.9 years.

Scenarios 4 and 5 showcases TES in conjunction with CHP and SWH, and without CHP in scenario 6. In Scenario 4, CHP was complemented by a small SWH plant and TES with an increased capacity. This reduces the emission between 25% and 44%, depending on emission rate. The total energy cost is reduced by 29% and the payback period is estimated to be 5.1 years.

Scenario 5 included a smaller CHP with a medium SWH and TES. The inclusion of an increased SWH field size and further increased TES size, together with a smaller CHP capacity, reduces the emission between 42% and 54%, depending on emission rate. The total energy cost is reduced by 24% and the estimated payback period is estimated to be 7.4 years.

Scenario 6 includes a large SWH field and a TES that allows the entire heat production to be met with SWH, and the CHP has therefore been eliminated. Elimination of CHP and a further increase of SWH field and TES size results in an emission reduction between 44% and 65%, depending on emission rate. The total energy cost is increased by 21% and the payback period is 21.6 years, making this technology combination the least cost effective and feasible.

All the presented results are based on the extra high energy price (Alaska price) and 30% tax credit/funding on investments, illustrating the highest potential savings and, consequently, the best economic outcomes. It is important to note that other energy prices only affect the economics and not the emission reductions in each scenario. Appendix B, section B.1 contains all Fairbanks simulation results specific economic outcomes; section B.1.1 contains economic results under different pricing conditions.

To illustrate the impact of different energy prices, scenario 3 shows the most favorable economic results at extra high energy price (Alaska price) and 30% tax credit/funding on investments with a decrease in total energy costs of 41% and a payback period of 1.9 years. Without the 30% tax credit, the total energy costs at the same energy price show a decrease of 38% and a payback period of 2.8 years, still making this scenario economically feasible. Table 5-3 summarizes the economic results at the different energy prices for Fairbanks.

Table 5-3. Economic results for scenario 3 at different energy prices for Fairbanks.

Price Levels	With 30% tax credit	Without 30% tax credit
High energy price	Total energy costs: decreased 34% Payback period: 3.9 years	Total energy costs: decreased 28% Payback period: 5.6 years
Medium energy price	Total energy costs: decreased 19% Payback period: 7 years	Total energy costs: decreased 9% Payback period: 10 years
Low energy price	Total energy costs: decreased 1% Payback period: 14.1 years	Total energy costs: increased 14% Payback period: 20.1 years
High gas and low electricity	Total energy costs: increased 16% Payback period: 23.5 years	Total energy costs: increased 27% Payback period: 33.6 years
Low gas and high electricity	Total energy costs: decreased 48% Payback period: 3.5 years	Total energy costs: decreased 41% Payback period: 5 years

As shown in Table 5-3, reducing energy prices leads to progressively less favorable economic outcomes. While scenario 3 exhibits the most economically favorable results, it remains viable only up to medium energy prices. At low energy prices, the total energy cost becomes prohibitively high, leading to an extended payback period of 14.1 to 20.1 years.

Furthermore, to assess whether gas or electricity prices exert a greater impact on the economy, simulations have been conducted for scenarios where each is the highest. In scenario 3, which is exclusively dependent on on-site power generation using gas, the gas price exhibits a significantly greater influence on the economy. High gas prices lead to a payback period ranging from 23.5 to 33.6 years, while low gas prices result in a payback period between 3.5 and 5 years.

Scenario 3 proves economically viable exclusively under high and extra high energy prices when coupled with a 30% tax credit, as well as under extra high energy prices without the tax credit. Conversely, scenario 2 emerges as the superior economic choice in all other pricing conditions, showcasing a total energy cost ranging between 69% and 85% with a payback period of 0.6 to 5.8 years. In contrast, scenario 3, under the same pricing conditions, demonstrates a total energy cost ranging between 81% and 114%, accompanied by a longer payback period of 7 to 20.1 years.

TES Technology Recommendations

All the simulated scenarios that include TES have been simulated as PTES, as the capacities are too large to feasibly be achieved by TTES. However, in scenario 4 through 6, the physical sizes of the required PTES will be considerable. An alternative to PTES is BTES, as this kind of TES is less surface area demanding and the area above the storage can be used for various applications.

When considering installing a BTES in Fairbanks, it is essential to consider the geological and hydrological conditions. The area primarily consists of permafrost and sedimentary rock formations, with limited aquifers. Groundwater resources are generally limited due to the presence of permafrost and the cold climate. Soil composition varies, with sandy and silty soils prevalent, impacting drilling feasibility. The depth to bedrock varies across the region, affecting borehole design. Understanding these factors is crucial for assessing the feasibility of BTES.

BTES offers the overall efficiency of 20%-80%, reaching up to 80% is in regions with unfractured, impermeable rock formations, a condition often found in this area. Coupled with the high winter heat demand, BTES could potentially be a favorable solution. However, to meet significant capacity requirements, deploying wide, deep, and/or multiple BTES units is essential.

Conclusion

Scenario 3 stands out as the most economically favorable at extra high energy prices (Alaska price) with a decrease in emissions between 10% and 39%, a decrease in total energy cost of 41% and a rapid payback period of 1.9 years. Additionally, on-site power generation and thermal storage enhance energy system resilience by decoupling electricity and heat demand in CHP, enabling excess heat production to cover electricity demand. However, economic feasibility declines as energy prices decrease.

While scenario 3 remains economically favorable down to medium energy prices, the total energy cost becomes impractical at low energy prices, resulting in an extended payback period of 14.1 to 20.1 years. Additionally, scenario 3 only excels economically under high and extra high energy prices with a 30% tax credit and extra high energy prices without the tax credit. Meanwhile, scenario 2 outperforms economically in all other pricing conditions, exhibiting a total energy cost ranging from 69% to 85% and a payback period of 0.6 to 5.8 years, in contrast to scenario 3's higher total energy cost of 81% to 114% and an extended payback period of 7 to 20.1 years under the same pricing conditions.

Scenario 6 achieves the most significant emissions reduction, ranging from 44% to 65%. However, even in the context of extra high energy prices (Alaska prices) and 30% tax credit/funding, the total energy costs still increase by 21%, and the payback period extends to 21.6 years. While this energy price presents the highest possible savings, the prolonged payback period raises concerns about its economic viability.

All TES scenarios are simulated as PTES due to capacity constraints. Scenarios 4 to 6 reveal challenges with the substantial physical sizes required and considering these challenges, BTES emerges as a spatially efficient alternative, offering flexibility in land use and offering an efficiency of up to 80% in regions with impermeable rock formations. The region's predominant permafrost and sedimentary rock formations, coupled with limited aquifers and groundwater due to the cold climate may pose challenges. Sandy and silty soils, along with variable bedrock depths, affect drilling feasibility. Despite the potential advantages of BTES, meeting large capacity requirements requires deploying wide, deep, and/or multiple BTES units.

5.1.2. CZ 7 – Duluth

Overall Observations

Duluth is in the northern part of the United States and is one of the coldest climate zones that have been simulated. Like Fairbanks, the heat demand is high in the winter and the cooling demand low in the summer, as illustrated in Figure 5-4. The gas and electricity infrastructure are more favorable than in Fairbanks, omitting the need for extra high energy prices.

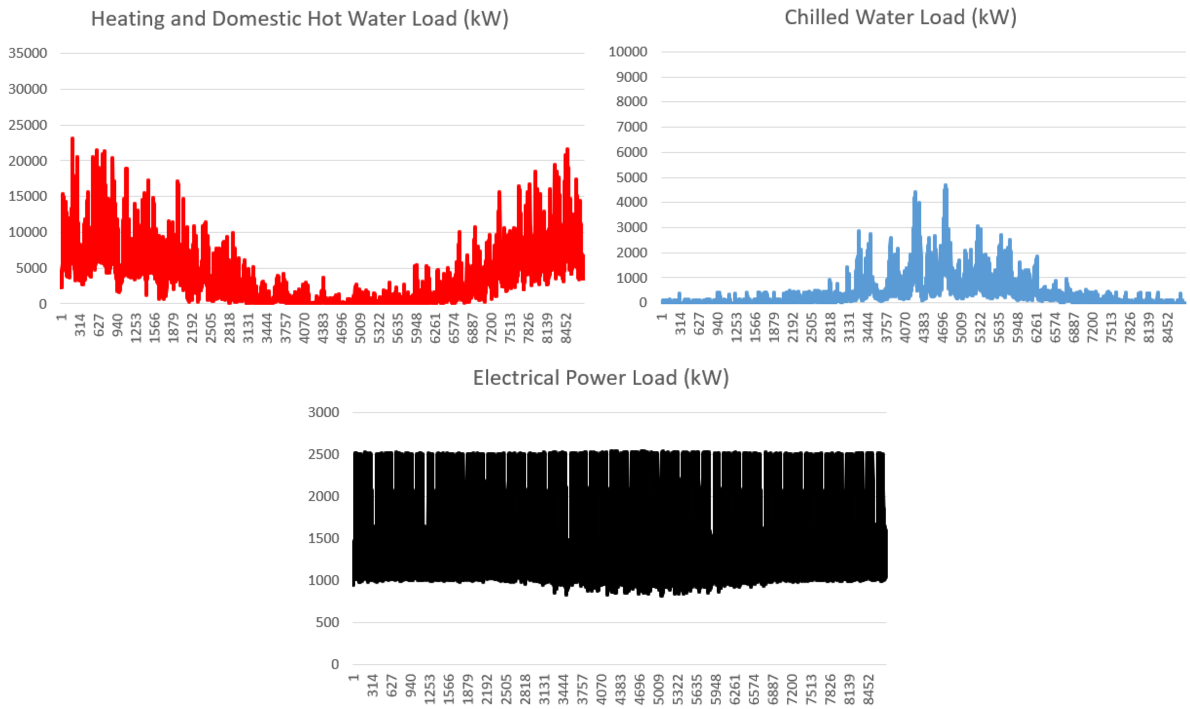


Figure 5-4. Load profiles of the heating, cooling, and electricity demands for Duluth.

As with Fairbanks, the same methodology is applied to this section in terms of scenarios, the reasoning behind them and the presented results. In the baseline scenario “0. Boiler only” establishes a baseline for comparing subsequent technology combinations in terms of emissions and economics.

CHP + TES

Scenario “1. CHP Baseload,” a CHP gas engine is introduced to meet both electricity and heating needs, sized for baseload electricity demand. The gas boiler and imported electricity supplement remaining demands.

Scenario “2. 3x CHP,” the CHP size is tripled compared to scenario 1. This adjustment aligns with the demand profile, where peak electricity demand is approximately three times higher than the baseload.

Scenario “3. 3x CHP with TES,” a 300,000 m3 TES is introduced to illustrate the resilience it brings. This addition enables the CHP to generate excess heat, ensuring more consistent electricity production by allowing for heat storage when demand is low.

Summary

Table 5-4 outlines simulated scenarios for Duluth, following the Fairbanks methodology. It covers TES capacities, SWH field sizes, and CHP capacities. Additionally, the table includes a summary of heating and cooling production, CAPEX breakdown, overall CAPEX, CAPEX after a 30% tax credit reduction, and potential savings from the tax credit reduction.

Table 5-4. Simulation parameters and economics for the Duluth simulation scenarios.

		0. Boiler only	1. CHP baseload	2. 3x CHP	3. 3x CHP w/TES	4. 3x CHP w/small SWH and TES	5. 2x CHP w/medium SWH and TES	6. Large SWH and TES
Component size								
TES	m^3	-	-	-	300,000.00	400,000.00	600,000.00	800,000.00
Solar plant	m^2	-	-	-	-	20,000.00	40,000.00	80,000.00
CHP	MW_{heat}	-	0.85	2.55	2.55	2.55	1.70	-
Energy production								
Heat production	MWh	28,284	28,284	28,284	28,284	28,284	28,284	28,482
Cooling production	MWh	3,374	3,374	3,374	3,374	3,374	3,374	3,374
Investment								
TES	USD	-	-	-	13,600,000	16,300,000	21,100,000	25,200,000
Solar plant	USD	-	-	-	-	5,860,000	11,720,000	23,440,000
CHP added capacity	USD	-	935,000	2,805,000	2,805,000	2,805,000	1,870,000	-
Sum	**USD**	-	**935,000**	**2,805,000**	**16,405,000**	**24,965,000**	**34,690,000**	**48,640,000**
Reduction due to tax credits	30%	-	280,500	841,500	4,921,500	7,489,500	10,407,000	14,592,000
Investment after tax credits	**USD**	-	**654,500**	**1,963,500**	**11,483,500**	**17,475,500**	**24,283,000**	**34,048,000**

Figure 5-5 summarizes the previously detailed emissions across various emission rates and total energy costs for each simulation scenario (Sweetser 2023). All scenarios are directly compared to the baseline scenario, represented as “100%” for total energy cost.

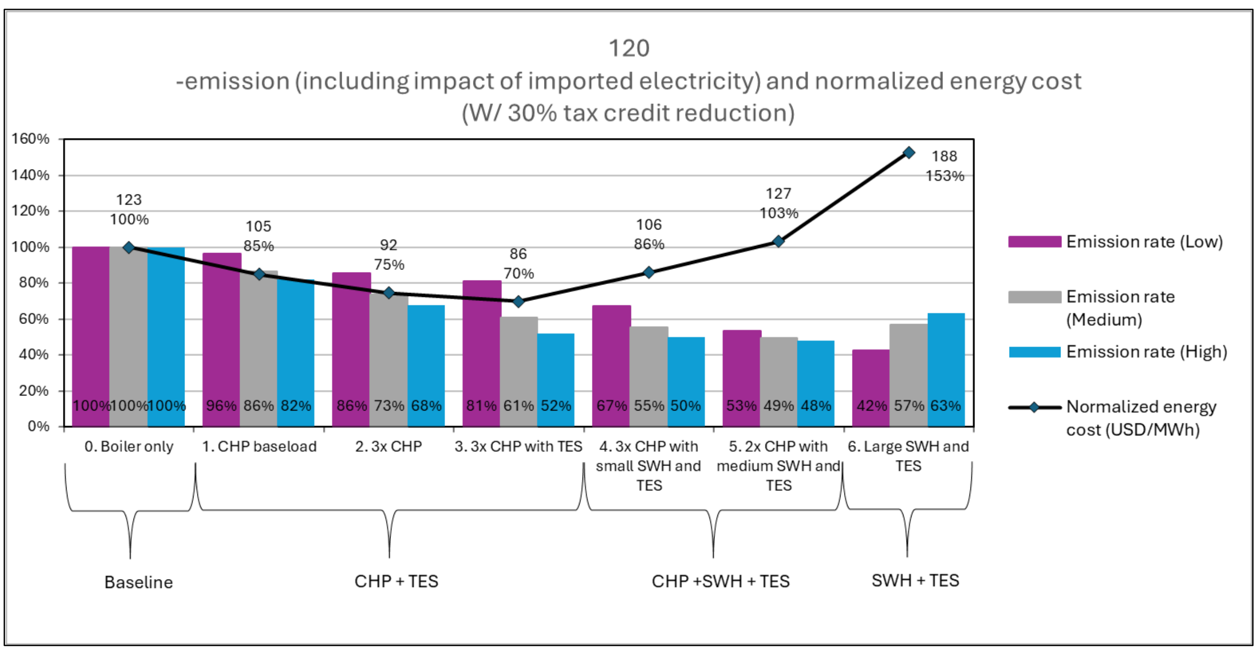


Figure 5-5. Combined graph of the CO_2 emissions at each emission rate and the total energy costs with 30% tax credit reduction for Duluth.

In Figure 5-6, the distribution of electricity demand fulfilled by imported electricity and CHP is depicted. The campus and electric chiller consistently maintain stable electricity consumption across all scenarios.

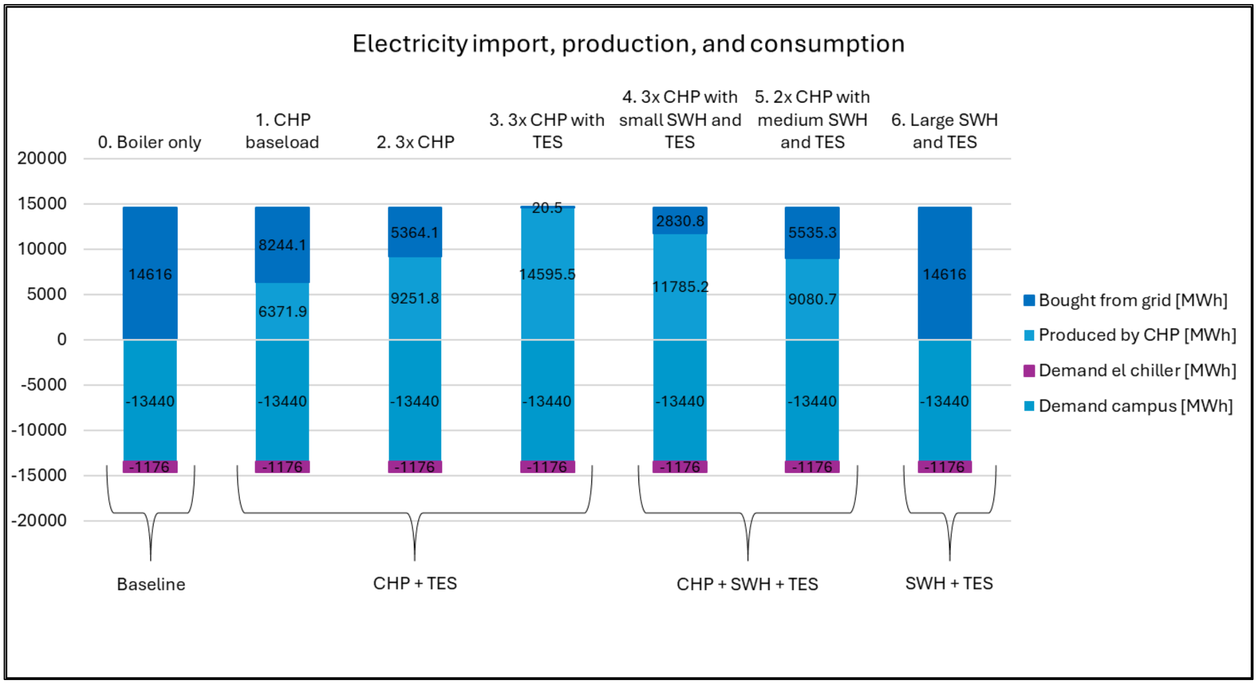


Figure 5-6. Electricity import, production and consumption for the Duluth scenarios.

Table 5-5 offers an economic analysis for each simulated scenario, covering initial investments, OPEX, simple payback period, loan repayment for CAPEX, yearly savings relative to the baseline scenario, and the total energy production cost, as previously summarized and compared in Figure 5-5.

Table 5-5. Breakdown of economics relating to CZ 7 – Duluth simulations at high energy prices and 30% tax credit/funding.

Base calculation		0. Boiler only	1. CHP baseload	2. 3x CHP	3. 3x CHP w/TES	4. 3x CHP w/small SWH and TES	5. 2x CHP w/medium SWH and TES	6. Large SWH and TES
Investment	USD	-	654,500	1,963,500	11,483,500	17,475,500	24,283,000	34,048,000
OPEX*	USD/year	3,904,012	2,910,453	2,461,380	1,628,152	1,772,540	1,900,426	2,977,995
OPEX savings	USD/year	-	993,559	1,442,632	2,275,860	2,131,472	2,003,586	926,017
Simple payback period	Years	-	0.7	1.4	5.0	8.2	12.1	36.8
CAPEX**	USD/year	-	45,815	137,445	803,845	1,223,285	1,699,810	2,383,360
Total Cost Savings	**USD/year**	**-**	**947,744**	**1,305,187**	**1,472,015**	**908,187**	**303,776**	**-1,457,343**
Production cost	USD/MWh	123	105	92	86	106	127	188
Reduction		100%	85%	75%	70%	86%	103%	153%

OPEX calculated in energyPRO.

** Calculated as 7%/year of investment, corresponding to 20-year annuity loan with an interest of app. 3% p.a.

The use of CHP only in scenarios 1 and 2 shows a reduction in emissions between 4% and 32% and a reduction in total energy costs between 15% and 25%. Adding TES to CHP in scenario 3 shows an emission reduction between 19% and 48% and the highest reduction in total energy cost of 30%.

Scenario 4 with CHP, a SWH plant and TES shows that emissions, depending on emission rate, are reduced between 33% and 50%, the total energy cost is reduced by 14% and the payback period is 8.2 years.

Scenario 5 with reduced CHP capacity, a medium SWH plant and TES shows reduced emissions between 47% and 52%, depending on emission rate. The total energy cost is increased by 3% and the payback period is 12.1 years.

Lastly, scenario 6 with no CHP, large SWH plant and TES shows reduced emissions between 37% and 58%, depending on the emission rate. The total energy cost has increased by 53% compared to the baseline, resulting in the longest payback period of 36.8 years.

All of the presented results are based on the high energy prices. Appendix B, section B.2 in Appendix B contains all results from the Duluth simulations can and section B.2.1 contains the economic results under the different pricing conditions.

Scenario 3 demonstrates economic superiority only at high energy prices with a 30% tax credit. Scenario 2 consistently has lower total energy costs across lower pricing conditions, ranging from 81% to 97%, with a payback period of 2.4 to 7 years, compared to scenario 3's range of 91% to 149% and a payback period of 9 to 25.9 years under the same conditions. This shows that scenario 3 is economically favorable only under high energy prices with a 30% tax credit.

TES technology recommendations

Given the scale of the simulated TES capacities, the use of either PTES or BTES is necessary. Similar to Fairbanks, Duluth benefits from favorable conditions for BTES, due to the region's substantial winter heat demand. The area primarily consists of sedimentary rock formations, potentially containing aquifers. Groundwater resources are present but may be limited compared to other regions. Soil composition varies, with sandy and clayey soils prevalent, impacting drilling feasibility. The depth to bedrock varies across the region, affecting borehole design.

Conclusion

Scenario 3 proves to be the most economically favorable with a decrease in emissions between 19% and 48%, a decrease in total energy cost of 30% and a payback period of 5 years. However, scenario 3 proves economically viable primarily under high energy prices with a 30% tax credit. Scenario 2 consistently demonstrates lower total energy costs than scenario 3 under various lower energy prices, ranging from 81% to 97% and a payback period of 2.4 and 7 years, while scenario 3 fluctuates between 91% and 149% and a payback period of 9 to 25.9 years. This highlights that scenario 3 is economically favorable solely under high energy prices with a 30% tax credit.

Scenario 6 has the lowest overall emissions with a decrease in emissions between 37% and 58% but with an increase in total energy costs of 53%, resulting in a payback period of 36.8 years, making this the least economically feasible scenario. Appendix B, section B.2 in Appendix B contains all presented results are from the high energy price simulations and section B.2.1

contains the results from the additional simulated energy prices. As with Fairbanks, the simulated TES sizes indicate that only PTES or BTES are viable technology candidates. Considering BTES, the region features primarily sedimentary rock formations, possibly housing aquifers, though groundwater resources may be limited compared to other areas. Soil composition varies, with sandy and clayey soils dominating, influencing drilling feasibility. The depth to bedrock varies, impacting borehole design.

CHP + SWH + TES

Scenario “4. 3x CHP with small SWH and TES,” TES capacity increases to 400,000 m3 and a 20,000 m2 SWH plant supplements the CHP units. The SWH plant now provides almost all the heat previously generated by the gas boiler, with enhanced TES capacity to provide resilience during periods of low SWH plant yield.

Scenario “5. 2x CHP with medium SWH and TES,” the aim is to showcase the impact of SWH partially replacing CHP heat production. The SWH area is doubled to 40,000 m2, and TES capacity is increased to 600,000 m3 for enhanced resilience. With reduced CHP heat production, its capacity is now twice the electricity baseload, necessitating some electricity import since the CHP alone cannot meet the entire demand.

SWH + TES

In the final scenario, “6. Large SWH and TES,” all heat comes from a doubled 80,000 m2 SWH field, and the CHP is eliminated. Increasing the TES capacity to 800,000 m3 ensures resilience. With no CHP, all electricity demand is met through imports, but this shifts the emission reduction trend, resulting in overall increased emissions with increasing emission rates.

5.1.3. CZ 6B – Helena

Overall Observations

Similar to Duluth, Helena is located in the northern part of the United States, but in a slightly warmer climate zone. This is reflected in the lower heating demand in the winter and higher cooling demand in the summer, as illustrated in Figure 5-7.

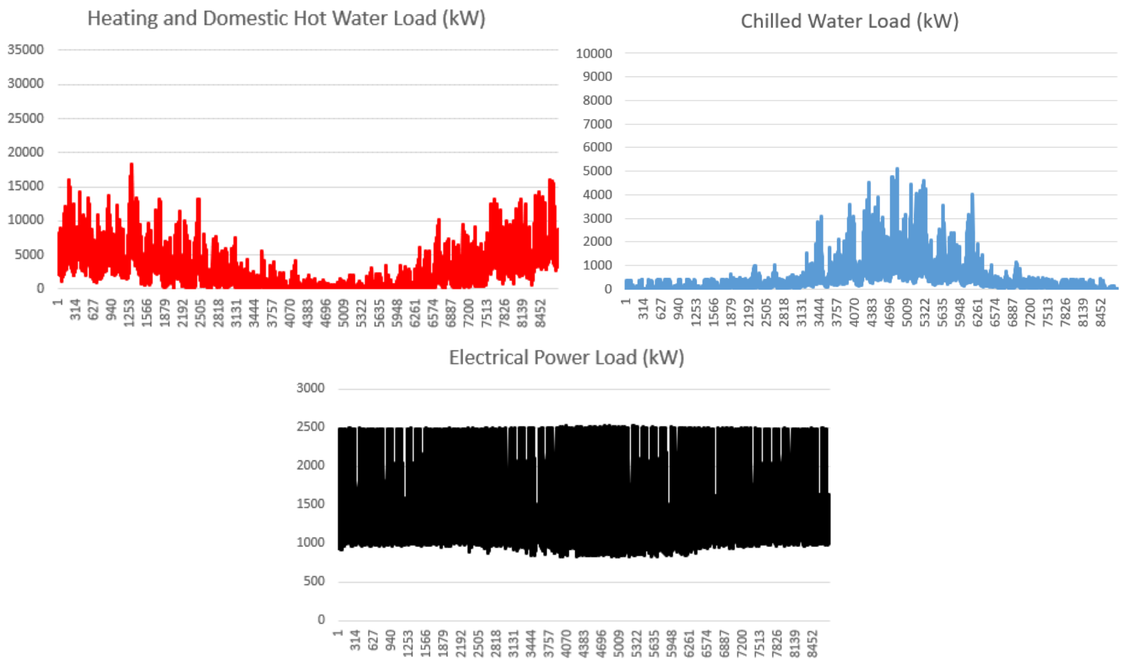


Figure 5-7. Load profiles of the heating, cooling, and electricity demands for Helena.

The approach employed in this section mirrors that of the previous simulations, maintaining a concise level of descriptive detail for the sake of clarity and efficiency.

As with the previously simulated climate zones, in the baseline “0. Boiler only” scenario, heat is from a gas boiler, cooling from an electric chiller (imported electricity), and electricity demand met by imported electricity. This sets the benchmark for comparing CO_2 emissions and economics in subsequent scenarios.

CHP + TES

Scenario “1. CHP Baseload” with CHP capacity to cover the electricity baseload. CO_2 emissions are reduced by 7% in the case with a low emission rate, 17% with a medium emission rate and 21% with a high emission rate. The total energy cost is reduced by 24% and the payback period is estimated to be 0.7 years.

Scenario “2. 3x CHP” triples the CHP capacity compared to scenario 1. CO_2 emissions are reduced by 9% in the case with a low emission rate, 24% with a medium emission rate and 30% with a high emission rate. The total energy cost is reduced by 33% and the payback period is estimated to be 1.5 years.

Scenario “3. 3x CHP with TES” is the same as scenario 2 but with 320,000 m^3 TES to provide resiliency. CO_2 emissions are reduced by 16% in the case with a low emission rate, 41% with a medium emission rate and 52% with a high emission rate. The total energy cost is reduced by 40% and the payback period is estimated to be 5.2 years.

CHP + SWH + TES

Scenario "4. 3x CHP with small SWH and TES" with 500,000 m^3 TES and a 20,000 m^2 SWH plant. CO_2 emissions are reduced by 30% in the case with a low emission rate, 41% with a medium emission rate and 45% with a high emission rate. The total energy cost is reduced by 13% and the payback period is estimated to be 10.4 years.

Scenario "5. 2x CHP with medium SWH and TES" with 575,000 m^3 TES and a 29,000 m^2 SWH plant. CO_2 emissions are reduced by 66% in the case with a low emission rate, 67% with a medium emission rate and remain at 67% with a high emission rate. The total energy cost is increased by 4% and the payback period is estimated to be 16 years.

Summary

Table B-21 in Appendix B details TES capacities, SWH field sizes, and CHP capacities for the Helena simulations and provides an overview of heating and cooling production, CAPEX breakdown, overall CAPEX, CAPEX after a 30% tax credit reduction, and potential savings from the tax credit reduction.

Figure B-72 summarizes total energy costs for each simulation scenario at each energy price level without the 30% tax credit reduction and Figure B-73 with the tax credit reduction. Figure B-81 summarizes the CO_2 emissions for each simulation scenario at each emission rate for both fuel and imported electricity. All figures are comparing the simulated scenarios directly to the "0. Boiler only" baseline, represented as "100%" for total energy cost.

Figure B-77 shows the distribution of electricity demand met by imported electricity and CHP.

Table B-27 provides an economic analysis for each simulated scenario, encompassing initial investments, OPEX, simple payback period, loan repayment for CAPEX and yearly savings relative to the "0. Boiler only" baseline, all at the high energy price with 30% tax credit reduction.

The scenario with the best overall economics is scenario "3. 3x CHP with TES" with a 40% total energy cost reduction compared to the baseline scenario and a payback period of 5.2 years. This scenario, however, does not present the lowest overall emissions, being between a reduction of 16% to 52% compared to the baseline scenario depending on emission rate. The scenario with the lowest overall emissions is scenario "5. 2x CHP with medium SWH and TES" with emission reductions between 46%-47% depending on emission rate. However, the total energy cost has increased by 4% compared to the baseline scenario and a payback period of 16 years, making this scenario less economically favorable.

The results presented are derived from high energy prices, as they display the highest savings and therefore the most prominent economic effects. All the simulation results for Helena are available in Appendix B, section B.3 while economic results under various pricing conditions are provided in section B.3.1.

As previously mentioned, scenario 3 demonstrates the lowest total energy cost of 60% relative to the baseline with a 5.2-year payback period at high energy prices with 30% tax credit. At the same energy prices without tax credit, scenarios 2 and 3 have almost equal total energy costs of 69% and 70%, respectively, relative to the baseline, with scenario 2 having a 2.1-year payback period compared to scenario 3's 7.4 years due to higher investment. Under low and medium energy prices with and without tax credit, scenario 2 consistently exhibits the lowest total energy cost (ranging from 89% to 107% relative to the baseline) and a payback period between 2.7 and 7.7 years. Under the same conditions, scenario 3's total energy cost ranges between 97% and 170%, with a payback time between 9.3 and 26.7 years. Therefore, scenario 3 is economically favorable only under high energy prices with tax credit, and under all other pricing conditions, scenario 2 stands as the most economically feasible option.

TES technology recommendations

All simulated TES capacities are modeled as PTES due to their significant size, rendering TTES impractical. An alternative consideration could be BTES, as the TES capacities in later scenarios would demand substantial space if PTES were employed.

Helena presents promising conditions for BTES, given the high winter heat demand and the surrounding rocky terrain. The area primarily consists of mountainous terrain with sedimentary and metamorphic rock formations, potentially containing limited aquifers. Groundwater resources may vary depending on the specific geological features. Soil composition varies, with rocky and clayey soils prevalent in mountainous areas. However, it is crucial to understand the underground conditions thoroughly, as the presence of karst terrain may pose challenges, potentially hindering the grouting of boreholes.

Conclusion

In Helena, scenario “3. 3x CHP with TES” is the most economically viable, reducing total energy costs by 40% and a payback period of 5.2 years. Yet, it lags in emissions reduction (16%-52%). Scenario “5. 2x CHP with medium SWH and TES” leads in emissions reduction (66%-67%) but incurs a 28% increase in total energy costs and a payback period of 16 years, making this scenario less economically favorable.

Results are based on high energy prices. Scenario 3 excels with a 60% total energy cost reduction and 5.2-year payback under high prices with a 30% tax credit. Scenario 2 consistently outperforms under other conditions, displaying lower total energy costs (89%-107%) and a payback period of 2.7-7.7 years. Scenario 3 is economically preferable only under high energy prices with a tax credit, while scenario 2 is the most feasible under other pricing conditions.

Regarding TES, all capacities are modeled as PTES due to their size. BTES is a potential alternative for Helena, but understanding underground conditions is crucial. The area is mostly mountainous, featuring sedimentary and metamorphic rock formations that might have some aquifers. Groundwater availability depends on local geological features. In mountainous areas, the soil is typically rocky and clayey. The presence of karst terrain may pose challenges, potentially hindering the grouting of boreholes.

SWH + TES

The final scenario, “6. Large SWH and TES” with 650,000 m^3 TES and a 38,000 m^2 SWH plant. CO_2 emissions are reduced by 45% in the case with a low emission rate, 31% with a medium emission rate and 26% with a high emission rate. The total energy cost is increased by 28% and the payback period is estimated to be 37.6 years.

5.1.4. CZ 6A – Minneapolis

Overall Observations

Minneapolis is geographically close to Duluth but further from Lake Superior, resulting in a warmer climate, which is reflected in a more balanced heating and cooling demand, as illustrated Figure 5-8.

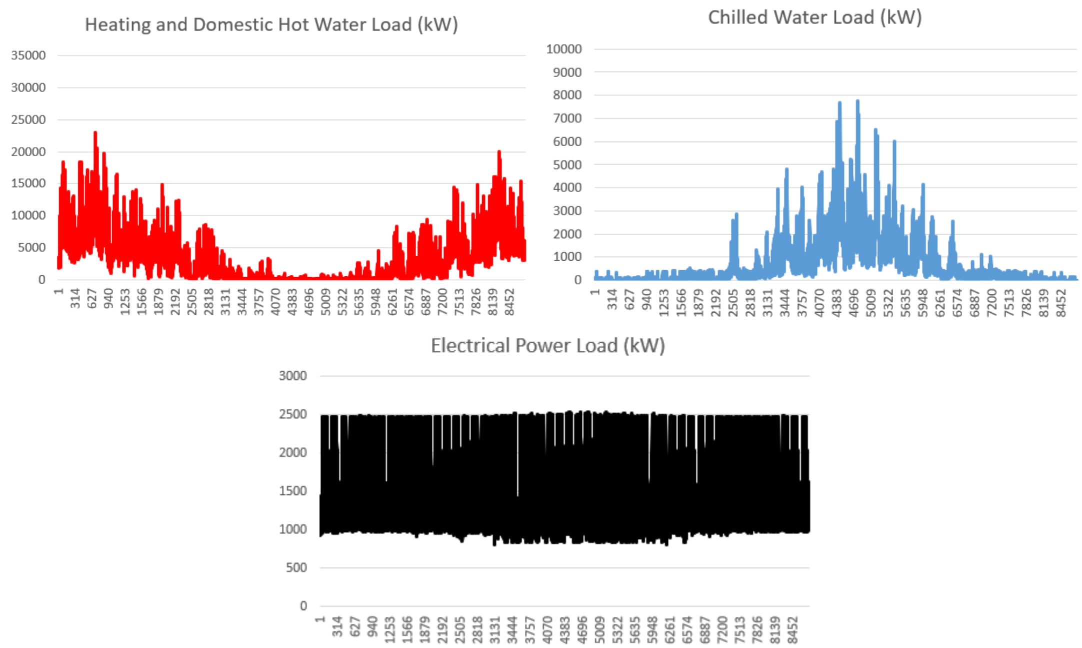


Figure 5-8. Load profiles of the heating, cooling, and electricity demands for Minneapolis.

As with the previously simulated climate zones, the baseline “0. Boiler only” scenario sets the benchmark for comparing CO_2 emissions and economics in subsequent scenarios.

CHP + TES

Scenario “1. CHP Baseload” with CHP to cover the baseload electricity demand. CO_2 emissions are reduced by 6% in the case with a low emission rate, 14% with a medium emission rate and 18% with a high emission rate. The total energy cost is reduced by 21% and the payback period is estimated to be 0.8 years.

Scenario “2. 3x CHP” with tripled CHP capacity to potentially cover entire electricity demand. CO_2 emissions are reduced by 8% in the case with a low emission rate, 21% with a medium emission rate and 26% with a high emission rate. The total energy cost is reduced by 29% and the payback period is estimated to be 1.6 years.

Scenario “3. 3x CHP with TES” is the same as scenario 2 but with 400,000 m^3 TES. CO_2 emissions are reduced by 15% in the case with a low emission rate, 39% with a medium emission rate and 50% with a high emission rate. The total energy cost is reduced by 37% and the payback period is estimated to be 5.7 years.

CHP + SWH + TES

Scenario “4. 3x CHP with small SWH and TES” with 500,000 m^3 TES and a 15,000 m^2 SWH plant. CO_2 emissions are reduced by 27% in the case with a low emission rate, 45% with a medium emission rate and 52% with a high emission rate. The total energy cost is reduced by 28% and the payback period is estimated to be 8 years.

Scenario "5. 2x CHP with medium SWH and TES" with reduced CHP capacity, 500,000 m^3 TES and a 30,000 m^2 SWH plant. CO_2 emissions are reduced by 37% in the case with a low emission rate, 41% with a medium emission rate and 43% with a high emission rate. The total energy cost is decreased by 10% and the payback period is estimated to be 12.3 years.

SWH + TES

The final scenario, "6. Large SWH and TES," with no CHP, 580,000 m^3 TES and a 58,000 m^2 SWH plant. CO_2 emissions are reduced by 48% in the case with a low emission rate, 34% with a medium emission rate and 28% with a high emission rate. The total energy cost is increased by 26% and the payback period is estimated to be 36.2 years.

Summary

Table B-35 details TES capacities, SWH field sizes, and CHP capacities for the Minneapolis simulations and provides an overview of heating and cooling production, CAPEX breakdown, overall CAPEX, CAPEX after a 30% tax credit reduction, and potential savings from the tax credit reduction.

Figure B-98 summarizes total energy costs for each simulation scenario at each energy price level without the 30% tax credit reduction and Figure B-99 with the tax credit reduction. Figure B-107 summarizes the CO_2 emissions for each simulation scenario at each emission rate for both fuel and imported electricity. All figures are comparing the simulated scenarios directly to the "0. Boiler only" baseline, represented as "100%" for total energy cost.

Figure B-103 shows the distribution of electricity demand met by imported electricity and CHP.

Table B-34 provides an economic analysis for each simulated scenario, encompassing initial investments, OPEX, simple payback period, loan repayment for CAPEX and yearly savings relative to the "0. Boiler only" baseline, all at the high energy price with 30% tax credit reduction.

The scenario demonstrating the most favorable overall economics is "3. 3x CHP with TES," achieving a 37% reduction in total energy costs compared to the baseline and a 5.7-year payback period. However, it does not yield the lowest overall emissions, showing reductions between 15% and 50% depending on the emission rate. In contrast, "5. 2x CHP with medium SWH and TES" attains the lowest overall emissions, with reductions ranging from 37% to 43%. Nonetheless, this scenario sees an 11% increase in total energy costs compared to the baseline, coupled with a 12.3-year payback period, rendering it less economically favorable.

The outcomes presented are based on high energy prices with 30% tax credit, showcasing substantial savings and impactful economic implications. Appendix B, section B.4 contains detailed simulation results for Minneapolis, and section B.4.1 contains economic outcomes under different pricing scenarios.

Scenario 3 performs best financially only at high energy prices with a 30% tax credit, displaying a 63% total energy cost relative to the baseline and a 5.7-year payback. In contrast, Scenario 2 is economically superior under all other pricing conditions, with total energy costs between 92% and 114% relative to the baseline and a payback period of 2.3 to 8.2 years. Scenario 3, in these pricing conditions, shows total energy costs between 93% and 184%, with a payback period ranging from 8.1 to 29.2 years. Therefore, scenario 3 is financially feasible exclusively at high energy prices with a 30% tax credit, while scenario 2 excels under all other pricing conditions.

TES Technology Recommendations

As with every previously simulated climate zone, all TES capacities are modeled as PTES due to their significant size, rendering TTES impractical. An alternative consideration could be BTES, as the TES capacities in later scenarios would demand substantial space if PTES were employed.

Minneapolis, near Duluth, shares similar recommendations for BTES implementation. The presence of numerous lakes in the surrounding terrain underscores the importance of a thorough understanding of underground conditions. Avoiding placement of BTES units near fast-flowing aquifers is essential to maintain higher efficiency.

Conclusion

In Minneapolis, "3. 3x CHP with TES" stands out as the most economically favorable scenario, with a 37% reduction in total energy costs and a 5.7-year payback period. Although it does not achieve the lowest emissions, with reductions ranging from 15% to 50%, its financial feasibility is notable. Conversely, "5. 2x CHP with medium SWH and TES" achieves the lowest overall emissions (37%-43%) but faces an 11% cost increase and a 12.3-year payback, making it less economically favorable.

These outcomes are based on high energy prices with a 30% tax credit, showcasing significant savings. For detailed results, refer to Appendix B, sections B.4 and B.4.1. Scenario 3 excels only under these specific conditions, while Scenario 2 outperforms in others.

Scenario 3 excels financially at high energy prices with a 30% tax credit, showing a 37% total energy cost reduction and a 5.7-year payback. Scenario 2 outperforms in other pricing conditions, with total energy costs between 92% and 114%, and a payback period of 2.3 to 8.2 years. In the same pricing conditions, scenario 3 presents total energy costs ranging from 93% to 184%, with a payback period spanning 8.1 to 29.2 years, making this scenario economically feasible only at high energy prices with a 30% tax credit, while scenario 2 excels under other pricing conditions.

All TES capacities are modeled as PTES due to their substantial size, making TTES impractical. An alternative, BTES, is worth considering for later scenarios, given its space efficiency. Minneapolis, akin to Duluth, supports BTES implementation, emphasizing the need for a thorough understanding of underground conditions, especially in areas with numerous lakes. Careful placement, avoiding fast-flowing aquifers, is crucial for optimal efficiency.

5.1.5. CZ 5C – Vancouver

Overall Observations

Situated in the northern part of the United States along the west coast, Vancouver experiences lower heat demand in winter, yet maintains consistency throughout the summer. Similarly, cooling demand decreases in summer but remains consistent during winter (Figure 5-9).

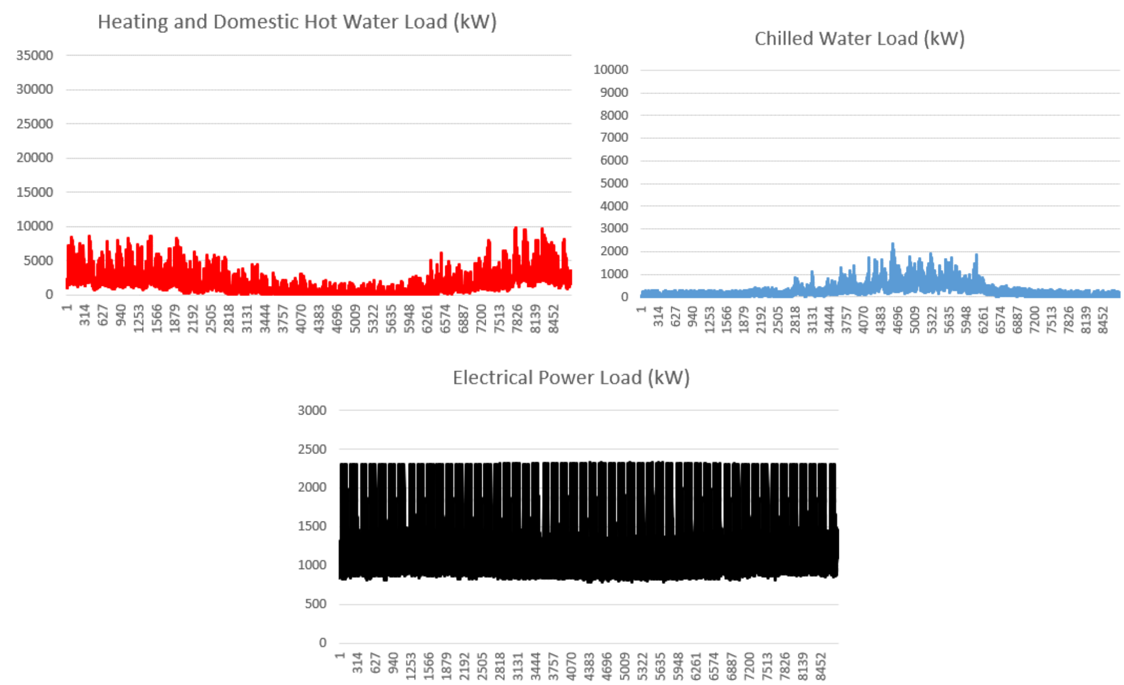


Figure 5-9. Load profiles of the heating, cooling, and electricity demands for Vancouver.

As with the previously simulated climate zones, the baseline "0. Boiler only" scenario sets the benchmark for comparing CO_2 emissions and economics in subsequent scenarios.

CHP + TES

Scenario "1. CHP Baseload" with CHP sized to meet baseload electricity demand. CO_2 emissions are reduced by 9% in the case with a low emission rate, 21% with a medium emission rate and 26% with a high emission rate. The total energy cost is reduced by 29% and the payback period is estimated to be 0.7 years.

Scenario "2. 3x CHP" with tripled CHP capacity compared to scenario 1. CO_2 emissions are reduced by 11% in the case with a low emission rate, 26% with a medium emission rate and 32% with a high emission rate. The total energy cost is reduced by 34% and the payback period is estimated to be 1.7 years.

Scenario "3. 3x CHP with TES" is the same as scenario 2 but with 130,000 m^3 TES. CO_2 emissions are reduced by 15% in the case with a low emission rate, 37% with a medium emission rate and 46% with a high emission rate. The total energy cost is reduced by 37% and the payback period is estimated to be 4.6 years.

CHP + SWH + TES

Scenario "4. 3x CHP with small SWH and TES" same as scenario 3 but with 200,000 m^3 TES and a 15,000 m^2 SWH plant. CO_2 emissions are reduced by 25% in the case with a low emission rate, 31% with a medium emission rate and 34% with a high emission rate. The total energy cost is reduced by 8% and the payback period is estimated to be 11.1 years.

Scenario "5. 2x CHP with medium SWH and TES" with reduced CHP capacity, 270,000 m^3 TES and a 25,000 m^2 SWH plant. CO_2 emissions are reduced by 31% in the case with a low emission rate, 27% with a medium emission rate and 25% with a high emission rate. The total energy cost is increased by 12% and the payback period is estimated to be 22.1 years.

SWH + TES

The final scenario, "6. Large SWH and TES" with no CHP, 330,000 m^3 TES and a 32,500 m^2 SWH plant. CO_2 emissions are reduced by 36% in the case with a low emission rate, 24% with a medium emission rate and 19% with a high emission rate. The total energy cost is increased by 27% and the payback period is estimated to be 44.1 years.

Summary

Table B-35 details TES capacities, SWH field sizes, and CHP capacities for the Vancouver simulations and gives an overview of heating and cooling production, CAPEX breakdown, overall CAPEX, CAPEX after a 30% tax credit reduction, and potential savings from the tax credit reduction.

Figure B-124 summarizes total energy costs for each simulation scenario at each energy price level without the 30% tax credit reduction and Figure B-125 with the tax credit reduction. Figure B-133 summarizes the CO_2 emissions for each simulation scenario at each emission rate for both fuel and imported electricity. All figures are comparing the simulated scenarios directly to the "0. Boiler only" baseline, represented as "100%" for total energy cost.

Figure B-129 shows the distribution of electricity demand met by imported electricity and CHP.

Table B-41 provides an economic analysis for each simulated scenario, encompassing initial investments, OPEX, simple payback period, loan repayment for CAPEX and yearly savings relative to the "0. Boiler only" baseline, all at the high energy price with 30% tax credit reduction.

Scenario 3 performs the best economically, with a 37% reduction in total energy costs and a relatively short 4.6-year payback period. It also achieves the lowest potential emissions, ranging from 15% to 46%. Scenario 5, while maintaining consistent emission reductions between 25% and 31%, sees a 12% increase in total energy costs and a prolonged payback period of 22.1 years, making it less financially feasible.

The presented results are derived from high energy prices with a 30% tax credit, highlighting the highest possible savings and thereby the most prominent economic effects. Appendix B, section B.5 contains detailed simulation results for Vancouver, and section B.5.1 contains economic outcomes under various pricing scenarios.

Like the other climate zones, scenario 3 emerges as the most economically favorable only under high energy prices with a 30% tax credit. Under all other pricing conditions, scenario 2 consistently demonstrates the lowest total energy cost, ranging from 83% to 109% relative to the baseline, with a payback period spanning from 2.4 to 8.7 years. Conversely, scenario 3, under these conditions, exhibits a total energy cost between 86% and 155%, coupled with a payback period ranging from 6.6 to 23.8 years.

TES Technology Recommendations

PTES is selected for modeling all TES capacities due to their considerable size, making TTES impractical. An alternative to consider is BTES, as using PTES in later scenarios would potentially require extensive space.

Since Vancouver is situated near the west coast at a low altitude, it demands special considerations for BTES. The groundwater's higher position in these areas may restrict the feasible depths for BTES construction, potentially affecting its thermal capacity especially since medium and high-temperature BTES (50-90°C) is best suited to high latitudes where excess heat in summer can be stored for winter discharge.

Conclusion

Scenario 3 proves to be the most economically favorable, with a 37% reduction in total energy costs and a 4.6-year payback period. It also achieves the lowest potential emissions, ranging from 15% to 46%. In contrast, Scenario 5 maintains consistent emission reductions between 25% and 31%, but its drawbacks include a 12% increase in total energy costs and a prolonged payback period of 22.1 years, making it less financially feasible.

These outcomes are based on high energy prices with a 30% tax credit. Appendix B, section B.5 contains detailed simulation results for Vancouver, and section B.5.1 contains economic outcomes under various pricing scenarios.

Similar to other climate zones, scenario 3 excels economically only under high energy prices with a 30% tax credit. In all other pricing conditions, scenario 2 consistently demonstrates the lowest total energy cost, ranging from 83% to 109% relative to the baseline, with a payback period from 2.4 to 8.7 years. On the contrary, scenario 3, under these conditions, exhibits a total energy cost between 86% and 155%, coupled with a payback period ranging from 6.6 to 23.8 years.

For modeling TES capacities, PTES is chosen due to its suitability for significant sizes, making TTES impractical. However, an alternative worth considering is BTES, especially for later scenarios, as using PTES may demand extensive space.

Given Vancouver's unique geographical considerations, especially its low altitude near the west coast, specific attention is required for BTES implementation. The higher position of groundwater in these areas may limit feasible depths for BTES construction, potentially affecting its thermal capacity, particularly since medium and high-temperature BTES (50-90°C) is best suited to high latitudes where excess heat in summer can be stored for winter discharge.

5.1.6. CZ 5B – Denver

Overall Observations

Denver is in the middle of the United States, far from the coasts, resulting in greater temperature extremes. Figure 5-10 shows a balanced heating demand peaking in the winter and similar cooling demand peaking in the summer.

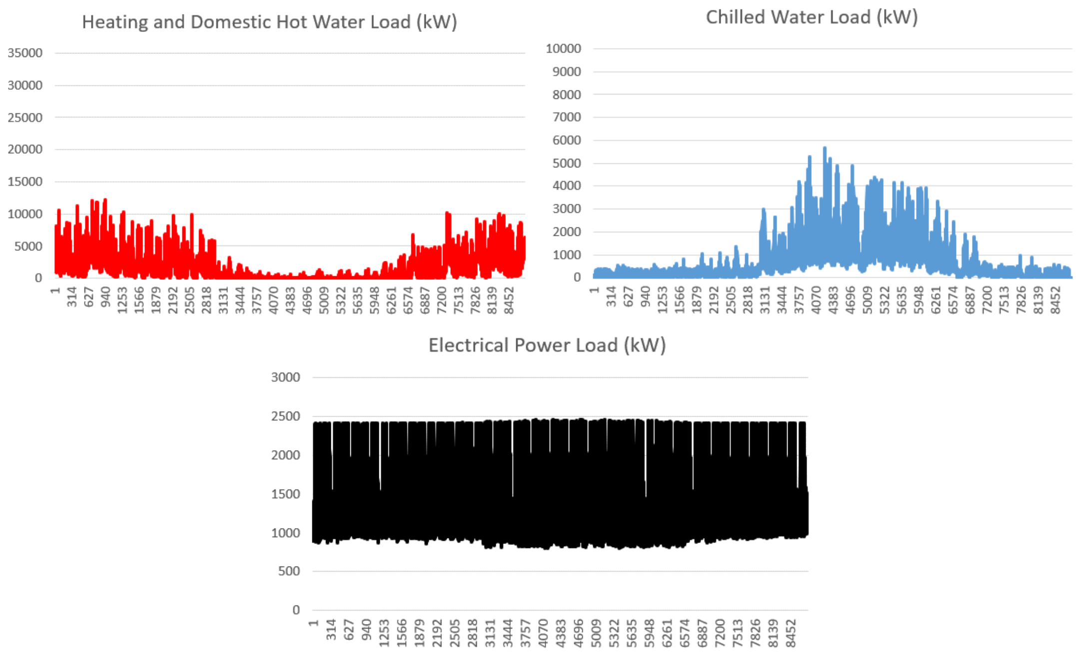


Figure 5-10. Load profiles of the heating, cooling, and electricity demands for Denver.

As with the previously simulated climate zones, the baseline “0. Boiler only” scenario sets the benchmark for comparing CO_2 emissions and economics in subsequent scenarios.

CHP + TES

Scenario “1. CHP Baseload” with CHP sized to meet baseload electricity demand. CO_2 emissions are reduced by 6% in the case with a low emission rate, 15% with a medium emission rate and 19% with a high emission rate. The total energy cost is reduced by 21% and the payback period is estimated to be 0.9 years.

Scenario “2. 3x CHP” with tripled CHP capacity compared to scenario 1. CO_2 emissions are reduced by 8% in the case with a low emission rate, 20% with a medium emission rate and 24% with a high emission rate. The total energy cost is reduced by 25% and the payback period is estimated to be 2 years.

Scenario “3. 3x CHP with TES” is the same as scenario 2 but with 130,000 m^3 TES. CO_2 emissions are reduced by 13% in the case with a low emission rate, 32% with a medium emission rate and 39% with a high emission rate. The total energy cost is reduced by 31% and the payback period is estimated to be 4.9 years.

CHP + SWH + TES

Scenario “4. 3x CHP with small SWH and TES” same as scenario 3 but with 180,000 m^3 TES and 10,000 m^2 SWH plant. CO_2 emissions are reduced by 25% in the case with a low emission rate, 26% with a medium emission rate and 27% with a high emission rate. The total energy cost is reduced by 6% and the payback period is estimated to be 10.8 years.

Scenario “5. 2x CHP with medium SWH and TES,” 200,000 m^3 TES and 18,000 m^2 SWH. CO_2 emissions are reduced by 29% in the case with a low emission rate, 24% with a medium emission rate and 22% with a high emission rate. The total energy cost is increased by 6% and the payback period is estimated to be 18.5 years.

SWH + TES

The final scenario, “6. Large SWH and TES” with reduced CHP capacity, 250,000 m^3 TES and a 26,000 m^2 SWH plant. CO_2 emissions are reduced by 33% in the case with a low emission rate, 21% with a medium emission rate and 17% with a high emission rate. The total energy cost is increased by 18% and the payback period is estimated to be 37.3 years.

Summary

Table B-42 details TES capacities, SWH field sizes, and CHP capacities for the Denver simulations and provides an overview of heating and cooling production, CAPEX breakdown, overall CAPEX, CAPEX after a 30% tax credit reduction, and potential savings from the tax credit reduction.

Figure B-150 summarizes total energy costs for each simulation scenario at each energy price level without the 30% tax credit reduction and Figure B-151 with the tax credit reduction. Figure B-133 summarizes the CO_2 emissions for each simulation scenario at each emission rate for both fuel and imported electricity. All figures are comparing the simulated scenarios directly to the “0. Boiler only” baseline, represented as “100%” for total energy cost.

Figure B-155 shows the distribution of electricity demand met by imported electricity and CHP.

Table B-48 provides an economic analysis for each simulated scenario, encompassing initial investments, OPEX, simple payback period, loan repayment for CAPEX and yearly savings relative to the “0. Boiler only” baseline, all at the high energy price with 30% tax credit reduction.

Scenario 3 emerges as the most economically advantageous, showcasing a 31% reduction in total energy costs compared to the baseline and a 4.9-year payback period. However, it falls short in achieving the lowest overall emissions, with reductions ranging from 13% to 39%, depending on the emission rate. On the other hand, Scenario 5, involving 2x CHP with medium SWH and TES, achieves the lowest overall emissions, with reductions ranging from 22% to 29%. Nevertheless, this scenario experiences a 22% increase in total energy costs compared to the baseline and comes with an 18.5-year payback period, making it less economically favorable.

The present results are from high energy prices with a 30% tax credit, emphasizing the most significant savings and economic implications. For all simulation outcomes for Denver, refer to Appendix B, section B.6. For economic results under various pricing scenarios, see section B.6.1.

Scenario 3 appears as the most economically favorable under high energy prices, both with and without the 30% tax credit, displaying a total energy cost ranging from 69% to 76% and a payback period spanning from 4.9 to 6.9 years. However, under all other pricing conditions, with or without the 30% tax credit, scenario 2 proves to be the more financially advantageous option, presenting a total energy cost between 83% and 94% and a payback period ranging from 5.2 to 10.4 years. In contrast, scenario 3, under these pricing conditions, exhibits a total energy cost between 83% and 126%, coupled with a payback period ranging from 8.7 to 24.9 years.

TES Technology Recommendations

All TES capacities are modeled as PTES due to their significant size, rendering TTES impractical. Considering BTES as an alternative is warranted, given that PTES in later scenarios would require substantial space.

BTES can be a suitable choice in Denver due to its high latitude and significant temperature fluctuations between seasons. The geological conditions, including its mountainous terrain, may provide suitable locations for deep boreholes. However, the presence of aquifers or thick unsaturated zones could affect heat transfer efficiency; thus a thorough soil examination is warranted.

Conclusion

Scenario 3 emerges as the most economically advantageous, with a 31% reduction in total energy costs and a 4.9-year payback period. Despite achieving the overall emission reductions between 13% and 39%, it falls short compared to Scenario 5, which shows reductions ranging from 22% to 29%. However, scenario 5 leads to a 22% increase in total energy costs and an 18.5-year payback period, making it less economically favorable.

The results are based on high energy prices with a 30% tax credit, emphasizing significant savings and economic implications. For detailed simulation outcomes for Denver, refer to Appendix B, section B.6. For economic results under various pricing scenarios, consult section B.6.1.

Scenario 3 proves economically favorable under high energy prices, with a total energy cost ranging from 69% to 76% and a 4.9 to 6.9-year payback period. However, under all other pricing conditions, with or without the 30% tax credit, scenario 2 emerges as the more financially advantageous option, presenting a total energy cost between 83% and 94% and a payback period ranging from 5.2 to 10.4 years. In contrast, Scenario 3 exhibits a total energy cost between 83% and 126%, with a payback period ranging from 8.7 to 24.9 years.

All TES capacities are modeled as PTES due to their significant size, rendering TTES impractical. Considering BTES as an alternative is warranted, given that PTES in later scenarios would require substantial space.

BTES could be suitable in Denver due to its high latitude and significant temperature fluctuations. The mountainous terrain offers potential locations for deep boreholes, but the presence of aquifers or thick unsaturated `zones may affect heat transfer efficiency, necessitating a thorough soil examination.

5.1.7. CZ 5A – Chicago

Overall Observations

Chicago is located close to Lake Michigan in the Midwest United States and has high heating demands in the winter and high cooling demand in the summer, as illustrated in Figure 5-11.

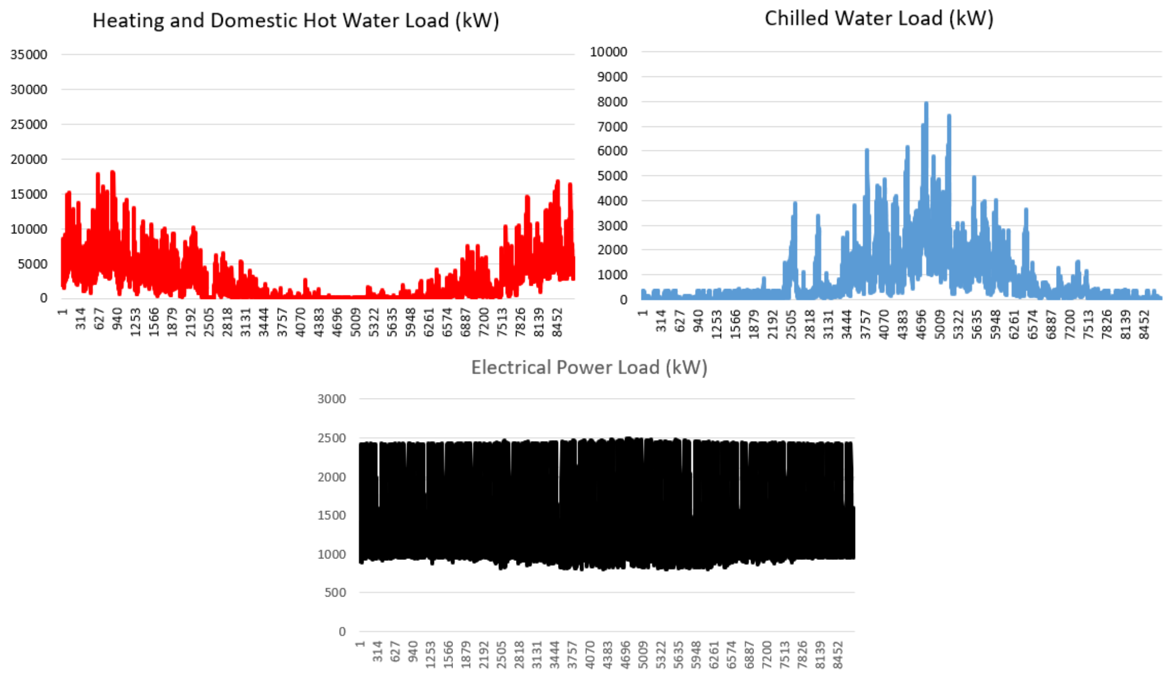


Figure 5-11. Load profiles of the heating, cooling, and electricity demands for Chicago.

As with the previously simulated climate zones, the baseline “0. Boiler only” scenario sets the benchmark for comparing CO_2 emissions and economics in subsequent scenarios.

CHP + TES

Scenario “1. CHP Baseload” with CHP sized to meet baseload electricity demand. CO_2 emissions are reduced by 4% in the case with a low emission rate, 13% with a medium emission rate and 17% with a high emission rate. The total energy cost is reduced by 21% and the payback period is estimated to be 0.8 years.

Scenario “2. 3x CHP” with tripled CHP capacity compared to scenario 1. CO_2 emissions are reduced by 5% in the case with a low emission rate, 18% with a medium emission rate and 23% with a high emission rate. The total energy cost is reduced by 26% and the payback period is estimated to be 1.8 years.

Scenario “3. 3x CHP with TES” is the same as scenario 2 but with 420,000 m^3 TES. CO_2 emissions are reduced by 9% in the case with a low emission rate, 37% with a medium emission rate and 48% with a high emission rate. The total energy cost is reduced by 37% and the payback period is estimated to be 6 years.

CHP + SWH + TES

Scenario “4. 3x CHP with small SWH and TES” same as scenario 3 but with 460,000 m^3 TES and a 12,000 m^2 SWH plant. CO_2 emissions are reduced by 26% in the case with a low emission rate, 42% with a medium emission rate and 49% with a high emission rate. The total energy cost is reduced by 27% and the payback period is estimated to be 8.6 years.

Scenario "5. 2x CHP with medium SWH and TES," 500,000 m^3 TES and 24,000 m^2 SWH. CO_2 emissions are reduced by 32% in the case with a low emission rate, 38% with a medium emission rate and 40% with a high emission rate. The total energy cost is increased by 12% and the payback period is estimated to be 13.3 years.

SWH + TES

The final scenario, "6. Large SWH and TES" with reduced CHP capacity, 500,000 m^3 TES and a 47,000 m^2 SWH plant. CO_2 emissions are reduced by 44% in the case with a low emission rate, 30% with a medium emission rate and 25% with a high emission rate. The total energy cost is increased by 23% and the payback period is estimated to be 42 years.

Summary

Table B-49 lists TES capacities, SWH field sizes, and CHP capacities for the Chicago simulations and gives an overview of heating and cooling production, CAPEX breakdown, overall CAPEX, CAPEX after a 30% tax credit reduction, and potential savings from the tax credit reduction.

Figure B-176 summarizes total energy costs for each simulation scenario at each energy price level without the 30% tax credit reduction and Figure B-177 with the tax credit reduction. Figure B-185 summarizes the CO_2 emissions for each simulation scenario at each emission rate for both fuel and imported electricity. All figures are comparing the simulated scenarios directly to the "0. Boiler only" baseline, represented as "100%" for total energy cost.

Figure B-181 shows the distribution of electricity demand met by imported electricity and CHP.

Table B-56 provides an economic analysis for each simulated scenario, encompassing initial investments, OPEX, simple payback period, loan repayment for CAPEX and yearly savings relative to the "0. Boiler only" baseline, all at the high energy price with 30% tax credit reduction.

Scenario 3 has the best economic performance, reducing total energy costs by 37% with a 6-year payback period. It also achieves emission reductions, ranging from 9% to 58%. Scenario 5, with consistent emission reductions between 32% and 40%, has a 12% increase in total energy costs and a longer payback period of 13.3 years, making it less financially feasible.

The results are based on high energy prices with a 30% tax credit, emphasizing significant savings and notable economic impacts. Appendix B, section B.7 givs detailed simulation results for Chicago, and section B.7.1 contains economic outcomes under different pricing scenarios.

Scenario 3 shows the most favorable economic results for high energy prices, both with and without the 30% tax credit reduction, displaying a total energy cost between 63% and 74% and a payback period ranging from 6 to 8.5 years. However, under all other pricing conditions, with or without the 30% tax credit, scenario 2 proves to be the more financially favorable option, presenting a total energy cost between 79% and 92% and a payback period ranging from 3.2 to 9.3 years. In contrast, scenario 3, under these pricing conditions, exhibits a total energy cost between 86% and 154%, coupled with a payback period ranging from 10.7 to 30.9 years.

TES Technology Recommendations

All TES capacities are modeled as PTES due to their significant size, making TTES impractical. Considering BTES as an alternative is worth exploring, as PTES in later scenarios would demand substantial space.

Chicago's distinct seasons and promising geological conditions make it a favorable location for BTES. Though, the proximity to Lake Michigan might pose challenges related to groundwater levels. It is necessary to assess the local hydrogeology to identify optimal BTES sites.

Conclusion

Scenario 3 outperforms economically, cutting total energy costs by 37% with a 6-year payback period and achieving emission reductions of 9% to 58%. Conversely, Scenario 5, with consistent emission reductions between 32% and 40%, sees a 12% increase in total energy costs and a longer payback period of 13.3 years, making it less financially viable.

Results are based on high energy prices with a 30% tax credit, emphasizing significant savings and economic impacts. Appendix B, section B.7 contains detailed simulation results for Chicago, and section B.7.1 contains economic outcomes under different pricing scenarios.

Scenario 3 is economically favorable at high energy prices, with and without the 30% tax credit, showing a total energy cost between 63% and 74% and a payback period of 6 to 8.5 years. However, under all other pricing conditions, with or without the 30% tax credit, scenario 2 proves more financially viable, with a total energy cost between 79% and 92% and a payback period of 3.2 to 9.3 years. In contrast, scenario 3, under these conditions, exhibits a total energy cost between 86% and 154%, with a payback period ranging from 10.7 to 30.9 years.

All TES capacities are modeled as PTES due to their significant size, making TTES impractical. Considering BTES as an alternative is worth exploring, as PTES in later scenarios would demand substantial space.

Chicago's distinct seasons and promising geological conditions make it a favorable location for BTES. However, the proximity to Lake Michigan might pose challenges related to groundwater levels. Assessing local hydrogeology is necessary to identify optimal BTES sites.

5.1.8. CZ 4C – Seattle

Overall Observations

Seattle is located close to the west coast of the United States and as a result, has a relatively balanced heating and cooling demand with no high peaks in the heating demand in the winter, as illustrated in Figure 5-12.`

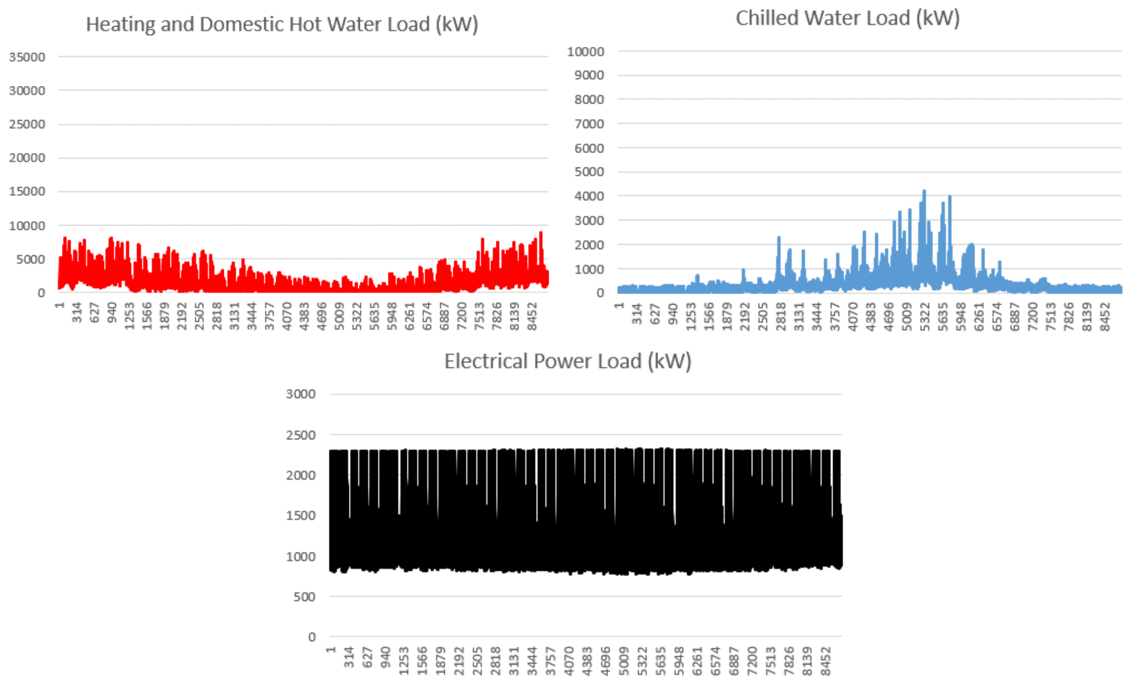


Figure 5-12. Load profiles of the heating, cooling, and electricity demands for Seattle.

As with the previously simulated climate zones, the baseline “0. Boiler only” scenario sets the benchmark for comparing CO_2 emissions and economics in subsequent scenarios.

CHP + TES

Scenario “1. CHP Baseload” with CHP sized to meet baseload electricity demand. CO_2 emissions are reduced by 8% in the case with a low emission rate, 20% with a medium emission rate and 24% with a high emission rate. The total energy cost is reduced by 22% and the payback period is estimated to be 0.8 years.

Scenario “2. 3x CHP” with tripled CHP capacity compared to scenario 1. CO_2 emissions are reduced by 10% in the case with a low emission rate, 24% with a medium emission rate and 29% with a high emission rate. The total energy cost is reduced by 29% and the payback period is estimated to be 2 years.

Scenario “3. 3x CHP with TES” is the same as scenario 2 but with 80,000 m^3 TES. CO_2 emissions are reduced by 13% in the case with a low emission rate, 32% with a medium emission rate and 39% with a high emission rate. The total energy cost is reduced by 31% and the payback period is estimated to be 4.6 years.

CHP + SWH + TES

Scenario "4. 3x CHP with small SWH and TES" is the same as scenario 3 but with 140,000 m^3 TES and a 10,000 m^2 SWH plant. CO_2 emissions are reduced by 20% in the case with a low emission rate, 27% with a medium emission rate and 30% with a high emission rate. The total energy cost is reduced by 11% and the payback period is estimated to be 9.3 years.

Scenario "5. 2x CHP with medium SWH and TES" with reduced CHP capacity, 200,000 m^3 TES and an 18,000 m^2 SWH plant. CO_2 emissions are reduced by 25% in the case with a low emission rate, 24% with a medium emission rate and remains at 24% with a high emission rate. The total energy cost is increased by 5% and the payback period is estimated to be 17.7 years.

SWH + TES

The final scenario, "6. Large SWH and TES" with no CHP, 265,000 m^3 TES and a 26,500 m^2 SWH plant. CO_2 emissions are reduced by 31% in the case with a low emission rate, 20% with a medium emission rate and 16% with a high emission rate. The total energy cost is increased by 24% and the payback period is estimated to be 46.1 years.

Summary

Table B-56 details TES capacities, SWH field sizes, and CHP capacities for the Seattle simulations and provides an overview of heating and cooling production, CAPEX breakdown, overall CAPEX, CAPEX after a 30% tax credit reduction, and potential savings from the tax credit reduction.

Figure B-202 summarizes total energy costs for each simulation scenario at each energy price level without the 30% tax credit reduction and Figure B-203 with the tax credit reduction. Figure B-211 summarizes the CO_2 emissions for each simulation scenario at each emission rate for both fuel and imported electricity. All figures are comparing the simulated scenarios directly to the "0. Boiler only" baseline, represented as "100%" for total energy cost.

Figure B-307 shows the distribution of electricity demand met by imported electricity and CHP.

Table B-62 provides an economic analysis for each simulated scenario, encompassing initial investments, OPEX, simple payback period, loan repayment for CAPEX and yearly savings relative to the "0. Boiler only" baseline, all at the high energy price with 30% tax credit reduction.

Scenario 3 performs best economically, cutting total energy costs by 31% with a 4.6-year payback period. It also achieves emission reductions, ranging from 13% to 39%. In contrast, Scenario 5, with consistent emission reductions between 24% and 25%, experiences a 5% increase in total energy costs and a longer payback period of 17.7 years, making it less financially feasible.

The outcomes are based on high energy prices with a 30% tax credit, highlighting substantial savings and significant economic impacts. Appendix B, section B.8 contains detailed simulation results for Seattle, and section B.8.1 contains economic outcomes under various pricing scenarios.

Under high energy prices with a 30% tax credit, Scenario 3 demonstrates the most favorable economic outcomes, with a 69% total energy cost and a 4.6-year payback period. However, in all other pricing conditions, with or without the 30% tax credit, scenario 2 emerges as the more financially favorable choice, featuring a total energy cost between 73% and 92% and a payback period ranging from 2.8 to 10.1 years. Conversely, under these pricing conditions, scenario 3 displays a total energy cost between 75% and 122%, coupled with a payback period ranging from 6.5 to 23.5 years.

TES Technology Recommendations

All TES capacities are simulated as PTES due to their significant size, making TTES unfeasible. Exploring BTES as an alternative is worth considering, as PTES in later scenarios would demand substantial space.

The moderate climate and proximity to the Puget Sound might limit the efficiency of BTES. However, the geology may allow for deep boreholes. It is advised to evaluate local groundwater conditions and geology for feasibility and if significant temperature deltas can be realized.

Conclusion

Scenario 3 outperforms economically, reducing total energy costs by 31% with a 4.6-year payback period and achieving emission reductions from 13% to 39%. In contrast, scenario 5, with consistent emission reductions between 24% and 25%, sees a 5% increase in total energy costs and a longer 17.7-year payback, making it less financially feasible.

Results are based on high energy prices with a 30% tax credit, emphasizing substantial savings. Appendix B, section B.8 contains detailed simulation results for Seattle and section B.8.1 contains economic outcomes under various pricing scenarios.

Under high energy prices with a 30% tax credit, scenario 3 demonstrates the most favorable outcomes, with a 69% total energy cost and a 4.6-year payback. However, in all other pricing conditions, scenario 2 is more financially favorable, with a total energy cost between 73% and 92% and a payback period ranging from 2.8 to 10.1 years. In contrast, under these pricing conditions, Scenario 3 displays a total energy cost between 75% and 122%, with a payback period ranging from 6.5 to 23.5 years.

All TES capacities are modeled as PTES due to their significant size, as TTES is unfeasible. Exploring BTES as an alternative is worth considering, as PTES in later scenarios would demand substantial space. The moderate climate and proximity to Puget Sound might limit BTES efficiency, but geological conditions may allow for deep boreholes. A thorough evaluation of local groundwater and geology is advised for feasibility and temperature delta realization.

5.1.9. CZ 4B – Albuquerque

Overall Observations

Albuquerque is like Seattle in that it also shows a balanced heating and cooling demand, as illustrated in Figure 5-13, although Albuquerque has almost no heating demand during some of the summer. This is because it is located inland but also more south in the United States, resulting in higher temperature extremes.

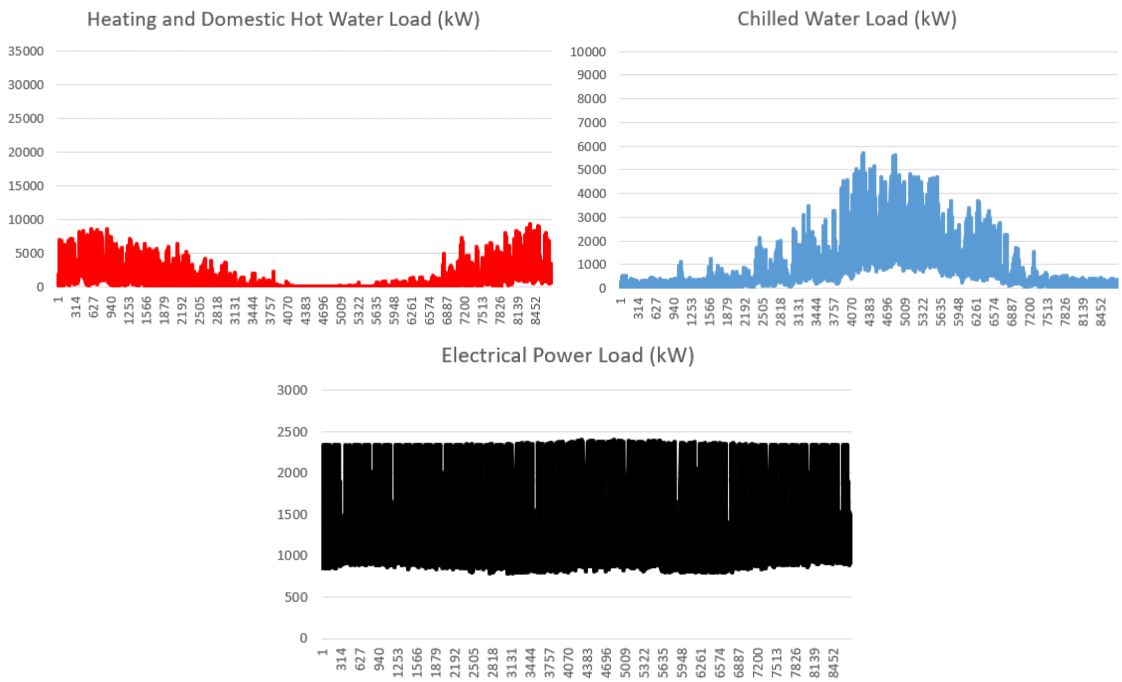


Figure 5-13. Load profiles of the heating, cooling, and electricity demands for Albuquerque.

As with the previously simulated climate zones, the baseline “0. Boiler only” scenario sets the benchmark for comparing CO_2 emissions and economics in subsequent scenarios.

CHP + TES

Scenario “1. CHP Baseload” with CHP sized to meet baseload electricity demand. CO_2 emissions are reduced by 6% in the case with a low emission rate, 13% with a medium emission rate and 16% with a high emission rate. The total energy cost is reduced by 17% and the payback period is estimated to be 1.1 years.

Scenario “2. 3x CHP” with tripled CHP capacity compared to scenario 1. CO_2 emissions are reduced by 7% in the case with a low emission rate, 16% with a medium emission rate and 20% with a high emission rate. The total energy cost is reduced by 18% and the payback period is estimated to be 2.7 years.

Scenario “3. 3x CHP with TES” is the same as scenario 2 but with 50,000 m^3 TES. CO_2 emissions are reduced by 10% in the case with a low emission rate, 23% with a medium emission rate and 28% with a high emission rate. The total energy cost is reduced by 21% and the payback period is estimated to be 4.9 years.

CHP + SWH + TES

Scenario "4. 3x CHP with small SWH and TES" is the same as scenario 3 but with 100,000 m^3 TES and a 7,000 m^2 SWH plant. CO_2 emissions are reduced by 19% in the case with a low emission rate, 17% with a medium emission rate and remaining at 17% with a high emission rate. The total energy cost is the same as the baseline scenario and the payback period is estimated to be 13.9 years.

Scenario "5. 2x CHP with medium SWH and TES" with reduced CHP capacity, 120,000 m^3 TES and a 10,000 m^2 SWH plant. CO_2 emissions are reduced by 22% in the case with a low emission rate, 16% with a medium emission rate and 14% with a high emission rate. The total energy cost is increased by 7% and the payback period is estimated to be 23.6 years.

SWH + TES

The final scenario, "6. Large SWH and TES" with no CHP, 140,000 m^3 TES and a 14,000 m^2 SWH plant. CO_2 emissions are reduced by 24% in the case with a low emission rate, 15% with a medium emission rate and 12% with a high emission rate. The total energy cost is increased by 12% and the payback period is estimated to be 36.8 years.

Summary

Table B-63 details TES capacities, SWH field sizes, and CHP capacities for the Albuquerque simulations and provides an overview of heating and cooling production, CAPEX breakdown, overall CAPEX, CAPEX after a 30% tax credit reduction, and potential savings from the tax credit reduction.

Figure B-229 summarizes total energy costs for each simulation scenario at each energy price level without the 30% tax credit reduction and Figure B-229 with the tax credit reduction. Figure B-237 summarizes the CO_2 emissions for each simulation scenario at each emission rate for both fuel and imported electricity. All figures are comparing the simulated scenarios directly to the "0. Boiler only" baseline, represented as "100%" for total energy cost.

Figure B-233 shows the distribution of electricity demand met by imported electricity and CHP.

Table B-69 provides an economic analysis for each simulated scenario, encompassing initial investments, OPEX, simple payback period, loan repayment for CAPEX and yearly savings relative to the "0. Boiler only" baseline, all at the high energy price with 30% tax credit reduction.

Scenario 3 demonstrates superior economic performance, with a 21% reduction in total energy costs and a 4.9-year payback period. It also achieves emission reductions ranging from 10% to 28%. Notably, this scenario offers the highest emission reduction at high emission rates. While scenarios 4 to 6 excel in emission reduction at low rates (19% to 24%), their performance at high rates (12% to 17%) falls short of Scenario 3's 28%. Therefore, Scenario 3 emerges as the most economically favorable choice with considerable emission reduction potential.

The presented results are from the simulations based on high energy prices and a 30% tax credit, demonstrating significant savings and economic impacts. Appendix B, section B.9 includes detailed simulation results for Albuquerque, and secvtion B.9.1 contains economic outcomes under various pricing scenarios.

In the context of high energy prices with a 30% tax credit, scenario 3 stands out for its favorable economic performance, presenting a 79% total energy costs, compared to the baseline, and a

4.9-year payback period. However, at medium energy prices, with and without the 30% tax credit, scenario 2 emerges as the more financially favorable choice, featuring a total energy cost between 86% and 89% and a payback period ranging from 4.8 to 6.9 years. Conversely, under these pricing conditions, scenario 3 displays a total energy cost between 89% and 96%, coupled with a payback period ranging from 8.8 to 12.5 years. The difference in total energy cost between scenario 2 and 3 at medium energy prices with and without tax credit reduction does not affect the emission reductions, whereas scenario 3 still presents the highest potential emission reductions.

TES Technology Recommendations

Given their considerable size, all TES capacities are simulated as PTES, rendering the use of TTES unfeasible. However, it is noteworthy that scenario 3's 50,000 m3 TES capacity nearly approaches the feasibility threshold for TTES. Considering the spatial demands of PTES in subsequent scenarios, investigating BTES as a potential alternative is advisable.

Albuquerque's climate fluctuations and geological conditions may make BTES a feasible option, especially for cooling needs in the hot summers. The presence of aquifers or shallow groundwater could decrease installation round-trip efficiency.

Conclusion

Based on the analysis, Scenario 3 emerges as the most economically favorable option, showcasing a 21% reduction in total energy costs and a relatively short payback period of 4.9 years. Additionally, it achieves notable emission reductions ranging from 10% to 28%, with particularly high reductions observed at high emission rates. While scenarios 4 to 6 perform well in reducing emissions at low rates, they fall short of Scenario 3's performance at high rates. Therefore, Scenario 3 not only offers significant cost savings but also demonstrates substantial emission reduction potential, making it the preferred choice among the scenarios analyzed.

The results are based on simulations conducted under high energy prices with a 30% tax credit, highlighting substantial savings and significant economic impacts. Appendix B, section B.9 contains detailed simulation outcomes for Albuquerque, and section B.9.1 contains economic assessments under various pricing scenarios.

In summary, Scenario 3 stands out for its favorable economic performance under high energy prices and a 30% tax credit, with Scenario 2 emerging as the more financially prudent choice at medium energy prices. Despite the cost differences between the two scenarios, Scenario 3 maintains its leadership in potential emission reductions, underscoring its overall superiority in both economic and environmental aspects.

All thermal energy storage capacities are simulated as PTES due to their significant size, rendering TTES unfeasible. However, scenario 3's TES capacity of 50,000 m^3 nearly approaches the feasibility limit for TTES. Given the spatial constraints of PTES in subsequent scenarios, exploring BTES as an alternative is recommended. In Albuquerque, BTES could prove viable, particularly for addressing cooling needs during hot summers. However, the presence of aquifers or shallow groundwater may impact installation efficiency.

5.1.10. CZ 4A - Baltimore

Overall Observations

Baltimore lies in a moderate climate zone close to the eastern U.S. coast. Its warmer climate brings a less balanced demand profile where heat demand is relatively low in the winter and cooling demand is several times higher than previous climate zones in the summer, as illustrated in Figure 5-14.

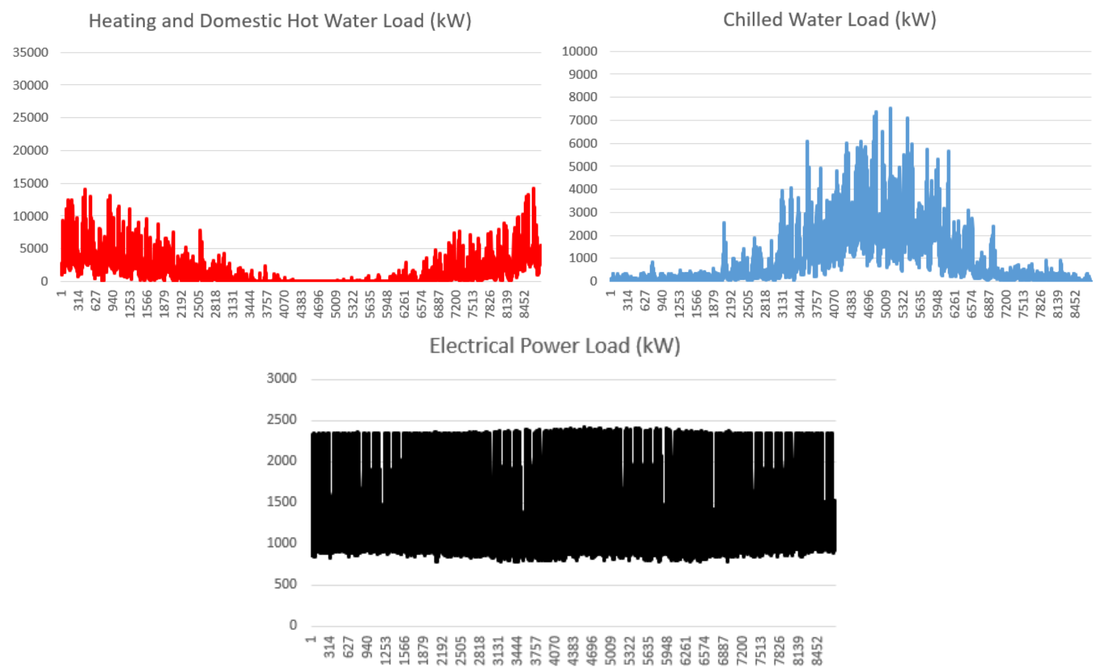


Figure 5-14. Load profiles of the heating, cooling, and electricity demands for Baltimore.

As with the previously simulated climate zones, the baseline “0. Boiler only” scenario sets the benchmark for comparing CO_2 emissions and economics in subsequent scenarios.

CHP + TES

Scenario “1. CHP Baseload” with CHP sized to meet baseload electricity demand. CO_2 emissions are reduced by 6% in the case with a low emission rate, 14% with a medium emission rate and 17% with a high emission rate. The total energy cost is reduced by 18% and the payback period is estimated to be 1 year.

Scenario “2. 3x CHP” with tripled CHP capacity compared to scenario 1. CO_2 emissions are reduced by 7% in the case with a low emission rate, 17% with a medium emission rate and 21% with a high emission rate. The total energy cost is reduced by 21% and the payback period is estimated to be 2.3 years.

Scenario “3. 3x CHP with TES” is the same as scenario 2 but with 100,000 m^3 TES. CO_2 emissions are reduced by 11% in the case with a low emission rate, 26% with a medium emission rate and 32% with a high emission rate. The total energy cost is reduced by 23% and the payback period is estimated to be 5.3 years.

CHP + SWH + TES

Scenario "4. 3x CHP with small SWH and TES" is the same as scenario 3 but with 120,000 m^3 TES and a 7,000 m^2 SWH plant. CO_2 emissions are reduced by 19% in the case with a low emission rate, 25% with a medium emission rate and 27% with a high emission rate. The total energy cost is reduced by 13% and the payback period is estimated to be 8.8 years.

Scenario "5. 2x CHP with medium SWH and TES" with reduced CHP capacity, 300,000 m^3 TES and a 14,000 m^2 SWH plant. CO_2 emissions are reduced by 21% in the case with a low emission rate, 25% with a medium emission rate and 26% with a high emission rate. The total energy cost is increased by 7% and the payback period is estimated to be 16.3 years.

SWH + TES

The final scenario, "6. Large SWH and TES" with no CHP, 380,000 m^3 TES and a 20,000 m^2 SWH plant. CO_2 emissions are reduced by 30% in the case with a low emission rate, 19% with a medium emission rate and 15% with a high emission rate. The total energy cost is increased by 20% and the payback period is estimated to be 45 years.

Summary

Table B-70 details TES capacities, SWH field sizes, and CHP capacities for the Baltimore simulations and provides an overview of heating and cooling production, CAPEX breakdown, overall CAPEX, CAPEX after a 30% tax credit reduction, and potential savings from the tax credit reduction.

Figure B-254 summarizes total energy costs for each simulation scenario at each energy price level without the 30% tax credit reduction and Figure B-256 with the tax credit reduction. Figure B-263 summarizes the CO_2 emissions for each simulation scenario at each emission rate for both fuel and imported electricity. All figures are comparing the simulated scenarios directly to the "0. Boiler only" baseline, represented as "100%" for total energy cost.

Figure B-259 shows the distribution of electricity demand met by imported electricity and CHP.

Table B-76 provides an economic analysis for each simulated scenario, encompassing initial investments, OPEX, simple payback period, loan repayment for CAPEX and yearly savings relative to the "0. Boiler only" baseline, all at the high energy price with 30% tax credit reduction.

Scenario 3 shows the best economic performance, reducing total energy costs by 23% with a payback period of 5.3 years. It also achieves emission reductions ranging from 11% to 32%. On the other hand, Scenario 5 maintains consistent emission reductions between 21% and 25% but only sees a 7% decrease in total energy costs. Additionally, it has a longer payback period of 16.3 years, making it less financially feasible.

The results provided are derived from simulations based on high energy prices and a 30% tax credit reduction, showcasing the most notable cost savings and economic implications. Appendix B, Section B.10 contains a detailed breakdown of simulation outcomes specific to Baltimore, and section B.10.1 contains economic analyses under different pricing scenarios.

At high energy prices with a 30% tax credit, scenario 3 realizes a 23% reduction in total energy costs and a 5.3-year payback period. Without the tax credit, scenario 2 has the lowest total energy costs, with a 19% reduction and a 3.3-year payback period compared to scenario 3's 17% reduction and 7.6-year payback period. At low energy costs, both with and without the tax credit, scenario 1 shows the lowest energy costs, with reductions between 9% and 11% and payback periods between 3.5 and 5.1 years.

TES Technology Recommendations

All simulated TES capacities are required to be either PTES or BTES. BTES can be beneficial in Baltimore to help in efficiently managing heating and cooling demands, where seasonal temperature changes are evident. The area primarily consists of coastal plains with sedimentary rock formations, potentially containing aquifers. Groundwater resources are present, but the proximity to the Chesapeake Bay may influence water quality and availability. Soil composition varies, with sandy and clayey soils prevalent, impacting drilling feasibility.

Conclusion

Scenario 3 demonstrates the most favorable economic performance, with a 23% reduction in total energy costs and a 5.3-year payback period. It also achieves significant emission reductions ranging from 11% to 32%. Conversely, Scenario 5 maintains consistent emission reductions between 21% and 25% but shows a modest 7% decrease in total energy costs and a longer payback period of 16.3 years, indicating lower financial feasibility.

These findings are based on simulations conducted under high energy prices with a 30% tax credit reduction, illustrating substantial cost savings and economic implications. Appendix B, section B.10 contains a detailed breakdown of simulation outcomes specific to Baltimore, and section B.10.1 contains economic analyses under different pricing scenarios.

While scenario 3 demonstrates the best economic results under high energy prices with a 30% tax credit, without the tax credit, scenario 2 has the lowest total energy costs, with a 19% reduction and a 3.3-year payback period compared to scenario 3's 17% reduction and 7.6-year payback period. At low energy costs, both with and without the tax credit, scenario 1 exhibits the lowest energy costs, with reductions ranging from 9% to 11% and payback periods between 3.5 and 5.1 years.

The simulated TES capacities are limited to PTES or BTES, with BTES serving to efficiently manage heating and cooling needs amid the area's marked seasonal temperature shifts. The region comprises primarily coastal plains with sedimentary rock formations, potentially hosting aquifers. Groundwater resources exist but may be impacted by proximity to the Chesapeake Bay, affecting quality and availability. Sandy and clayey soils are prevalent, affecting drilling feasibility.

5.2. Hot Climate Zones

5.2.1. CZ 3C - San Francisco

Overall Observations

The demand profiles and geographical location favored the system architecture suited for hot climate zones, despite San Francisco being classified as a moderate climate zone. Therefore, San Francisco has been chosen to be characterized as a hot climate zone in this project. San Francisco is located at the west coast and has a low cooling demand and a heat demand that varies little throughout the year, as illustrated in Figure 5-15.

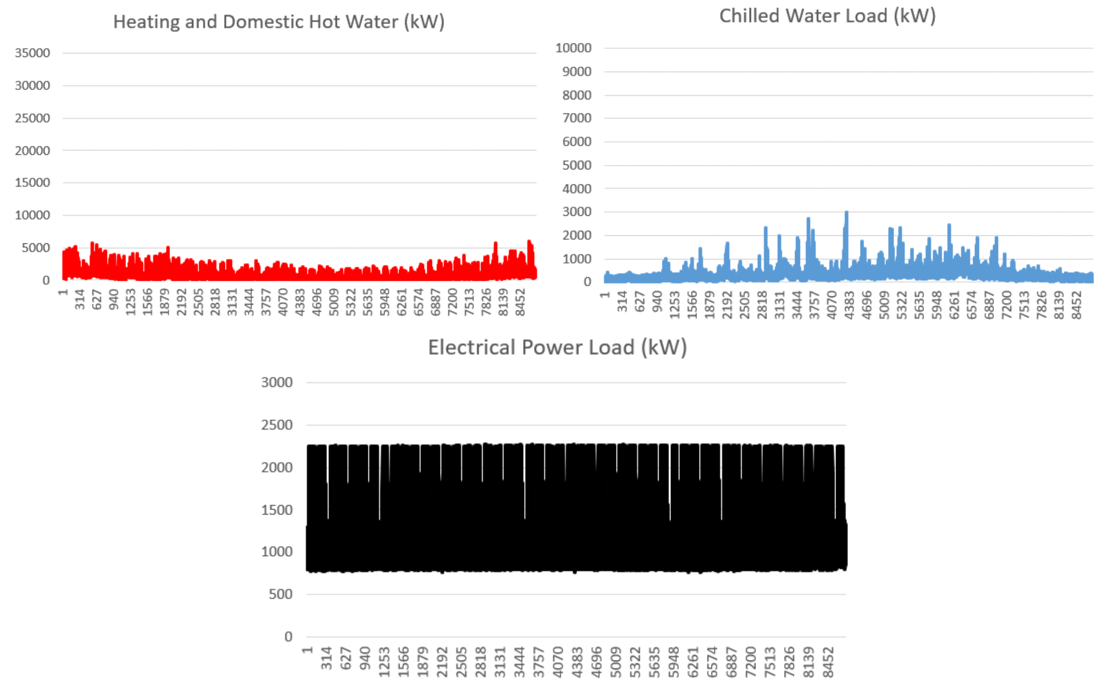


Figure 5-15. Load profiles of the heating, cooling, and electricity demands for San Francisco.

Similar to the approach taken for cold/moderate climate zones, the methodology for hot climate zones follows suit, with the baseline “0. Boiler only” scenario serving as the reference point for comparing emissions and economics in subsequent scenarios. As outlined in sections 3.4 and 3.5, hot climate zones employ a different system architecture and set of model scenarios. The key distinction is the use of absorption chillers and cold TES in simulated scenarios, given the high cooling demand characteristic of hot climate zones, making these technologies advantageous. The high cooling demand in hot climate zones is commonly accompanied by a low heating demand, making waste heat from CHP and heat generated by SWH often unnecessary. This renders absorption chillers beneficial, as they can efficiently convert heat energy into cooling energy. Furthermore, cold TES offers resilience by decoupling production and demand.

CHP / ABS + TES

Scenario “1. CHP Baseload and ABS” with CHP sized to meet baseload electricity demand and absorption chiller to convert excess heat to cooling. CO_2 emissions are reduced by 50% in the case with a low emission rate, 51% with a medium emission rate and by 52% with a high emission rate. The total energy cost is reduced by 33% and the payback period is estimated to be 1.4 years.

Scenario “2. 3x CHP and 3x ABS” with tripled CHP capacity compared to scenario 1 to cover the entire electricity demand and absorption chiller to convert excess heat to cooling. CO_2 emissions are reduced by 49% in the case with a low emission rate, 55% with a medium emission rate and by 57% with a high emission rate. The total energy cost is reduced by 36% and the payback period is estimated to be 3.4 years.

Scenario “3. 3x CHP and 3x ABS with TES.” Same as scenario 2 but with 1,000 m^3 cold TES and 1,000 m^3 hot TES to provide necessary resilience. CO_2 emissions are reduced by 49% in the case with a low emission rate, 56% with a medium emission rate and by 60% with a high emission rate. The total energy cost is reduced by 39% and the payback period is estimated to be 3.4 years.

CHP / ABS + SWH + TES

Scenario "4. 3x CHP and 3x ABS with small SWH and TES." Same as scenario 3 but with 1,000 m^3 cold TES, 1,000 m^3 hot TES and a 7,000 m^2 SWH plant. CO_2 emissions are reduced by 55% in the case with a low emission rate, 52% with a medium emission rate and by 51% with a high emission rate. The total energy cost is reduced by 13% and the payback period is estimated to be 8.3 years.

Scenario "5. 3x CHP and 3x ABS with medium SWH and TES" mirrors scenario 4. Its purpose is to expand the SWH field, eliminating heat production from the boiler and cooling from the electric chiller but since this objective has already been accomplished in the prior scenario, this particular simulation scenario is redundant in this climate zone.

Scenario "6. 3x CHP and 6x ABS with medium SWH and TES" is the same as scenario 4 but with double absorption chiller capacity and cold TES omitted. This is done to assess the economic impact of combining CHP and SWH alongside increased ABS capacity, albeit without the resilience provided by cold TES. CO_2 emissions are reduced by 55% in the case with a low emission rate, 52% with a medium emission rate and by 51% with a high emission rate. The total energy cost is increased by 8% and the payback period is estimated to be 10.8 years.

ABS + SWH + TES

The final scenario, "7. 6x ABS with large SWH and TES," with 75,000 m^3 hot TES, a 14,300 m^2 SWH plant and omitted CHP necessitating all electricity to be imported by the public grid. CO_2 emissions are reduced by 61% in the case with a low emission rate, 48% with a medium emission rate and by 41% with a high emission rate. The total energy cost is increased by 24% and the payback period is estimated to be 45.6 years.

Summary

Table 5-6 provides a comprehensive list of simulated scenarios for San Francisco, detailing TES capacities, SWH field sizes, and CHP capacities. It further includes a summary of total heating and cooling production, a breakdown of CAPEX for various technology and equipment, the overall CAPEX, the CAPEX after a potential 30% tax credit reduction, and the potential savings resulting from the tax credit reduction.

Table 5-6. **Simulation parameters and economics for the San Francisco simulation scenarios.**

		0. Boiler only	1. 1. CHP Baseload and ABS	2. 3x CHP and 3x ABS	3. 3x CHP and 3x ABS w/TES	4. 3x CHP and 3x ABS w/small SWH and TES	5. 3x CHP and 3x ABS w/medium SWH and TES	6. 3x CHP and 6x ABS w/medium SWH and TES	7. 6x ABS w/large SWH and TES
Component size									
TES	m^3	-	-	-	2,000	2,000	2,000	1,000	75,000
Hot TES	m^3	-	-	-	1,000	1,000	1,000	1,000	75,000
Cold TES	m^3	-	-	-	1,000	1,000	1,000	-	-
Solar plant	m^2	-	-	-	-	7,000	7,000	7,000	14,300
CHP	MW_{heat}	-	0.85	2.55	2.55	2.55	2.55	2.55	0.00
ABS	$MW_{cooling}$	-	0.7	2.1	2.1	2.1	2.1	4.2	4.2
Energy production and consumption									
Heat production	MWh	5,109	5,109	5,109	5,109	5,109	5,109	5,109	5,109
Cooling production	MWh	3,288	3,288	3,288	3,288	3,288	3,288	3,288	3,288
Electricity Consumption (WO Cooling)	MWh	11,492	11,492	11,492	11,492	11,492	11,492	11,492	11,492
Investment									
TES	USD	-	-	-	600,000	600,000	600,000	400,000	5,700,000
Solar Plant	USD	-	-	-	-	2,051,000	2,051,000	2,051,000	4,189,900
CHP added capacity	USD	-	935,000	2,805,000	2,805,000	2,805,000	2,805,000	2,805,000	-
ABS added capacity	USD	-	1,020,000	3,060,000	3,060,000	3,060,000	3,060,000	6,120,000	6,120,000
Sum	**USD**	-	**1,955,000**	**5,865,000**	**6,465,000**	**9,706,000**	**9,706,000**	**12,566,000**	**18,440,900**
Reduction due to tax credits	30%	-	586,500	1,759,500	1,939,500	2,911,800	2,911,800	3,769,800	5,532,270
Investment after tax credits	**USD**	-	**1,368,500**	**4,105,500**	**4,525,500**	**6,794,200**	**6,794,200**	**8,796,200**	**12,908,630**

A summary of the emissions at the different emission rates and the total energy costs for each simulation scenario are presented in Figure 5-2. All of the total energy costs are presented in percents compared to the baseline Scenario, which is why the total energy cost is denoted as "100%" at this scenario.

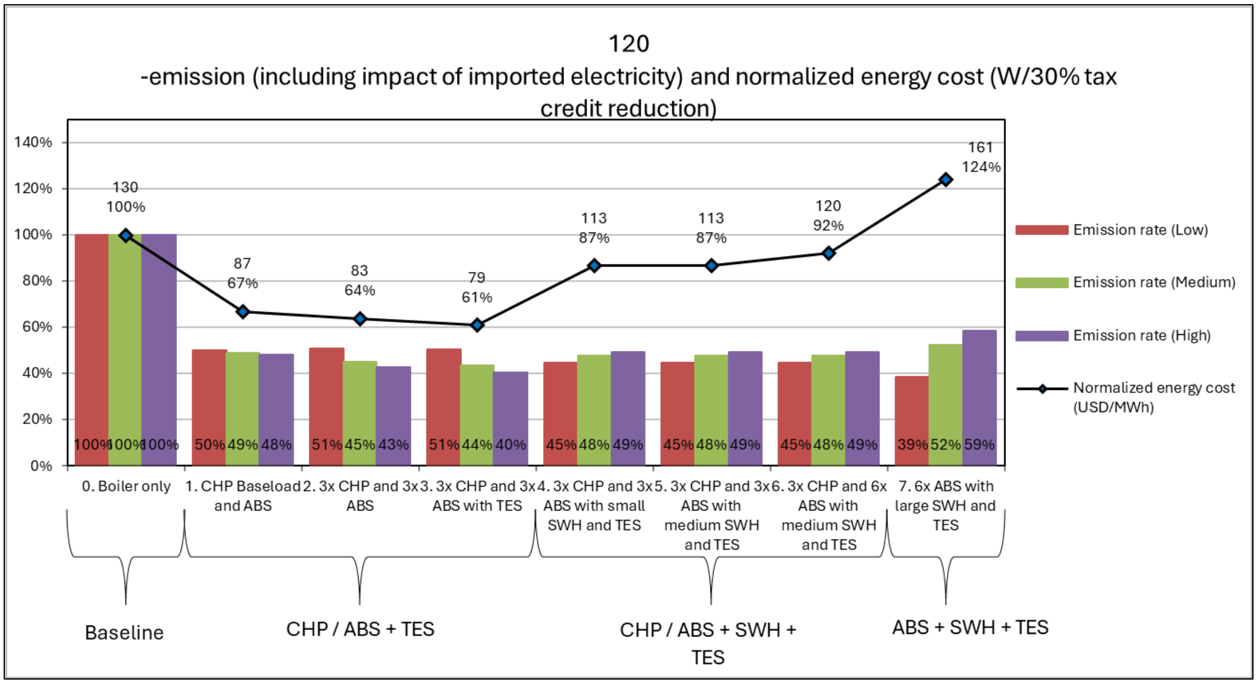


Figure 5-16. Combined graph of the CO_2 emissions at each emission rate and the total energy costs with 30% tax credit reduction for San Francisco.

Figure B-284 shows the distribution of electricity demand met by imported electricity and CHP.

Table B-83 provides an economic analysis for each simulated scenario, encompassing initial investments, OPEX, simple payback period, loan repayment for CAPEX and yearly savings relative to the “0. Boiler only” baseline, all at the high energy price with 30% tax credit reduction.

Scenario 3 demonstrates optimal economic performance, reducing total energy costs by 39% with a payback period of 4.3 years. While it nearly achieves the highest emission reductions, ranging from 49% to 60%, scenarios 4 and 6 surpass it under low emission rates, with reductions ranging from 55% to 61%. However, due to the lower total energy cost in scenario 4, it is the recommended choice.

These results are derived from the simulations conducted under high energy prices, supplemented by a 30% tax credit, emphasizing the most considerable savings and significant economic outcomes. Appendix B, section B.11 provides a comprehensive breakdown of all simulation results, and section B.11.1 provides economic results under different pricing conditions.

Under high energy prices with a 30% tax credit, scenario 3 exhibits the most favorable economic outcomes, with a 61% reduction in total energy costs compared to the baseline, and a 3.4-year payback period. Scenario 3 remains economically favorable under both high and medium energy prices, regardless of the tax credit status, with total energy cost reductions ranging from 17% to 39%. However, under low energy prices, scenario 2 emerges as the most economically advantageous, with total energy costs ranging from a 2% decrease to an 11% increase, contrasting scenario 3's total energy costs, which range from a 1% decrease to a 13% increase under the same pricing conditions.

TES Technology Recommendations

All scenarios, except for scenario 7, feature TES capacities small enough to be met with TTES. Conversely, scenario 7 necessitates the use of either PTES or BTES due to its considerable TES capacity.

While San Francisco's geological conditions may provide a foundation for BTES implementation, the mild and relatively consistent climate in the region could affect the potential efficiency gains. Considering these conditions, it is strongly recommended to conduct a thorough evaluation of the local geology and groundwater levels to determine the feasibility and cost effectiveness of BTES systems in this unique climatic setting. This assessment will help in making informed decisions regarding the practicality and utility of BTES within the context of San Francisco's specific environmental factors.

Conclusion

Scenario 3 offers the best economic performance, cutting total energy costs by 39% with a 4.3-year payback period. Although it nearly achieves the highest emission reductions (49% to 60%), scenarios 4 and 6 surpass it under low emission rates (55% to 61%). However, scenario 4, with lower total energy costs, is recommended.

These results are derived from simulations conducted under high energy prices with a 30% tax credit, highlighting substantial savings and significant economic outcomes. Scenario 3 remains economically favorable under both high and medium energy prices, with total energy cost reductions ranging from 17% to 39%. However, under low energy prices, scenario 2 emerges as the most economically advantageous, with total energy costs ranging from a 2% decrease to an 11% increase, contrasting scenario 3's total energy costs, which range from a 1% decrease to a 13% increase under the same pricing conditions.

All scenarios, except scenario 7, feature TES capacities small enough to be met with TTES. Scenario 7 necessitates the use of either PTES or BTES due to its considerable TES capacity. Considering San Francisco's geological conditions, further evaluation is needed to assess the feasibility and cost effectiveness of BTES implementation, despite the potential efficiency gains in this unique climatic setting.

5.2.2. CZ 3B Other - Las Vegas

Overall Observations

Las Vegas has a modest heating demand in the winter and almost no heating demand in the summer. The cooling demand is high in the summer and more consistent throughout the year with the demand slope rising earlier and falling later in the year, as illustrated in Figure 5-17.

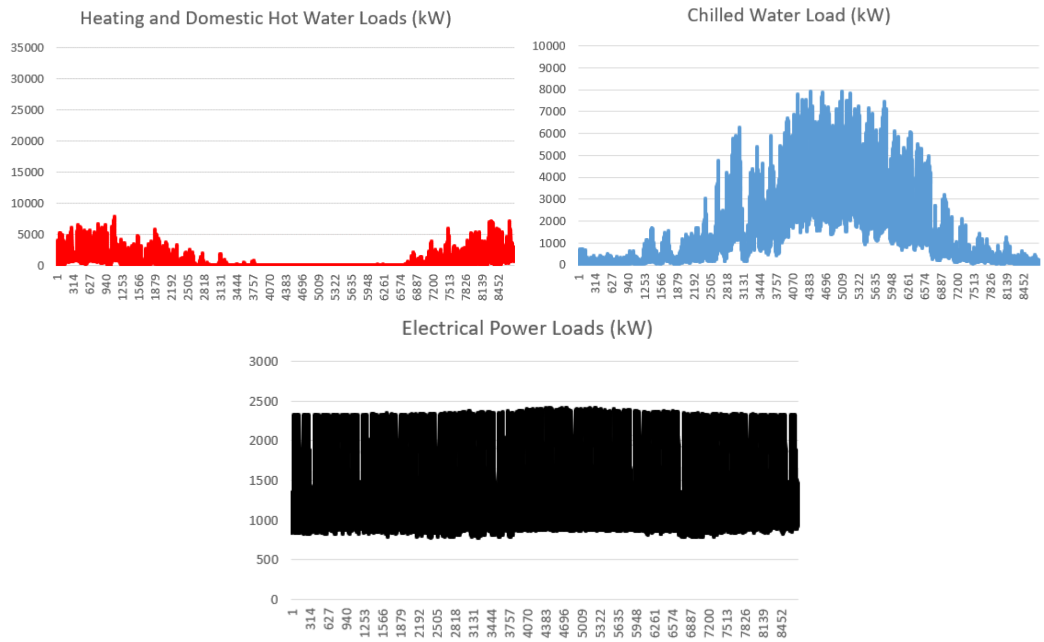


Figure 5-17. Load profiles of the heating, cooling and electricity demands for Las Vegas.

As with the previously simulated climate zones, the baseline “0. Boiler only” scenario sets the benchmark for comparing CO_2 emissions and economics in subsequent scenarios.

CHP / ABS + TES

Scenario “1. CHP Baseload and ABS” with CHP sized to meet baseload electricity demand and absorption chiller to convert excess heat to cooling. CO_2 emissions are reduced by 39% in the case with a low emission rate, 42% with a medium emission rate and by 43% with a high emission rate. The total energy cost is reduced by 29% and the payback period is estimated to be 1.4 years.

Scenario “2. 3x CHP and 3x ABS” with tripled CHP capacity compared to scenario 1 to cover the entire electricity demand and absorption chiller to convert excess heat to cooling. CO_2 emissions are reduced by 36% in the case with a low emission rate, 51% with a medium emission rate and by 57% with a high emission rate. The total energy cost is reduced by 47% and the payback period is estimated to be 2.4 years.

Scenario “3. 3x CHP and 3x ABS with TES.” Same as scenario 2 but with 3,000 m^3 cold TES and 14,000 m^3 hot TES to provide necessary resilience. CO_2 emissions are reduced by 39% in the case with a low emission rate, 54% with a medium emission rate and by 62% with a high emission rate. The total energy cost is reduced by 50% and the payback period is estimated to be 3 years.

CHP / ABS + SWH + TES

Scenario “4. 3x CHP and 3x ABS with small SWH and TES.” Same as scenario 3 but with 400,000 m^3 cold TES, 125,000 m^3 hot TES and a 7,000 m^2 SWH plant. CO_2 emissions are reduced by 39% in the case with a low emission rate, 56% with a medium emission rate and by 64% with a high emission rate. The total energy cost is reduced by 19% and the payback period is estimated to be 10.1 years.

Scenario “5. 3x CHP and 3x ABS with medium SWH and TES” with 500,000 m^3 cold TES, 100,000 m^3 hot TES and a 9,200 m^2 SWH plant. CO_2 emissions are reduced by 40% in the case with a low emission rate, 57% with a medium emission rate and by 64% with a high emission rate. The total energy cost is reduced by 16% and the payback period is estimated to be 10.9 years.

Scenario “6. 3x CHP and 6x ABS with medium SWH and TES” is the same as scenario 5 but with double absorption chiller capacity, 3,000 m^3 cold TES and 180,000 m^3 hot TES. CO_2 emission reductions are identical to scenario 5, but the total energy cost is reduced by 29% and the payback period is estimated to be 8.1 years.

ABS + SWH + TES

The final scenario, “7. 6x ABS with large SWH and TES,” with 3,000 m^3 cold TES, 140,000 m^3 hot TES and a 22,500 m^2 SWH plant. CHP has been omitted, necessitating all electricity to be imported by the public grid. CO_2 emissions are reduced by 57% in the case with a low emission rate, 46% with a medium emission rate and by 41% with a high emission rate. The total energy cost is increased by 22% and the payback period is estimated to be 30.8 years.

Summary

Table B-91 details TES capacities, SWH field sizes, and CHP capacities for the Las Vegas simulations and provides an overview of heating and cooling production, CAPEX breakdown, overall CAPEX, CAPEX after a 30% tax credit reduction, and potential savings from the tax credit reduction.

Figure B-333 summarizes total energy costs for each simulation scenario at each energy price level without the 30% tax credit reduction and Figure B-341 with the tax credit reduction. Figure B-341 summarizes the CO_2 emissions for each simulation scenario at each emission rate for both fuel and imported electricity. All figures are comparing the simulated scenarios directly to the “0. Boiler only” baseline, represented as “100%” for total energy cost.

Figure B-337 shows the distribution of electricity demand met by imported electricity and CHP.

Table B-97 provides an economic analysis for each simulated scenario, encompassing initial investments, OPEX, simple payback period, loan repayment for CAPEX and yearly savings relative to the “0. Boiler only” baseline, all at the high energy price with 30% tax credit reduction.

Scenario 3 exhibits the strongest economic performance, with a 50% reduction in total energy costs and a payback period of 3 years. Additionally, it achieves emission reductions ranging from 39% to 62%. Conversely, scenario 7 features the lowest emissions, with reductions ranging from 41% to 57%. However, it experiences a 22% increase in total energy costs and a lengthy payback period of 30.8 years, rendering it the least economically favorable scenario.

These presented results are from simulations conducted under high energy prices with a 30% tax credit, underscoring significant cost savings and notable economic implications. Appendix B, section B.12 provides a thorough breakdown of all simulation results, and section B.12.1 provides economic outcomes under the other pricing conditions.

Under high energy prices with a 30% tax credit, scenario 3 demonstrates the most favorable economic outcomes, with a 50% reduction in total energy costs compared to the baseline, and a 3-year payback period. Even without the tax credit, scenario 3 remains the optimal economic choice, with a total energy cost reduction of 55% and a payback period of 4.2 years. At medium energy prices with the tax credit, scenarios 2 and 3 tie in total energy cost at 66%, differing only in payback time, with scenario 2 at 4.5 years and scenario 3 at 5.6 years. For low energy prices, both with and without the tax credit, scenario 1 offers the lowest total energy cost, ranging from 88% to 91%, with payback times between 5.9 and 8.5 years.

Technology Recommendations

The TES capacities in scenario 3, along with the cold TES in scenarios 6 and 7, enable the feasible use of TTES. However, the remaining TES capacities necessitate the use of either PTES or BTES.

In the Las Vegas area, geological considerations for implementing BTES involve the Basin and Range Province, characterized by sedimentary rock formations. Localized aquifers may occur, influenced by sedimentary deposits, with variable soil compositions including sandy, clayey, and silty soils. The depth to bedrock varies, impacting drilling feasibility, while groundwater movement is controlled by topography and geological structures. Geological hazards such as earthquakes, landslides, and subsidence should also be considered when assessing BTES feasibility and mitigating risks in the region.

Conclusion

Scenario 3 emerges as the most economically favorable option, showcasing a 50% reduction in total energy costs and a 3-year payback period, with emission reductions ranging from 39% to 62%. In contrast, scenario 7, despite achieving lower emissions (41% to 57% reduction), experiences a 22% increase in total energy costs and a lengthy 30.8-year payback period, making it economically less favorable.

Appendix B, section B.12 provides a thorough breakdown of all simulation results, and section B.12.1 provides economic outcomes under the other pricing conditions.

Scenario 3 demonstrates the most favorable economic outcomes, remaining so even without the tax credit, achieving a 55% cost reduction with a 4.2-year payback period. At medium energy prices with the tax credit, scenarios 2 and 3 tie in total energy cost at 66%, differing only in payback time (scenario 2 at 4.5 years, scenario 3 at 5.6 years). For low energy prices, scenario 1 offers the lowest total energy cost, ranging from 88% to 91%, with payback times between 5.9 and 8.5 years.

TES capacities in scenario 3, along with cold TES in scenarios 6 and 7, enable feasible TTES use. However, remaining TES capacities require either PTES or BTES use. Geological considerations are vital for BTES implementation in the Las Vegas area, considering sedimentary rock formations, localized aquifers, variable soil compositions, and depth to bedrock, alongside factors like groundwater movement and geological hazards such as earthquakes, landslides, and subsidence.

5.2.3. CZ 3B Coast - Los Angeles

Overall Observations

Los Angeles is located in the southern United States at the west coast; it has a low heat demand and fairly consistent cooling demand throughout the year; both overall demands are relatively low, as illustrated in Figure 5-18.

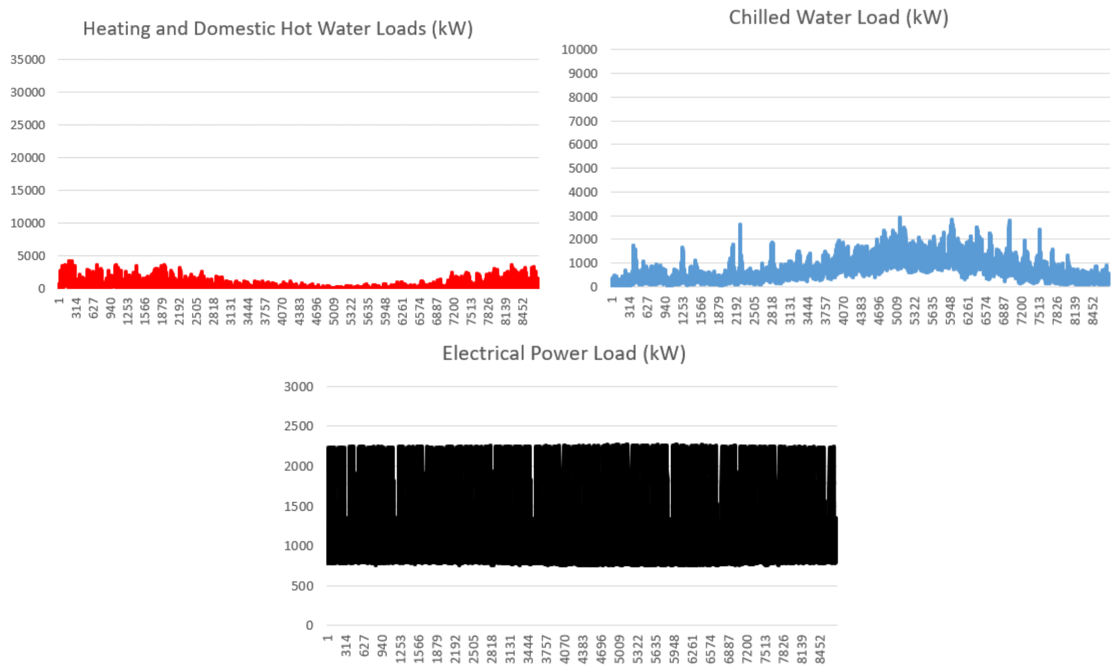


Figure 5-18. Load profiles of the heating, cooling, and electricity demands for Los Angeles.

As with the previously simulated climate zones, the baseline “0. Boiler only” scenario sets the benchmark for comparing CO_2 emissions and economics in subsequent scenarios.

CHP / ABS + TES

Scenario “1. CHP Baseload and ABS” with CHP sized to meet baseload electricity demand and absorption chiller to convert excess heat to cooling. CO_2 emissions are reduced by 27% in the case with a low emission rate, 37% with a medium emission rate and by 41% with a high emission rate. The total energy cost is reduced by 33% and the payback period is estimated to be 1.4 years.

Scenario “2. 3x CHP and 3x ABS” with tripled CHP capacity compared to scenario 1 to cover the entire electricity demand and absorption chiller to convert excess heat to cooling. CO_2 emissions are reduced by 24% in the case with a low emission rate, 43% with a medium emission rate and by 50% with a high emission rate. The total energy cost is reduced by 41% and the payback period is estimated to be 3.1 years.

Scenario “3. 3x CHP and 3x ABS with TES.” Same as scenario 2 but with 500 m^3 cold TES and 50,000 m^3 hot TES to provide necessary resilience. CO_2 emissions are reduced by 33% in the case with a low emission rate, 39% with a medium emission rate and by 41% with a high emission rate. The total energy cost is reduced by 38% and the payback period is estimated to be 4.9 years.

CHP / ABS + SWH + TES

Scenario "4. 3x CHP and 3x ABS with small SWH and TES." Same as scenario 3 but with 500 m^3 cold TES, 600 m^3 hot TES and a 7,000 m^2 SWH plant. CO_2 emissions are reduced by 33% in the case with a low emission rate, 39% with a medium emission rate and by 41% with a high emission rate. The total energy cost is reduced by 17% and the payback period is estimated to be 7.4 years.

Scenario "5. 3x CHP and 3x ABS with medium SWH and TES" is identical to scenario 4 as its purpose is to expand the SWH field to eliminate heat production from the boiler and cooling from the electric chiller. Since this objective has already been accomplished in the prior scenario, this particular simulation scenario is redundant in this climate zone.

Scenario "6. 3x CHP and 6x ABS with medium SWH and TES" is the same as scenario 4 but with double absorption chiller capacity, no cold TES and 600 m^3 hot TES. CO_2 emissions are reduced by 33% in the case with a low emission rate, 39% with a medium emission rate and by 41% with a high emission rate. The total energy cost is reduced by 11% and the payback period is estimated to be 9.8 years.

ABS + SWH + TES

The final scenario, "7. 6x ABS with large SWH and TES" with 10,000 m^3 hot TES, a 16,000 m^2 SWH plant and omitted CHP necessitating all electricity to be imported by the public grid. CO_2 emissions are reduced by 43% in the case with a low emission rate, 32% with a medium emission rate and by 27% with a high emission rate. The total energy cost is increased by 18% and the payback period is estimated to be 38 years.

Summary

Table B-91 in Appendix B details TES capacities, SWH field sizes, and CHP capacities for the Los Angeles simulations and provides an overview of heating and cooling production, CAPEX breakdown, overall CAPEX, CAPEX after a 30% tax credit reduction, and potential savings from the tax credit reduction.

Figure B-333 shows total energy costs for each simulation scenario at each energy price level without the 30% tax credit reduction and Figure B-334 with the tax credit reduction. Figure B-341 summarizes the CO_2 emissions for each simulation scenario at each emission rate for both fuel and imported electricity. All figures are comparing the simulated scenarios directly to the "0. Boiler only" baseline, represented as "100%" for total energy cost.

Figure B-337 shows the distribution of electricity demand met by imported electricity and CHP.

Figure B-97 provides an economic analysis for each simulated scenario, encompassing initial investments, OPEX, simple payback period, loan repayment for CAPEX and yearly savings relative to the "0. Boiler only" baseline, all at the high energy price with 30% tax credit reduction.

Scenario 2 presents the most favorable economics, with a 41% reduction in total energy costs and a payback period of 3.1 years. Additionally, scenario 2 also provides the highest overall emission reductions ranging from 24% to 50%.

The results provided are based on simulations carried out under high energy prices with a 30% tax credit, emphasizing notable cost savings and significant economic implications. Appendix B, section B.13 provides a detailed breakdown of all simulation outcomes, and section B.13.1 provides further information on economic outcomes under different pricing conditions.

Under high energy prices with a 30% tax credit, scenario 2 presents the best economics, showcasing a 41% reduction in total energy costs compared to the baseline, along with a 3.1-year payback period. At high energy prices without the tax credit, scenario 2 maintains its economic favorability, presenting a total energy cost reduction of 64% and a payback period of 4.4 years.

At medium energy prices, with the tax credit, scenario 2 remains the most feasible option with a total energy cost of 73%, compared to the baseline, and a payback time of 5.8 years. At medium energy prices without the tax credit, together with low energy prices with and without tax credit, scenario 1 presents the best economics with total energy prices ranging from 76% to 91% and a payback period between 3.9 and 9 years.

Technology Recommendations

Every simulated TTES capacity, except for the hot TES in scenario 3, is suitable for TTES. For the hot TES in scenario 3, either PTES or BTES should be used.

Los Angeles features diverse underground conditions, including sedimentary rocks, alluvial deposits, and volcanic remnants. Groundwater basins like the Central and San Fernando Basins are significant water sources, with potential for groundwater activities. The underground varies from sandy to rocky substrates. Detailed geological and hydrological surveys are essential for assessing BTES feasibility and identifying suitable sites.

Conclusion

Scenario 2 proves most economically favorable, with a 41% reduction in total energy costs and a 3.1-year payback period. It also achieves the highest overall emission reductions, ranging from 24% to 50%. Even without the tax credit, it maintains economic favorability, with a 64% total energy cost reduction and a 4.4-year payback period.

At medium energy prices with the tax credit, scenario 2 remains the most feasible, with a 73% total energy cost compared to the baseline and a 5.8-year payback time. However, at medium energy prices without the tax credit, as well as at low energy prices with and without the tax credit, scenario 1 presents the best economics, with total energy prices ranging from 76% to 91% and a payback period between 3.9 and 9 years.

Appendix B, section B.13 provides a detailed breakdown of all simulation outcomes, and section B.13.1 provides further information on economic outcomes under different pricing conditions.

Regarding TTES capacities, all simulated capacities except for the hot TES in Scenario 3 are suitable for TTES. For the hot TES in Scenario 3, either PTES or BTES should be considered.

Los Angeles offers diverse underground conditions, including sedimentary rocks, alluvial deposits, and volcanic remnants. Groundwater basins like the Central and San Fernando Basins provide significant water sources, and the underground varies from sandy to rocky substrates. Conducting detailed geological and hydrological surveys is crucial for assessing BTES feasibility and identifying suitable sites.

5.2.4. CZ 3A – Atlanta

Overall Observations

Atlanta is in the southern United States and inland; it experiences higher temperature extremes, resulting in high heating demand in the winter and very low heating demand in the summer. Additionally, Atlanta has a very high cooling demand in the summer and low cooling demand in the winter, as illustrated in Figure 5-19.

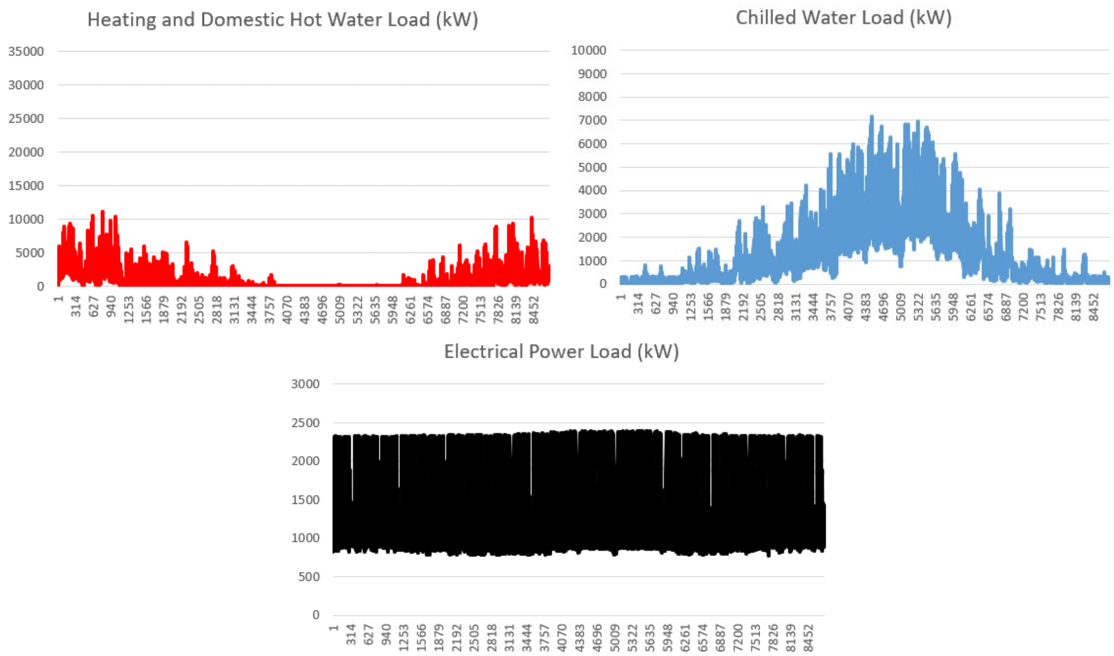


Figure 5-19. Load profiles of the heating, cooling, and electricity demands for Atlanta.

As with the previously simulated climate zones, the baseline "0. Boiler only" scenario sets the benchmark for comparing CO_2 emissions and economics in subsequent scenarios.

CHP / ABS + TES

Scenario "1. CHP Baseload and ABS" with CHP sized to meet baseload electricity demand and absorption chiller to convert excess heat to cooling. CO_2 emissions are reduced by 47% in the case with a low emission rate, 48% with a medium emission rate and by 49% with a high emission rate. The total energy cost is reduced by 29% and the payback period is estimated to be 1.4 years.

Scenario "2. 3x CHP and 3x ABS" with tripled CHP capacity compared to scenario 1 to cover the entire electricity demand and absorption chiller to convert excess heat to cooling. CO_2 emissions are reduced by 45% in the case with a low emission rate, 56% with a medium emission rate and by 61% with a high emission rate. The total energy cost is reduced by 47% and the payback period is estimated to be 2.4 years.

Scenario "3. 3x CHP and 3x ABS with TES." Same as scenario 2 but with 2,000 m^3 cold TES and 40,000 m^3 hot TES to provide necessary resilience. CO_2 emissions are reduced by 47% in the case with a low emission rate, 60% with a medium emission rate and by 66% with a high emission rate. The total energy cost is reduced by 48% and the payback period is estimated to be 3.6 years.

CHP / ABS + SWH + TES

Scenario "4. 3x CHP and 3x ABS with small SWH and TES" is the same as scenario 3 but with 30,000 m^3 cold TES, 53,000 m^3 hot TES and a 7,000 m^2 SWH plant. CO_2 emissions are reduced by 49% in the case with a low emission rate, 61% with a medium emission rate and by 67% with a high emission rate. The total energy cost is reduced by 40% and the payback period is estimated to be 5.5 years.

Scenario "5. 3x CHP and 3x ABS with medium SWH and TES" with 320,000 m^3 cold TES, 92,000 m^3 hot TES and an 11,800 m^2 SWH plant. CO_2 emissions are reduced by 50% in the case with a low emission rate, 62% with a medium emission rate and by 68% with a high emission rate. The total energy cost is reduced by 20% and the payback period is estimated to be 9.9 years.

Scenario "6. 3x CHP and 6x ABS with medium SWH and TES" with double absorption chiller capacity, 182,000 m^3 cold TES, 92,000 m^3 hot TES and a 12,500 m^2 SWH plant. CO_2 emissions are reduced by the same amount as in scenario 5. The total energy cost is reduced by 21% and the payback period is estimated to be 9.8 years.

ABS + SWH + TES

The final scenario, "7. 6x ABS with large SWH and TES" with 2,000 m^3 cold TES, 140,000 m^3 hot TES, a 44,000 m^2 SWH plant and omitted CHP necessitating all electricity to be imported by the public grid. CO_2 emissions are reduced by 65% in the case with a low emission rate, 52% with a medium emission rate and by 46% with a high emission rate. The total energy cost is increased by 39% and the payback period is estimated to be 44.3 years.

Summary

Table B-98 in Appendix B details TES capacities, SWH field sizes, and CHP capacities for the Atlanta simulations and provides an overview of heating and cooling production, CAPEX breakdown, overall CAPEX, CAPEX after a 30% tax credit reduction, and potential savings from the tax credit reduction.

Figure B 359 summarizes total energy costs for each simulation scenario at each energy price level without the 30% tax credit reduction and Figure B 360 with the tax credit reduction. Figure B 367 summarizes the CO2 emissions for each simulation scenario at each emission rate for both fuel and imported electricity. All figures are comparing the simulated scenarios directly to the "0. Boiler only" baseline, represented as "100%" for total energy cost.

Figure B 363 shows the distribution of electricity demand met by imported electricity and CHP.

Table B-104 provides an economic analysis for each simulated scenario, encompassing initial investments, OPEX, simple payback period, loan repayment for CAPEX and yearly savings relative to the "0. Boiler only" baseline, all at the high energy price with 30% tax credit reduction.

Scenario 3 demonstrates the most favorable economics, with a 48% reduction in total energy costs and a payback period of 3.6 years. While scenarios 5 and 6 both achieve the highest emission reductions, scenario 6 stands out as the most favorable choice due to its slightly better economic performance. With emission reductions ranging from 50% to 68%, a 21% reduction in total energy cost, and a payback period of 9.8 years, scenario 6 emerges as the recommended option for maximizing emission reductions.

The presented results are derived from the simulations based on high energy prices with a 30% tax credit, as these present the highest savings and most substantial economic implications.

Appendix B, section B.14 provides all simulation results and section B.14.1 provides the economic results under every simulated pricing condition.

Although scenario 3 emerges as the most economical option under high energy prices with a 30% tax credit, scenario 2 outperforms economically under high energy prices without the tax credit and under medium energy prices with and without the tax credit. Scenario 2 exhibits total energy costs ranging from 57% to 73% compared to the baseline, with a payback period between 3.5 and 6.5 years. Conversely, scenario 3 demonstrates total energy costs between 59% and 81% with a payback period between 5.2 and 9.6 years under the same pricing conditions. At low energy prices, both with and without the tax credit, scenario 1 presents the most favorable economic performance, with total energy costs between 89% and 92% and a payback period between 6.2 and 8.8 years.

Technology Recommendations

The cold TES in scenarios 3, 4 and 7 are the only TES capacities where TTES remain feasible. All other simulated TES capacities in the additional scenarios have to be either PTES or TTES.

When considering BTES in Atlanta, it is essential to consider the geological and hydrological conditions. The area is primarily sedimentary rock, potentially containing fractured zones suitable for aquifers. Soil composition varies, impacting drilling feasibility, and the depth to bedrock varies across the region, affecting borehole design. Understanding these factors is crucial for successful BTES implementation.

Conclusion

Scenario 3 demonstrates the most favorable economics, achieving a 48% reduction in total energy costs with a 3.6-year payback period. While scenarios 5 and 6 achieve the highest emission reductions, scenario 6 emerges as the most favorable choice due to its slightly better economic performance. With emission reductions ranging from 50% to 68%, a 21% reduction in total energy cost, and a payback period of 9.8 years, scenario 6 stands out for maximizing emission reductions. These findings stem from simulations based on high energy prices with a 30% tax credit, which highlighted significant savings and economic impacts.

Scenario 2, however, outperforms economically under high energy prices without the tax credit, as well as under medium energy prices with and without the tax credit, displaying total energy costs between 57% and 73% compared to the baseline, with a payback period ranging from 3.5 to 6.5 years. In contrast, scenario 3 exhibits total energy costs between 59% and 81% with a payback period between 5.2 and 9.6 years under the same pricing conditions. At low energy prices with and without the tax credit, scenario 1 presents the most favorable economic performance, with total energy costs between 89% and 92% and a payback period between 6.2 and 8.8 years.

Moreover, it is noteworthy that cold TES capacities in scenarios 3, 4, and 7 are the only ones feasible for TTES. All other simulated TES capacities in additional scenarios may require PTES or BTES.

Considering BTES implementation in Atlanta, understanding the geological and hydrological conditions is crucial. The area primarily comprises sedimentary rock with potential fractured zones suitable for aquifers. Variability in soil composition affects drilling feasibility, while the depth to bedrock varies across the region, impacting borehole design. These factors must be carefully assessed for successful BTES deployment.

5.2.5. CZ 2B – Phoenix

Overall Observations

Phoenix is located inland in the southern United States; it has extremely high temperatures and the heating demand is high in the winter and almost nonexistent in the summer. Cooling demand is consistently high in the winter but exceptionally high in the summer, as illustrated in Figure 5-20.

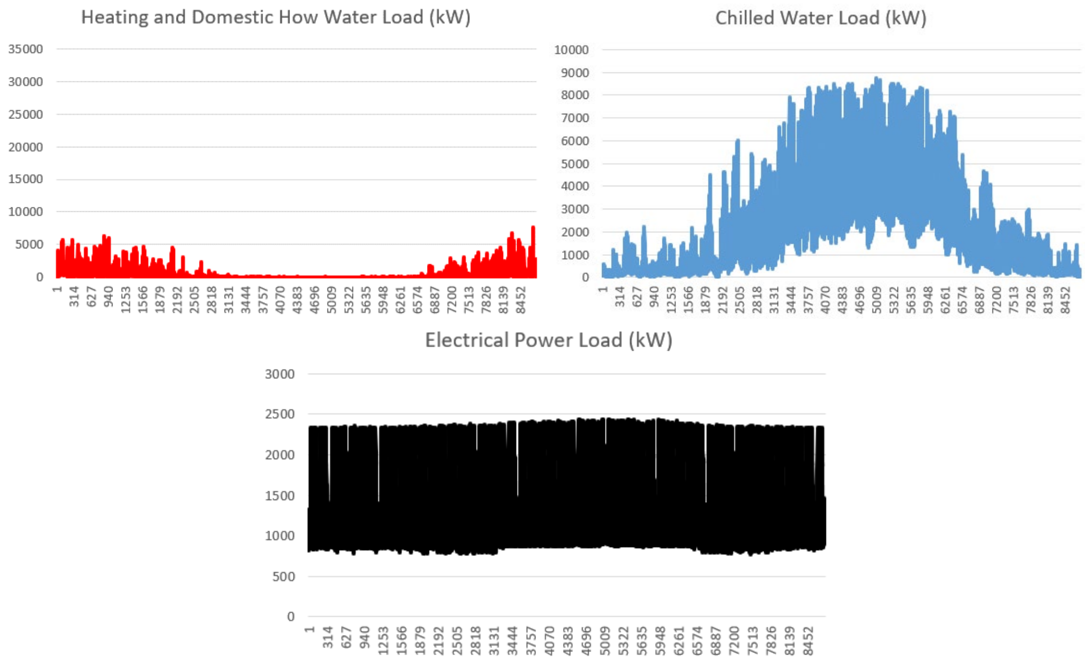


Figure 5-20. Load profiles of the heating, cooling, and electricity demands for Phoenix.

As with the previously simulated climate zones, the baseline “0. Boiler only” scenario sets the benchmark for comparing CO_2 emissions and economics in subsequent scenarios.

CHP / ABS + TES

Scenario “1. CHP Baseload and ABS” with CHP sized to meet baseload electricity demand and absorption chiller to convert excess heat to cooling. CO_2 emissions are reduced by 23% in the case with a low emission rate, 31% with a medium emission rate and by 35% with a high emission rate. The total energy cost is reduced by 28% and the payback period is estimated to be 1.4 years.

Scenario “2. 3x CHP and 3x ABS” with tripled CHP capacity compared to scenario 1 to cover the entire electricity demand and absorption chiller to convert excess heat to cooling. CO_2 emissions are reduced by 17% in the case with a low emission rate, 42% with a medium emission rate and by 52% with a high emission rate. The total energy cost is reduced by 48% and the payback period is estimated to be 2.3 years.

Scenario “3. 3x CHP and 3x ABS with TES.” Same as scenario 2 but with 8,000 m^3 cold TES and 20,000 m^3 hot TES to provide necessary resilience. CO_2 emissions are reduced by 21% in the case with a low emission rate, 48% with a medium emission rate and by 58% with a high emission rate. The total energy cost is reduced by 49% and the payback period is estimated to be 3.2 years.

CHP / ABS + SWH + TES

Scenario "4. 3x CHP and 3x ABS with small SWH and TES" is the same as scenario 3 but with 310,000 m^3 cold TES, 50,000 m^3 hot TES and a 7,000 m^2 SWH plant. CO_2 emissions are reduced by 21% in the case with a low emission rate, 48% with a medium emission rate and by 58% with a high emission rate. The total energy cost is reduced by 27% and the payback period is estimated to be 8.4 years.

Scenario "5. 3x CHP and 3x ABS with medium SWH and TES" with 1,025,000 m^3 cold TES, 80,000 m^3 hot TES and a 12,500 m^2 SWH plant. CO_2 emissions are reduced by 25% in the case with a low emission rate, 51% with a medium emission rate and by 60% with a high emission rate. The total energy cost is the same as the baseline and the payback period is estimated to be 14.3 years.

Scenario "6. 3x CHP and 6x ABS with medium SWH and TES" with double absorption chiller capacity, 15,000 m^3 cold TES, 280,000 m^3 hot TES and a 12,500 m^2 SWH plant. CO_2 emission reductions are the same as in scenario 5. The total energy cost is reduced by 22% and the payback period is estimated to be 9.5 years.

ABS + SWH + TES

The final scenario, "7. 6x ABS with large SWH and TES" with 15,000 m^3 cold TES, 230,000 m^3 hot TES, a 44,000 m^2 SWH plant and omitted CHP necessitating all electricity to be imported by the public grid. CO_2 emissions are reduced by 46% in the case with a low emission rate, 37% with a medium emission rate and by 34% with a high emission rate. The total energy cost is increased by 40% and the payback period is estimated to be 41.6 years.

Summary

Table B-105 details TES capacities, SWH field sizes, and CHP capacities for the Phoenix simulations and provides an overview of heating and cooling production, CAPEX breakdown, overall CAPEX, CAPEX after a 30% tax credit reduction, and potential savings from the tax credit reduction.

Figure B 385 summarizes total energy costs for each simulation scenario at each energy price level without the 30% tax credit reduction and Figure B 386 with the tax credit reduction. Figure B 393 summarizes the CO2 emissions for each simulation scenario at each emission rate for both fuel and imported electricity. All figures are comparing the simulated scenarios directly to the "0. Boiler only" baseline, represented as "100%" for total energy cost.

Figure B 389 shows the distribution of electricity demand met by imported electricity and CHP.

Table B-111 provides an economic analysis for each simulated scenario, encompassing initial investments, OPEX, simple payback period, loan repayment for CAPEX and yearly savings relative to the "0. Boiler only" baseline, all at the high energy price with 30% tax credit reduction.

Scenario 3 exhibits the most favorable economics, with a 49% reduction in total energy costs and a 3.2-year payback period. Like the Atlanta simulations, scenarios 5 and 6 achieve the highest emission reductions, but scenario 6 stands out due to its better economic performance. With emission reductions ranging from 25% to 60%, a 22% reduction in total energy cost, and a payback period of 9.5 years, scenario 6 emerges as the recommended option for maximizing emission reductions.

The results presented stem from simulations conducted under high energy prices supplemented by a 30% tax credit, reflecting significant savings and substantial economic impacts. Appendix B, section B.15 provides simulation outcomes and section B.15.1 provides economic results under various simulated pricing conditions.

Scenario 3 is the most economic option under high energy prices and with 30% tax credit, however, scenario 2 performs best economically under high energy prices without the tax credit and under medium energy prices with and without the tax credit, with total energy costs ranging from 56% to 72%, compared to the baseline, and a payback time between 3.3 and 6.2 years. In contrast, under the same pricing conditions, scenario 3 shows total energy costs between 57% and 78% with a payback time between 4.5 and 8.6 years. At low energy prices, both with and without the tax credit, scenario 1 presents the best economy with total energy costs between 89% and 93% with a payback time between 6.2 and 8.9 years.

Technology Recommendations

The simulated TES capacities in scenario 3, as well as the cold TES capacities in scenarios 6 and 7, are suitable for TTES. The remaining TES capacities necessitate either PTES or BTES to be used.

When considering installing a BTES in Phoenix, it is essential to consider the geological and hydrological conditions. The area primarily consists of desert terrain with sedimentary rock formations, which may result in limited aquifers. Groundwater resources are generally scarce in this arid region. Soil composition varies, with sandy and rocky soils prevalent, which could affect drilling feasibility. The depth to bedrock varies across the region, which could impact borehole design. Understanding these factors is crucial for successful BTES implementation.

Conclusion

Scenario 3 offers the most favorable economics, with a 49% reduction in total energy costs and a 3.2-year payback period. Scenarios 5 and 6 achieve the highest emission reductions, with Scenario 6 emerging as the preferred choice due to its slightly better economic performance. Scenario 6 showcases emission reductions ranging from 25% to 60%, along with a 22% decrease in total energy cost and a payback period of 9.5 years.

These results are based on simulations conducted under high energy prices with a 30% tax credit, emphasizing significant savings. Although scenario 3 offers the best economics under high energy prices with a 30% tax credit, scenario 2 outperforms economically under high energy prices without the tax credit and under medium energy prices with and without the tax credit, with total energy costs ranging from 56% to 72% compared to the baseline, and a payback period between 3.3 and 6.2 years. Conversely, under the same pricing conditions, scenario 3 demonstrates total energy costs between 57% and 78% with a payback period between 4.5 and 8.6 years. At low energy prices, both with and without the tax credit, scenario 1 offers the most economical solution, with total energy costs between 89% and 93% and a payback period between 6.2 and 8.9 years.

Furthermore, the simulated TES capacities in Scenario 3, as well as the cold TES capacities in Scenarios 6 and 7, are suitable for TTES. However, all other TES capacities require either PTES or BTES for implementation.

Regarding BTES installation in Phoenix, understanding the geological and hydrological conditions is crucial. The region predominantly features desert terrain with sedimentary rock formations, potentially limiting aquifers. Groundwater resources are generally scarce in this arid region. Additionally, soil composition varies, with prevalent sandy and rocky soils, potentially impacting drilling feasibility. The depth to bedrock varies across the region, influencing borehole design. These factors must be carefully considered for successful BTES implementation.

5.2.6. CZ 2A – Houston

Overall Observations

Houston is in the southern United States relatively close the Mexican border and has a very high cooling demand and the highest peak in the cooling demand of all the climate zones. The heating demand is highest in the winter and almost nonexistent much of the summer, as illustrated in Figure 5-21.

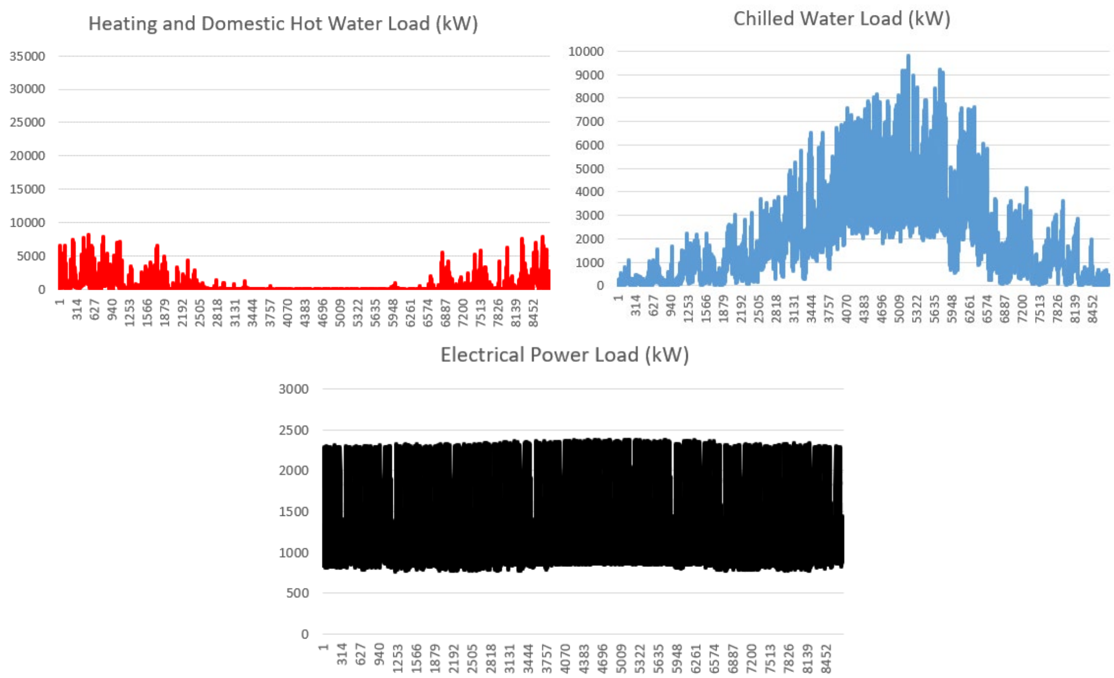


Figure 5-21. Load profiles of the heating, cooling, and electricity demands for Houston.

As with the previously simulated climate zones, the baseline "0. Boiler only" scenario sets the benchmark for comparing CO_2 emissions and economics in subsequent scenarios.

CHP / ABS + TES

Scenario "1. CHP Baseload and ABS" with CHP sized to meet baseload electricity demand and absorption chiller to convert excess heat to cooling. CO_2 emissions are reduced by 29% in the case with a low emission rate, 36% with a medium emission rate and by 38% with a high emission rate. The total energy cost is reduced by 28% and the payback period is estimated to be 1.4 years.

Scenario "2. 3x CHP and 3x ABS" with tripled CHP capacity compared to scenario 1 to cover the entire electricity demand and absorption chiller to convert excess heat to cooling. CO_2 emissions are reduced by 25% in the case with a low emission rate, 46% with a medium emission rate and by 54% with a high emission rate. The total energy cost is reduced by 48% and the payback period is estimated to be 2.3 years.

Scenario "3. 3x CHP and 3x ABS with TES." Same as scenario 2 but with 5,000 m^3 cold TES and 5,000 m^3 hot TES to provide necessary resilience. CO_2 emissions are reduced by 25% in the case with a low emission rate, 49% with a medium emission rate and by 58% with a high emission rate. The total energy cost is reduced by 52% and the payback period is estimated to be 2.7 years.

CHP / ABS + SWH + TES

Scenario "4. 3x CHP and 3x ABS with small SWH and TES" is the same as scenario 3 but with 30,000 m^3 cold TES, 55,000 m^3 hot TES and a 7,000 m^2 SWH plant. CO_2 emissions are reduced by 27% in the case with a low emission rate, 50% with a medium emission rate and by 60% with a high emission rate. The total energy cost is reduced by 40% and the payback period is estimated to be 5.4 years.

Scenario "5. 3x CHP and 3x ABS with medium SWH and TES" with 1,000,000 m^3 cold TES, 90,000 m^3 hot TES and a 22,700 m^2 SWH plant. CO_2 emissions are reduced by 33% in the case with a low emission rate, 54% with a medium emission rate and by 63% with a high emission rate. The total energy cost is increased by 8% and the payback period is estimated to be 16 years.

Scenario "6. 3x CHP and 6x ABS with medium SWH and TES" with double absorption chiller capacity, 15,000 m^3 cold TES, 250,000 m^3 hot TES and a 22,700 m^2 SWH plant. CO_2 emission reductions are the same as scenario 5. The total energy cost is reduced by 16% and the payback period is estimated to be 10.9 years.

ABS + SWH + TES

The final scenario, "7. 6x ABS with large SWH and TES" with 25,000 m^3 cold TES, 230,000 m^3 hot TES, a 44,000 m^2 SWH plant and omitted CHP necessitating all electricity to be imported by the public grid. CO_2 emissions are reduced by 52% in the case with a low emission rate, 42% with a medium emission rate and by 37% with a high emission rate. The total energy cost is increased by 41% and the payback period is estimated to be 41.9 years.

Summary

Table B-112 details TES capacities, SWH field sizes, and CHP capacities for the Houston simulations and provides an overview of heating and cooling production, CAPEX breakdown, overall CAPEX, CAPEX after a 30% tax credit reduction, and potential savings from the tax credit reduction.

Figure B 411 summarizes total energy costs for each simulation scenario at each energy price level without the 30% tax credit reduction and Figure B 412 with the tax credit reduction. Figure B 419 summarizes the CO2 emissions for each simulation scenario at each emission rate for both fuel and imported electricity. All figures are comparing the simulated scenarios directly to the "0. Boiler only" baseline, represented as "100%" for total energy cost.

Figure B 415 shows the distribution of electricity demand met by imported electricity and CHP.

Table B-118 provides an economic analysis for each simulated scenario, encompassing initial investments, OPEX, simple payback period, loan repayment for CAPEX and yearly savings relative to the "0. Boiler only" baseline, all at the high energy price with 30% tax credit reduction.

Scenario 3 exhibits the most favorable economics, with a 52% reduction in total energy costs and a 2.7-year payback period. Scenarios 5 and 6 achieve the highest emission reductions, but scenario 6 stands out due to its better economic performance. With emission reductions ranging from 33% to 63%, a 16% reduction in total energy cost, and a payback period of 10.9 years, scenario 6 emerges as the recommended option for maximizing emission reductions.

The outcomes reported are based on simulations performed under high energy prices with a 30% tax credit, showcasing noteworthy savings and considerable economic implications. Appendix B, section B.16 provides all simulation results, and section B.16.1 provides economic outcomes under different pricing conditions.

Scenario 3 is the most economic option under high energy prices and with a 30% tax credit. In addition, scenario 3 remains the most economic scenario under high energy prices without the tax credit, as well as medium energy prices with the tax credit, with a total energy cost ranging between 54% and 64%, compared to the baseline, and a payback period between 3.8 and 5 years. Under medium energy prices without the tax credit, scenario 2 performs best economically with a total energy cost of 72% and a payback period of 6.3 years. Under low pricing conditions, with and without the tax credit, scenario 1 is the most economic with a total energy cost between 89% and 92% with a payback period between 6.2 and 8.8 years.

Technology Recommendations

In scenario 3, along with the cold TES capacities in scenarios 4, 6, and 7, TTES is applicable for use. For the remaining TES capacities, either PTES or BTES is required.

In evaluating the installation of a BTES system in Houston, it is imperative to assess the geological and hydrological conditions. The region is characterized by coastal plains with sedimentary rock formations, which may harbor aquifers. However, the proximity to the Gulf of Mexico raises concerns about potential saltwater intrusion into groundwater resources. Soil composition, ranging from clayey to sandy, presents considerations for drilling feasibility. Furthermore, the variable depth to bedrock across the area impacts borehole design. A thorough understanding of these factors is essential for the successful implementation of BTES.

Conclusion

Scenario 3 proves most economically favorable, with a 52% reduction in total energy costs and a short 2.7-year payback period. Although scenarios 5 and 6 achieve the highest emission reductions, scenario 6 stands out due to its better economic performance. It achieves emission reductions ranging from 33% to 63%, along with a 16% decrease in total energy costs and a payback period of 10.9 years, making it the recommended choice for maximizing emission reductions while maintaining economic viability.

Scenario 3 proves to be the most economical choice under high energy prices and with a 30% tax credit. It remains the top economic performer under high energy prices without the tax credit, as well as under medium energy prices with the tax credit. Total energy costs range from 54% to 64% compared to the baseline, with payback periods between 3.8 and 5 years. In contrast, scenario 2 performs best economically under medium energy prices without the tax credit, with a total energy cost of 72% and a payback period of 6.3 years. Scenario 1 emerges as the most economical option under low pricing conditions, with total energy costs between 89% and 92% and payback periods between 6.2 and 8.8 years.

Appendix B, section B.16 provides all simulation results, and section B.16.1 provides economic outcomes under different pricing conditions.

In terms of technology implementation, TTES is applicable for scenario 3 and cold TES capacities in scenarios 4, 6, and 7, whereas PTES or BTES is necessary for the remaining TES capacities.

When considering the installation of a BTES system in Houston, it is imperative to carefully evaluate geological and hydrological conditions. The region's characteristics, such as coastal plains with sedimentary rock formations and variable bedrock depth, play a crucial role in determining the feasibility and success of BTES implementation. Understanding these factors is paramount for ensuring the effectiveness and sustainability of the system.

5.2.7. CZ 1A – Miami

Overall Observations

Miami is located at the most southern point in mainland United States and consequently is one of the hottest simulated climate zones. The heating demand is consistently low, and the cooling demand is also high throughout the year, peaking in the summer, as illustrated in Figure 5-22.

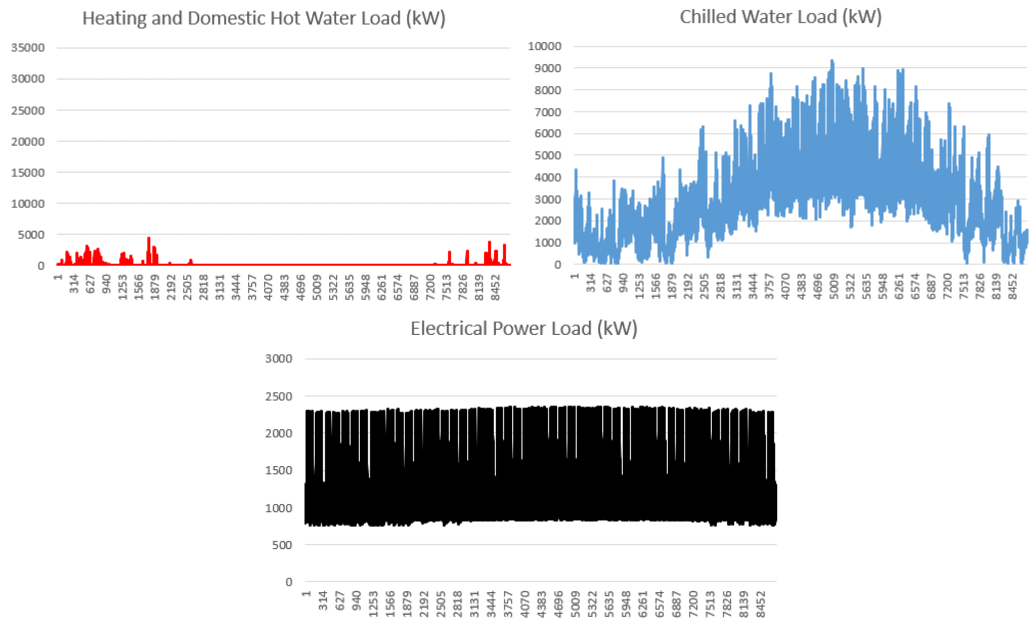


Figure 5-22. Load profiles of the heating, cooling, and electricity demands for Miami.

As with the previously simulated climate zones, the baseline “0. Boiler only” scenario sets the benchmark for comparing CO_2 emissions and economics in subsequent scenarios.

CHP / ABS + TES

Scenario “1. CHP Baseload and ABS” with CHP sized to meet baseload electricity demand and absorption chiller to convert excess heat to cooling. CO2 emissions are increased by 4% in the case with a low emission rate, reduced by 17% with a medium emission rate and by 24% with a high emission rate. The total energy cost is reduced by 26% and the payback period is estimated to be 1.4 years.

Scenario “2. 3x CHP and 3x ABS” with tripled CHP capacity compared to scenario 1 to cover the entire electricity demand and absorption chiller to convert excess heat to cooling. CO_2 emissions are increased by 15% in the case with a low emission rate, reduced by 32% with a medium emission rate and by 46% with a high emission rate. The total energy cost is reduced by 51% and the payback period is estimated to be 2.1 years.

Scenario “3. 3x CHP and 3x ABS with TES.” Same as scenario 2 but with 10,000 m^3 cold TES to provide necessary resilience. CO_2 emissions are increased by 16% in the case with a low emission rate, reduced by 33% with a medium emission rate and by 49% with a high emission rate. The total energy cost is reduced by 52% and the payback period is estimated to be 2.6 years.

CHP / ABS + SWH + TES

Scenario "4. 3x CHP and 3x ABS with small SWH and TES" is the same as scenario 3 but with the addition of a 10,000 m^3 hot TES and a 7,000 m^2 SWH plant. CO_2 emissions are increased by 12% in the case with a low emission rate, reduced by 35% with a medium emission rate and by 50% with a high emission rate. The total energy cost is reduced by 46% and the payback period is estimated to be 3.9 years.

Scenario "5. 3x CHP and 3x ABS with medium SWH and TES" with 450,000 m^3 cold TES, 75,000 m^3 hot TES and a 17,500 m^2 SWH plant. CO_2 emissions are increased by 5% in the case with a low emission rate, reduced by 39% with a medium emission rate and by 53% with a high emission rate. The total energy cost is reduced by 16% and the payback period is estimated to be 10.9 years.

Scenario "6. 3x CHP and 6x ABS with medium SWH and TES" with double absorption chiller capacity, 50,000 m^3 cold TES, 300,000 m^3 hot TES and a 32,000 m^2 SWH plant. CO_2 emissions are reduced by 4% in the case with a low emission rate, 44% with a medium emission rate and by 57% with a high emission rate. The total energy cost is reduced by 10% and the payback period is estimated to be 12.2 years.

ABS + SWH + TES

The final scenario, "7. 6x ABS with large SWH and TES" with 100,000 m^3 cold TES, 200,000 m^3 hot TES, a 55,500 m^2 SWH plant and omitted CHP necessitating all electricity to be imported by the public grid. CO_2 emissions are reduced by 31% in the case with a low emission rate, 29% with a medium emission rate and by 29% with a high emission rate. The total energy cost is increased by 40% and the payback period is estimated to be 36.6 years.

Summary

Table B-112 details TES capacities, SWH field sizes, and CHP capacities for the Miami simulations and provides an overview of heating and cooling production, CAPEX breakdown, overall CAPEX, CAPEX after a 30% tax credit reduction, and potential savings from the tax credit reduction.

Figure B 411 summarizes total energy costs for each simulation scenario at each energy price level without the 30% tax credit reduction and Figure B 412 with the tax credit reduction. Figure B 419 summarizes the CO2 emissions for each simulation scenario at each emission rate for both fuel and imported electricity. All figures are comparing the simulated scenarios directly to the "0. Boiler only" baseline, represented as "100%" for total energy cost.

Figure B 415 shows the distribution of electricity demand met by imported electricity and CHP.

Table B-118 provides an economic analysis for each simulated scenario, encompassing initial investments, OPEX, simple payback period, loan repayment for CAPEX and yearly savings relative to the "0. Boiler only" baseline, all at the high energy price with 30% tax credit reduction.

Scenario 3 exhibits the most favorable economics, with a 52% reduction in total energy costs and a 2.6-year payback period. Scenario 6 showcases the highest emission reductions ranging from 4% to 57%. Additionally, it presents a total energy cost reduction of 10% and a payback period of 12.2 years.

The presented results are from the simulations performed under high energy prices with a 30% tax credit, displaying the highest savings and most prominent economic impacts. Appendix B, section B.17 provides all simulation outcomes, and section B.17.1 provides economic results under the other pricing conditions.

Scenario 3 is the most economic option under high energy prices and with a 30% tax credit. Without the tax credit, it is tied with scenario 2. Under medium energy prices both with and without the tax credit, as well as low energy prices with the tax credit, scenario 2 is the most economic option with total energy costs ranging from 63% to 89% compared to the baseline and a payback period between 4 and 9.9 years. Under low energy prices without the tax credit, scenario 1 is the most economic option with a total energy cost of 94% and a payback period of 9.6 years.

Technology Recommendations

The TES capacities in scenarios 3 and 4 are suitable for TTES. The remaining TES capacities require either PTES or BTES to be used.

In evaluating the installation of BTES in Miami, thorough consideration of the geological and hydrological conditions is essential. Miami's terrain primarily comprises coastal plains with sedimentary rock formations, potentially housing aquifers. In addition to abundant groundwater resources, saltwater intrusion from the nearby Atlantic Ocean can occur. Sandy soil composition prevalent in the area impacts drilling feasibility, while variations in the depth to bedrock necessitate tailored borehole design. A comprehensive understanding of these factors is paramount for the successful implementation of BTES.

Conclusion

Scenario 3 demonstrates the most favorable economics, with a 52% reduction in total energy costs and a 2.6-year payback period. Scenario 6 achieves the highest emission reductions ranging from 4% to 57%, along with a 10% reduction in total energy costs and a payback period of 12.2 years.

The results are based on simulations conducted under high energy prices with a 30% tax credit, presenting significant savings and economic impacts. Appendix B, section B.17 provides all simulation outcomes, and section B.17.1 provides economic results under the other pricing conditions.

Scenario 3 is the most economic under high energy prices and with a 30% tax credit. Without the tax credit, it is tied with scenario 2. Under medium energy prices with or without the tax credit, and low energy prices with the tax credit, scenario 2 is the most economic, with total energy costs ranging from 63% to 89% and a payback period of 4 to 9.9 years. Under low energy prices without the tax credit, scenario 1 is the most economic, with a total energy cost of 94% and a payback period of 9.6 years.

In scenarios 3 and 4, TES capacities are suitable for TTES, while the remaining require PTES or BTES. Evaluating BTES installation in Miami requires thorough consideration of its geological and hydrological conditions, primarily coastal plains with sedimentary rock formations potentially housing aquifers. Abundant groundwater resources exist, but saltwater intrusion from the Atlantic Ocean is possible. Sandy soil impacts drilling feasibility, while varied bedrock depth requires tailored borehole design. Understanding these factors is vital for BTES implementation.

5.2.8. CZ 0A – Guam

Overall Observations

The last and most unusual climate zone to be presented is Guam, an island in the Pacific Ocean relatively close to the Philippines. This is by far the hottest climate zone and is reflected in the fact that it has almost no heating demand and a large, consistent cooling demand year-round, as illustrated in Figure 5-23. Given the very remote location, there is very little natural gas and electricity infrastructure, making this location reliant on being self-sufficient on heating, cooling, and electricity production.

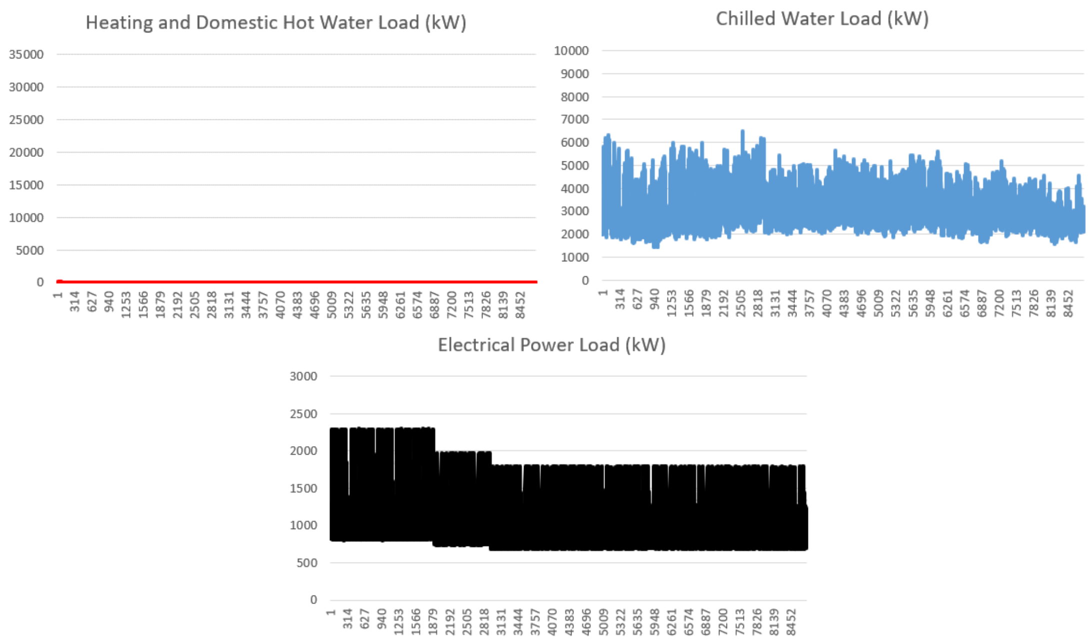


Figure 5-23. Load profiles of the heating, cooling, and electricity demands for Guam.

As with the previously simulated climate zones, the baseline "0. Boiler only" scenario sets the benchmark for comparing CO_2 emissions and economics in subsequent scenarios.

CHP / ABS + TES

Scenario "1. CHP Baseload and ABS" with CHP sized to meet baseload electricity demand and absorption chiller to convert excess heat to cooling. CO_2 emissions are increased by 12% in the case with a low emission rate, reduced by 16% with a medium emission rate and by 25% with a high emission rate. The total energy cost is reduced by 29% and the payback period is estimated to be 1.4 years.

Scenario "2. 3x CHP and 3x ABS" with tripled CHP capacity compared to scenario 1 to cover the entire electricity demand and absorption chiller to convert excess heat to cooling. CO_2 emissions are increased by 23% in the case with a low emission rate, reduced by 31% with a medium emission rate and by 47% with a high emission rate. The total energy cost is reduced by 53% and the payback period is estimated to be 2.2 years.

Scenario "3. 3x CHP and 3x ABS with TES." Same as scenario 2 but with 1,000 m^3 cold TES to provide necessary resilience. CO_2 emissions are increased by 23% in the case with a low emission rate, reduced by 31% with a medium emission rate and by 47% with a high emission rate. The total energy cost is reduced by 52% and the payback period is estimated to be 2.4 years.

CHP / ABS + SWH + TES

Scenario "4. 3x CHP and 3x ABS with small SWH and TES" is the same as scenario 3 but with the addition of a 1,000 m^3 hot TES and a 7,000 m^2 SWH plant. CO_2 emissions are increased by 19% in the case with a low emission rate, reduced by 33% with a medium emission rate and by 49% with a high emission rate. The total energy cost is reduced by 48% and the payback period is estimated to be 3.6 years.

Scenario "5. 3x CHP and 3x ABS with medium SWH and TES" with 1,000 m^3 cold TES, 50,000 m^3 hot TES and a 17,500 m^2 SWH plant. CO_2 emissions are increased by 10% in the case with a low emission rate, reduced by 38% with a medium emission rate and by 53% with a high emission rate. The total energy cost is reduced by 36% and the payback period is estimated to be 6.6 years.

Scenario "6. 3x CHP and 6x ABS with medium SWH and TES" with double absorption chiller capacity, 1,000 m^3 cold TES, 85,000 m^3 hot TES and a 33,500 m^2 SWH plant. CO_2 emissions are reduced by 3% in the case with a low emission rate, 45% with a medium emission rate and by 59% with a high emission rate. The total energy cost is reduced by 18% and the payback period is estimated to be 10.5 years.

ABS + SWH + TES

The final scenario, "7. 6x ABS with large SWH and TES" with 1,000 m^3 cold TES, 85,000 m^3 hot TES, a 48,500 m^2 SWH plant and omitted CHP necessitating all electricity to be imported by the public grid. CO_2 emissions are reduced by 30% across all emission rates. The total energy cost is increased by 29% and the payback period is estimated to be 28.9 years.

Summary

Table B-126 details TES capacities, SWH field sizes, and CHP capacities for the Guam simulations and provides an overview of heating and cooling production, CAPEX breakdown, overall CAPEX, CAPEX after a 30% tax credit reduction, and potential savings from the tax credit reduction.

Figure B 463 summarizes total energy costs for each simulation scenario at each energy price level without the 30% tax credit reduction and Figure B 465 with the tax credit reduction. Figure B 471 summarizes the CO2 emissions for each simulation scenario at each emission rate for both fuel and imported electricity. All figures are comparing the simulated scenarios directly to the "0. Boiler only" baseline, represented as "100%" for total energy cost.

Figure B 467 shows the distribution of electricity demand met by imported electricity and CHP.

Table B-132 provides an economic analysis for each simulated scenario, encompassing initial investments, OPEX, simple payback period, loan repayment for CAPEX and yearly savings relative to the "0. Boiler only" baseline, all at the high energy price with 30% tax credit reduction.

Scenario 2 demonstrates the most favorable economic performance, achieving a 53% reduction in total energy costs and a 2.2-year payback period. Meanwhile, Scenario 6 stands out for its significant emission reductions, ranging from 3% to 59%. Additionally, it features an 18% reduction in total energy costs and a 10.5-year payback period.

The results presented stem from simulations conducted under high energy prices with a 30% tax credit, highlighting substantial savings and significant economic impacts. Appendix B, section B.18 provides all simulation results, and section B.18.1 provides economic results under alternative pricing conditions.

Scenario 2 emerges as the most economical choice under high energy prices and with a 30% tax credit. Similarly, at high energy prices without the tax credit, as well as medium energy prices with and without the tax credit, scenario 2 maintains its economic superiority with total energy costs ranging from 51% to 69% compared to the baseline, and a payback period between 3.2 and 6.1 years. Under low energy prices with the tax credit, scenarios 1 and 2 share the same total energy cost of 90%, but scenario 1 boasts the shortest payback time at 6.7 years. Without the tax credit, scenario 1 emerges as the most economical choice with a total energy cost of 94% and a payback time of 9.6 years.

Technology Recommendations

The TES capacities outlined in scenarios 3 and 4, along with the cold TES capacities featured in scenarios 5, 6, and 7, are suitable to TTES use. The remaining TES capacities require either PTES or BTES implementation to be viable.

In evaluating the potential installation of a BTES in Guam, it is imperative to assess the geological and hydrological conditions. The island's composition primarily consists of volcanic rock formations, which may pose challenges for conventional BTES installation methods. Limited groundwater resources and the absence of prevalent aquifers further complicate potential implementation. Varied soil compositions, including volcanic ash and coral limestone, present additional considerations for drilling feasibility. The fluctuating depth to bedrock across the island necessitates tailored borehole design.

Conclusion

Scenario 2 shows the best economic performance, with a 53% decrease in total energy costs and a 2.2-year payback period. Scenario 6 achieves the highest emission reductions, ranging from 3% to 59%, with an 18% reduction in total energy costs and a 10.5-year payback period.

The results are based on simulations under high energy prices with a 30% tax credit, providing significant savings and economic impacts. Appendix B, section B.18 provides all simulation results, and section B.18.1 provides economic results under alternative pricing conditions.

Scenario 2 is the most economical under high energy prices with a 30% tax credit. It also outperforms in scenarios without the tax credit and under medium energy prices, with total energy costs ranging from 51% to 69% compared to the baseline and payback periods between 3.2 and 6.1 years. Under low energy prices with the tax credit, scenarios 1 and 2 have the same total energy cost of 90%, but scenario 1 has a shorter payback time at 6.7 years. Without the tax credit, scenario 1 is the most economical with a total energy cost of 94% and a payback time of 9.6 years.

TES capacities in Scenarios 3 and 4, as well as cold TES capacities in scenarios 5, 6, and 7, are suitable for TTES use, while others require PTES or BTES implementation. When considering BTES installation in Guam, geological and hydrological conditions must be carefully evaluated, given the island's volcanic composition, limited groundwater resources, and varied soil compositions.

CHAPTER 6. DISCUSSION

6.1. General

When constructing an energy system, large equipment investments are only feasible when they yield high subsequent savings or if they generate income. Otherwise, the payback time will not make sense compared to the lifetime of the equipment. This study omitted export of energy, which makes the economy rely solely on savings. When the energy prices are low, the savings from switching to alternative energy sources are also low. This means that the threshold at which equipment investments begin to make economic sense is also low.

In short, the economics associated with higher energy prices make it more attractive to invest in cheaper alternative energy sources. This is the reason solar energy shows poor economy in most of the simulations and in turn why TES is not always a good idea to implement. If the energy is cheap and is anticipated to remain so, there is little incentive to store it.

Imported electricity shows a much higher GHG emission per imported MWh than locally produced by CHP, which seems counterintuitive considering the presumably more advanced and intricate electricity production that occurs at a modern powerplant than in a comparatively simple gas engine.

One key aspect of TES is that it contributes to resilience, i.e., its ability to decouple energy generation and consumption. This decoupling allows for a more flexible and adaptable energy system that can respond to fluctuating demands and intermittent energy sources. By storing excess thermal energy during off-peak hours, off-peak seasons, or when renewable generation exceeds demand, TES systems ensure a reliable and continuous energy supply during periods of increased demand or when renewable sources are not available.

Regarding the TES, the highest storage temperature is set to be 90°C (194°F) and the return temperature to 71°C (159.8°F). In Danish PTES systems, the return temperature is 40°C (104°F) which is a higher temperature difference between when stored and returning HTF. This results in a higher overall efficiency of the TES and thereby a smaller dimension needed to store the same energy, which affects the CAPEX and OPEX of the TES. If this principle were used in the simulations, the total energy costs would be lower as the CAPEX and OPEX would be reduced.

Within hot climate zones such as Guam, using SWH fields to provide heat for absorption chillers may prove inefficient. An alternative strategy could involve leveraging photovoltaics to support CHP systems in generating electricity for electric chillers, offering a potentially less complex and more cost-effective solution for fulfilling cooling requirements.

In all the pure solar energy scenarios, the high emission rates for imported electricity often show an increase in overall emissions when the entire electricity demand, including the consumption of the electric chiller, must be met by imported electricity — which could be reduced by the inclusion of absorption chillers. Similarly, some of the moderate climate zones have a high cooling demand and could potentially benefit from having them simulated with cold TES.

During the simulations, electric chillers are solely deployed for cooling purposes within the cold and moderate climate zones. Conversely, in hot climate zones, a combination of electric and absorption chillers is used. Considering absorption chillers for certain cold and moderate climate zones may reduce the reliance on imported electricity, particularly in scenarios incorporating SWH plants.

6.2. BTES

In climate zones requiring extensive TES, boreholes are a space-efficient option, particularly for urban or constrained environments. Large-scale TES scenarios can especially benefit from BTES, significantly reducing physical space requirements. Medium and high-temperature BTES (50-90°C) is best suited to high latitudes. However, BTES availability hinges on geological and hydrogeological factors, making precise favorable locations challenging to determine.

BTES systems have the potential to excel in energy efficiency, especially for seasonal heating and cooling, offering consistent and reliable thermal energy storage. However, they rely on heat transfer rates between the heat transfer fluid (HTF) in borehole pipes and the surrounding material, potentially limiting high output demands. With a well-designed closed loop system, BTES can have 100 years of operation with minimal maintenance[*], in contrast to the 25-year certification for PTES. This extended operational life can enhance the payback period and overall economy.

The current maximum achievable depth for BTES in the US is around 1200 ft (365.76m), limiting the achievable storage capacity of each borehole. Additionally, the charging and discharging rates for BTES are 40-60 W/m, making the necessary size of BTES in, e.g., Fairbanks, with heating load topping 30MW, unfeasible to achieve.

High demand for drilling contractors and limited supply may lead to extended project timelines, necessitating meticulous planning. Effective management of drill cuttings and fluids is vital for environmental impact reduction. Noise generated during drilling requires mitigation strategies, and rigorous quality control ensures vertical borehole construction.

[*] Acc. Mark A. Worthington, Underground Energy, LLC.

CHAPTER 7. CONCLUSION

The methodology employed to simulate energy systems across various climate zones involved a structured approach to address key factors influencing system design and performance. The process began with the development of a comprehensive building complex model, considering various building types, sizes, and occupancy patterns to capture diverse energy demand profiles. Different climate zones were identified and characterized to represent a range of environmental conditions, including temperature variations and seasonal patterns. This step ensured the inclusion of diverse geographical settings, from cold/moderate to hot climate zones. Detailed demand profiles were established for each climate zone, accounting for heating, cooling, and electricity requirements based on climatic data and building characteristics. This allowed for the accurate estimation of energy needs under varying environmental conditions. Various system architectures were designed to meet the energy demands of the building complex efficiently. This involved selecting suitable technologies for heating, cooling, and electricity generation, considering factors such as energy efficiency, resilience, and environmental impact. A range of model scenarios were developed to assess different energy strategies and technology combinations across the diverse climate zones. These scenarios were tailored to specific climatic conditions and energy objectives, allowing for comprehensive analysis and comparison. Relevant input data and boundary conditions were defined for each scenario, including energy prices, heating values, emission rates, equipment maintenance costs, capital expenditures (CAPEX) as well as establishing a common measure of total energy costs. This step ensured that the simulations were grounded in real-world parameters and constraints. By following this structured methodology, the simulation process was able to effectively capture the complexities of energy systems in the various climate zones, facilitating informed decision-making and optimization strategies for sustainable energy management.

7.1. CZ 8 - Fairbanks

Scenario 3 stands out as the most economically favorable at extra high energy prices (Alaska price) with a decrease in emissions between 10% and 39%, a decrease in total energy cost of 41% and a rapid payback period of 1.9 years. Additionally, on-site power generation and thermal storage enhance energy system resilience by decoupling electricity and heat demand in CHP, enabling excess heat production to cover electricity demand. However, economic feasibility declines as energy prices decrease.

While scenario 3 remains economically favorable down to medium energy prices, the total energy cost becomes impractical at low energy prices, resulting in an extended payback period of 14.1 to 20.1 years. Additionally, scenario 3 only excels economically under high and extra high energy prices with a 30% tax credit and extra high energy prices without the tax credit. Meanwhile, scenario 2 outperforms economically in all other pricing conditions, exhibiting a total energy cost ranging from 69% to 85% and a payback period of 0.6 to 5.8 years, in contrast to scenario 3's higher total energy cost of 81% to 114% and an extended payback period of 7 to 20.1 years under the same pricing conditions.

Scenario 6 achieves the most significant emissions reduction, ranging from 44% to 65%. However, even in the context of extra high energy prices (Alaska prices) and 30% tax credit/funding, the total energy costs still increase by 21%, and the payback period extends to

21.6 years. While this energy price presents the highest possible savings, the prolonged payback period raises concerns about its economic viability.

All TES scenarios are simulated as PTES due to capacity constraints. Scenarios 4 to 6 reveal challenges with the substantial physical sizes required and considering these challenges, BTES emerges as a spatially efficient alternative, offering flexibility in land use and offering an efficiency of up to 80% in regions with impermeable rock formations. The region's predominant permafrost and sedimentary rock formations, coupled with limited aquifers and groundwater due to the cold climate may pose challenges. Sandy and silty soils, along with variable bedrock depths, affect drilling feasibility. Despite the potential advantages of BTES, meeting large capacity requirements requires deploying wide, deep, and/or multiple BTES units.

7.2. CZ 7 - Duluth

Scenario 3 proves to be the most economically favorable with a decrease in emissions between 19% and 48%, a decrease in total energy cost of 30% and a payback period of 5 years. However, scenario 3 proves economically viable primarily under high energy prices with a 30% tax credit. Scenario 2 consistently demonstrates lower total energy costs than scenario 3 under various lower energy prices, ranging from 81% to 97% and a payback period of 2.4 and 7 years, while scenario 3 fluctuates between 91% and 149% and a payback period of 9 to 25.9 years. This highlights that scenario 3 is economically favorable solely under high energy prices with a 30% tax credit.

Scenario 6 has the lowest overall emissions with a decrease in emissions between 37% and 58% but with an increase in total energy costs of 53%, resulting in a payback period of 36.8 years, making this the least economically feasible scenario.

As with Fairbanks, the simulated TES sizes indicate that only PTES or BTES are viable technology candidates. Considering BTES, the region features primarily sedimentary rock formations, possibly housing aquifers, though groundwater resources may be limited compared to other areas. Soil composition varies, with sandy and clayey soils dominating, influencing drilling feasibility. The depth to bedrock varies, impacting borehole design.

7.3. CZ 6B - Helena

In Helena, scenario “3. 3x CHP with TES” is the most economically viable, reducing total energy costs by 40% and a payback period of 5.2 years. Yet, it lags in emissions reduction (16%-52%). Scenario “5. 2x CHP with medium SWH and TES” leads in emissions reduction (66%-67%) but incurs a 28% increase in total energy costs and a payback period of 16 years, making this scenario less economically favorable.

Results are based on high energy prices. Scenario 3 excels with a 60% total energy cost reduction and 5.2-year payback under high prices with a 30% tax credit. Scenario 2 consistently outperforms under other conditions, displaying lower total energy costs (89%-107%) and a payback period of 2.7-7.7 years. Scenario 3 is economically preferable only under high energy prices with a tax credit, while scenario 2 is the most feasible under other pricing conditions.

Regarding TES, all capacities are modeled as PTES due to their size. BTES is a potential alternative for Helena, but understanding underground conditions is crucial. The area is mostly mountainous, featuring sedimentary and metamorphic rock formations that might have some aquifers. Groundwater availability depends on local geological features. In mountainous areas, the soil is typically rocky and clayey. The presence of karst terrain may pose challenges, potentially hindering the grouting of boreholes.

7.4. CZ 6A - Minneapolis

In Minneapolis, "3. 3x CHP with TES" stands out as the most economically favorable scenario, with a 37% reduction in total energy costs and a 5.7-year payback period. Although it does not achieve the lowest emissions, with reductions ranging from 15% to 50%, its financial feasibility is notable. Conversely, "5. 2x CHP with medium SWH and TES" achieves the lowest overall emissions (37%-43%) but faces an 11% cost increase and a 12.3-year payback, making it less economically favorable.

Scenario 3 excels financially at high energy prices with a 30% tax credit, showing a 37% total energy cost reduction and a 5.7-year payback. Scenario 2 outperforms in other pricing conditions, with total energy costs between 92% and 114%, and a payback period of 2.3 to 8.2 years. In the same pricing conditions, scenario 3 presents total energy costs ranging from 93% to 184%, with a payback period spanning 8.1 to 29.2 years, making this scenario economically feasible only at high energy prices with a 30% tax credit, while scenario 2 excels under other pricing conditions.

All TES capacities are modeled as PTES due to their substantial size, making TTES impractical. An alternative, BTES, is worth considering for later scenarios, given its space efficiency. Minneapolis, akin to Duluth, supports BTES implementation, emphasizing the need for a thorough understanding of underground conditions, especially in areas with numerous lakes. Careful placement, avoiding fast-flowing aquifers, is crucial for optimal efficiency.

7.5. CZ 5C - Vancouver

Scenario 3 proves to be the most economically favorable, with a 37% reduction in total energy costs and a 4.6-year payback period. It also achieves the lowest potential emissions, ranging from 15% to 46%. In contrast, Scenario 5 maintains consistent emission reductions between 25% and 31%, but its drawbacks include a 12% increase in total energy costs and a prolonged payback period of 22.1 years, making it less financially feasible.

Similar to other climate zones, scenario 3 excels economically only under high energy prices with a 30% tax credit. In all other pricing conditions, scenario 2 consistently demonstrates the lowest total energy cost, ranging from 83% to 109% relative to the baseline, with a payback period from 2.4 to 8.7 years. On the contrary, scenario 3, under these conditions, exhibits a total energy cost between 86% and 155%, coupled with a payback period ranging from 6.6 to 23.8 years.

For modeling TES capacities, PTES is chosen due to its suitability for significant sizes, making TTES impractical. However, an alternative worth considering is BTES, especially for later scenarios, as using PTES may demand extensive space. Given Vancouver's unique geographical considerations, especially its low altitude near the west coast, specific attention is required for BTES implementation. The higher position of groundwater in these areas may limit feasible depths for BTES construction, potentially affecting its thermal capacity, particularly since medium and high-temperature BTES (50-90°C) is best suited to high latitudes where excess heat in summer can be stored for winter discharge.

7.6. CZ 5B - Denver

Scenario 3 emerges as the most economically advantageous, with a 31% reduction in total energy costs and a 4.9-year payback period. Despite achieving overall emission reductions between 13% and 39%, it falls short compared to Scenario 5, which shows reductions ranging from 22% to 29%. However, scenario 5 leads to a 22% increase in total energy costs and an 18.5-year payback period, making it less economically favorable.

Scenario 3 proves economically favorable under high energy prices, with a total energy cost ranging from 69% to 76% and a 4.9 to 6.9-year payback period. However, under all other pricing conditions, with or without the 30% tax credit, scenario 2 emerges as the more financially advantageous option, presenting a total energy cost between 83% and 94% and a payback period ranging from 5.2 to 10.4 years. In contrast, Scenario 3 exhibits a total energy cost between 83% and 126%, with a payback period ranging from 8.7 to 24.9 years.

All TES capacities are modeled as PTES due to their significant size, rendering TTES impractical. Considering BTES as an alternative is warranted, given that PTES in later scenarios would require substantial space. BTES could be suitable in Denver due to its high latitude and significant temperature fluctuations. The mountainous terrain offers potential locations for deep boreholes, but the presence of aquifers or thick unsaturated zones may affect heat transfer efficiency, necessitating a thorough soil examination.

7.7. CZ 5A - Chicago

Scenario 3 outperforms economically, cutting total energy costs by 37% with a 6-year payback period and achieving emission reductions of 9% to 58%. Conversely, Scenario 5, with consistent emission reductions between 32% and 40%, sees a 12% increase in total energy costs and a longer payback period of 13.3 years, making it less financially viable.

Scenario 3 is economically favorable at high energy prices, with and without the 30% tax credit, showing a total energy cost between 63% and 74% and a payback period of 6 to 8.5 years. However, under all other pricing conditions, with or without the 30% tax credit, scenario 2 proves more financially viable, with a total energy cost between 79% and 92% and a payback period of 3.2 to 9.3 years. In contrast, scenario 3, under these conditions, exhibits a total energy cost between 86% and 154%, with a payback period ranging from 10.7 to 30.9 years.

All TES capacities are modeled as PTES due to their significant size, making TTES impractical. Considering BTES as an alternative is worth exploring, as PTES in later scenarios would demand substantial space. Chicago's distinct seasons and promising geological conditions make it a favorable location for BTES. However, the proximity to Lake Michigan might pose challenges related to groundwater levels. Assessing local hydrogeology is necessary to identify optimal BTES sites.

7.8. CZ 4C - Seattle

Scenario 3 outperforms economically, reducing total energy costs by 31% with a 4.6-year payback period and achieving emission reductions from 13% to 39%. In contrast, scenario 5, with consistent emission reductions between 24% and 25%, sees a 5% increase in total energy costs and a longer 17.7-year payback, making it less financially feasible.

Under high energy prices with a 30% tax credit, scenario 3 demonstrates the most favorable outcomes, with a 69% total energy cost and a 4.6-year payback. However, in all other pricing conditions, scenario 2 is more financially favorable, with a total energy cost between 73% and 92% and a payback period ranging from 2.8 to 10.1 years. In contrast, under these pricing conditions, Scenario 3 displays a total energy cost between 75% and 122%, with a payback period ranging from 6.5 to 23.5 years.

All TES capacities are modeled as PTES due to their significant size, as TTES is unfeasible. Exploring BTES as an alternative is worth considering, as PTES in later scenarios would demand substantial space. The moderate climate and proximity to Puget Sound might limit BTES efficiency, but geological conditions may allow for deep boreholes. A thorough evaluation of local groundwater and geology is advised for feasibility and temperature delta realization.

7.9. CZ 4B - Albuquerque

Based on the analysis, Scenario 3 emerges as the most economically favorable option, showcasing a 21% reduction in total energy costs and a relatively short payback period of 4.9 years. Additionally, it achieves notable emission reductions ranging from 10% to 28%, with particularly high reductions observed at high emission rates. While scenarios 4 to 6 perform well in reducing emissions at low rates, they fall short of scenario 3's performance at high rates. Therefore, Scenario 3 not only offers significant cost savings but also demonstrates substantial emission reduction potential, making it the preferred choice among the scenarios analyzed.

In summary, Scenario 3 stands out for its favorable economic performance under high energy prices and a 30% tax credit, with Scenario 2 emerging as the more financially prudent choice at medium energy prices. Despite the cost differences between the two scenarios, Scenario 3 maintains its leadership in potential emission reductions, underscoring its overall superiority in both economic and environmental aspects.

All thermal energy storage capacities are simulated as PTES due to their significant size, rendering TTES unfeasible. However, scenario 3's TES capacity of 50,000 m^3 nearly approaches the feasibility limit for TTES. Given the spatial constraints of PTES in subsequent scenarios, exploring BTES as an alternative is recommended. In Albuquerque, BTES could prove viable, particularly for addressing cooling needs during hot summers. However, the presence of aquifers or shallow groundwater may impact installation efficiency.

7.10. CZ 4A - Baltimore

Scenario 3 demonstrates the most favorable economic performance, with a 23% reduction in total energy costs and a 5.3-year payback period. It also achieves significant emission reductions ranging from 11% to 32%. Conversely, Scenario 5 maintains consistent emission reductions between 21% and 25% but shows a modest 7% decrease in total energy costs and a longer payback period of 16.3 years, indicating lower financial feasibility.

While scenario 3 demonstrates the best economic results under high energy prices with a 30% tax credit, without the tax credit, scenario 2 has the lowest total energy costs, with a 19% reduction and a 3.3-year payback period compared to scenario 3's 17% reduction and 7.6-year payback period. At low energy costs, both with and without the tax credit, scenario 1 exhibits the lowest energy costs, with reductions ranging from 9% to 11% and payback periods between 3.5 and 5.1 years.

The simulated TES capacities are limited to PTES or BTES, with BTES serving to efficiently manage heating and cooling needs amid the area's marked seasonal temperature shifts. The region comprises primarily coastal plains with sedimentary rock formations, potentially hosting aquifers. Groundwater resources exist but may be impacted by proximity to the Chesapeake Bay, affecting quality and availability. Sandy and clayey soils are prevalent, affecting drilling feasibility.

7.11. CZ 3C - San Francisco

Scenario 3 offers the best economic performance, cutting total energy costs by 39% with a 4.3-year payback period. Although it nearly achieves the highest emission reductions (49% to 60%), scenarios 4 and 6 surpass it under low emission rates (55% to 61%). However, scenario 4, with lower total energy costs, is recommended.

These results are derived from simulations conducted under high energy prices with a 30% tax credit, highlighting substantial savings and significant economic outcomes. Scenario 3 remains economically favorable under both high and medium energy prices, with total energy cost reductions ranging from 17% to 39%. However, under low energy prices, scenario 2 emerges as the most economically advantageous, with total energy costs ranging from a 2% decrease to an 11% increase, contrasting scenario 3's total energy costs, which range from a 1% decrease to a 13% increase under the same pricing conditions.

All scenarios, except scenario 7, feature TES capacities small enough to be met with TTES. Scenario 7 necessitates the use of either PTES or BTES due to its considerable TES capacity. Considering San Francisco's geological conditions, further evaluation is needed to assess the feasibility and cost effectiveness of BTES implementation, despite the potential efficiency gains in this unique climatic setting.

7.12. CZ 3B Other - Las Vegas

Scenario 3 emerges as the most economically favorable option, showcasing a 50% reduction in total energy costs and a 3-year payback period, with emission reductions ranging from 39% to 62%. In contrast, scenario 7, despite achieving lower emissions (41% to 57% reduction), experiences a 22% increase in total energy costs and a lengthy 30.8-year payback period, making it economically less favorable.

Scenario 3 demonstrates the most favorable economic outcomes, remaining so even without the tax credit, achieving a 55% cost reduction with a 4.2-year payback period. At medium energy prices with the tax credit, scenarios 2 and 3 tie in total energy cost at 66%, differing only in payback time (scenario 2 at 4.5 years, scenario 3 at 5.6 years). For low energy prices, scenario 1 offers the lowest total energy cost, ranging from 88% to 91%, with payback times between 5.9 and 8.5 years.

TES capacities in scenario 3, along with cold TES in scenarios 6 and 7, enable feasible TTES use. However, remaining TES capacities require either PTES or BTES use. Geological considerations are vital for BTES implementation in the Las Vegas area, considering sedimentary rock formations, localized aquifers, variable soil compositions, and depth to bedrock, alongside factors like groundwater movement and geological hazards such as earthquakes, landslides, and subsidence.

7.13. CZ 3B Coast - Los Angeles

Scenario 2 proves most economically favorable, with a 41% reduction in total energy costs and a 3.1-year payback period. It also achieves the highest overall emission reductions, ranging from 24% to 50%. Even without the tax credit, it maintains economic favorability, with a 64% total energy cost reduction and a 4.4-year payback period.

At medium energy prices with the tax credit, scenario 2 remains the most feasible, with a 73% total energy cost compared to the baseline and a 5.8-year payback time. However, at medium energy prices without the tax credit, as well as at low energy prices with and without the tax credit, scenario 1 presents the best economics, with total energy prices ranging from 76% to 91% and a payback period between 3.9 and 9 years.

Regarding TTES capacities, all simulated capacities except for the hot TES in Scenario 3 are suitable for TTES. For the hot TES in Scenario 3, either PTES or BTES should be considered. Los Angeles offers diverse underground conditions, including sedimentary rocks, alluvial deposits, and volcanic remnants. Groundwater basins like the Central and San Fernando Basins provide significant water sources, and the underground varies from sandy to rocky substrates. Conducting detailed geological and hydrological surveys is crucial for assessing BTES feasibility and identifying suitable sites.

7.14. CZ 3A - Atlanta

Scenario 3 demonstrates the most favorable economics, achieving a 48% reduction in total energy costs with a 3.6-year payback period. While scenarios 5 and 6 achieve the highest emission reductions, scenario 6 emerges as the most favorable choice due to its slightly better economic performance. With emission reductions ranging from 50% to 68%, a 21% reduction in total energy cost, and a payback period of 9.8 years, scenario 6 stands out for maximizing emission reductions. These findings stem from simulations based on high energy prices with a 30% tax credit, which highlighted significant savings and economic impacts.

Scenario 2, however, outperforms economically under high energy prices without the tax credit, as well as under medium energy prices with and without the tax credit, displaying total energy costs between 57% and 73% compared to the baseline, with a payback period ranging from 3.5 to 6.5 years. In contrast, scenario 3 exhibits total energy costs between 59% and 81% with a payback period between 5.2 and 9.6 years under the same pricing conditions. At low energy prices with and without the tax credit, scenario 1 presents the most favorable economic performance, with total energy costs between 89% and 92% and a payback period between 6.2 and 8.8 years.

Moreover, it is noteworthy that cold TES capacities in scenarios 3, 4, and 7 are the only ones feasible for TTES. All other simulated TES capacities in additional scenarios may require PTES or BTES. Considering BTES implementation in Atlanta, understanding the geological and hydrological conditions is crucial. The area primarily comprises sedimentary rock with potential fractured zones suitable for aquifers. Variability in soil composition affects drilling feasibility, while the depth to bedrock varies across the region, impacting borehole design. These factors must be carefully assessed for successful BTES deployment.

7.15. CZ 2B - Phoenix

Scenario 3 offers the most favorable economics, with a 49% reduction in total energy costs and a 3.2-year payback period. Scenarios 5 and 6 achieve the highest emission reductions, with Scenario 6 emerging as the preferred choice due to its slightly better economic performance. Scenario 6 showcases emission reductions ranging from 25% to 60%, along with a 22% decrease in total energy cost and a payback period of 9.5 years.

These results are based on simulations conducted under high energy prices with a 30% tax credit, emphasizing significant savings. Although scenario 3 offers the best economics under high energy prices with a 30% tax credit, scenario 2 outperforms economically under high energy prices without the tax credit and under medium energy prices with and without the tax credit, with total energy costs ranging from 56% to 72% compared to the baseline, and a payback period between 3.3 and 6.2 years. Conversely, under the same pricing conditions, scenario 3 demonstrates total energy costs between 57% and 78% with a payback period between 4.5 and 8.6 years. At low energy prices, both with and without the tax credit, scenario 1 offers the most economical solution, with total energy costs between 89% and 93% and a payback period between 6.2 and 8.9 years.

Furthermore, the simulated TES capacities in Scenario 3, as well as the cold TES capacities in Scenarios 6 and 7, are suitable for TTES. However, all other TES capacities require either PTES or BTES for implementation. Regarding BTES installation in Phoenix, understanding the geological and hydrological conditions is crucial. The region predominantly features desert terrain with sedimentary rock formations, potentially limiting aquifers. Groundwater resources are generally scarce in this arid region. Additionally, soil composition varies, with prevalent sandy and rocky soils, potentially impacting drilling feasibility. The depth to bedrock varies across the region, influencing borehole design. These factors must be carefully considered for successful BTES implementation.

7.16. CZ 2A - Houston

Scenario 3 proves most economically favorable, with a 52% reduction in total energy costs and a short 2.7-year payback period. Although scenarios 5 and 6 achieve the highest emission reductions, scenario 6 stands out due to its better economic performance. It achieves emission reductions ranging from 33% to 63%, along with a 16% decrease in total energy costs and a payback period of 10.9 years, making it the recommended choice for maximizing emission reductions while maintaining economic viability.

Scenario 3 proves to be the most economical choice under high energy prices and with a 30% tax credit. It remains the top economic performer under high energy prices without the tax credit, as well as under medium energy prices with the tax credit. Total energy costs range from 54% to 64% compared to the baseline, with payback periods between 3.8 and 5 years. In contrast, scenario 2 performs best economically under medium energy prices without the tax credit, with a total energy cost of 72% and a payback period of 6.3 years. Scenario 1 emerges as the most economical option under low pricing conditions, with total energy costs between 89% and 92% and payback periods between 6.2 and 8.8 years.

In terms of technology implementation, TTES is applicable for scenario 3 and cold TES capacities in scenarios 4, 6, and 7, whereas PTES or BTES is necessary for the remaining TES capacities. When considering the installation of a BTES system in Houston, it is imperative to carefully evaluate geological and hydrological conditions. The region's characteristics, such as coastal plains with sedimentary rock formations and variable bedrock depth, play a crucial role in determining the feasibility and success of BTES implementation. Understanding these factors is paramount for ensuring the effectiveness and sustainability of the system.

7.17. CZ 1A - Miami

Scenario 3 demonstrates the most favorable economics, with a 52% reduction in total energy costs and a 2.6-year payback period. Scenario 6 achieves the highest emission reductions ranging from 4% to 57%, along with a 10% reduction in total energy costs and a payback period of 12.2 years.

Scenario 3 is the most economic under high energy prices and with a 30% tax credit. Without the tax credit, it is tied with scenario 2. Under medium energy prices with or without the tax credit, and low energy prices with the tax credit, scenario 2 is the most economic, with total energy costs ranging from 63% to 89% and a payback period of 4 to 9.9 years. Under low energy prices without the tax credit, scenario 1 is the most economic, with a total energy cost of 94% and a payback period of 9.6 years.

In scenarios 3 and 4, TES capacities are suitable for TTES, while the remaining require PTES or BTES. Evaluating BTES installation in Miami requires thorough consideration of its geological and hydrological conditions, primarily coastal plains with sedimentary rock formations potentially housing aquifers. Abundant groundwater resources exist, but saltwater intrusion from the Atlantic Ocean is possible. Sandy soil impacts drilling feasibility, while varied bedrock depth requires tailored borehole design. Understanding these factors is vital for BTES implementation.

7.18. CZ 0A - Guam

Scenario 2 shows the best economic performance, with a 53% decrease in total energy costs and a 2.2-year payback period. Scenario 6 achieves the highest emission reductions, ranging from 3% to 59%, with an 18% reduction in total energy costs and a 10.5-year payback period.

Scenario 2 is the most economical under high energy prices with a 30% tax credit. It also outperforms in scenarios without the tax credit and under medium energy prices, with total energy costs ranging from 51% to 69% compared to the baseline and payback periods between 3.2 and 6.1 years. Under low energy prices with the tax credit, scenarios 1 and 2 have the same total energy cost of 90%, but scenario 1 has a shorter payback time at 6.7 years. Without the tax credit, scenario 1 is the most economical with a total energy cost of 94% and a payback time of 9.6 years.

TES capacities in Scenarios 3 and 4, as well as cold TES capacities in scenarios 5, 6, and 7, are suitable for TTES use, while others require PTES or BTES implementation. When considering BTES installation in Guam, geological and hydrological conditions must be carefully evaluated, given the island's volcanic composition, limited groundwater resources, and varied soil compositions.

7.19. Summary

Table 7-1 lists a thorough summary of the most economical scenarios and those achieving the greatest emission reductions. Cost effectiveness is determined by the highest simulated energy price with a 30% tax credit applied. Furthermore, it delineates the technologies integrated into each scenario, serving as a point of reference, and facilitating comparison.

Table 7-1. Summary of the scenarios being either the most economic or achieves the highest emission reductions. All results a based on the highest simulated energy price and with 30% tax credit.

	Most economic	Highest emission reduction	Technology combinations
Fairbanks	3	6	3: 3x CHP and 200,000 m^3 hot TES 6: No CHP, 2 million m^3 hot TES and 180,000 m^2 SWH
Duluth	3	6	3: 3x CHP and 300,000 m^3 hot TES 6: No CHP, 800,000 m^3 hot TES and 80,000 m^2 SWH
Helena	3	5	3: 3x CHP and 320,000 m^3 hot TES 5: 1x CHP, 575,000 m^3 hot TES and 29,000 m^2 SWH
Minneapolis	3	5	3: 3x CHP and 400,000 m^3 hot TES 5: 2x CHP, 500,000 m^3 hot TES and 30,000 m^2 SWH
Vancouver	3	5	3: 3x CHP and 130,000 m^3 hot TES 5: 1x CHP, 270,000 m^3 hot TES and 25,000 m^2 SWH
Denver	3	5	3: 3x CHP and 130,000 m^3 hot TES 5: 1x CHP, 200,000 m^3 hot TES and 18,000 m^2 SWH
Chicago	3	5	3: 3x CHP and 420,000 m^3 hot TES 5: 2x CHP, 500,000 m^3 hot TES and 24,000 m^2 SWH
Seattle	3	5	3: 3x CHP and 80,000 m^3 hot TES 5: 1x CHP, 200,000 m^3 hot TES and 18,000 m^2 SWH
Albuquerque	3	3	3: 3x CHP and 50,000 m^3 hot TES
Baltimore	3	5	3: 3x CHP and 100,000 m^3 hot TES 5: 3x CHP, 300,000 m^3 hot TES and 14,000 m^2 SWH
San Francisco	3	4	3: 3x CHP, 3x ABS, 1,000 m^3 hot TES and 1,000 m^3 cold TES 4: 3x CHP, 3x ABS, 1,000 m^3 hot TES, 1,000 m^3 cold TES and 7,000 m^2 SWH
Las Vegas	3	7	3: 3x CHP, 3x ABS, 14,000 m^3 hot TES and 3,000 m^3 cold TES 7: 6x ABS, 140,000 m^3 hot TES, 3,000 m^3 cold TES and 22,500 m^2 SWH
Los Angeles	2	2	2: 3x CHP, 3x ABS
Atlanta	3	6	3: 3x CHP, 3x ABS, 40,000 m^3 hot TES and 2,000 m^3 cold TES 6: 3x CHP, 6x ABS, 92,000 m^3 hot TES, 182,000 m^3 cold TES and 12,500 m^2 SWH
Phoenix	3	6	3: 3x CHP, 3x ABS, 20,000 m^3 hot TES and 8,000 m^3 cold TES 6: 3x CHP, 6x ABS, 280,000 m^3 hot TES, 15,000 m^3 cold TES and 12,500 m^2 SWH
Houston	3	6	3: 3x CHP, 3x ABS, 5,000 m^3 hot TES and 5,000 m^3 cold TES 6: 3x CHP, 6x ABS, 250,000 m^3 hot TES, 15,000 m^3 cold TES and 22,700 m^2 SWH
Miami	3	6	3: 3x CHP, 3x ABS and 10,000 m^3 cold TES 6: 3x CHP, 6x ABS, 300,000 m^3 hot TES, 50,000 m^3 cold TES and 32,000 m^2 SWH
Guam	2	6	2: 3x CHP and 3x ABS 6: 3x CHP, 6x ABS, 85,000 m^3 hot TES, 1,000 m^3 cold TES and 33,500 m^2 SWH

Based on the extensive analysis of energy scenarios across the various climate zones, it is evident that scenario 3 consistently emerges as the most economically favorable option in many locations. This scenario typically offers substantial reductions in total energy costs along with relatively short payback periods, making it an attractive choice for energy system implementation. Additionally, scenario 3 often demonstrates notable emission reductions, albeit sometimes being surpassed by other scenarios in specific locations. Despite this, its strong economic performance, especially under high energy prices with a 30% tax credit, positions it as a preferred option for balancing both economic and environmental considerations. However, it is essential to note that the suitability of scenarios varies depending on factors such as energy prices, tax credits, and geographical conditions. While Scenario 3 stands out under certain conditions, other scenarios, such as scenario 2, prove to be more economically viable in different pricing scenarios or locations. In addition to scenario 3's consistent economic favorability, it is notable that certain scenarios, particularly scenario 6, excel in emission reductions. While Scenario 6 often comes with longer payback periods and, at times, higher total energy costs, its ability to achieve significant emission reductions makes it a crucial option for prioritizing environmental sustainability. Furthermore, the variability in economic performance across different pricing scenarios highlights the importance of flexibility in energy planning. While a scenario may prove economically viable under certain conditions, its feasibility can change significantly with fluctuations in energy prices or the availability of tax credits. This underscores the need for dynamic energy strategies capable of adapting to changing market conditions.

Furthermore, when exploring TES solutions, the consideration of scale is paramount. For smaller capacities, TTES emerges as a practical choice, offering versatility while meeting operational needs. However, for larger capacities exceeding 30,000 m^3, the focus shifts to either PTES or BTES, both pivotal in enhancing energy system efficiency. The selection between PTES and BTES depends on various factors, including spatial constraints, geological attributes, and scalability requisites. While PTES suits specific scenarios, BTES stands out for its spatial efficiency and potential long-term cost effectiveness. Yet, successful BTES deployment demands meticulous evaluation of geological and hydrological features at the site. Variables like soil composition, groundwater levels, and geological formations profoundly influence the feasibility and efficacy of BTES systems. Therefore, comprehensive surveys and assessments are imperative to pinpoint suitable locations and ensure project success. Tailored energy planning approaches are indispensable. What proves effective in one locale may not translate well elsewhere, underscoring the necessity for localized solutions that accommodate distinct environmental dynamics and resource availabilities.

The findings underscore the importance of considering both short-term economic viability and long-term environmental sustainability when designing energy systems. While economic factors such as total energy costs and payback periods are crucial for immediate decision-making, the long-term benefits of emission reductions and energy efficiency must not be overlooked.

References

Aalborg CSP. 2022. *Operational Costs for Equipment, CHP/Boiler/Electric Chiller/Absorption Chiller/Solar Field*. Aalborg, Denmark: Aalborg CSP.

ASHRAE. 2004. *Energy Standard for Buildings except Low-Rise Residential Buildings*. ANSI/ASHRAE/IESNA Standard 90.1-2004. Atlanta, GA: ASHRAE.

Case, M.P., A. Zhivov, R.L. Liesen, and M. Zhivov. 2016. *A Parametric Study of Energy Efficiency Measures Used in Deep Energy Retrofits for Two Building Types and U.S. Climate Zones*. ASHRAE Transactions. 2016 ASHRAE Transactions Volume 1

Drijver B, Willemsen A. 2001. “Groundwater as a Heat Source for Geothermal Heat Pumps.” *International Summer School on Direct Application of Geothermal Energy*. Bad Urach, Germany: International Geothermal Association. pp. 156–166.

EPA 2021. Heating value for natural gas, June 2021, https://www.epa.gov/sites/default/files/2015-07/documents/fuel_and_carbon_dioxide_emissions_savings_calculation_methodology_for_combined_heat_and_power_systems.pdfMangold D., T. Schmidt, A. Dohna, and D. Spar. 2016. “Guideline for Seasonal Thermal Energy Storage Systems in the Built Environment.” *Solites*. Project EU-FP7.

Foley, Gearoid. September 2022. *Equipment Efficiencies, CHP/Boiler/Electric Chiller/Absorption Chiller*. Princeton, NJ: Integrated CHP Systems Corp.

Sibbitt, Bruce, and Doug McClenahan. 2015. Large Systems Seasonal Borehole Thermal Energy Storage – Guidelines for design & construction. International Energy Agency Solar Heating and Cooling Programme (IEA-SHC) Info Sheet 45.B.3.1. IEA-SHC Task 45. https://task45.iea-shc.org/Data/Sites/1/publications/IEA-SHC-T45.B.3.1-INFO-Seasonal%20storages-Borehole-Guidelines.pdf.

Sweetser, Richard. March 2023. *CO_2 Emission Rates for Electricity and Natural Gas*. Herndon, VA: Exergy Partners Corp.

Zhivov, Alexander, Richard J. Liesen, Stephan Richter, Reinhard Jank, Franklin H. Holcomb. 2010. “Towards a Net Zero Building Cluster Energy Systems Analysis for a Brigade Combat Team Complex.” *Proceedings of ASME 2010 4th International Conference on Energy Sustainability*. ES2010. May 17-22, 2010 Phoenix, Arizona, USA. Paper No. ES2010-90487.