ADVANCED TURBINE AIRFOILS FOR EFFICIENT CHP SYSTEMS: *ENERGY STORAGE INTEGRATION ANALYSIS*

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Disclaimer

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ACRONYMS AND ABBREVIATIONS

Btu	British thermal unit
CAES	Compressed air storage
CEMS	Continuous emissions monitoring system
CEPCI	Chemical Engineering Plant Cost Index
CHP	Combined heat and power
CO	Carbon monoxide
CO_2	Carbon dioxide
COE	Cost of electricity
D	Diameter
DOE	Department of Energy
ESC	Energy Solutions Center
Eng. CM H.O. & Fees	Engineering, construction management and home office, and fees
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ES	Energy storage
ESS	Energy storage system
ft	Foot
ft^2	Square feet
ft^3	Cubic feet
gal	Gallon
GT	Gas turbine
GW	Gigawatt
h	Hour
H	Height
HP	High pressure
HPT	High Pressure Turbine
HRSG	Heat recovery steam generator
IP	Intermediate pressure
KNO_3	Potassium nitrate
kW, kWe	Kilowatt electric
kWh	Kilowatt-hour
lb, lbm	Pound mass
LCOE	Levelized cost of electricity
LC	Low-capacity
Li-Ion	Lithium ion
LP	Low pressure
MMBtu	Million British thermal unit
mol	Mole
MW, MWe	Megawatt electric
Na-NiCl	Sodium-nickel chloride
NaBr	sodium bromide
$NaNO_2$	Sodium nitrite
$NaNO_3$	Sodium nitrate
NaS	Sodium Sulfide
Na_2S_4	Disodium tetrasulfide
NETL	National Energy Technology Laboratory
NGCC	Natural gas combined cycle
NHMC	Non-methane hydrocarbons
Ni	Nickel
Ni-Cd	Nickel-cadmium
NOx	Oxides of nitrogen
NREL	National Renewable Energy Laboratory
O&M	Operation and maintenance
OH	Overhead
Pa	Pascal
PNNL	Pacific Northwest National Laboratory
PPA	Power purchase agreements
PSBB	Polysulfide-bromide battery
psi	Pounds per square inch
psig	Pounds per square inch gauge
s	Second
SBIR	Small Business Innovation Research
SCR	Selective catalytic reduction
ST	Steam turbine
T&D	Transmission and distribution
TBC	Thermal barrier coating
TEA	Techno-economic analysis
TES	Thermal storage system
U.S.	United States
UPS	Uninterrupted Power Supply
V	Volt
wt%	Weight percent
ZnBr	Zinc bromide
°F	Degrees Fahrenheit
°R	Degrees Rankine

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1 INTRODUCTION

The objective of this study is to analyze the previously developed combined heat and power (CHP) plant with the upgraded gas turbine [1] to include an energy storage system to improve the operational flexibility. The analysis includes identifying a candidate CHP configuration for the energy storage system (ESS) integration and identifying possible storage systems to be integrated. A qualitative analysis was made to down select possible storage technologies and a techno-economic analysis (TEA) was made for the CHP system with the selected storage technology.

The upgrades in the CHP gas turbine of the preceding study [1] were to increase the firing temperature by 212 degrees Fahrenheit (°F) and use advanced internal cooling for the turbine blades enabled by additive manufacturing. Indicated upgrades also required some changes in the inlet and exhaust design due to increased inlet flowrate for better performance. Increasing the firing temperature also necessitated using advanced coatings. The design of the upgraded gas turbine was made by considering multiple parameters such as the power output, thermal efficiency and increase in the compression ratio. The final design is selected by using the maxima of the power output and thermal efficiency as well as a compression ratio that will not require significant changes in the compressor design.

The gas turbine performance specifics of the baseline and upgraded CHP engines are compared in Exhibit 1-1.

Exhibit 1-1. Baseline and upgraded gas turbine specifics to be used in the analysis

Parameter	Baseline Engine	Upgraded Engine
Engine Specs		
Power Output	6100 kW	7592 kW
Thermal Efficiency (gas turbine)	33.1%	35.3%
Turbine Inlet Temperature	2000 °F	2180 °F
Compressor Pressure Ratio	14.7	16.4
Exhaust Temperature	968 °F	989 °F
Year of Introduction	2015	2021+
Turbomachinery	15 Stage Compressor, 4 Stage Turbine	
Cooling Specs		
Cooling Type	Internal Cooling, Thermal Barrier Coating (TBC), and Purge Cooling	
Internal Cooling Effectiveness	0.62	0.7
TBC Biot Number	0.3	0.31
Total Coolant Fraction (wrt. main stream)	9.6%	12.9%

The previous study was made concurrently with a market analysis study about the impacts of the upgraded gas turbine on the current and future CHP markets. [2] The study included interviews with four different CHP facilities to understand their experiences with these systems and their expectations for future development. Major interview topics included the following:

- Facility's motivation in deciding for a CHP with a gas turbine
- Major challenges or barriers that currently exist
- Prioritization of the steam versus electrical generation in the facility and in selection of plant metrics

The findings from the interviews showed that in some cases power from the grid needed to be made to meet the peak demand from the campus to offset the production gap, which is usually about 25 percent of the peak demand. In addition, power generation during low demand times might be avoided because running the facility in lower loads below 50 percent might cause regulatory issues with nitrogen oxides (NOx) emissions and sometimes is not economical (dependent on each state's regulations).

ESSs are typically being considered for renewable power plants for filling in the low production periods due to lack of light (for solar systems) or slower winds (for wind turbines). [3] However, an example application with ice storage was made to a CHP facility at the University of Arizona, [4, 5] where ice is used to store energy during the night and used to produce chilled water during the day, thereby reducing air conditioning electrical loads.

Integration of storage systems to fossil power plants are currently being investigated and considered as a good option to increase the plant flexibility. Based on the aforementioned findings from the facility interviews, energy storage systems are deemed to be a good alternative to improve the plant flexibility, fill in the power production gaps in peak demand times, and supply energy to the host facility when operating the gas turbine at low load conditions incurs higher emissions.

This report includes the results of a brief literature survey on energy storage systems applicable to CHP plants, details of a business case scenario for a candidate CHP plant for ESS integration, details of the quantitative ESS selection process, and the results of the TEA for the CHP plant with the selected storage system.

2 CHP BUSINESS CASE SCENARIO FOR ENERGY STORAGE INTEGRATION

The type, size, and integration of the energy storage system to the power plant is primarily dependent on the demand or electrical load curves. The load curves determine the duration and the amount of the extra power required and the times when the storage system can be charged without impacting the grid reliability.

The focus of this study is a de-centralized energy storage application, which is different than the centralized storage where the storage is used to regulate the grid operations such as load regulation or backup power sourcing. In the current case, the storage will only support the host facility and its primary purpose is to supply energy in high demand times. A university case is determined to be the example site for the CHP application with energy storage, because of an example application case of cold-water storage at the University of Arizona [4, 5] and also for the previous data collaboration with such facilities. [2] A hypothetical case scenario is then generated based on the received and obtained data. The case scenario is then used for down selection of applicable energy storage systems.

2.1 PRELIMINARY ANALYSIS WITH CHP FACILITY DATA

An example case from the real world was sought for determining the configuration, plant performance details, and load demand curves for the current study. For this purpose, four universities previously involved in the market research analysis [2] were contacted. Vanderbilt University provided data for the study and an energy storage assessment was made based on the received data to understand if Vanderbilt's case can be set directly as an example case for the current study.

Vanderbilt University has a moderate sized campus with 252 buildings and 52 megawatts (MW) of peak load, which usually occurs in the summer. The CHP plant on the campus can produce 90 percent of heating and 40 percent of the cooling needs of the campus. [6] Based on the previous interview with the university, steam demand was the primary factor in determining the configuration and metrics of the power plant. [2] The CHP plant was renovated in 2015, where the fuel type was converted to natural gas from coal. The campus also includes a hospital, which is the primary facility that is targeted to be served by the power plant.

The campus CHP plant has three gas turbines, with only two of them operational, and each gas turbine is connected to separate heat recovery steam generator (HRSG) units. The operational gas turbines are Solar Taurus 70, which can generate up to 7 MW. The HRSG's are duct fired and can output 27.8 pound mass (lbm/s) steam in the fired mode and 8 lbm/s in the unfired mode. Based on the received electric load data, the CHP production is 17 MW short of the campus demand, in average. Based on the interviews and the data, the CHP plant load is at 100 percent at all times. In the upgrade program of 2015 involving the natural gas conversion, the two steam turbines were removed from the plant.

A quick assessment for energy storage application was made for Vanderbilt University with the load data received. As a general rule, a facility needs to produce more power than the demand for energy storage to be feasible. However, in some cases energy storage can be used to reduce the cooling loads, which frees up a portion of the power generated from the plant to be used elsewhere. The following conclusions were made:

- If the third gas turbine, which generates 5–7 MW of power is operational, then on some winter days more power than the demand could be generated that might be used to charge the energy storage system.
- If the steam turbines were not removed, then they might add about 11 MW to the current production, which would generate more power than the demand some portion of the year.

Since the existing power generation is below the demand at all times, battery storage is not an option. Since there is no steam turbine, thermal storage is not possible at the current conditions, because such systems use the steam turbine for discharging.

Mechanical storage such as compressed air storage (CAES) is not an option for Vanderbilt because during charging of the CAES a portion of the compressor air needs to be directed to the storage cave, which will eventually reduce the gas turbine power output. This is not acceptable because the university runs the gas turbines at full load at all times.

Therefore, only the storage systems that can reduce cooling loads, such as the chilled water storage, could be considered for this case. REOpt Lite software by National Renewable Energy Laboratory (NREL) [7] was run with the load data provided by Vanderbilt for a techno-economic assessment of chilled water storage integration. The results showed that such a system is applicable and can save up to $14,000,000 in a 25-year lifetime. The required chilled water tank size is calculated to be 336,892 gallons, which can fit into three 102,000-gallon steel tanks and a smaller tank with 37,000-gallon capacity. Based on the sizes of these tanks from a representative commercial supplier's data, [8] 0.1 acres of area will be required for the storage tanks. However, the university indicated that the storage area cannot be accommodated near the CHP plant due to the existence of nearby buildings.

The preliminary analysis with the Vanderbilt University data showed that the business case scenario of the CHP plant carries extreme importance for energy storage system integration to be feasible. The following aspects are determined to have the highest importance:

- Amount of the excess power generated by the CHP Plant
- Times and durations of peak and low demand
- Typical load on the gas turbines
- Steam cycle configuration
- Facilities and environmental feasibility

2.2 EXAMPLE CASE CHP PLANT: CASE STUDY UNIVERSITY

Although the CHP facility data obtained from universities could not be used directly as the example case for this study, some of the real data was still used to build a hypothetical case scenario for the current study. The example scenario is a university located in east Michigan and has about 20,000–30,000 students. The facility peak load is 17.3 MW and campus includes a small hospital, some resident halls, recreation, and data centers. The size of this hypothetical campus is similar to Vanderbilt, Eastern Michigan, and University of Colorado campuses.

The campus has a CHP plant with the specifics listed in Exhibit 2-1.

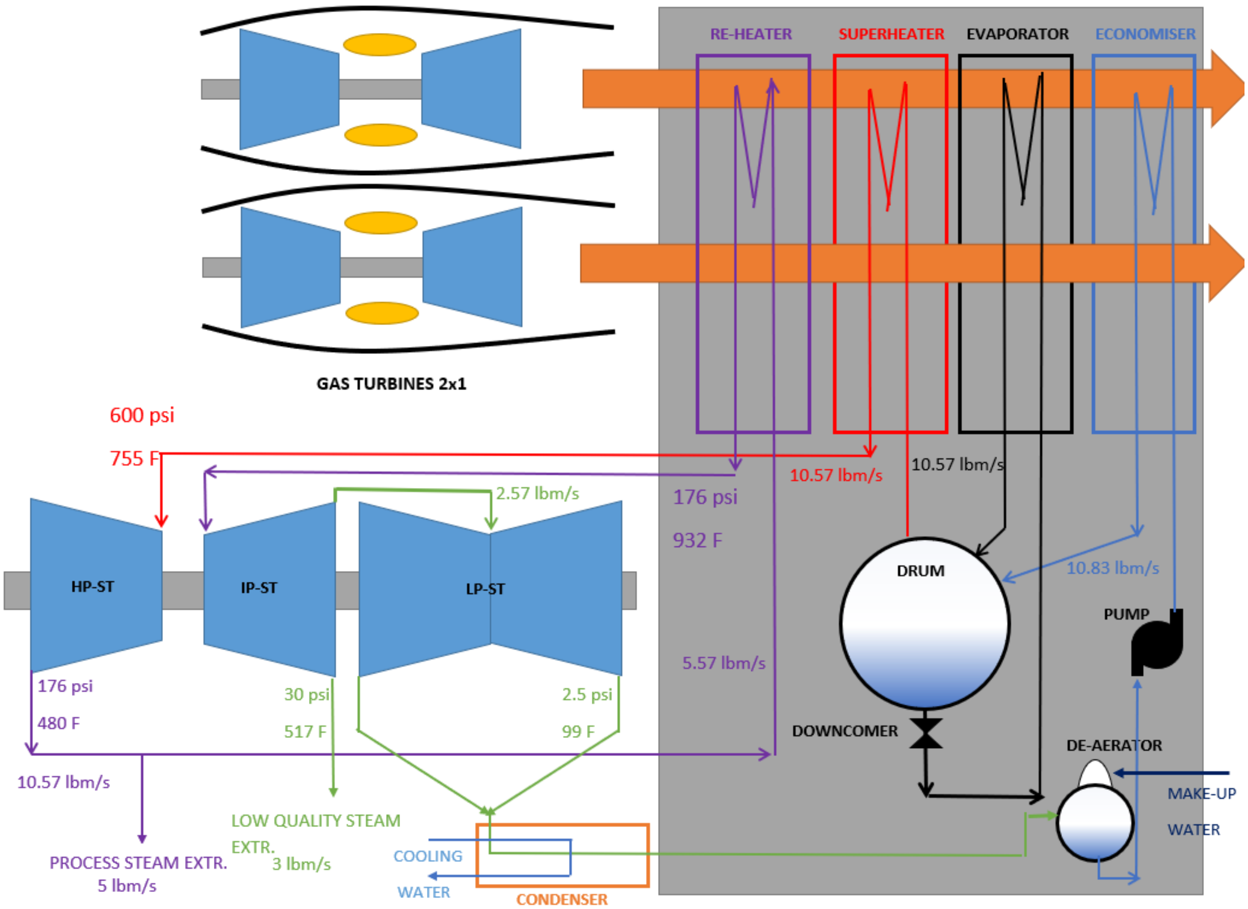
Exhibit 2-1. Case study university CHP plant specifics

Parameter	Value
Total Plant Capacity	15.3 MW
Primary Mover	2 Gas Turbines (6.1 MW capacity each)
Secondary Mover	3-pressure Level Steam Turbine (3.2 MW capacity)
HRSG Type	Unfired
Steam Generation Rate	8.3 lbm/s

The CHP plant configuration is schematically shown in Exhibit 2-2. In the plant configuration, two steam extractions exist, where the higher pressure one is at 160 pounds per square inch gauge (psig) and is after the exit of the high-pressure steam turbine. The remainder of the steam is re-heated and used in the intermediate pressure turbine where the low-pressure steam at 15 psig is extracted before entering the low-pressure turbine. Each steam extraction is used in different campus heating and cooling systems that require different intake steam conditions.

The university occasionally purchases power from the grid when the load is above 15.3 MW, which usually occurs in the summer months due to increased cooling loads. Due to state emissions regulations, running the facility below a 4 MW load might incur penalties due to increased emissions from the gas turbines operating at low loads. The CHP plant can provide 100 percent of the base load from the campus. If the campus load is less than 11 MW, excess power is sold back to the grid via a power purchase agreement.

Exhibit 2-2. System flowchart for the case study university CHP plant

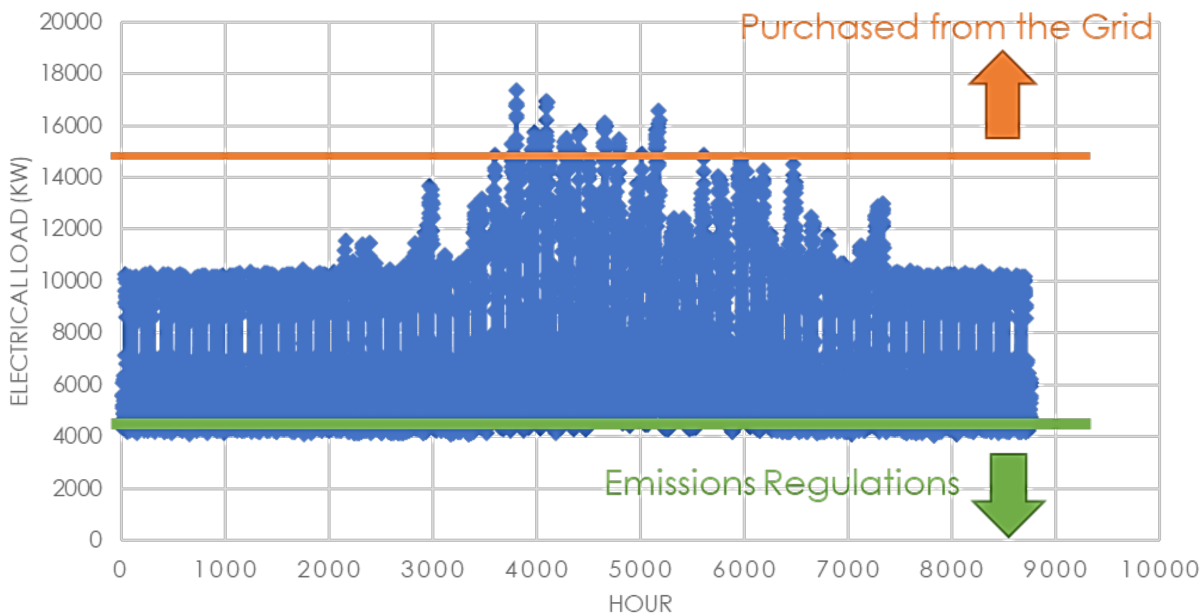


REOpt Software by NREL [7] was used to generate the campus load data for the case study university The load item weights are selected by comparing the load data curve shape with the actual load data obtained from Vanderbilt University. The load simulation uses the building types on the campus. The building types simulated include a hospital, large office, school, large hotel and a 24/7 flat load and their load weights are listed as follows:

- Hospital—35%
- Office Building (Large)—15%
- School—20%
- Hotel (Large)—25%
- 24/7 Schedule Flat Load—5%

In the building list presented, the hotel represents the residence halls, and the 24/7 flat load represents the facilities on the campus that have a constant load all the time, regardless of the time of the day, such as the recreation centers and data centers. Based on the indicated load items and the campus specifics, the load curve was generated by REOpt as presented in Exhibit 2-3.

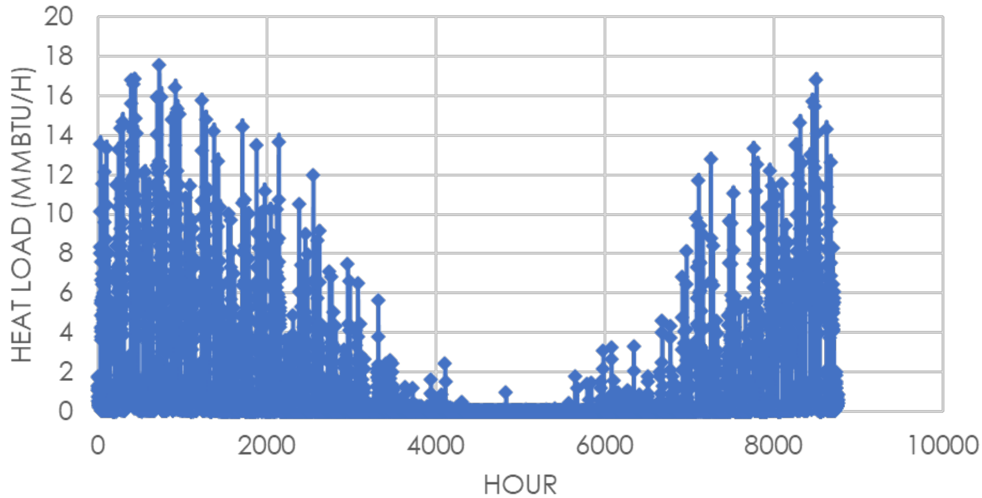
Exhibit 2-3. Campus annual electrical load data generated for case study university



The heating load of the campus was also simulated to be later used in estimating the impact of the storage system on steam demand, especially for the storage options that use steam for charging. As of the time of performing this analysis, the REOpt load simulation software [7] offers various heat load simulations for specific building types, rather than for a campus with multiple building types. Current selections for the heat load simulation include hospital, school, office building, supermarket, midrise apartment, warehouse and scheduled flat loads.

Of the various building types indicated, only the ones that generate the electrical load were used in determining the appropriate annual heat load distribution. For the hypothetical case study university scenario, the heat load simulation type was selected by comparing the simulation outputs with Vanderbilt University's heat load data. Hotel load, large office load, and school loads are the ones tried in the simulator. Among these options, "school" simulator was selected to be the most representative data for a university scenario and is presented in Exhibit 2-4.

Exhibit 2-4. Campus annual heat load data generated for case study university



The business case of the CHP plant is also important in determining the feasibility of the energy storage system integration. For the example case analyzed in this study, the CHP plant is owned and operated by the university. This is an important point, especially in the financing structure and in power purchase agreement rates applicable to CHP plants. CHP plants that are owned or partially financed by the local utility companies can get higher rates when selling to the grid, because it is considered a portion of the investment capital cost. If the plant is owned and operated by the host facility, however, the power purchase agreement rates are typically lower but are usually determined after negotiations with the utility companies that will purchase the excess power.

For the case study university, the university is planning to expand the campus and increase the number of buildings served by the plant. The university also wants to be able to operate their facility in "power island" mode, which means that no grid power purchase is to be made at any time of the year. The following points were identified to consider an energy storage system:

- The fraction of the campus load covered by the plant is expected to decrease; therefore, increasing the power purchase costs
- There have been some issues with the grid reliability (desire to operate in power island mode)
- Elimination of the indirect emissions entirely when the campus demand drops below 4 MW, and the power is purchased from the grid (grid power is assumed to be generated with fossil fuels)
- Increase in the flexibility of the plant

Currently, the CHP plant's capacity factor is 85 percent, which is the typical value for university CHP plants. [2] The campus power plant generates 93 percent of the campus load; the remainder of the campus load is purchased from the grid at $0.11 per kilowatt-hour (kWh) rate. [8] In the low demand times, where the campus load is at 8 MW, excess power is sold to the grid at 0.035 $/kWh. The grid purchase rate used in this study is the average value for the power purchase agreements (PPA) from the following resources:

- Michigan DTE Energy--0.049 $/kWh [9]
- California PG&E Energy—0.029 $/kWh [10]
- Nashville Electric Service—0.04 $/kWh [11]

PPA rates obtained above are for the CHP plants that are not financed by the grid company. If the campus load drops below 4.5 MW, no power generation is made by the campus CHP plant. The natural gas purchase rate of the plant is 7.73 $/million (MM) British thermal units (Btu) (MMBtu). [8]

3 Energy Storage System Selection for the CHP Plant

ESSs are the systems that can time shift energy by storing it at times of lower demand and discharge it during times more power generation is needed from the facility. The storage system might utilize kinetic, chemical, potential, or electrochemical energy conversion methods. [12] Some of the storage types applicable to fossil fuel power plants are shown in Exhibit 3-1.

For the thermal energy storage systems (TESs), the temperature of a solid or liquid is increased or decreased to store the energy. The thermal energy storage might necessitate phase change such as for the case of phase change material, water or air or simply increases the temperature such as in sand and concrete types.

For the mechanical storage, the energy is stored increasing the kinetic or potential energy of the storage medium. Pumped hydro systems are similar to the dams and use Francis turbines to charge and discharge the system. Compressed air storage pressurizes the air in a cavity and injects it to a gas turbine during the discharge.

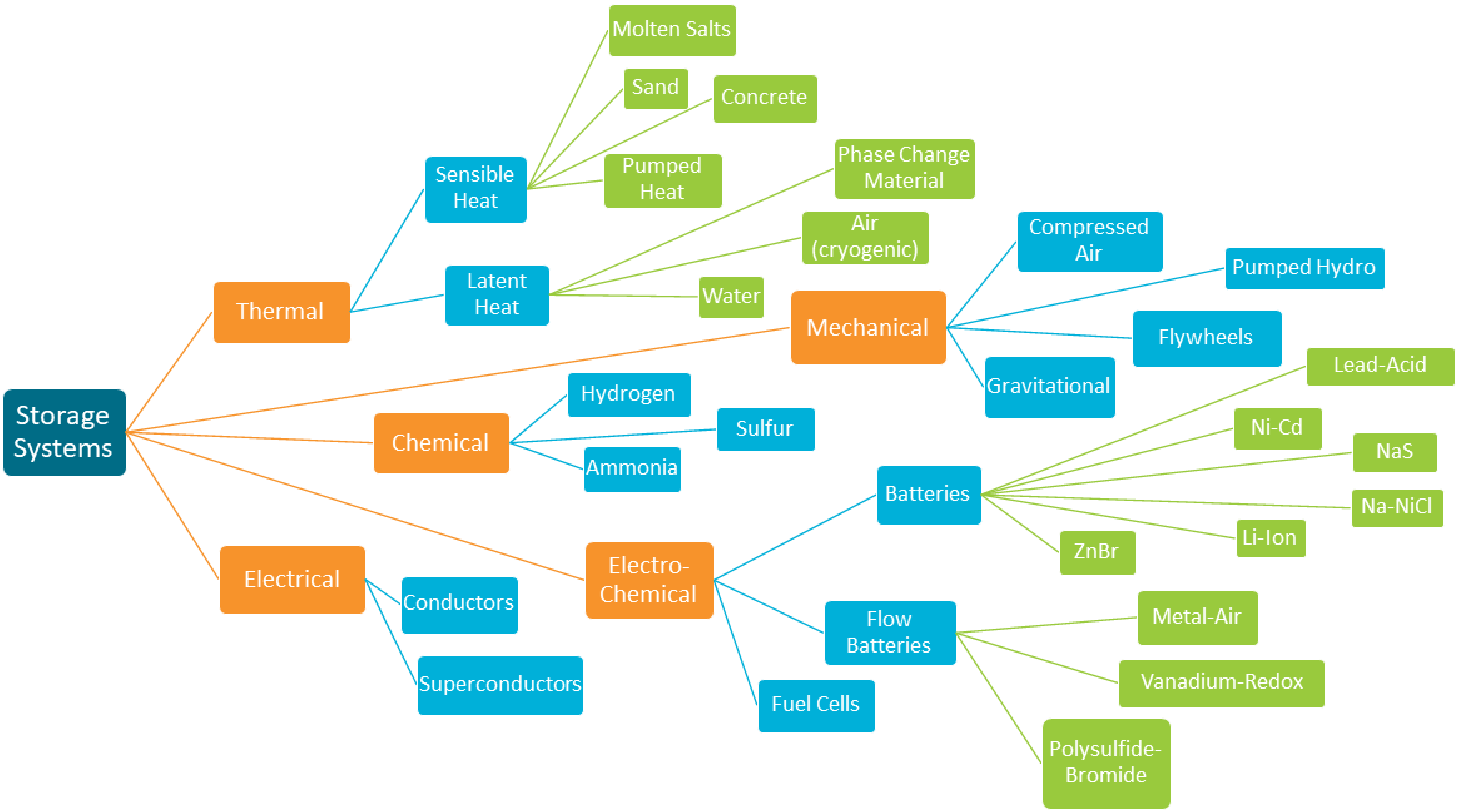
Chemical storage methods involve use of electrolysis or reversible reactions to store the energy as chemical energy. Hydrogen, sulfur, or ammonia are generated with electrolysis, where the electrical input comes from the power plant, and then stored to be used as a fuel in the gas turbine or boiler systems when discharging.

Electro-chemical storage methods include batteries that store energy by creating electrically charged ions. Flow batteries are also another type of electro-chemical storage and employ redox reactions for storing the energy. Fuel cells are also a special type of battery, where steam-methane reforming is used to generate power.

Finally, electrical storage systems use magnetic fields and conductors to store energy. They might use conductors and superconductors for storage.

The theory, expanded definitions, and the details on operating principles of each energy storage system are out of the scope of this work and can be found in the open literature. [13] The details of the energy storage system selection process for the case study university power plant described in Section 2 are given in the following subsections.

Exhibit 3-1. ESS types applicable to fossil power plant integration



3.1 Determining of the Storage System Requirements

The electrical load data generated for the hypothetical case in Exhibit 2-3 was analyzed to determine energy storage system requirements. The following information from the load data were used in determining the storage system requirements:

- Number of peak and low load instances
- Minimum time between the peak or low load instances
- Minimum peak or low load duration
- Maximum peak or low load duration

The load profile properties listed above translate to the storage requirements as shown in Exhibit 3-2.

Exhibit 3-2. Relation of storage system properties to electrical load profile properties

Load Profile Property	Storage System Requirement
Minimum Time between the Peak/Low Loads	Storage Duration
Minimum and Maximum Peak/Low Load Duration	Minimum and Maximum Discharge Time
Minimum and Maximum Load from the Threshold	Minimum and Maximum Storage Size
Number of Peaks in a Year	Cycle Life

The minimum time between the peak loads is related to the storage duration because it is the amount of time that the storage system needs to be charged and ready to be dispatched. The minimum and maximum peak or low load duration is related to minimum and maximum discharge times respectively, because it is the required amount of time that the system needs to support the load. The storage size is related to the minimum and maximum load difference from the threshold values, which are the load levels when the storage system will be activated. Especially for battery systems, the number of peaks in a year is directly related to the total cycle life of the storage system, which is the time when the storage system needs to be replaced or its components need to be renewed. Based on the load data presented in Exhibit 2-3, the storage system requirements for the case study university are determined as listed in Exhibit 3-3.

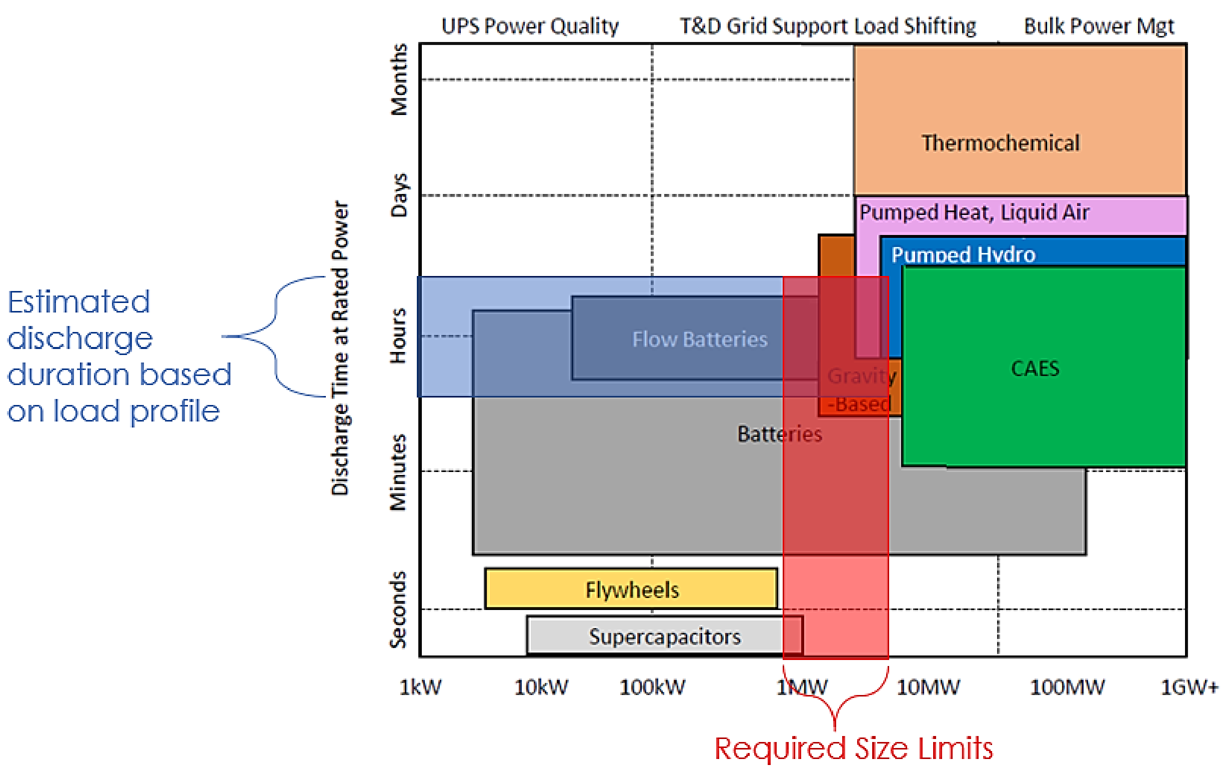
Exhibit 3-3. Storage system requirements for the case study university

Parameter	Value
Storage Duration	13–19 hours
Minimum and Maximum Discharge Time	6–9 hours
Minimum and Maximum Storage Size	2–5 MW
Cycle Life	2870 cycles (for 10 years ESS lifetime)

3.2 FILTERING ANALYSIS OF ENERGY STORAGE SYSTEMS

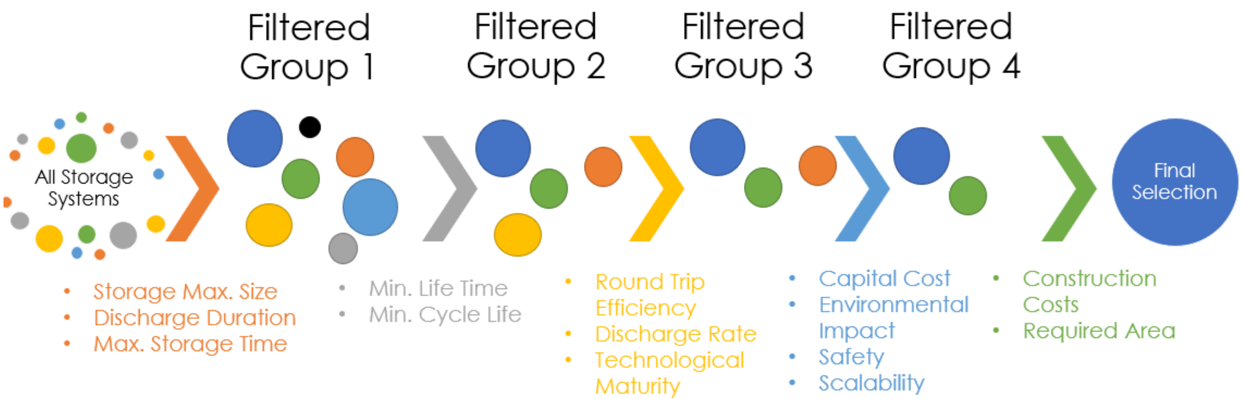
Before starting the filtering analysis, a broader selection was made by using the energy storage systems chart developed by the United States (U.S.) Department of Energy (DOE). [14] Based on the load profile, the estimated discharge duration should be in the range of hours to multiple hours. The required storage size is 2–5 MW, which corresponds to the shaded areas shown in Exhibit 3-4. [14] The intersection of the shaded areas is then used in determining the specific types of storage systems to be used in filtering analysis.

Exhibit 3-4. Broader selection of applicable ESS types for filtering analysis by using the ESS properties chart from DOE



The requirements from Exhibit 3-3 are then used as filters at a 5-step down selection process, in which at least two storage system properties are used in each step and applied to the selected general ESS types from Exhibit 3-4. The filtering criteria are prioritized according to the identified requirements from the data; the first couple of filters are directly from the requirements but the later ones are determined from the specifics of example and applicable storage systems in the literature and by engineering judgement. The filtering analysis process with the filtering criteria are schematized in Exhibit 3-5.

Exhibit 3-5. Storage system filtering analysis process with filtering criteria



The reason for developing the filtering system is because of the high number of available storage technologies, which is about 30, and the high number of storage properties, which is about 17, that generate a big matrix for selection. Trying to select systems in a big matrix eventually makes it challenging to easily identify the systems that are most suitable for the system requirements.

3.2.1 Criteria 1: Storage Size, Discharge Duration and Maximum Storage Time

The first group of filters are used directly from the system requirements. The list of applicable technologies determined from the broader selection are listed in Exhibit 3-6 with their properties to be used in this first filtering step. [15] The resources of each property are indicated on the leading columns.

Exhibit 3-6. ESSs selected for the first filtering step listed with their properties

Technology Name	Power Rating Range (MW) [15]	Max. Discharge Time (h) [15]	Max. Storage Time (h) [15]
Compressed Air ES	5-300	1-24+	1-730+
Gravity	2-8	0.5-6+	6-10
Lead-Acid Battery	0-20	0-6+	0.5-24+
Ni-Cd Battery	0-40	0-6+	0.5-24+
NaS Battery	0.05-8	0-6+	0-6+
Polysulfide-Bromide Battery	1-15	0-10	1-730+
Fuel Cells	0-50	0-24+	1-730+
Superconducting Magnetic ES	0.1-10	0-0.002	0-6+
Cryogenic Air ES	0.1-300	1-8	0.5-24+
High Temperature Thermal ES	0-60	1-24+	0.5-730+
Low Temperature Thermal ES	0-60	1-8	0.5-24+

In Exhibit 3-6, the systems that have a power rating range that covers the 2–5 MW range are indicated with green, which is satisfied by all of the systems listed. The systems that have maximum discharge time ranges equal or greater than the 6–9 hour range are indicated with green and the ones that are out of the range are indicated with red. The systems that can satisfy the maximum storage time of 19 hours are indicated with green, while the ones that might meet this criterion marginally are indicated with yellow. It should be noted that the plus (+) signs next to the maximum storage time means that the system might have a potential to exceed the indicated limits and the values do not correspond to the maximums; therefore, NaS and superconducting magnetic energy storage systems are marked as “marginal” for this criterion. Based on the indicated filtering criteria, gravity and superconducting magnetic electrical storage systems are eliminated at this step.

3.2.2 Criteria 2: Minimum Lifetime and Minimum Cycle Life

The remaining systems are then used in the second filtering criteria, which is the estimated lifetime and maximum cycle life. The lifetime is estimated to be greater than 10 years for the CHP integrated storage systems in order for them to be economically feasible and also from the NREL’s estimate of a 25-year lifetime for a typical CHP plant. [16] The systems used in the second filtering criteria are listed with their properties from the indicated resources in Exhibit 3-7.

Exhibit 3-7. ESSs selected for the second filtering step listed with their properties

Technology Name	Lifetime (years) [15]	Max. Cycle Life [15]
Compressed Air ES	20-40	∞
Lead-Acid Battery	5-15	500-1000
Ni-Cd Battery	10-20	2000-2500
NaS Battery	10-15	2500-3000
Polysulfide-Bromide Battery	10-15	12000-15000
Fuel Cells	5-15	1000-2000
Cryogenic Air ES	20-40	∞
High Temperature Thermal ES	20-30	∞
Low Temperature Thermal ES	10-20	∞

The same color code from the previous exhibit is used in Exhibit 3-7 to indicate the systems that fit into elimination criteria (green) and the ones that are out of the range (red). For an ESS lifetime greater than or equal to 10 years and a maximum number of cycles that are greater than 2800 cycles, the following systems are eliminated at this step:

- Lead-Acid battery
- Ni-Cd Battery
- Fuel Cells

3.2.3 Criteria 3: Round Trip Efficiency, Discharge Rate and Technological Maturity

The remaining storage options from the previous step are then used in the third filter, which is the round-trip efficiency, self-discharge rate per day and technology readiness level as being a measure of system maturity. Round-trip efficiency criteria were set to 50 percent by engineering judgement and a comparison of the storage technologies. The self-discharge rate is desired to be as low as possible, because the maximum storage duration is 19 hours, which can be much longer especially in low demand times. Therefore, this criterion was set to be less than 5 percent by considering the storage duration times. Technology readiness level 6 corresponds to the level where a prototype of the technology exists, and it is tested in the intended environment close to the expected performance. This is the level before commercialization of the technology; based on the status of all the ESS technologies, this criterion was set to greater than equal to 6. The systems used in the third filtering criteria are listed with their properties from the indicated resources in Exhibit 3-8.

Exhibit 3-8. ESSs selected for the third filtering step listed with their properties

Technology Name	Round Trip Efficiency [15,16]	Self Discharge per Day [15,16]	Technology Readiness Level [15,16]
Compressed Air ES	75%	1%	7
NaS Battery	80%	20%	8
Polysulfide-Bromide Battery	75%	1%	6
Cryogenic Air ES	40%	0.8%	3
High Temperature Thermal ES	50%	0.5%	6
Low Temperature Thermal ES	50%	0.5%	7

The color code system used in the previous exhibits is also used here. Based on the indicated criteria, cryogenic air energy storage and NaS battery systems were eliminated at this step.

3.2.4 Criteria 4: Capital Cost and Environmental Impact

The fourth filter includes the capital cost and estimated environmental impact of the system. The capital cost is determined to be less than 100 $/kWh for non-battery systems and 400 $/kWh for battery systems. These cost limits were determined by comparing the capital costs of other technologies, reviewing example storage applications, and reducing the impact on techno-economic metrics as much as possible. The environmental impact is desired to be less than minimum. The systems used in the fourth filtering criteria are listed with their properties from the indicated resources in Exhibit 3-9.

Exhibit 3-9. ESSs selected for the fourth filtering step listed with their properties

Technology Name	Capital Cost ($/kWh) [15,17]	Environmental Impact [15,16]	Description [15]
Compressed Air ES	50	Negative	Construction, relies on NG combustion
Polysulfide-Bromide Battery	350	Negative	Toxic remains
High Temperature Thermal ES	60	Small	Storage media leaks
Low Temperature Thermal ES	50	Small	Storage media leaks

The color code system used in the previous exhibits is also used here. All of the technologies analyzed at this stage pass the capital cost criteria. For the environmental impact, the compressed air storage system is expected to have negative impacts during construction and the flow batteries are susceptible to toxic remains. However, given that both of the systems are at low commercialization levels it is expected that these technologies will be developed further, and their environmental impact will be reduced as they are commercialized. Therefore, no elimination was made at this step.

3.2.5 Criteria 5: Construction Costs, Required Area, Safety and Scalability

Since the storage system will be integrated to an existing CHP plant, it is desired to have the construction costs be less than medium. The targeted application is a university. For universities that have downtown campuses, having the required area can be a problem, as was the case for Vanderbilt University. Therefore, the required area filter is set to be less than high. The safety of the system is desired to be as high as possible, but since most of the analyzed systems are in mid-level technological development levels and can be made safer in the future, this filter is set to be bigger than or equal to medium. Finally, power scalability is the availability of the system to fit into different power scales than its originally intended power size. This is desired to be greater than or equal to medium because for the CHP applications; most of the analyzed systems will need to be downscaled as they are typically developed for higher power sizes or intended for grid scale support. The systems used in the final filtering criteria are listed with their properties from the indicated resources in Exhibit 3-10.

Exhibit 3-10. ESSs selected for the final filtering step listed with their properties

Technology Name	Construction Cost[17]	Required Area[17]	Safety[16]	Scalability[16]
Compressed Air ES	Very High	Very High	Medium	Good
Polysulfide-Bromide Battery	Low	Medium	Medium	Medium
High Temperature Thermal ES	Low	Medium	Good	Good
Low Temperature Thermal ES	Low	Medium	Good	Good

The color code system used in the previous exhibits is also used here. Based on the filtering criteria for this step, the compressed air energy storage was eliminated due to having high construction costs and requiring high area. Therefore, the selections for the battery and non-battery systems are polysulfide-bromide battery and TESs, respectively.

3.3 FILTERING ANALYSIS OF THERMAL ENERGY STORAGE SYSTEMS

3.3.1 Criteria 1: Storage Size, Discharge Duration and Maximum Storage Time

TESs include a wide variety; therefore, another filtering iteration was made for selecting the TES for the example CHP case scenario. Pumped heat, phase change materials, and sensible heat systems are the analyzed systems for the filtering study. The complete list presented in Exhibit 3-11 was obtained from an Electric Power Research Institute (EPRI) study on current TESs in the world. [17] Similar to the previous analysis, the first three filtering criteria were set directly from the system requirements. The minimum and maximum storage size criterion is set to 2–5 MW, the discharge time limits are 6–9 hours and the storage duration is 13–19 hours.

Exhibit 3-11. TES systems selected for the first filtering step listed with their properties

Technology Type	Material	Size Range (MW) [16,17,18]	Max. Discharge Time (h) [16,17,18]	Max. Storage Time (h) [16,17,18]
Pumped Heat	Liquid Salt	2-10	10	24
Pumped Heat	Gravel	2-6	10	8
Phase Change Mat.	Aluminum	0-200	8	50*
Phase Change Mat.	Silicon	1-100	100	50
Sensible Heat	Concrete	0.1-364	96	6
Sensible Heat	Crushed Rock	2-100	24	8-10*
Sensible Heat	Molten Salt	1-1000	10	11
Sensible Heat	Sand	0.28-780	24	24

*Exact data cannot be found; estimated from similar technologies

In Exhibit 3-11, the same color code system is used with the filtering analysis of Section 3.2. All of the systems analyzed at this step pass the size range and maximum discharge time criteria. However, gravel pumped heat and concrete systems do not meet the maximum storage time criteria. Crushed rock and molten salt systems marginally meet the storage time criterion. Therefore, gravel and concrete systems were eliminated at this step.

3.3.2 Criteria 2: Minimum Lifetime, Round Trip Efficiency and Technological Maturity

The system lifetime, round-trip efficiency, and technology readiness level are used in the second filter. The limits of each criterion were the same used in the filtering analysis performed in Section 3.2, except for the technology readiness level. This criterion was set to be greater than or equal to 5, based on the comparison of the current levels of the existing thermal storage technologies. The systems used in the second filtering criteria are listed with their properties from the indicated resources in Exhibit 3-12.

Exhibit 3-12. TES systems selected for the second filtering step listed with their properties

Technology Type	Material	Lifetime (years) [16,17,18]	Round Trip Efficiency [16,17,18]	Technology Readiness Level [16,17,18]
Pumped Heat	Liquid Salt	25-35*	60%	4
Phase Change Mat.	Aluminum	10-20	80%	3
Phase Change Mat.	Silicon	10-50	50%	3
Sensible Heat	Crushed Rock	30-40	40%	5
Sensible Heat	Molten Salt	30-40	92%	9
Sensible Heat	Sand	30-40	88%	5

All of the systems analyzed in this step satisfied the minimum 10-year lifetime criterion. The following systems were eliminated at this step:

- Liquid Salt Pumped Heat
- Aluminum Phase Change Material
- Silicon Phase Change Material
- Crushed Rock Sensible Heat

3.3.3 Criteria 3: Capital Cost, Environmental Impact, Safety and Scalability

The last filter is used to select between the last two remaining systems, which are the molten salt and the sand systems. The capital cost criterion used is the same as the previous analysis and is set to be 100 $/kWh. The environmental impact criterion is set to be less than or equal to medium. The safety criterion is set to be greater than or equal to medium, to allow for the systems that will become safer as they are developed. The scalability criterion is set to be bigger than medium. The system properties and color code of each property criterion is presented in Exhibit 3-13. [18, 19]

Exhibit 3-13. TES systems selected for the final filtering step listed with their properties

Technology Type	Material	Capital Cost ($/kWh) [16,17,18]	Environmental Impact [16,17,18]	Safety [19]	Scalability [19]
Sensible Heat	Molten Salt	88	Medium	Medium	Good
Sensible Heat	Sand	138	Low	Good	Good

Based on the indicated criteria, the sand system is eliminated due to the expected capital cost. However, per an EPRI study [18] as the sand system gets developed in the future, it is expected to have capital costs less than 100 $/kWh. Molten salt TES is selected to be the non-battery option for the example CHP scenario.

4 SELECTED ENERGY STORAGE SYSTEMS

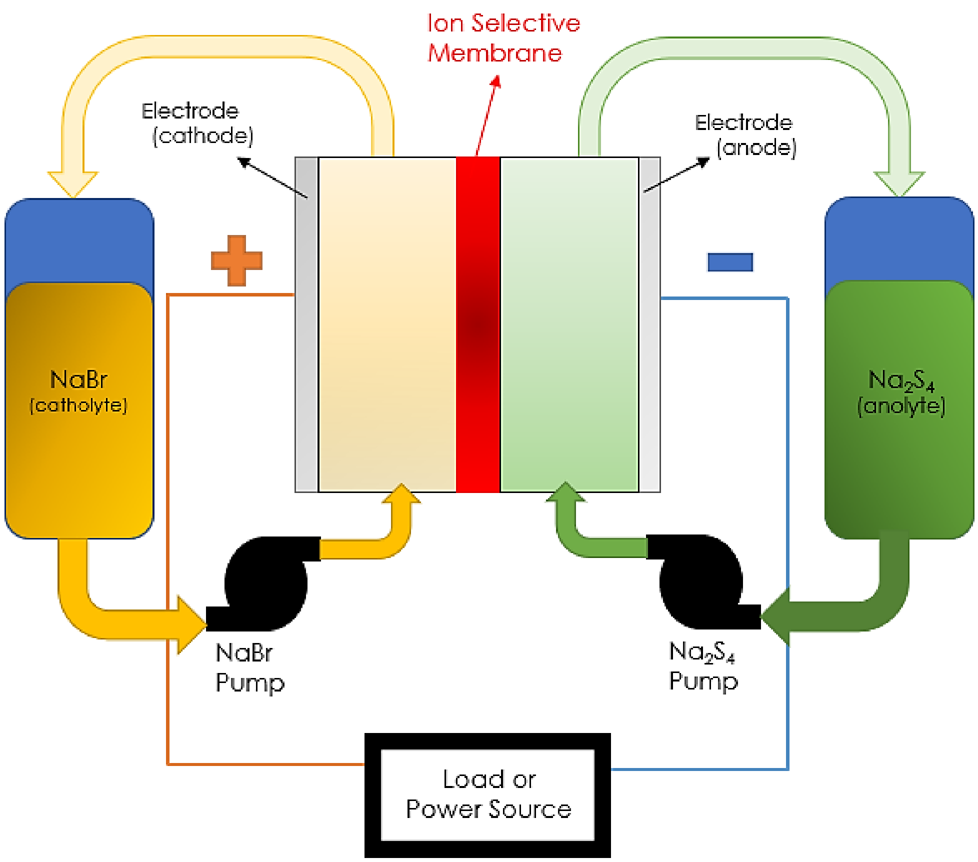
The basic descriptions, basic operation principles, major sub-components, and capital cost calculations of the selected systems are presented in the subsequent sections.

4.1 POLYSULFIDE-BROMIDE BATTERY

4.1.1 System Description

A polysulfide-bromide battery (PSBB) is a redox flow battery that uses sodium bromide (NaBr) as the catholyte and sodium tetrasulfide (Na_2S_4) as the anolyte. These types of batteries can also use other polysulfides as the anolyte. The catholyte and anolyte are stored in two separate tanks. The flows of the anolyte and catholyte are driven by the pumps. A redox reaction occurs on the ion selective membrane interface, which transfers the electrons from one side to another. The charge difference eventually generates a voltage potential. The system is schematized in Exhibit 4-1.

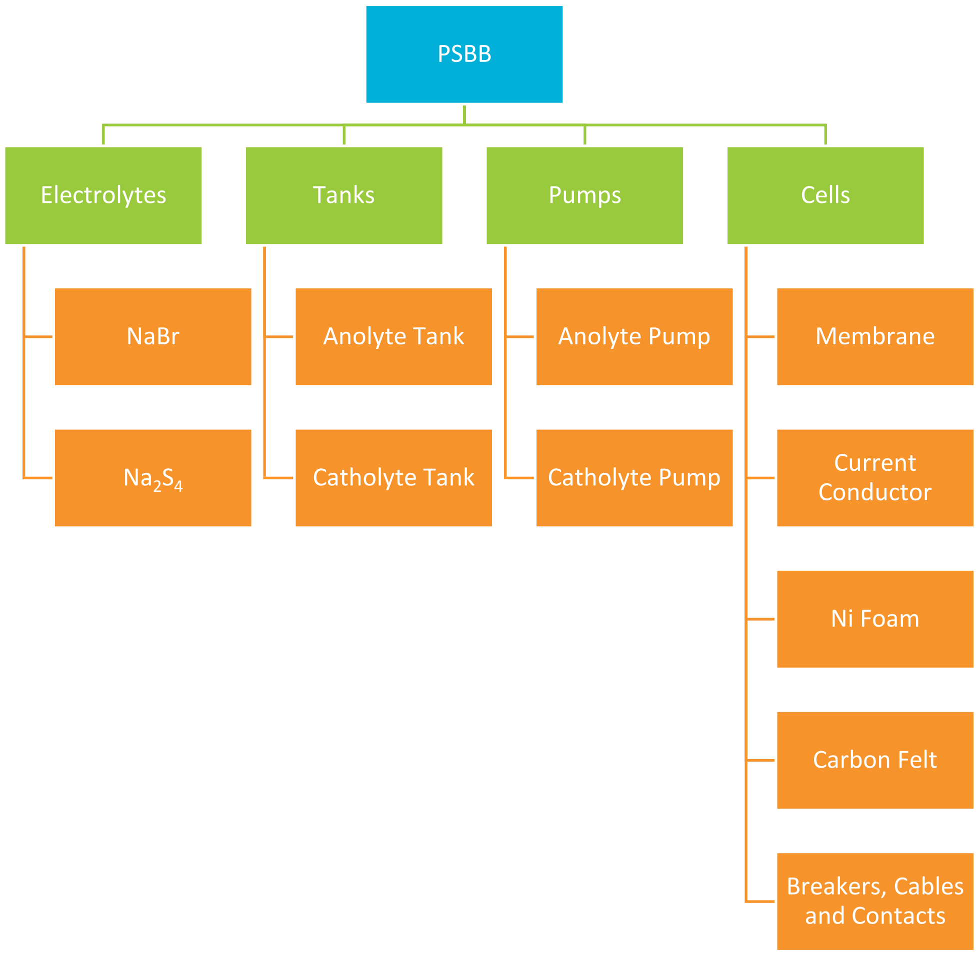
Exhibit 4-1. Polysulfide-bromide flow battery system



According to an EPRI and University of Tennessee project on the TEA of this system, [20] the membrane cost is the highest cost item in the system which was estimated to be 93 $/ft^2. A single cell is estimated to generate 0.8 Volts. Multiple stacks of cells are used to generate higher voltage, hence multiple membranes are needed. In the example study by EPRI, for a 3 MW storage it is estimated to have 20 stacks having 375 cells in total. The charging efficiency of the system is estimated to be 77 percent. [20]

The major subcomponents of a PSBB are shown in Exhibit 4-2.

Exhibit 4-2. Polysulfide-bromide flow battery subcomponents



4.1.2 System Integration to Example Case CHP Plant

The integration of the PSBB system to the case study university CHP Plant will not require significant modifications to the plant configuration, as the battery only needs the electrical charge from the generator to be charged and will send the generated current to the grid directly (i.e., without using the generator on the CHP side) during discharging. Therefore, the only modifications to the existing CHP plant are estimated to consist of the following items:

- The cabling between the plant and the battery
- Voltage regulators and other cabling from battery to the grid
- Circuit controller and circuit breakers

4.1.3 Capital Cost Items

The capital costs of the subcomponents for the PSBB shown in Exhibit 4-2 are calculated by using chemical engineering plant cost calculation methods [21] or by scaling from a previous study made for 3 MW PSBB system [20] for the 36 MWh battery that will be required by the example CHP plant. In the following subsections, the details of the capital cost calculations for the subcomponents are provided.

4.1.3.1 Electrolyte Chemicals

The redox reaction requires 5 mol/L NaBr and 1 mol/L Na_2S_4. [20] The net redox reaction between the anolyte and catholyte for calculating the stoichiometry is given by Equation 1.

$$Na_2S_4 \rightleftharpoons 2Na^+ + 4S^{-2}$$
$$2Na^+ + 2Br^{-1} \leftrightharpoons 2NaBr$$

Equation 1

$$Na_2S_4 + 2Br^- \leftrightharpoons 2NaBr + 4S^{-2}$$

From Equation 1, the molar flowrate ratio of NaBr to Na_2S_4 is 2:1. The required molar flowrate of each electrolyte can be calculated by using Equation 2.

$$\dot{n} = \frac{3600 * i_{cell} * A_{cell} * N_{cell}}{96485}$$

Equation 2

In Equation 2, i_{cell} is the current density in each cell and is 46.5 A/ft^2 for a PSBB. [20] The total number of cells are calculated to be 10,000 and required cell area is 10.76 ft^2 (details are given in Section 4.1.2.4). With the indicated parameters and using the stoichiometry, the molar flowrates, total masses and the total cost of each electrolyte are calculated as shown in Exhibit 4-3.

Exhibit 4-3. Electrolyte chemicals capital cost calculations

Parameter	NaBr	Na_2S_4
Molar Flowrate (mol/h)	186,558	93,279
Total Mass required (lbm)	380,869	322,036
Cost ($/lbm) [20]	2.51	0.17
Capital Cost ($-2021)	**$956,738**	**$56,040**

4.1.3.2 Electrolyte Pumps

Centrifugal pumps are used in flow batteries to circulate the electrolytes. Chemical engineering cost analysis methods from Ulrich et al. [21] are used to estimate the pump costs for each electrolyte. These methods use the required pump power, pump material types, and suction pressure ratio to calculate the cost of the pump. The methodology uses log-log curves based on historical price quote databases.

The required molar flowrates for each electrolyte are used to estimate the pumping power and pump efficiency. The required pump power can be calculated by using Equation 3.

$$\mathbf{P} = \frac{\dot{V}\Delta P}{\eta_{pump}} \qquad \textbf{\textit{Equation 3}}$$

In Equation 3, $\dot{V}$ is the volumetric flowrate of the electrolyte, ΔP is the pump pressure rise and η_{pump} is the pump efficiency. The efficiency of the pump is calculated by Equation 4 from Ulrich et al. [21]

$$\eta_{pump} = \left(1 - 0.12\dot{V}^{-0.27}\right)\left(1 - \mu^{0.8}\right) \qquad \textbf{\textit{Equation 4}}$$

In Equation 4, μ is the viscosity of the electrolyte fluid.

The materials used for each electrolyte pump are another important parameter in the cost estimation. It is important to select the pump materials such that the electrolytes would not react with the metal and cause corrosion on the pump blades. Cast steel is safe to be used for NaBr flow as it is durable, cheaper, and does not react with the flow. [20] However, for the Na_2S_4 flow cast steel will corrode and cannot be used as the pump material of this electrolyte. Nickel alloys, although expensive, need to be used for this electrolyte's pump material.

The calculated pump power, efficiency, selected materials and required electrolyte flowrates are then used to calculate the capital cost of each pump, as presented in Exhibit 4-4.

Exhibit 4-4. Electrolyte pumps capital cost calculations

Parameter	NaBr Pump	Na_2S_4 Pump
Volumetric Flowrate (ft^3/s)	0.37	0.91
Flow Viscosity (Pa-s)	0.003	0.018
Pump Efficiency	58%	65%
Required Pump Pressure Rise (psi)	158	125
Pump Work Input (kW)	0.89	1.99
Material	Cast Steel	Ni Alloy
Capital Cost ($-2021)	**$33,928**	**$73,954**

4.1.3.3 Electrolyte Tanks

The volumes of the electrolyte storage tanks are calculated using the required electrolyte mass amounts with 10 percent excess volume. Excess volume is required for overflows, servicing, and maintenance requirements. [20, 21] Chemical engineering cost analysis methods from Ulrich et al. [21] are used to estimate the tank costs. Cone-roof tank geometry is selected for easier maintenance and electrolyte replacements. [20] The tank materials were selected by using corrosion tables for NaBr and Na_2S_4 and considering the material costs.

The cost calculation methodology for chemicals storage tanks from Ulrich et al. [21] uses the tank volume, tank type, and tank material as the inputs. For the NaBr electrolyte tank from the corrosion tables of NaBr, [22] fiberglass is a durable material for stationary NaBr storage and is also cheaper than other material options (e.g., stainless steel). For the Na_2S_4 electrolyte, the corrosion tables from Ulrich et al. [21] were used. Ideally, nickel alloys should be used as the tank material, but stainless steel is a cheaper alternative with satisfactory durability.

The volumes of the cone roofed cylindrical tanks are calculated by using online calculation tools provided in several tank manufacturer websites. [23] For the stainless-steel chemical storage tanks, 144” is the maximum possible production diameter [23] and the diameter of the Na_2S_4 tank is therefore calculated by using this limitation.

With the indicated inputs, the capital costs of the electrolyte tanks are calculated as shown in Exhibit 4-5.

Exhibit 4-5. Electrolyte tanks capital cost calculations

Calculated Specs	NaBr Tank	Na_2S_4 Tank
Required Amount	380,869 lbm	322,036 lbm
Density	199.2 lbm/ft^3	60.43 lbm/ft^3
Required Volume	1912 ft^3	5329 ft^3
Tank Volume (with 10% excess)	15,732 gal	43,851 gal
Material	Fiberglass	Stainless Steel
Dimensions	163” D, 14.6 ft H	144” D, 51.8 ft H
Capital Cost ($-2021)	**$48,844**	**$68,654**

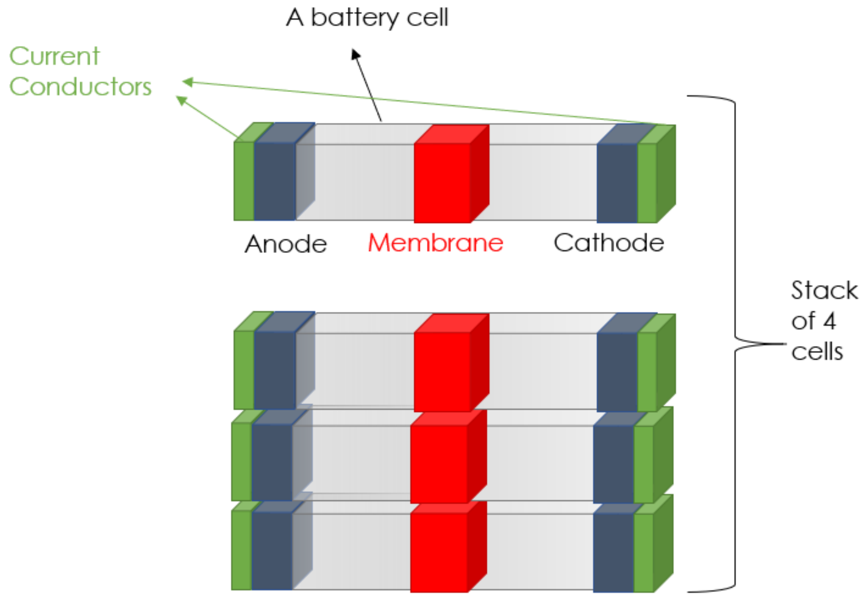
4.1.3.4 Cells

The battery consists of several stacks, each containing multiple cells. Each cell consists of the following items:

- Ion selective membrane
- Current conductor
- Cathode
- Anode

Cells generate the voltage, which is about 0.8V for the PSBB. [20] The redox reaction between the electrolytes occur at the cells and the ion selective membrane passes the electrons between the electrodes. The current conductors are located at the ends of each electrode and conducts the current flow. The cells are connected in series and grouped in stacks. The structure of the cells and the stacks are shown in Exhibit 4-6.

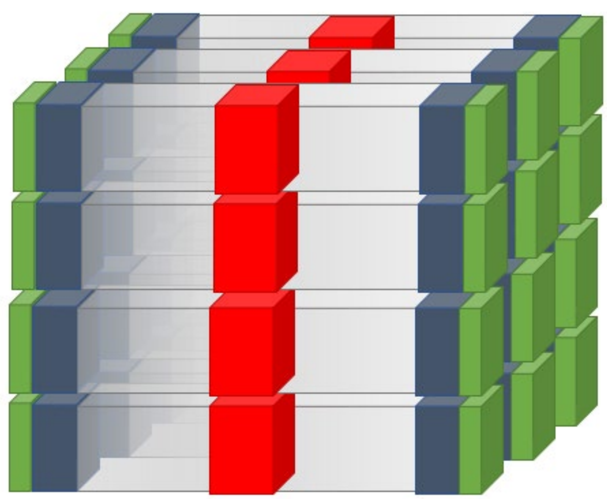
Exhibit 4-6. Cell and stack structures used in flow batteries



For the PSBB, cathode material is nickel foam, and anode material is carbon felt. [20]

Multiple stacks are then used to obtain higher voltages and are usually connected in series. The cell block of a flow battery is therefore a combination of multiple stacks, as illustrated in Exhibit 4-7.

Exhibit 4-7. Flow battery cell block containing multiple stacks



For a 36 MWh battery, with 46.5 A/ft^2 current density the total cell voltage required is calculated to be 8000V. For the PSBB, each cell is capable of generating 0.8V; [20] therefore, the total number of cells is calculated as 10,000.

The required number of stacks can be found by using Equation 5.

$$N_{stacks} = \frac{Battery\ Power\ (Watts)}{V_{cell} * i_{cell}\left(\frac{A}{ft^2}\right) * A_{cell}(ft^2) * N_{cell\ per\ stack}}$$

Equation 5

In Equation 5, V_{cell} is the cell voltage (0.8V), i_{cell} is the current density, A_{cell} is the required cell cross sectional area, and $N_{cell\ per\ stack}$ is the total number of cells per stack. The required cell cross sectional area is calculated from the required membrane surface area and electrode areas. This value is calculated as 10.76 ft^2 for PSBB operation. [20] The number of cells per stack is determined from the practical limits of cell construction and operability and used as 375 for the polysulfide-bromide type flow battery. [20] The cell properties are summarized in Exhibit 4-8.

Exhibit 4-8. Cell block properties

Item	Value
Voltage Required for 36 MWh	8000 V [20]
Voltage per Cell	0.8 V
Design Cell Current Density	46.46 A/ft^2 [20]
Number of Cells per Stack	375
Number of Stacks	27
Number of Cells (total)	10,000
Required Membrane per Cell	10.76 ft^2
Required Carbon Felt per Cell	10.76 ft^2
Required Nickel Foam per Cell	10.76 ft^2
Required Current Conductor per Cell	10.76 ft^2

The ion selective membrane cost is estimated to be the highest cost item of the PSBB. [20] A recent DOE Small Business Innovation Research (SBIR) project carried out by Bettergy Corporation developed a low-cost ion selective membrane for commercial flow batteries and its cost is estimated as 12.94 $/ft^2$. [24] The low-cost ion selective membrane is used as the membrane material of the 36 MWh battery.

For the basic cell structure shown in Exhibit 4-6 and with the indicated materials for the cells and the calculated electrical properties, the cell block properties are calculated as presented in Exhibit 4-9.

Exhibit 4-9. Cell block capital cost calculation

Cost Item	Value
Membrane Cost ($\$/ft^2$)	12.94 [24]
Carbon Felt Cost ($\$/ft^2$)	2.102 [20]
Nickel Foam Cost ($\$/ft^2$)	2.102 [20]
Current Conductor Cost ($\$/ft^2$)	5.356 [20]
Cell Circuit Breakers, Contacts and Cables Cost ($/kW)	20.34 [20]
Total Cell Cost ($-2021)	$266
Total Cell Cost (including construction costs-10% of cell cost)	$293
Capital Cost for the Cell Block (includes cabling and construction)	**$3,728,446**

4.1.3.5 Other Cost Items

The cost items included in this category are for:

- Building and Site Preparation
- Instrumentation and Controls
- Other Costs related to battery operation

HydroWires Project by PNNL [25] was used to estimate the building and site preparation costs of the 36 MWh PSBB. The PNNL project estimates 140–200 $/kW for the building and site preparation costs; an average of 170 $/kW was used in this study for this cost item.

Instrumentation and controls and other battery operation costs are scaled from University of Tennessee and EPRI's 18 MWh battery study [20] by using Equation 6 .

$$Cost = (Ref.Cost) * \left(\frac{MWh}{Ref.MWh}\right) * \left(\frac{CEPCI-2021}{CEPCI-2014}\right) \qquad \textbf{\textit{Equation 6}}$$

In Equation 6, the ratio for the CEPCI indices for 2021 costs are 1.13.

4.1.4 Total Capital Cost

The total capital cost of the 36 MWh PSBB for the example CHP plant is then calculated by summing up each cost item from Section 4.1.2. Following cost assumptions are used for the indicated items:

- Engineering, Capital Management and Home Office and Fees is 10% of the bare erected cost [18]
- Process contingency is 20% [18]
- Project contingency is 10% [18]

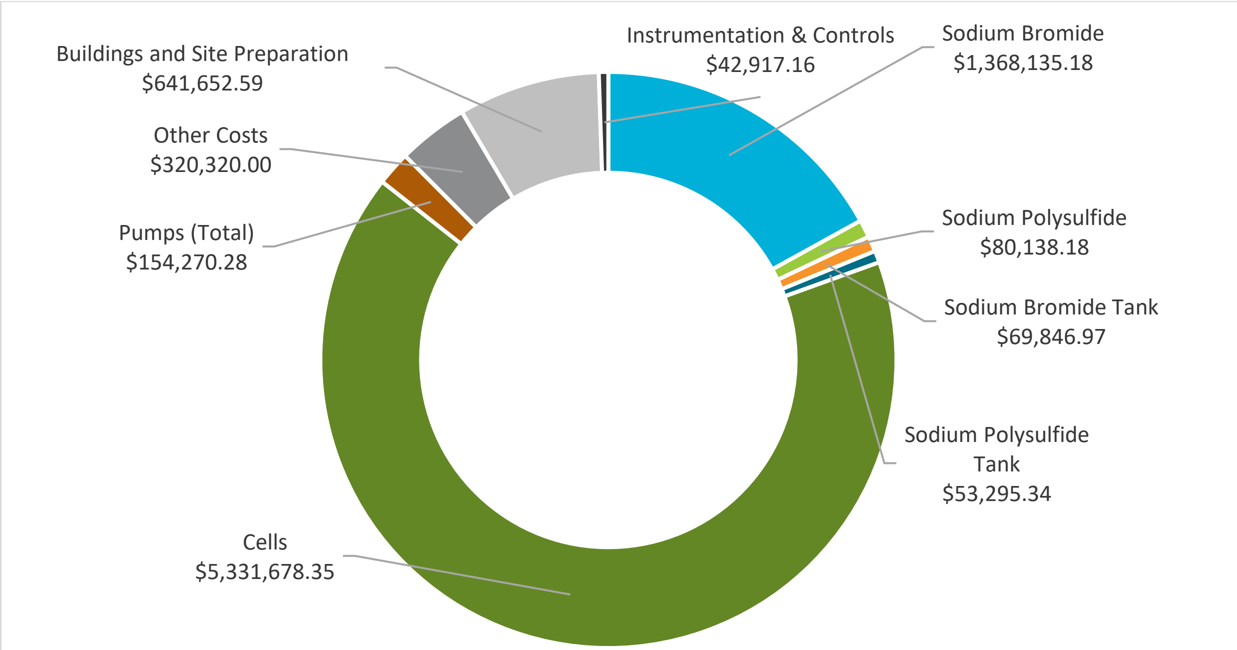
The indicated cost assumptions are used from an EPRI study made for energy storage integration to fossil fuel power plants. [18] With the indicated assumptions, the total capital cost of the PSBB is calculated as shown in Exhibit 4-10.

Exhibit 4-10. PSBB capital cost calculation

Cost Item	Capital Cost		Contingencies				
	Process Facilities Capital Cost	Eng. CM H.O. & Fees 10%	Process 20%	Project 10%	Total Cost	$/kW	$/kWh
Sodium Bromide	$956,738	$95,674	$210,482	$105,241	$1,368,135	$342.0	$37.63
Sodium Polysulfide	$56,041	$5,604	$12,329	$6,165	$80,138	$20.03	$2.20
Sodium Bromide Tank	$48,844	$4,884	$10,746	$5,373	$69,847	$17.46	$1.92
Sodium Polysulfide Tank	$37,269	$3,727	$8,199	$4,100	$53,295	$13.32	$1.47
Cells	$3,728,446	$372,845	$820,258	$410,129	$5,331,678	$1,333	$146.6
Pumps (Total)	$107,881	$10,788	$23,734	$11,867	$154,270	$38.57	$4.24
Other Costs	$224,000	$22,400	$49,280	$24,640	$320,320	$80.08	$8.81
Buildings and Site Preparation	$448,708	$44,871	$98,716	$49,358	$641,653	$160.4	$17.65
Instrumentation & Controls	$30,012	$3,001	$6,603	$3,301	$42,917	$10.73	$1.18
Total Battery System Cost	**$5,637,940**	**$563,794**	**$1,240,347**	**$620,173**	**$8,062,254**	**$2,016**	**$221.7**

It should be noted that the total battery system cost in terms of $/kWh is lower than the example studies (350 $/kWh [18], 393 $/kWh [25]) because of the usage of the low-cost membrane as the membrane material. The cost item distributions on the total battery system cost are shown in Exhibit 4-11.

Exhibit 4-11. PSBB capital cost items distribution



From the cost distribution in Exhibit 4-11, the following cost items of PSBB have the highest impact on the total capital cost of the system:

- Cell block cost
- Sodium bromide cost

Reduction in the costs in either of these two items does have the highest potential to reduce the overall cost of the PSBB.

4.1.5 Operation and Maintenance Costs

A PNNL study on various battery storage system costs indicates the following for the flow battery operation and maintenance costs: [25]

- Variable operating costs are 0.03 $/kWh
- Fixed operating costs are 9 $/kW-year

Wicker et al. [26] on flow battery storage costs calculates the variable operating costs as 4.83 percent of the capital plant cost including the storage.

Based on the indicated literature for the PSSB system, the following values are used for the operation and maintenance cost items:

- Variable operating costs are 4.83% of capital plant cost (including the battery)
- Fixed operation costs are 9 $/kWh-year

4.2 Molten Salt Thermal Energy Storage

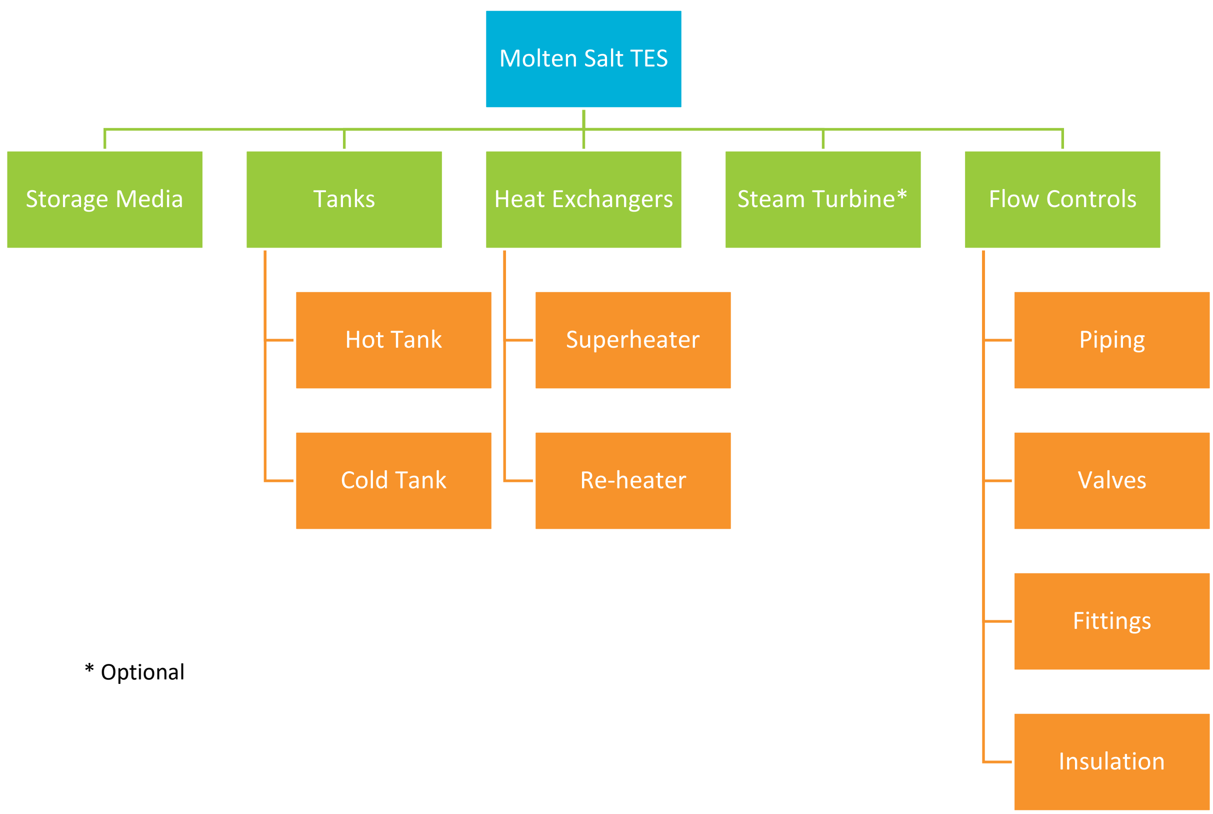
4.2.1 System Description

Molten salt TES is a sensible heat storage system. This storage system increases the temperature of a heat transfer salt to store the energy. Heat transfer salt is usually a mixture of sodiumnitrate ($NaNO_3$) and potassiumnitrate (KNO_3). In some compositions, sodiumnitrite ($NaNO_2$) is also added to the mixture. [18]

The integration of this system is primarily made with solar power systems, where the salt is heated directly or indirectly (through a thermal oil) at the power tower, which collects the solar beams. In fossil fueled plants, a portion of the superheater and re-heater steam from the HRSG are used in heat exchangers to heat the salt. Regardless of the type of plant it is integrated into, this storage system requires steam generation and a steam turbine to charge and discharge.

The major subcomponents of molten salt TES are shown in Exhibit 4-12.

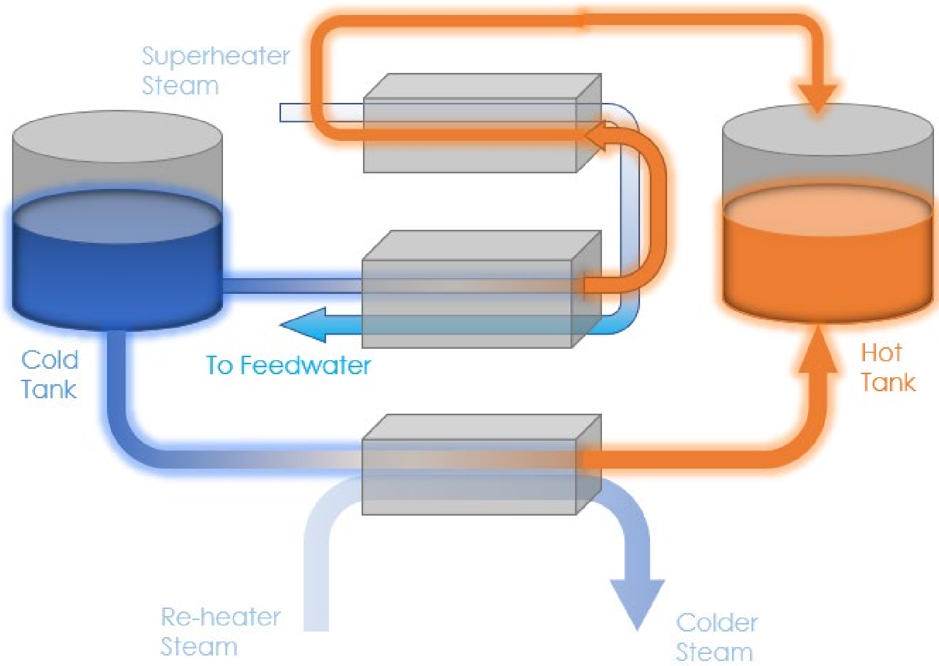
Exhibit 4-12. Molten salt TES subcomponents



4.2.1.1 Charging Process

In the charging process, cold salt from the cold tank is pumped through the heat exchangers that use the superheater steam to increase the steam temperature. Hot salt is then discharged to the hot tank, which is insulated. The steam used in heating up the salt condenses to water and is added to the feedwater system. The charging process is schematized in Exhibit 4-13.

Exhibit 4-13. Molten salt TES charging process



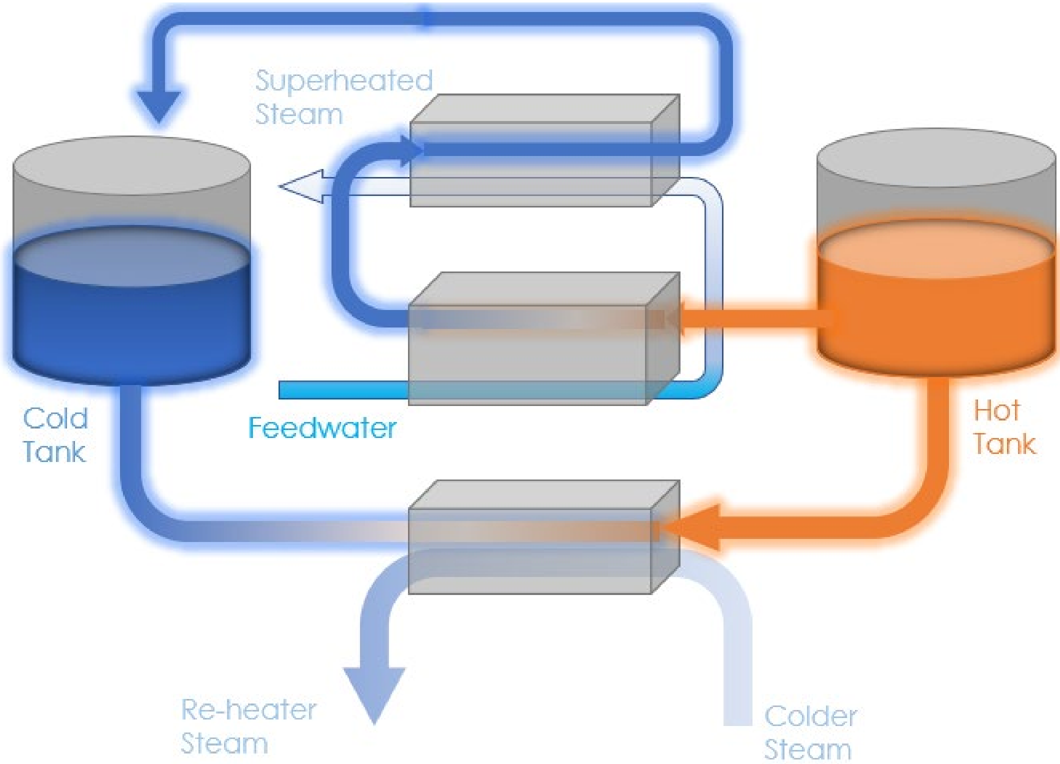
In bigger storage size systems, another stream of cold salt is used and heated by the re-heater steam and is added to the hot tank. The re-heater steam used to increase the salt temperature can be discharged and, for a CHP plant, it could probably be used to supplement the customer steam demand.

4.2.1.2 Discharging Process

When the system discharges, superheated steam is generated and fed into the steam turbine to generate power. While discharging, the direction of the salt flow is reversed from the charging loop. In this case, the hot salt is pumped to the heat exchangers to be used to generate the superheated steam. The colder salt is then discharged to the cold storage tank. A portion of the feedwater stream is used in the discharging process to be converted into the superheated steam. The discharging process is schematized in Exhibit 4-14.

In bigger size systems, some portion of the hot salt flow can be used to supplement re-heater steam. In this case, a colder steam from the system (e.g., high pressure turbine discharge steam) can be used. One major limitation of the molten salt TES system design is that the salt flow should never reach the salt melting temperature, which is around 1050 °F, [18] at any point in the system.

Exhibit 4-14. Molten salt TES discharging process

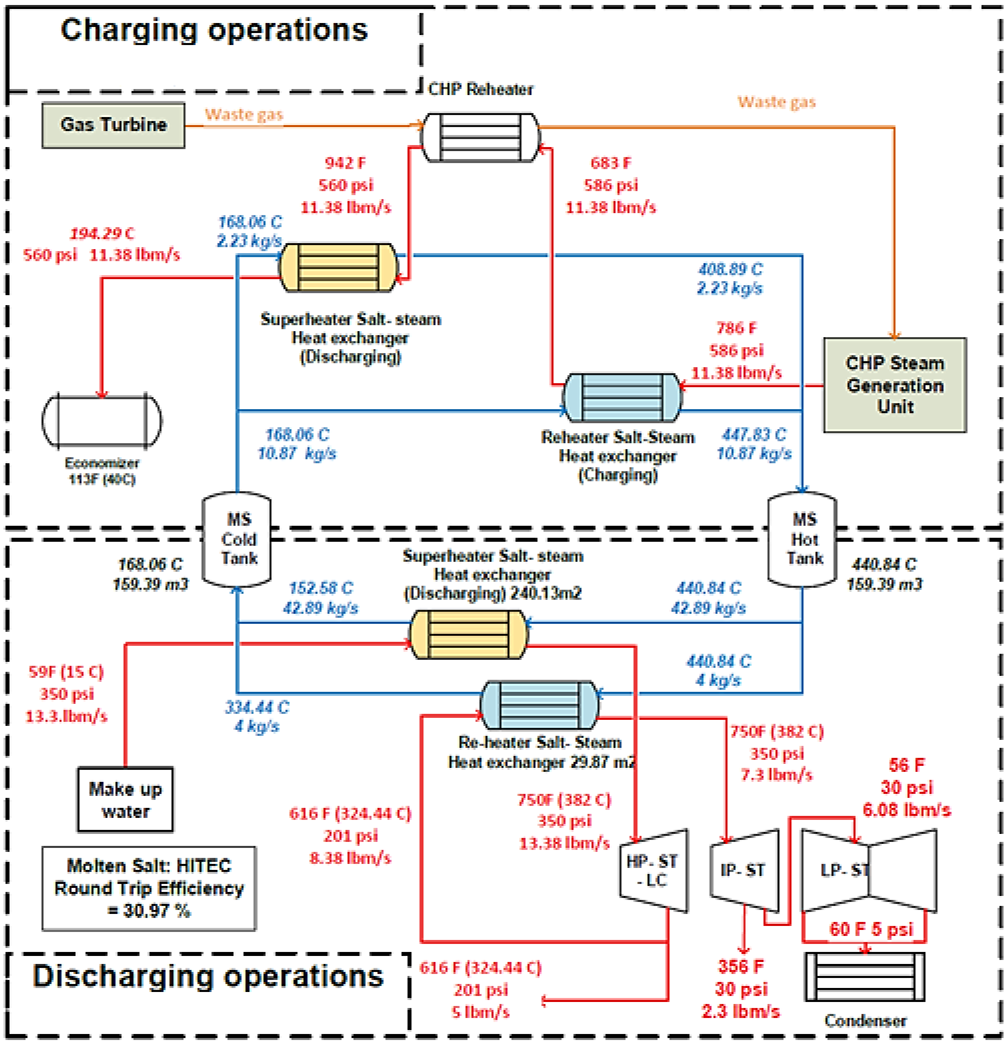


4.2.2 System Integration to Example Case CHP Plant

The molten salt TES will require steam from the HRSG in the example CHP plant to be directed to its heat exchangers during charging. Similarly, steam generated from the molten salt TES during discharging needs to be connected to the existing steam turbine train to generate power.

A UTSR project on energy storage system modelling is carried out by West Virginia University and Texas A&M University. Texas A&M University developed various thermal energy storage system models, including molten salt thermal energy system. The developed model in this project utilizes an optimization algorithm to find optimum system design. The general specifics from the current study such as the ESS discharge duration, ESS storage capacity, HRSG steam flowrates and CHP cycle configuration were the main inputs of the molten salt model. Several iterations were made to obtain the most feasible charging configuration and highest possible round-trip efficiency. The storage system design made by Texas A&M with its specifications are shown in Exhibit 4-16.

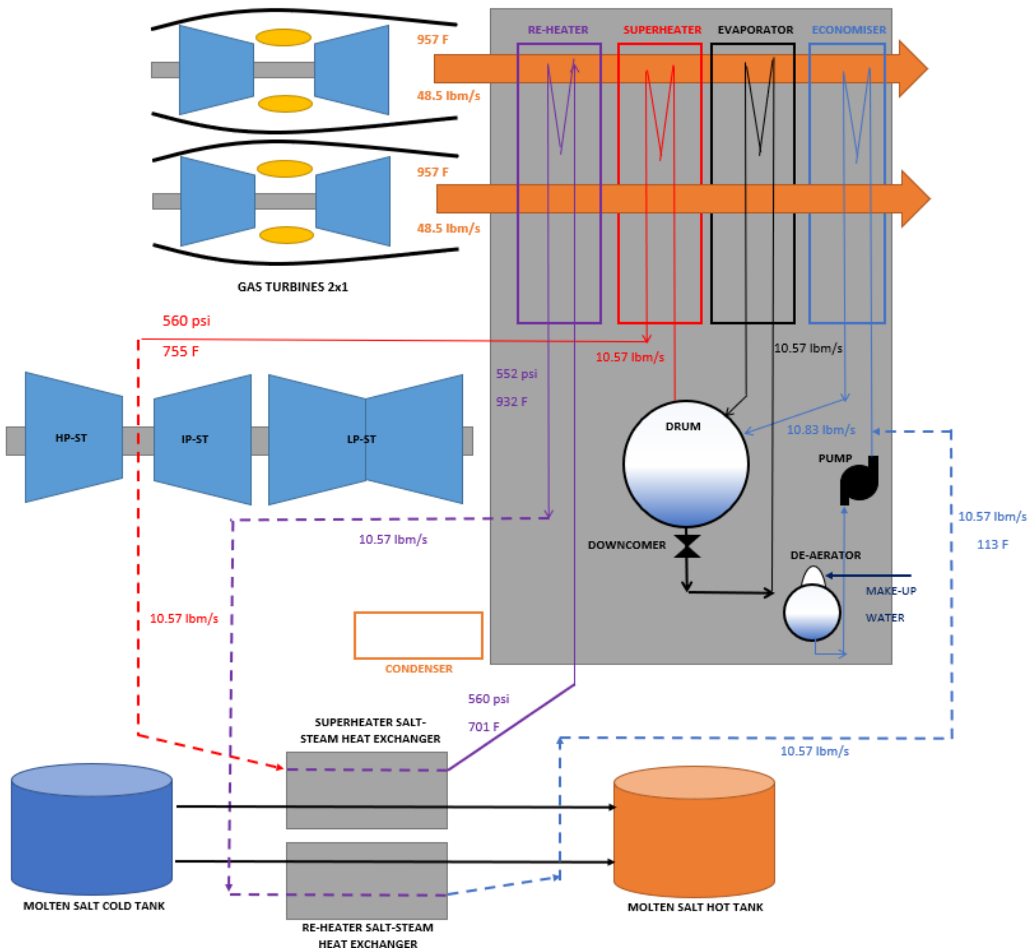
Exhibit 4-15. Molten Salt TES design by Texas A&M University for this study



Calculated round trip efficiency of the 36 MWh molten salt system is 31%. Re-heater is included in the charging loop to increase the charging efficiency. The system design and the parameters from the study were used in estimating the capital cost of the molten salt system.

During the charging operation, where the campus load demand is below 8 MW, the steam turbine will shut down and the steam used for running the steam turbine will be directed to the molten salt TES heat exchangers to heat up the salt mixture. The superheater heat exchanger will intake the superheated steam and use it to increase the molten salt temperature from 335 °F to 766 °F. Condensed steam from the heat exchanger will be added as a feedwater stream to the economizer. Makeup water could be used to supplement the feedwater stream, if the condensed water flowrate is less than the design feedwater flowrate for the economizer. If the water pressure level is lower, than the condensed water can be mixed at the de-aerator. The condensed water exit temperature from the heat exchanger should be less than or equal to 123 °F. The flowchart of the example CHP plant with the molten salt TES for the charging process is schematized in Exhibit 4-16.

Exhibit 4-16. CHP plant flowchart during molten salt TES charging process



During the discharging operation, the gas turbines will be shut down. The key component in molten salt TES integration is the existing steam turbine, as it will be used to generate the power during discharging. If the TES system can produce steam that is at the same quality with the steam turbine admittance conditions, then the existing steam turbine can be used as is, which will eventually reduce the capital cost of the storage system.

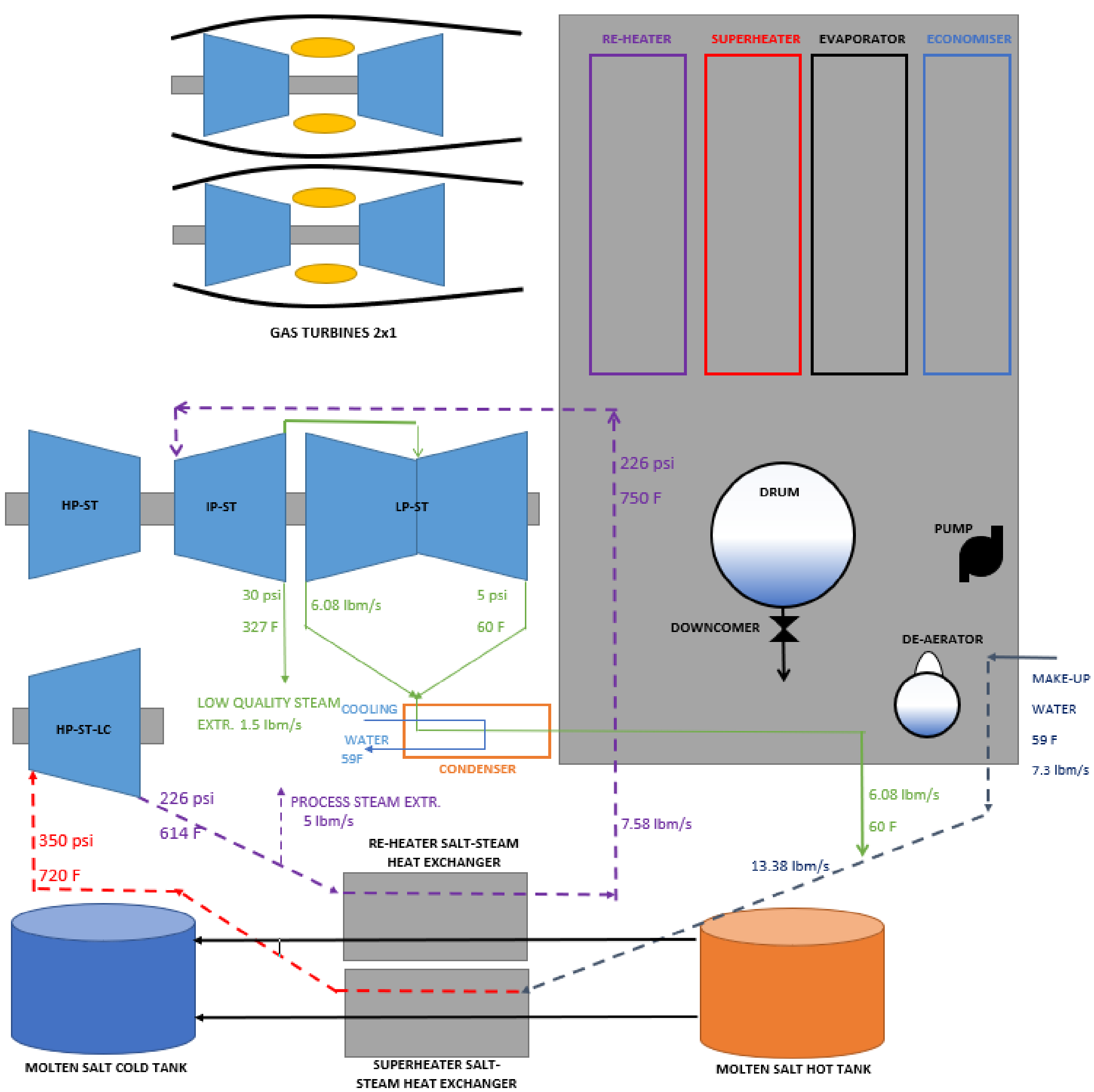
However, the steam that will be generated by the molten salt system during discharging has the pressure that corresponds to the saturation temperature that is at least 54 °F less than the saturation temperature of the charging steam. This operational limitation comes from the heat exchanger designs and maximum possible pressurization levels. For the charging steam conditions of 600 pounds per square inch (psi) and 755 °F, the drop in the discharging steam pressure from the charging steam pressure is calculated to be 250 psi.

The existing steam turbine in the example CHP plant cannot operate with the discharge steam conditions. A remedy is to use a smaller capacity steam turbine that can use the discharge steam and has a steam output that is closer to the steam admittance conditions of the intermediate pressure section of the existing steam turbine. Therefore, the intermediate and lower pressure sections of the existing steam turbine will still be able to be used during the discharging operation and the high-pressure section will be bypassed.

However, indicated operation will require slightly higher steam flowrates than the charging conditions (10.57 lbm/s is used for charging but 13.38 lbm/s will need to be generated during discharging) in order to produce 3.5 MW from the steam turbine while discharging.

Makeup water will be used to generate the superheated steam in the first heat exchanger. The superheated steam at 350 psi and 720 °F will then be expanded at the small capacity steam turbine. A portion of the exiting steam will then be used in the re-heater heat exchanger to generate the re-heated steam at 243 psi and 1085 °F for intermediate steam turbine. The customer steam extraction locations will be the same, but the customer steam extractions will slightly increase to offset the increased steam generation rate. The described discharging operation is schematized in Exhibit 4-17.

Exhibit 4-17. CHP plant flowchart during molten salt TES discharging process



4.2.3 Capital Cost Items

The capital costs of the subcomponents for the molten salt TES shown in Exhibit 4-12 are calculated by using process systems cost analysis methods [21] or by scaling from a previous study made for a 4,040 MWh system for the National Energy Technology Laboratory (NETL) Case B12A Power Plant integration [18] for the 36 MWh battery that will be required by the example CHP plant. In the following subsections, the details of the capital cost calculations for the subcomponents are provided.

4.2.3.1 Storage Media

Molten salt is a mixture of heat transfer salts, varying in composition. Two of the frequently used commercial salt blends are given with their mixture weight percentages as follows:

- Solar Salt (60% $NaNO_3$ – 40% KNO_3)
- HITEC Salt (40% $NaNO_3$ – 53% KNO_3 – 7% $NaNO_2$)

The prices of each blend are obtained as follows:

- Solar Salt – 0.47 $/lbm [18]
- HITEC Salt – 1.09 $/lbm [18]

Among these two options, HITEC blend is selected for the current study due to its higher heat transfer performance from Texas A&M University's study. The EPRI study on molten salt TES indicates that 25.2 tons of molten salt is needed for each MWh storage. With the indicated properties, the capital cost of the storage media is calculated as shown in Exhibit 4-18.

Exhibit 4-18. Storage chemicals capital cost calculations

Parameter	NaBr
Selected Salt Blend	HITEC
Storage Size (MWh)	36
Salt required (tons/MWh)	25.2 [18]
Total Salt Mass required (tons)	1,010
Cost ($/lbm)	1.09 [18]
Capital Cost ($-2021)	**$2,203,387**

4.2.3.2 Storage Tanks

The storage volumes for the hot and cold tanks are calculated by using the required salt mass amount with 10 percent excess. Chemical engineering cost estimation methods [21] are used to calculate the tank costs.

Cone-roof cylindrical and flat bottom tank geometry is selected for easier maintenance and salt replacements. Stainless steel is selected as the tank material from a safety analysis made by SANDIA Labs for molten salt storage systems. [27] Nickel alloys are another alternative safe material for molten salt storage, [27] but this selection increases the cost. However, based on the amount of salt required, the tank volumes will require large diameters that would possibly be out of the steel tank production limits. Therefore, concrete is used as the wall support material. The cost calculations, therefore, includes the steel tank cost with concrete walls.

Calculated tank volumes will require diameters that would be out of shipped steel tank production limits; concrete wall support and on-site production will be required. Tank insulation and foundation costs are directly scaled with salt amounts from Herrmann et al. [28] The total tank cost includes the insulation and foundation costs.

With the indicated inputs, the capital costs of the electrolyte tanks are calculated as shown in Exhibit 4-19.

Exhibit 4-19. Salt tanks capital cost calculations

Calculated Specs	Values
Required Amount (total)	1,010 tons
Density	135.8 lbm/ft^3
Required Volume (total)	11,258 ft^3
Tank Volume (with 10% excess) (total)	92,639 gal
Material	Stainless Steel +Concrete
Number of Tanks	2
Dimensions (each)	34' 2" D, 8' 5" H
Capital Cost ($-2021) (total)	**$310,570**

4.2.3.3 Salt Pumps

Centrifugal pumps are used to circulate the salt from the tanks. Chemical engineering cost analysis methods [21] are used to estimate the pump costs by using the same methodology in Section 4.1.3.2. The salt volumetric flowrate and required pump suction pressure, however, were scaled from an example study by Herrmann et al. [28] for a 50 MWh capacity system designed for solar power plants and uses two salt tanks. The total volumetric flowrate and suction pressure for the 36 MWh system were linearly scaled by using the system power capacities. Linear scaling is expected to give accurate results as the difference between the designed system and reference system's capacities is very small.

Equation 3 and Equation 4 are then used with solar salt type molten salt mixture properties to calculate the pump power and efficiency. The solar salt chemical properties used in the calculations are obtained from a study by Caraballo et al. [29]

For the pump material to be used with molten salt flow, a pump design analysis study by Barth et al. [30] for the high temperature molten salt flow pumps for solar power applications was used. Stainless steel was selected to be the pump material.

The calculated pump power, efficiency, selected materials, and required volumetric flowrate are then used to calculate the capital cost of the pumps, as presented in Exhibit 4-20.

Exhibit 4-20. Salt pumps capital cost calculations

Calculation Items	Values
Volumetric Flowrate (ft^3/s)	0.7
Flow Viscosity (Pa-s)	0.00285
Pump Efficiency	65%
Required Pump Pressure Rise (psi)	60
Pump head (ft)	63
Pump Work Input (kW)	15.2
Material	Stainless Steel
Capital Cost ($-2021)	**$98,574**

4.2.3.4 Heat Exchangers

Molten salt systems can utilize two types of heat exchange processes: [28]

- Steam to thermal oil to salt heat exchangers
- Steam to salt heat exchangers

Thermal oil (usually Therminol ®) is used as an intermediary in solar systems to transfer heat from the steam to salt. In power plants involving an HRSG, steam temperature is expected to be high enough for effective and direct heat transfer to the salt. In either molten salt heat exchanger types, shell and tube design is used. [28]

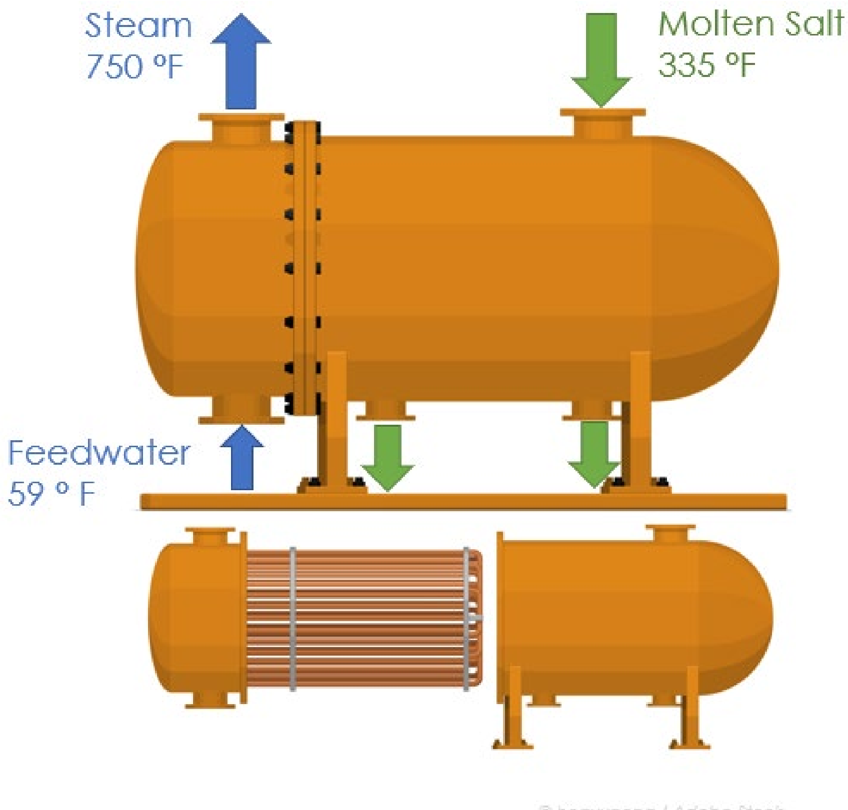
Among the many possible types of shell and tube heat exchangers, U-Tube type is used in molten salt systems. [28] From the system integration analysis made in Section 4.2.2, two heat exchangers will be needed for each:

- Superheater steam
- Re-heater steam

The re-heater steam heat exchanger will be used to re-heat the high-pressure turbine exit steam during discharging. It is not expected to be used during charging of the system, as the superheated steam flow would be enough to charge the system. The heat exchanger total heat transfer area is calculated for the steam temperatures from the flowcharts in Exhibit 4-16 and Exhibit 4-17 by Texas A&M University. The molten salt temperature was scaled and used from an EPRI study made for molten salt TES integration to fossil fuel systems. [18]

The heat exchanger design and the flow temperatures and directions of the molten salt and steam are schematized in Exhibit 4-21.

Exhibit 4-21. U-tube shell and tube heat exchanger for the molten salt TES



The charging process was used in heat exchanger sizing calculations, which gives 2,906 ft^2 total heat exchanger area for the specified molten salt and steam temperatures. Charging process is typically used to size the heat exchanger because it is the most critical step. [28] The overall heat exchanger area is reduced when the re-heater steam is included in the charging loop.

The molten salt requires pressurization when used in a heat exchanger. The pressurization between the molten salt and steam is calculated to be 288 psi (15 bar) for effective heat transfer in a study by Herrmann et al. [28] Pressurization is made at the shell side, where the molten salt flow is made. Herrmann et al. [28] suggests using one of the following material types for molten salt heat exchangers:

- Stainless steel tube and stainless-steel shell
- Stainless steel tube and carbon steel shell

The options above are determined by using the heat transfer effectiveness and corrosion considerations. The heat exchanger cost increases significantly with the material types used. [21] Stainless steel is selected for the tube and carbon steel is selected for the shell material to reduce the costs of the system. The heat exchanger design specifics that are used in cost calculations are summarized in Exhibit 4-22. The chemical engineering cost analysis methods from Ulrich et al. [21] were used to calculate the total capital cost of the heat exchangers. The method uses the heat exchanger area, the pressurization side and materials used at each section.

Exhibit 4-22. Heat exchanger specifics and capital cost calculations

Calculated Specs	Values
Heat Exchanger Area (total)	2,906 ft^2
Shell Side Pressure	72 psi
Tube Side Pressure	290 psi
Pressurization Side	Shell Side
Shell Flow	Molten Salt
Tube Flow	Steam
Shell Material	Carbon Steel
Tube Material	Stainless Steel
Capital Cost ($-2021)	**$147,996**

4.2.3.5 Discharging Steam Turbine

During the discharging process, the generated steam from the molten salt TES usually has significantly lower pressure than the steam admittance pressure to the high-pressure steam turbine.

For the example CHP plant configuration, the superheated steam used for charging is the steam used by the high-pressure steam turbine. During the charging process the steam turbine will be shut down and all of the superheated steam will be used for charging of the molten salt TES. The steam that will be generated by the molten salt system during discharging has the pressure that corresponds to the saturation temperature that is at least 54°F less than the saturation temperature of the charging steam. The charging and discharging steam conditions for the example plant are compared in Exhibit 4-23.

Exhibit 4-23. Charging and discharging steam properties

Parameter	Charging Steam to HPT	Discharging Steam to HPT
Temperature	600 psi	350 psi
Pressure	755 °F	750 °F
Flowrate	10.57 lbm/s	13.38 lbm/s

Steam turbines typically have a degree of flexibility in terms of admittance pressures and temperatures. However, the amount of pressure reduction from the charging to discharging steam is significantly high for a typical steam turbine admittance flexibility limit. Therefore, a small capacity steam turbine was decided to be used with 700 kW power size in place of the high-pressure section of the existing 3-pressure level steam turbine. The exit flow from the small capacity turbine is designed such that it will be within the limits of the intermediate pressure steam turbine's steam admittance limits.

The specifics of the discharging steam turbine are calculated by using the steam turbine model developed at NETL in the previous part of this study [1]. An Environmental Protection Agency (EPA) study for CHP plant cost items [31] was used to estimate the total installed cost of the discharging steam turbine. The study lists total installed costs for typical steam turbine sizes used in CHP plants, ranging from 500 kW to 15 MW. The turbine power output is used in linear scaling from the cost data [31] to obtain the capital cost of the discharging steam turbine. The turbine specifics and the capital cost are presented in Exhibit 4-24.

Exhibit 4-24. Discharging steam turbine specifics and capital cost calculation

Specifics	Values
Steam Turbine Type	Single Pressure
Pressure Ratio	0.574
Exit Temperature	616 F
Power Output	700 kW
Capital Cost ($-2021)	**$684,551**

4.2.3.6 Other Cost Items

The cost items included in this category are for:

- Piping, insulation, valves, and fittings
- Foundations and structures
- Instrumentation and controls

An EPRI study for a 4,040 MWh molten salt TES designed for NETL B12A power plant integration [18] was used for these items for cost scaling. For all the indicated items, Equation 7 is used for calculating the capital costs.

$$Cost = (Ref.Cost) * \left(\frac{MWh}{Ref.MWh}\right)^{0.8} * \left(\frac{CEPCI - 2021}{CEPCI - 2014}\right) \qquad \textbf{\textit{Equation 7}}$$

The scaling exponent, 0.8, is the suggested value to be used in scaling from the indicated EPRI study. [18] The costs are then adjusted to 2021 from 2017 using CEPCI value, which is 1.09.

4.2.4 Total Capital Cost

The total capital cost of the 36 MWh molten salt TES for the example CHP plant is then calculated by summing up each cost item from Section 4.2.3. Following cost assumptions are used for the indicated items:

- Engineering, Capital Management and Home Office and Fees is 10% of the bare erected cost [18]
- Process contingency is 20% [18]

- Project contingency is 10% [18]

The indicated cost assumptions are used from the example EPRI study. [18] With the indicated assumptions, the total capital cost of the molten salt TES is calculated as shown in Exhibit 4-25.

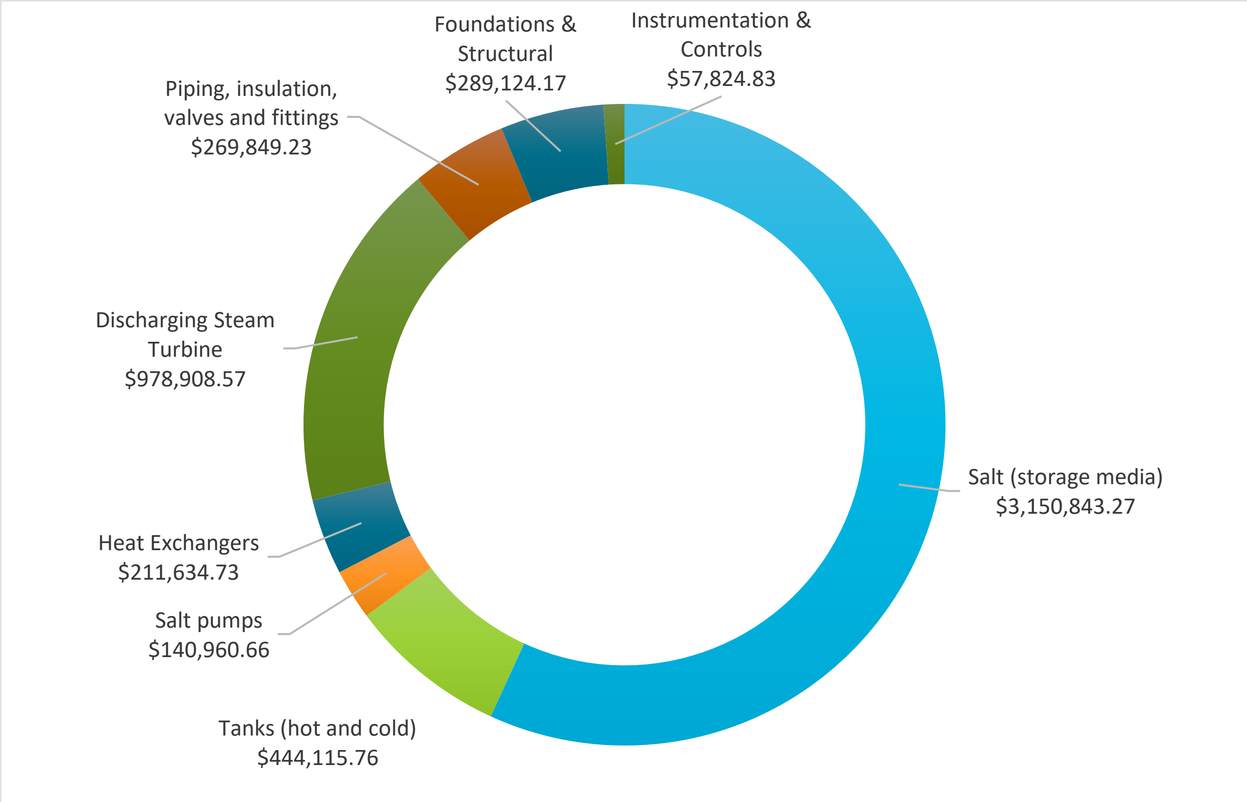
Exhibit 4-25. Molten salt TES capital cost calculation

Cost Item	Capital Cost		Contingencies		Total Cost		
	Process Facilities Capital Cost	Eng. CM H.O & Fees 10%	Process 20%	Project 10%	Cost	$/kW	$/kWh
Salt (storage media)	$2,203,387	$220,338.69	$484,745	$242,373	$3,150,843	$788	$78.7
Tanks (hot and cold)	$310,570	$31,057.0	$68,326	$34,163	$444,116	$111	$11.1
Salt pumps	$98,574	$9,857.4	$21,686	$10,843	$140,961	$35.2	$3.52
Heat Exchangers	$147,996	$14,799.6	$32,559	$16,280	$211,635	$52.9	$5.29
Discharging Steam Turbine	$684,551	$68,455.1	$150,601	$75,301	$978,909	$248	$24.5
Piping, insulation, valves, and fittings	$188,706	$18,870.6	$41,515	$20,758	$269,849	$67.5	$6.74
Foundations & Structural	$202,185	$20,218.5	$44,481	$22,240	$289,124	$72.3	$7.22
Instrumentation & Controls	$40,437	$4,044	$8,896	$4,448	$57,825	$14.5	$1.44
Total TES Cost	$3,876,406	$387,641	$852,809	$426,405	**$5,543,261**	**$1,386**	**$139**

The total capital cost in terms of $/kWh basis (kWh size is for the storage system) is calculated as 139 $/kWh, which is higher than the value used in filtering analysis (88 $/kWh). This is due to the inclusion of the discharging steam turbine (+24.5 $/kWh) in the capital cost estimations, which is usually not included in such estimations. However, the capital cost of the steam turbine consists of about 18 percent of the capital cost of the system and should not be omitted for realistic cost analysis.

The cost item distributions on the total molten salt TES cost are shown in Exhibit 4-26.

Exhibit 4-26. Molten salt TES capital cost item distributions



From the cost item distributions shown in Exhibit 4-26, the following cost items have the highest impact on the total capital cost of the system:

- Molten Salt
- Steam Turbine
- Heat Exchangers
- Salt Tanks

Reduction in the costs in either of these items does have the highest potential to reduce the overall cost. However, steam turbine and heat exchanger technologies are well established and are not specific to heat storage applications. Therefore, it is not expected that the cost of these two items could be reduced further. For the heat exchanger, using an alternative material at the shell side that is also highly resistant to molten salt corrosion could reduce the cost of this item further. Molten salt costs and salt tank costs are expected to be the more likely venues for further reducing the system costs.

4.2.5 Operation and Maintenance Costs

The EPRI study for non-battery bulk energy storage systems for fossil fuel plants, [18] indicates that the operating cost is 0.3 percent of the capital cost (annual). For the molten salt TES considered for the example CHP plant, the indicated value was used in the calculations.

5 TECHNO-ECONOMIC ANALYSIS OF THE CHP PLANT WITH ENERGY STORAGE

Cost analysis of the case study CHP plant is performed for the plant configurations with baseline and upgraded gas turbines (see Exhibit 1-1 for gas turbine details). The total capital cost of the case study CHP with the selected storage system costs are then used in calculating plant cost metrics such as the cost of electricity (COE) and payback period. The COE was calculated by using three different methodologies in order to make the results from this study comparable to the results from a wide range of studies in the literature. The following subsections include the capital cost analysis of the example CHP plant with and without the energy storage and the results of the TEA.

5.1 CHP PLANT COSTS

5.1.1 Capital Cost

Capital cost data for CHP plant items were obtained from an EPA study [31] made for different CHP gas turbine sizes ranging from 3 MW to 44 MW. In the referenced EPA study, [31] the capital costs of the CHP plant items are listed for each gas turbine size separately and based on the vendor quotes and historic price data for those items. The study also includes operation and maintenance cost estimates. The term "Total installed cost" in the reference study is the total overnight cost of the power plant and includes project contingency, financing, and development fees.

The total installed cost of the CHP plant is calculated by using Equation 8. [31]

$$\begin{matrix} Total \\ Installed \\ Cost \end{matrix} = \begin{matrix} Total \\ Installed \\ Capital \end{matrix} + \begin{matrix} Project \\ Financing \end{matrix} + \begin{matrix} Project \\ Constr. \\ and\ Mngmt. \end{matrix} + Shipping + \begin{matrix} Dvlpmt. \\ Fees \end{matrix} + \begin{matrix} Project \\ Contingency \end{matrix} \qquad \textbf{Equation 8}$$

In Equation 8, the total installed capital is calculated by using Equation 9.

$$Total\ Installed\ Capital = Total\ Equipment\ Cost + Construction\ Cost \qquad \textbf{Equation 9}$$

In Equation 9, the "Total Equipment Cost" is the sum of individual CHP plant item costs as shown in Equation 10.

$$\begin{matrix} Total \\ Equipment \\ Cost \end{matrix} = \begin{matrix} Gas \\ Turbine \\ System \\ Cost \end{matrix} + \begin{matrix} Steam \\ Cycle \\ System \\ Cost \end{matrix} + \begin{matrix} Energy \\ Storage \\ System \\ Cost \end{matrix} + \begin{matrix} Buildings \\ Cost \end{matrix} \qquad \textbf{Equation 10}$$

The Gas Turbine System Cost is calculated by using Equation 11.

$$\begin{matrix} Gas \\ Turbine \\ System\ Cost \end{matrix} = \begin{matrix} Combustion \\ Turbine\ Cost \end{matrix} + \begin{matrix} Fuel\ Delivery \\ System\ Cost \end{matrix} + \begin{matrix} Electrical\ Equipment \\ Cost \end{matrix} \qquad \textbf{\textit{Equation 11}}$$

Steam Cycle System Cost is calculated by using Equation 12.

$$\begin{matrix} Steam \\ Cycle \\ System\ Cost \end{matrix} = \begin{matrix} HRSG \\ Cost \end{matrix} + \begin{matrix} Steam\ Turbine \\ Cost \end{matrix} + \begin{matrix} SCR\ \&\ Exhaust\ Treatment\ System \\ Cost \end{matrix} \qquad \textbf{\textit{Equation 12}}$$

For the CHP plant capital cost analysis with the energy storage, the “Energy Storage System Cost” item in Equation 10 is used from the calculated capital costs for the storage systems of Section 4. It should be noted that the ESS’s project and process contingency, engineering, procurement, and construction management costs are included in the calculated ESS equipment cost. It is assumed that these contingencies include the contingencies related to retrofitting the storage systems into the CHP plant.

The equipment cost items listed for various gas turbine power ranges in the referenced study [31] are then interpolated by using the baseline and upgraded gas turbine’s power output values. The CHP plant capital costs for the plants using the baseline and upgraded gas turbines are then calculated as shown in Exhibit 5-1. Th ESS costs are used directly from Section 4.1.4 for PSBB and Section 4.2.4 for molten salt TES.

CHP Payback Analysis Tool by Energy Solutions Center (ESC) [32] is used to compare the calculated costs for the CHP plant with the baseline engine. The tool includes federal CHP Investment Tax Credit in the cost calculations, which is 10 percent of the capital project cost. The tool also estimates operations and maintenance costs. The CHP plant costs calculated in this study are compared with the ESC CHP Calculator [32] results for the example CHP plant with 15.3 MW capacity in Exhibit 5-2. The comparison was made for 100 percent capacity factor.

Exhibit 5-1. CHP plant capital cost calculations with baseline and upgraded gas turbine engines with and without ESS

Cost Components	Baseline Engine	Upgraded Engine	Baseline Engine with PSB	Upgraded Engine with PSB	Baseline Engine with Molten Salt TES	Upgraded Engine with Molten Salt TES
Net GT Capacity (kW)	12200	15184	12200	15184	12200	15184
Net ST Capacity (kW)	3200	3500	3200	3500	3200	3500
Equipment Costs ($/1000)						
Combustion Turbines	$8,940	$10,555	$8,940	$10,555	$8,940	$10,555
Electrical Equipment	$1,465	$1,524	$1,465	$1,524	$1,465	$1,524
Fuel System	$1,409	$1,575	$1,409	$1,575	$1,409	$1,575
HRSG	$1,350	$1,577	$1,350	$1,577	$1,350	$1,577
SCR, CO and CEMS	$1,198	$1,365	$1,198	$1,365	$1,198	$1,365
Building	$649	$664	$649	$664	$649	$664
Steam Turbine	$1,396	$1,524	$1,396	$1,524	$1,396	$1,524
Steam Turbine Eqp., Constr. & Building	$978	$1,067	$978	$1,067	$978	$1,067
Energy Storage System	$0	$0	$8,107	$8,107	$5,543	$5,543
Total for Equipment ($/1000)	***$17,385***	***$19,851***	***$25,492***	***$27,958***	***$22,928***	***$25,394***
Installation ($/1000)						
Construction	$4,759	$5,413	$4,759	$5,413	$4,759	$5,413
Total Installed Capital ($/1000)	***$22,144***	***$25,264***	***$30,251***	***$33,371***	***$27,687***	***$30,807***
Other Costs ($/1000)						
Project/Construction Management	$1,183	$1,289	$1,183	$1,289	$1,183	$1,289
Shipping	$308	$353	$308	$353	$308	$353
Development Fees	$1,502	$1,726	$1,501	$1,726	$1,501	$1,726
Project Contingency	$739	$826	$739	$826	$739	$826
Project Financing	$582	$728	$582	$728	$582	$728
Total Installed Cost ($/1000)	**$26,457**	**$30,185**	**$34,564**	**$38,293**	**$32,000**	**$35,729**
Installed Cost in $/kW	**2,168.58**	**1,987.97**	**2,833.10**	**2,521.90**	**2,622.95**	**2,353.05**

Exhibit 5-2. CHP plant capital cost analysis results are compared with ESC CHP calculator results

Cost Item	ESC CHP Calculator [32]	Calculated Values
Total Installed Cost	$27,209,520	$26,456,714
Operation & Maintenance Cost (Annual)	$1,608,336	$1,603,214
Average Monthly Savings (Returns)	$624,228	$608,784

The details of calculating the operation and maintenance (O&M) costs are provided in Section 5.1.2. In Exhibit 5-2, the differences between the calculations are explained as follows:

- Calculator tool uses an estimate for fuel consumption, which is higher than the baseline case values
- Calculator tools estimation for customer steam flowrate is higher than the baseline case values (customer steam flowrate is not a user input for ESC CHP Calculator)

The differences are, however, within the acceptable limits for the purposes of this study and is not expected to yield significant differences in TEA metrics.

5.1.2 Operation and Maintenance Costs

The plant operation and maintenance costs are calculated by using the listed Turbine O&M, Balance of Plant O&M, and Steam Turbine O&M costs in the reference EPA study. [31] The reference study includes O&M costs of these items on a $/kWh basis, where the power in kWh is the annual production rate from the power plant.

Linear interpolation with the gas turbine power size was made to estimate the operation and maintenance costs for the example CHP plant without the ESS. The ESS O&M costs are calculated by using the values from Sections 4.1.5 for PSBB and 4.2.5 for the molten salt TES. The results for the O&M costs are shown in Exhibit 5-3.

Exhibit 5-3. CHP plant O&M costs analysis

Cost Components	Baseline Engine	Upgraded Engine	Baseline Engine with PSBB	Upgraded Engine with PSBB	Baseline Engine with Molten Salt TES	Upgraded Engine with Molten Salt TES
Total Installed Cost ($/1000)	**$26,457**	**$30,185**	**$34,564**	**$38,293**	**$31,121**	**$34,758**
Installed Cost in $/kW	***2,168.58***	***1,987.97***	***2,833.10***	***2,521.90***	***2,550.93***	***2,289.13***
Capacity Factor	82%	82%	85%	85%	85%	85%
GT Annual Power Production (MWh)	87.635	109.069	90.841	113.06	90.841	113.06
ST Annual Power Production (MWh)	22.986	25.141	23.827	26.061	23.827	26.061
ESS Annual Power Production (MWh)	0	0	4.556	4.556	4.556	4.556
Gas Turbine O&M Rate ($/kWh)	0.0083	0.0075	0.0083	0.0075	0.0083	0.0075
Steam Turbine O&M Rate ($/kWh)	0.0090	0.0089	0.0090	0.0089	0.0090	0.0089
Balance of Plant O&M Rate($/kWh)	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031
Energy Storage O&M Rate ($/kWh)	0	0	0.0483	0.0483	0.0211	0.0235
Gas Turbine O&M-Annual ($/1000)	$794	$896	$794	$896	$794	$896
Balance of Plant O&M-Annual ($/1000)	$296	$369	$296	$369	$296	$369
Steam Turbine O&M-Annual ($/1000)	$224	$243	$224	$243	$224	$243
Energy Storage O&M-Annual ($/1000)	$0	$0	$225	$225	$96.0	$107
Total O&M-Annual ($/1000)	**$1,315**	**$1,508**	**$1,539**	**$1,733**	**$1,411**	**$1,615**

The plant capacity factor of 82 percent is determined from the business case scenario described in Section 2 and is lower than typical value of 85 percent for CHP plants because of the power purchase from the grid.

5.2 Cost of Electricity

The COE is calculated differently for CHP plants than natural gas combined cycle (NGCC) power plants due to the following:

- Steam is considered as a revenue item (a product) for CHP plants, whereas steam is consumed internally to generate electricity and is not considered an individual product for NGCC plants
- For CHP plants, some portion of the power generated can be sold to the grid; only the sold power is the revenue item (the product) whereas for the NGCC plants, all of the generated power is the revenue item (product)
- The host facility's power purchase from the grid is counted as a cost to the CHP plant

California Energy Commission [33] uses two types of COE metrics to evaluate the CHPs: total power cost ($/kWh) and net power cost ($/kWh). NETL's Levelized cost of electricity (LCOE) methodology for NGCC's can also be used in CHP evaluation with some modifications.

Formulae provided by the California Energy Commission for the net and total power costs do not include the revenues related selling to the grid or costs incurred from purchasing power from the grid. Total and net power cost and payback period calculations are modified in this study from an EPA report on CHP plants exporting and/or purchasing power from the grid. [34]

5.2.1 Total Power Cost

The total power cost formula is provided as shown in Equation 13. [33]

$$Total\ Power\ Cost = \frac{Lifetime\ Net\ Capital\ Cost + Fuel\ Cost + Operation\&Maintenance\ Cost}{Total\ Electric\ Produced\ (annual)}$$ **Equation 13**

In Equation 13, the lifetime net capital cost is the annualized capital cost of the plant over the estimated plant life. [33] The plant life is 25 years for this study. The capacity factors are used from their respective values for each case in Exhibit 5-3. Lifetime net capital cost is calculated by using Equation 14.

$$Lifetime\ Net\ Capital\ Cost = \frac{Capital\ Cost}{Total\ Plant\ Life\ (years) \times Capacity\ Factor}$$ **Equation 14**

CHP's that purchase power from the grid, the total power cost should include the purchased power cost as shown in Equation 15. [34]

$$Total\ Power\ Cost = \frac{\begin{matrix}Lifetime\ Net\\ Capital\ Cost\end{matrix} + Fuel\ Cost + \begin{matrix}Operation\&Maintenance\\ Cost\end{matrix} + \begin{matrix}Purchased\ Power\\ Cost\end{matrix}}{Total\ Electric\ Produced\ (annual)}$$ **Equation 15**

The fuel cost is calculated with Equation 16.

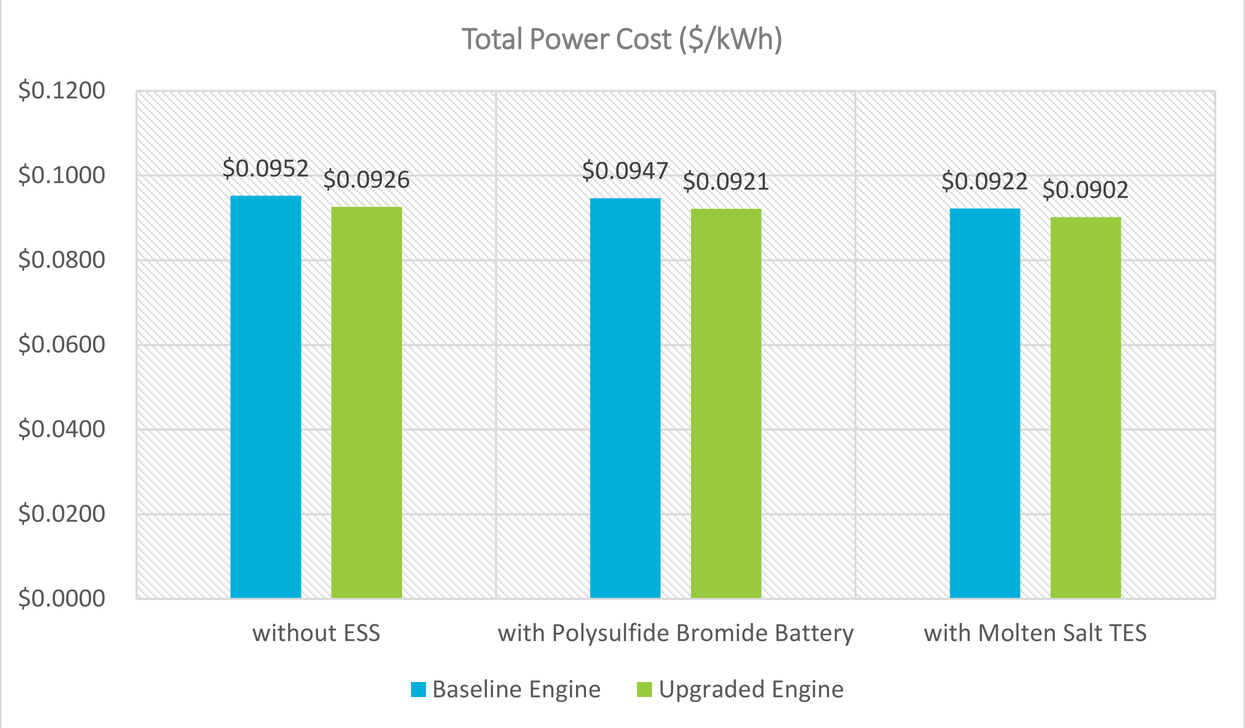
$$Fuel\ Cost = CHP\ Plant\ Heat\ Rate\ \times Natural\ Gas\ Rate \times Total\ Electric\ Produced\ (annual)$$ **Equation 16**

The CHP plant heat rate for each analysis case is calculated with the CHP plant model developed for the previous part of the study [1] and given in Exhibit 5-1. The natural gas rate is used from the business case scenario described in Section 2 as 7.73 $/MMBtu.

From the load curve data, the amount of the power purchased is calculated as 4,556,383 kWh annually. The electricity purchase price is used as 110 $/MWh [8] as detailed in the business case scenario.

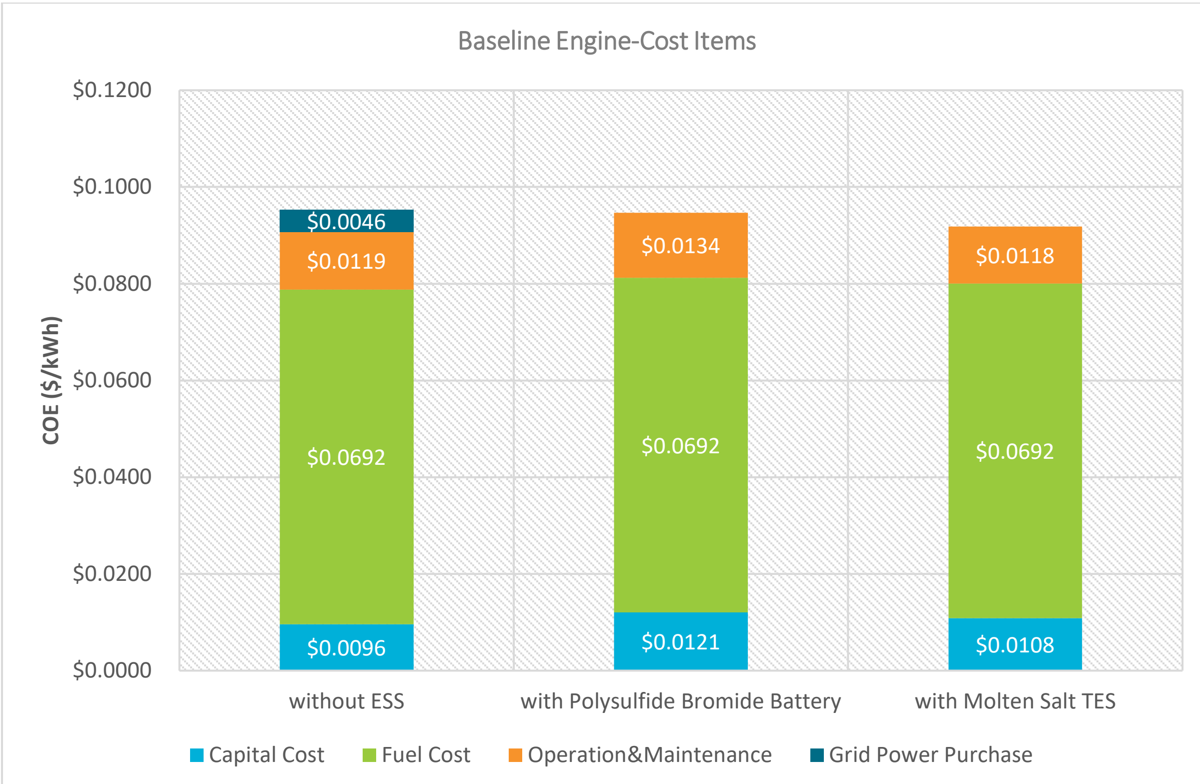
Operation and maintenance cost is used from Exhibit 5-3 for each case without and with the ESS. After the indicated cost calculations, the total power cost for each case without and with the storage are calculated. Total power costs are compared in Exhibit 5-4.

Exhibit 5-4. Total power cost comparison for example CHP plant without and with ESS



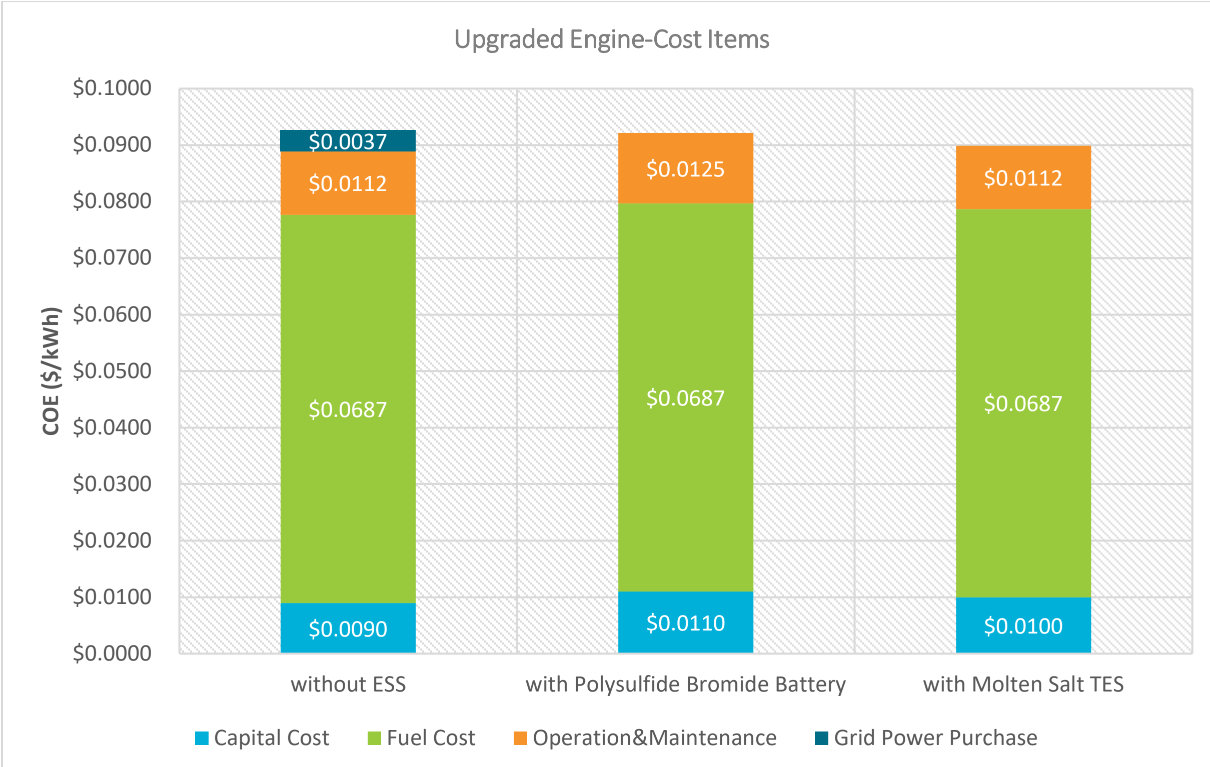
The cost items comprising of the total power cost are shown and compared for the example CHP plant featuring baseline engine without and with the ESS in Exhibit 5-5.

Exhibit 5-5. Cost item distribution for the example CHP plant featuring baseline GT



The cost items comprising of the total power cost are shown and compared for the example CHP plant featuring upgraded engine without and with the ESS in Exhibit 5-6.

Exhibit 5-6. Cost item distribution for the example CHP plant featuring upgraded GT



From the cost distributions, the capital cost of the CHP plants with either of the ESS are higher; the system with the PSBB is the highest. The additional O&M costs of the molten salt TES was overcome by the increase in annual power generation and therefore did not have a significant impact on the total power cost. However, from the comparison in Exhibit 5-4, all the CHP configurations with the ESS are expected to have lower total power cost; making the use of either storage system feasible.

5.2.2 Net Power Cost

The net power cost is the total power cost less the revenue items such as the steam cost, [33] as shown in Equation 17.

$$Net\ Power\ Cost = Total\ Power\ Cost - \frac{Useful\ Thermal\ Energy}{Total\ Power\ Produced\ (annual)} \times Steam\ Cost\left(\frac{\$}{MMBtu}\right)$$ ***Equation 17***

In Equation 17, the useful thermal energy (Btu/kWh) is calculated from the total steam enthalpy of the customer steam from the plant as shown in Equation 18.

$$Useful\,Thermal\,Energy\; = (HP\;Steam\;Flowrate\left(\frac{lbm}{s}\right) \times HP\;Steam\;Enthalpy\left(\frac{Btu}{lbm}\right) + LP\;Steam\;Flowrate\left(\frac{lbm}{s}\right) \times LP\;Steam\;Enthalpy\left(\frac{Btu}{lbm}\right)$$

Equation 18

In the cost analysis calculations, the customer steam flowrates for the high- and low-pressure extractions are used from the CHP plant specifics calculated in the previous study [1] and are listed in Exhibit 5-7.

Exhibit 5-7. Customer steam parameters for net power cost calculation

Parameter	CHP Plant with Baseline GT	CHP Plant with Upgraded GT
HP Steam Flowrate	5 lbm/s	5 lbm/s
LP Steam Flowrate	3 lbm/s	4 lbm/s
HP Steam Enthalpy	1261 Btu/lbm	1261 Btu/lbm
LP Steam Enthalpy	1294 Btu/lbm	1294 Btu/lbm

The steam cost is used as 6.49 $/MMBtu from the market analysis report of the previous study. [35] For the CHP plants that sell power to the grid, the net cost formula should be as given in Equation 19 [33] (modified with sold power cost [34]).

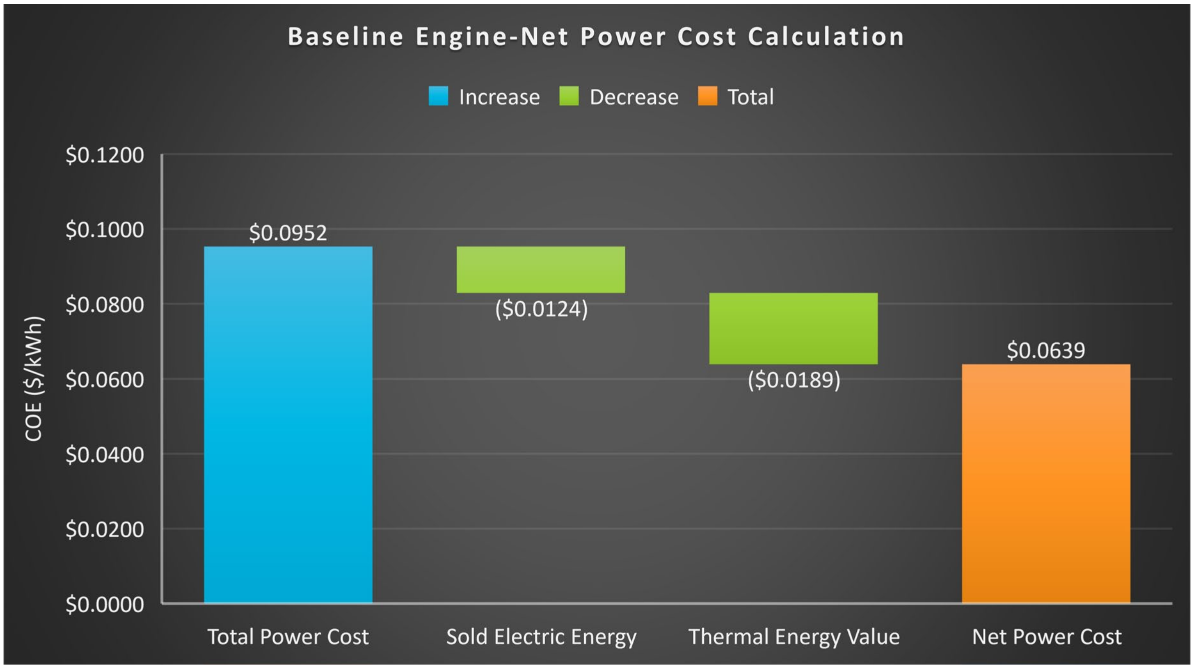
$$\begin{matrix}Net\\Power\\Cost\end{matrix} = \begin{matrix}Total\\Power\\Cost\end{matrix} - Useful\,Th.\;Energy\left(\frac{Btu}{kWh}\right) \times Steam\;Cost\left(\frac{\$}{MMBtu}\right) - \begin{matrix}Sold\\Power\\Cost\end{matrix}\left(\frac{\$}{kWh}\right)$$

Equation 19

Sold power cost depends on the power purchase agreement between the CHP plant and the grid. An average sold power cost of 0.035 $/kWh is used in the net power cost calculations. (See details in Section 2.2)

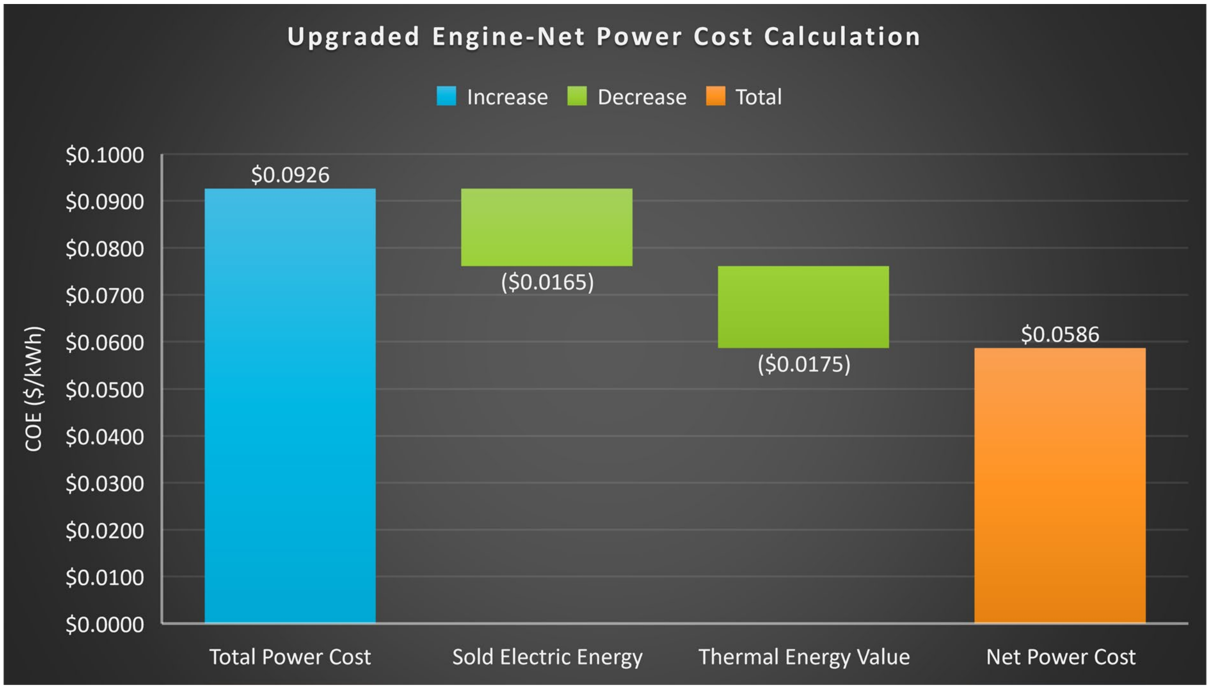
The net power cost is obtained by subtracting the CHP revenue items from the total power cost. The weights of each revenue item in the net power cost calculation for the CHP plant with baseline engine are shown in Exhibit 5-8.

Exhibit 5-8. Net power cost calculation process is shown for the CHP plant with the baseline engine (without ESS)



The weights of each plant revenue item in the net power cost calculation are shown for the CHP plant with the upgraded engine in Exhibit 5-9.

Exhibit 5-9. Net power cost calculation process is shown for the CHP plant with the upgraded engine (without ESS)

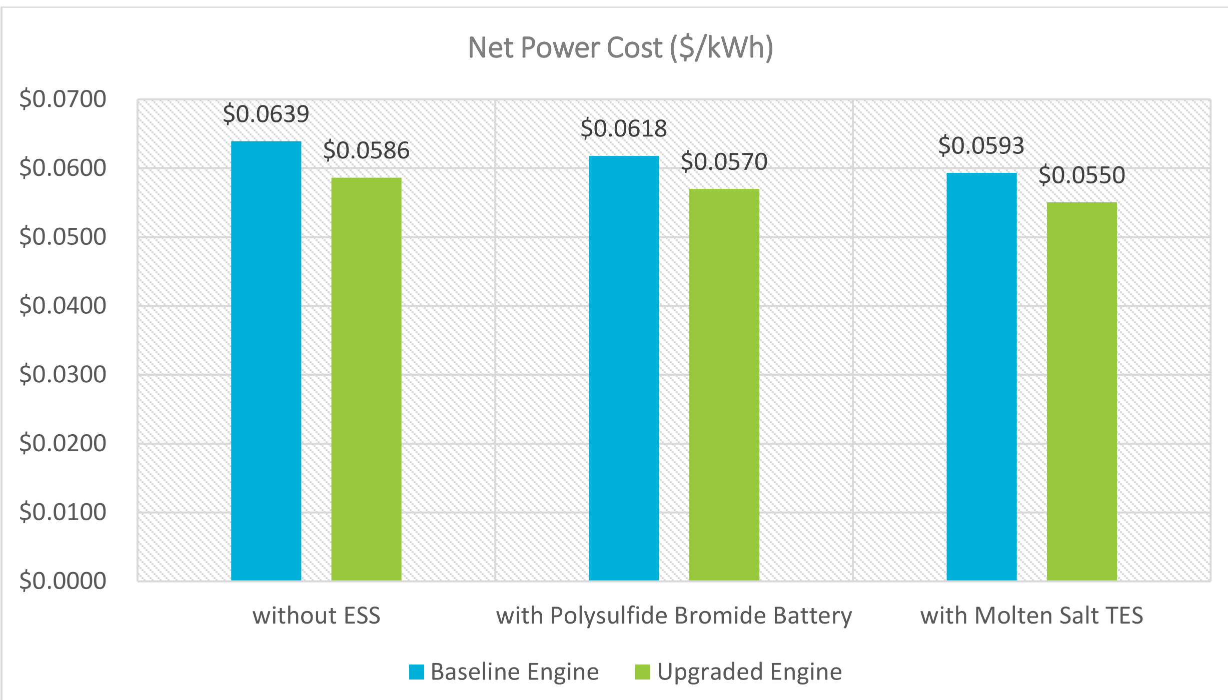


Comparing the revenue item weights in the net power cost calculations for the baseline and upgraded engine shows that the sold electric energy revenue is much higher for the upgraded engine. This is because of the higher power output from the upgraded engine and having more excess power that can be sold to the grid.

Since the main purpose of the example CHP plant is to generate power and steam generation is a secondary product, the example CHP plant with the upgraded engine is designed to use the steam mostly for power generation. The customer steam flowrate of the plant using the upgraded engine therefore has not significantly increased from the baseline values. Hence, the thermal energy revenue is lower for the upgraded engine case than the baseline case, but the net power cost is considerably lower for this case as the power sold revenues are increased.

The net power cost is calculated for the cases with the ESS as well. The results are compared in Exhibit 5-10 for both engine cases.

Exhibit 5-10. Net power cost calculation is compared for the systems without and with the ESS



From the results in Exhibit 5-10, the net power costs are reduced with the usage of either of the ESSs. The lowest net power cost is obtained for the cases with the molten salt TES because of the lower capital cost of this system as compared to PSBB.

5.2.3 Levelized Cost of Electricity

NETL has developed a COE calculation method that is intended to be used for NGCC power plants, which is similar to the total power cost calculation with additional details included on the operation and maintenance costs and the financing structure of the power plant. [36] The main difference in the method is the inclusion of the fixed charge rate and the capital recovery periods in the calculation of the capital cost. LCOE method also divides the operation and maintenance costs into two categories: variable and fixed costs. The LCOE formula for NGCC plants is given with Equation 20.

$$LCOE = \frac{FCR * TOC * CPR + \begin{matrix} Fixed \\ Operating \\ Costs \end{matrix} + Cap.\ Factor \times \begin{matrix} Variable \\ Operating \\ Costs \end{matrix}}{Cap.\ Factor \times Total\ Power\ Produced\ (annual)}$$ **Equation 20**

The total overnight cost (TOC) of Equation 20 corresponds to the “Total Installed Cost” item of this study. For the example CHP plant, the FCR and CPR factors are used from the three-year financing structure described in Quality Guidelines for Energy System Studies Methodology [36] and used in this study as 0.0707 and 0.063, respectively.

Usage of the LCOE formula developed for NGCC plants for a CHP plant directly might result in erroneous results because of the differences in the revenue items. The LCOE formula was modified in this study to include the CHP revenue items such as the steam cost and sold power cost. The modified formula used in this study is given with Equation 21.

$$LCOE = \frac{FCR * TOC * CPR + \begin{matrix} Fixed \\ Operating \\ Costs \end{matrix} + Cap.\ Factor \times \begin{matrix} Variable \\ Operating \\ Costs \end{matrix} - \begin{matrix} CHP \\ Revenues \end{matrix}}{Cap.\ Factor \times Total\ Power\ Produced\ (annual)}$$ **Equation 21**

The CHP Revenues are the sum of the steam and power sold cost, as shown in Equation 22.

$$CHP\ Revenues = Steam\ Cost + Power\ Sold\ Cost$$ **Equation 22**

The calculation of the steam cost and the power sold costs are the same with the calculations made in net power cost calculations (Section 5.2.2). However, the calculations of the variable and fixed operating costs are made differently than the previous two methods.

The variable and fixed operating costs are scaled from NGCC cases except for the water costs. NETL Cost Performance Template for NGCC’s was used for the operational costs scaling. Operating labor per shift is estimated to consist of one skilled operator, one foreman, and one technician. Operating labor costs are then scaled by using the total installed cost of CHP plant. An example calculation for the CHP Plant with the baseline engine for the fixed operating costs is presented in Exhibit 5-11.

Exhibit 5-11. Fixed operating cost calculation for the example CHP plant with baseline engine

Operating & Maintenance Labor				
Operating Labor			**Operating Labor Requirements per Shift**	
Operating Labor Rate (base):	38.50	**$/hour**	Skilled Operator:	1.0
Operating Labor Burden:	30.00	**% of base**	Operator:	0.0
Labor O-H Charge Rate:	25.00	**% of labor**	Foreman:	1.0
			Lab Techs, etc.:	1.0
			Total:	**3.0**

Fixed Operating Costs			
		Annual Cost	
		($)	**($/kW-net)**
Annual Operating Labor:		$1,315,314	$85.410
Maintenance Labor:		$201,071	$13.057
Administrative & Support Labor:		$379,096	$24.617
Property Taxes and Insurance:		$529,134	$34.359
Total:		**$2,424,616**	**$157.443**

It should be noted that the O&M costs of the ESS are not included in the calculations shown in Exhibit 5-11. These costs are included in LCOE calculation by adding them to the fixed operating costs calculated above.

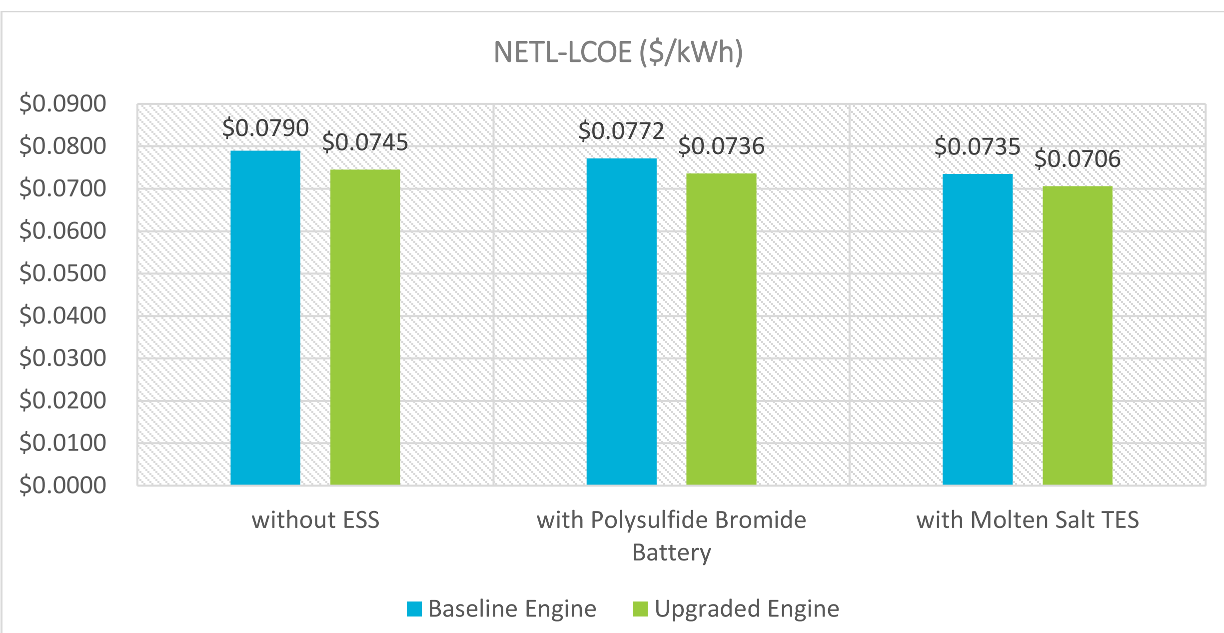
The variable operating costs are calculated as follows: water costs are directly calculated using the feedwater and makeup water flowrates from the CHP plant flowsheets in the previous part of this study. [1] The State of Michigan requires CHP plants to use exhaust filtering systems to reduce emissions such as the selective catalytic reduction system, therefore an SCR system is included in the example CHP plant's configuration. The total installed CHP plant cost also includes the SCR system cost. Ammonia and SCR catalyst rates are scaled from NGCC cases using the exhaust flowrate as the scaling variable. The exhaust flowrate for the reference NGCC case was for NETL B31A, where two F-Class gas turbines are used. An example calculation for the CHP plant with the baseline engine for the variable operating costs is presented in Exhibit 5-12.

Exhibit 5-12. Variable operating cost calculation for the example CHP plant with baseline engine

Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$301,607	$2.31680
Consumables						
	Consumption				**Cost ($)**	
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	348	$1.90	$0	$233,156	$1.79099
Makeup and Waste Water Treatment Chemicals (ton):	0	0.20	$550	$0	$39,467	$0.30317
Ammonia (19 wt%, ton):	0	0.14	$300	$0	$14,850	$0.11407
SCR Catalyst (ft^3):	230	0.13	$150	$34,517	$6,672	$0.05125
Subtotal:				$34,517	$294,145	$2.25948
Waste Disposal						
SCR Catalyst (ft^3):	0	0.13	$2.50	$0	$111	$0.00085
Subtotal:				**$0**	**$111**	**$0.00085**
Variable Operating Costs Total:				**$34,517**	**$595,862**	**$4.57714**

With the indicated calculations for the operating costs, the CHP revenues calculated previously, the total installed cost of each CHP plant case (including the ESS) and the annual power production rates, CHP adaptation of the LCOE calculations are performed. The results are compared for the example CHP plant without and with the ESS in Exhibit 5-13.

Exhibit 5-13. LCOE comparison of the example CHP plant without and with the ESS



Comparison of the LCOE values with typical NGCC cases show that LCOE are higher for CHPs because of their lower power output ranges. As the power output increases, such as for the case in upgrading the gas turbine, the LCOE reduces down significantly. For the cases with either ESSs the LCOE is lower than the case without the storage because of the increased power sold revenues. The molten salt TES system gives lower LCOE than PSBB because of its lower capital costs and lower operating costs.

5.2.4 Comparison of the COE Calculation Methods

In this section, a comparison of the three COE calculation methods was made and with some COE calculators available in the open literature.

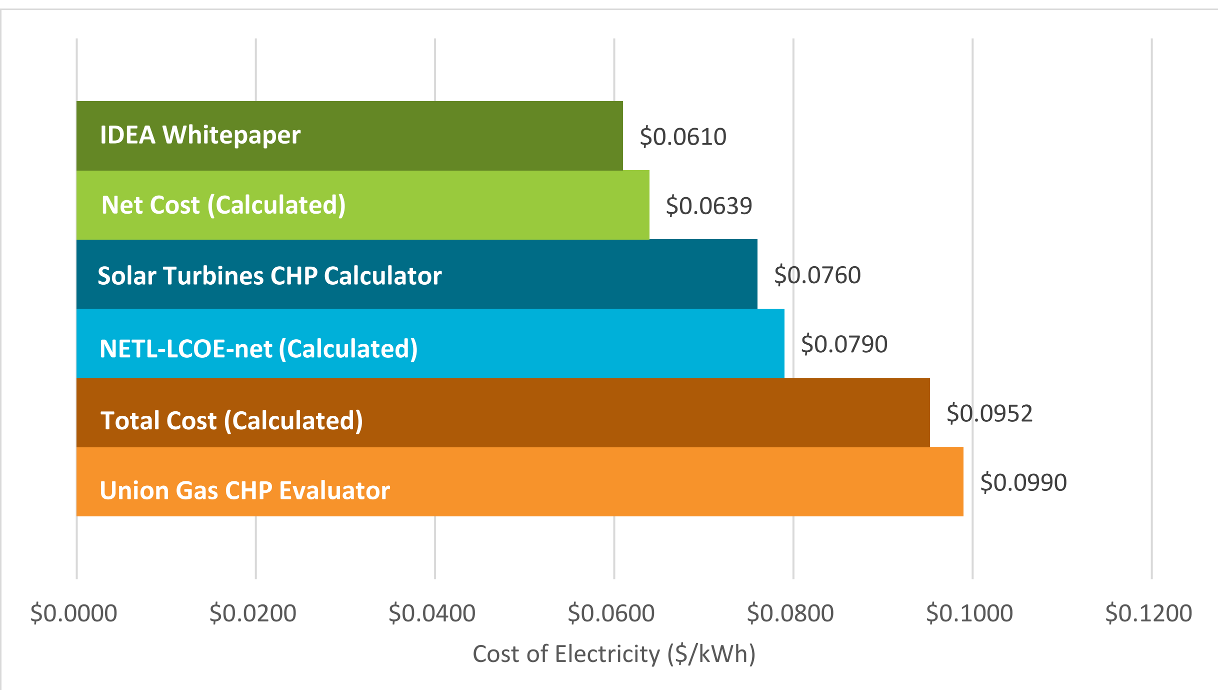
Modified NETL LCOE calculation method calculates higher COE than net power cost method even if it includes the CHP revenues.

CHP calculators from open literature are used to compare COE for the baseline case from the following resources:

- Union Gas CHP Evaluation Tool [37]
- Solar Turbines Cogeneration Calculator [38]
- International District Energy Association Report [39]

Total and net cost calculations are in between the open literature estimations, making the results obtained in this study comparable to the other CHP studies. The comparison of the COE calculation methods is presented in Exhibit 5-14.

Exhibit 5-14. COE calculation methods comparison for example CHP plant with baseline engine (without ESS)



5.3 PAYBACK PERIOD

The payback period is one of the most important and frequently used techno-economic metrics used in evaluating the CHP plants investments. It is the minimum amount of time that is required for CHP operation in order to pay off the capital investment made for building the plant. Therefore, it is desired to be as low as possible, because it also indicates the amount of time where the CHP plant will yield no net revenue.

The payback period of a CHP plant is calculated with Equation 23. [33]

$$Payback\ Period\ (years) = \frac{Capital\ Cost}{\begin{matrix}Electricity\\ Value\end{matrix} + \begin{matrix}Thermal\\ Energy\\ Value\end{matrix} - \begin{matrix}Grid\\ Power\\ Purchase\end{matrix} - Fuel\ Cost - O\&M\ Cost} \qquad \textbf{Equation 23}$$

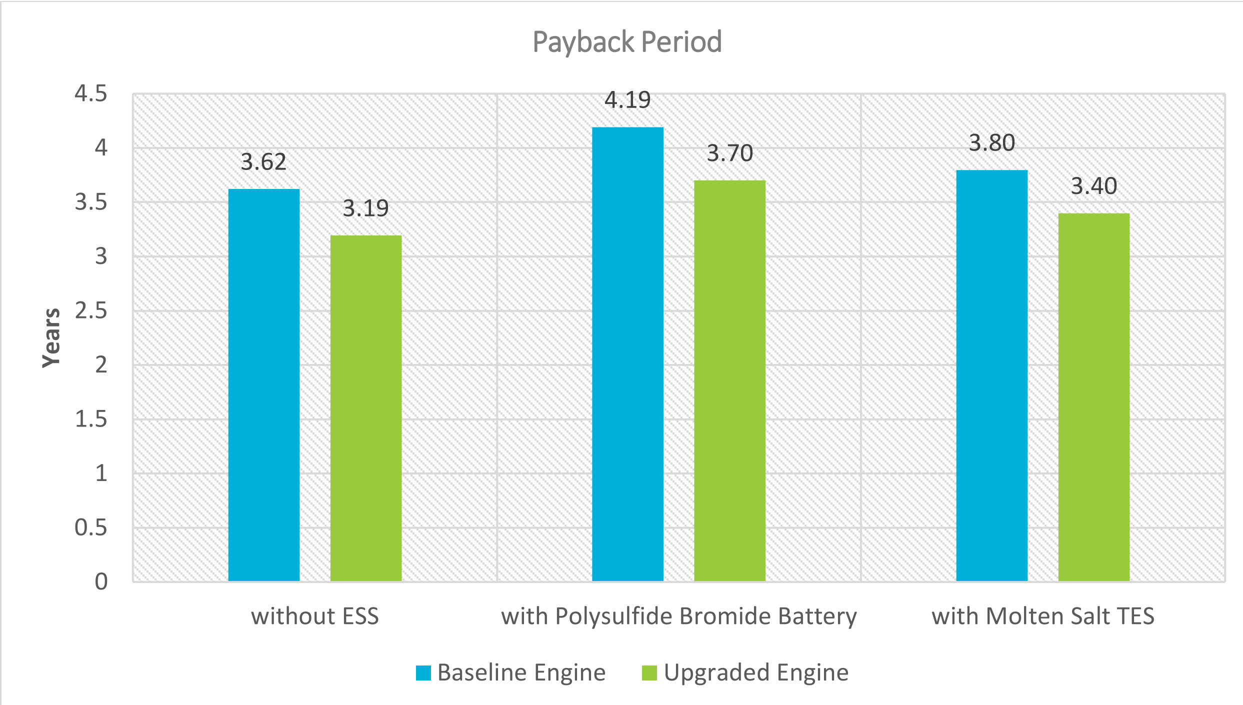
The denominator of Equation 23 is the "Annual Return." The original form of the payback period equation does not include the grid power purchase cost and power sold value; Equation 23 is modified from an EPA report. [34] With the power sold revenue included in the Annual Return, the payback period formula becomes as shown in Equation 24.

$$\begin{matrix}Payback\\ Period\\ (years)\end{matrix} = \frac{Capital\ Cost}{\begin{matrix}Electricity\\ Value\end{matrix} + \begin{matrix}Thermal\\ Energy\\ Value\end{matrix} + \begin{matrix}Power\\ Sold\\ Value\end{matrix} - \begin{matrix}Grid\\ Power\\ Purchase\end{matrix} - Fuel\ Cost - O\&M\ Cost} \qquad \textbf{Equation 24}$$

ESC CHP calculator tool [32] used to compare the results of the CHP plant capital costs and O&M costs calculated 3.6 years of payback period for the example CHP plant with the baseline engine (without ESS). The calculation for the same CHP plant case with Equation 24 gives 3.62 years of payback period.

The payback period of the example CHP plant without and with the ESS for baseline and upgraded engine cases are compared in Exhibit 5-15.

Exhibit 5-15. Payback period comparison for example CHP plant without and with ESS



The comparison of the payback period shows that the highest annual return from the baseline case can be obtained by upgrading the gas turbine due to the increase in the available electric power to be sold to the grid, therefore increasing the revenues. The cases with either ESSs increased the payback periods for the cases with either of the engines because of the increased capital cost of the plant. The annual return did not change significantly from the system without the ESS to the systems with the ESS; therefore, the driving factor in the changes of the payback period times are mostly due to the differences in the capital costs.

However, the increase in the payback period by including the PSBB in the CHP configuration is about seven months and six months for the baseline and upgraded engines, respectively. The increase in the payback period for the cases using molten salt TES is about two months for both cases. Especially for the molten salt TES it can be concluded that the payback period of the original CHP plant is not impacted by the added capital cost of this system. Even for the PSBB, an increase about 6–7 months is not a significant increase.

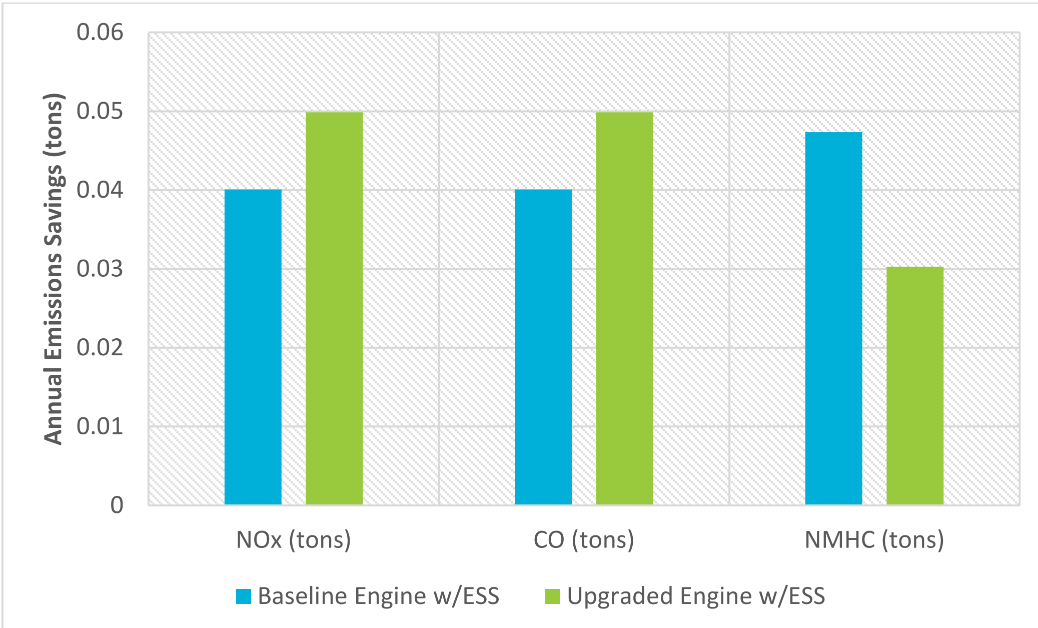
5.4 EMISSIONS

Although emissions are not directly a techno-economic metric, it is included as part of the TEA in this study because in several states the NOx and carbon dioxide (CO_2) emissions in particular can be taxed or additional fees need to be paid by the CHP plant. Therefore, reduction in the emissions by the energy storage systems can reduce the plant operating costs in the long term.

The emissions for the example CHP plant with and without the storage are calculated by using an EPA report data on various CHP gas turbine sizes. [31] Avoided emissions by using the ESS are calculated using the total power output and gas turbine efficiencies with the database in the

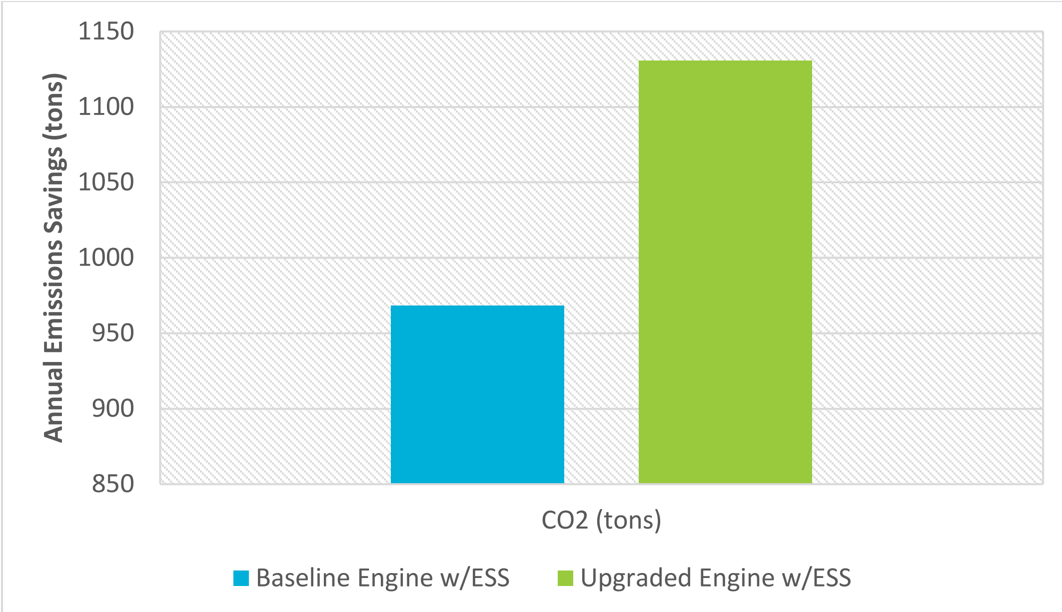
EPA report. [31] The reduction in NOx, carbon monoxide (CO), and non-methane hydrocarbons (NHMC) emissions by using the ESS from the baseline plant without ESS are compared in Exhibit 5-16.

Exhibit 5-16. Emissions reductions by using the ESSs



The reduction in the CO_2 emissions when using the ESS from the baseline plant without the ESS are compared in Exhibit 5-17.

Exhibit 5-17. CO_2 emissions reductions by using the ESSs



The results of the emissions analyses show that both storage systems will reduce the CHP plant emissions. This is because either system will not require fossil fuels to operate.

Instead of using ESS, when power is purchased from the grid, it will be mostly sourced from a plant that uses fossil fuel. The reduction in the emissions are therefore the avoided emissions from sourcing the extra power.

6 CONCLUSION

In this study, the feasibility of ESS integration to a combined heat and power plant was analyzed. A business case scenario, that would make use of the energy storage system effectively, was generated by using the data obtained from current CHP plant operators. The example CHP plant scenario is determined to be a power plant of 15.3 MW capacity with two gas turbines connected to a single HRSG unit with a 3-pressure level steam turbine. The gas turbines in the example plant are the “baseline gas turbines” of the previous CHP analysis study on improving CHP gas turbine efficiencies. [1] Per the business case scenario, a 4 MW capacity storage system is required to increase the plant flexibility to support an increase in host facility load demand and increase power sold profits to the grid company.

Energy storage system selection for the example case CHP plant was made by using a 5-step filtering process, where in each step two to three filtering criteria were used to down-select the best possible battery and non-battery energy storage systems for the case scenario. At the end of the selection process, polysulfide-bromide flow battery and molten salt TES were selected for integration.

Each of the selected ESSs were analyzed in terms of their sub-components, operation principles, and how they could be integrated to an existing CHP power plant. Capital cost items for each ESS were determined and their design specifics are identified for 36 MWh energy storage capacity. The costs of each item were then determined either by scaling from example studies from the literature or calculated by using process analysis cost calculation methodologies. The total capital costs of each ESS are then obtained and the weights of each cost item on the total capital cost are determined.

The cost analysis and integration analysis made for the PSBB showed that the highest cost items are the cell block cost and NaBr electrolyte costs. It should be noted here that the ion selective membrane used in the cost analysis of the study is not a commercialized technology, and currently commercial membrane costs are about four times higher than the membrane costs used in this study. However, low-cost membrane technology is expected to be commercialized in the near future as the energy storage systems find increased usage.

The cost analysis and integration analysis results for the molten salt TES showed that the highest cost items are the molten salt, steam turbine, heat exchangers and salt pumps. Among these possible further cost reduction items, molten salt and salt pump costs are expected to be the more likely venues for further reducing the system costs. The lower steam pressure in the molten salt TES discharge steam brought some additional system integration considerations that are overcome by using an additional low-capacity steam turbine in place of the high-pressure section of the existing steam turbine. Molten salt melting temperature related problems are not expected to happen in the example scenario, as the steam temperatures are not high enough for that condition to occur. Therefore, attemperator usage is not considered for the CHP integration, which is typically done for molten salt TES integrations to bigger power plants.

Techno-economic analysis on the example CHP plant with the selected ESS was performed and COE, payback period, and emissions reductions were calculated. For the example business case scenario, the following conclusions were determined:

- Both storage system types have the potential to reduce COE of a CHP plant
- Both storage system types are able to provide the required operational flexibility and create revenue
- Both storage system types can reduce the overall emissions
- Upgraded engine provides the lowest COE with or without the storage

Comparison of the impacts on the payback period with the ESS yields the following conclusions:

- The molten salt storage system does not increase the payback period significantly for both baseline and upgraded engine cases
- The reduction in the COE is more significant with the molten salt system
- The PSBB increases the payback period, even with the low-cost membrane
- The PSBB also has higher operation and maintenance costs

In conclusion, for the analysis business case scenario the molten salt storage system integration is the most feasible option for the CHP. The PSBB should be considered only if the molten salt system requires steam rates that would significantly reduce the CHP efficiency or cause significant disruptions to the steam supply during charging.

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