

Duke University
Durham, North Carolina

Energy Needs Analysis Final Report

Submitted by:



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1 EXECUTIVE SUMMARY

This report details the results of an energy System Needs analysis for the utilities at Duke University, which assessed the current loads and production/distribution assets, ability to recover or adjust easily to an unforeseen event or outage (resiliency assessment) and the impact of future loads on the systems. The following utility systems were assessed: Chilled Water, Steam, Hot Water, Electrical Power, City Water/Reclaim Water, and Natural Gas.

Each of the utility systems were assessed for its current ability to meeting the following System Needs:

- Utility Resiliency and Reliability
- Campus Load Growth
- Carbon Action Plan

Low carbon alternative fuel sources are considered, such as biogas and solar photovoltaics.

1.1 SYSTEM NEEDS

The following System Needs were identified to occur by the year 2025. Table 1.1 provides a summary of the major System Needs. Section 1.2 and 1.3 outline solutions to meet these needs.

EXISTING		E-W Interconnect 70,000 pph	Emergency Cooling 6,000 tons	Standby Power 5.4 MW
GROWTH	Firm Cooling 15,000 tons	Hot Water Plants 8,000 pph / year	Emergency Cooling 5,000 tons	Standby Power 4.5 MW
RESILIENCY		NCSP 30,000 pph	2 MGD NPW	Standby Power 10+ MW

Table 1.1 – System Needs Summary Matrix

Other items that are desirable for completion include:

- Eliminate the East Campus to West Campus steam and condensate interconnect pipeline.
- Provide a North Campus Steam Plant (NCSP) at North Pavilion to protect against a pipeline outage
- Create a method to shutdown West Campus Steam Plant (WCSP) in summer for maintenance
- A backup fuel or heating source is required for East Campus Steam Plant (ECSP)

- Ability to turn down WCSP below 50 kpph if other sources are available

A detailed description of the System Needs is as described below:

- Cooling
 - **Load Growth:** The historical peak chilled water (CHW) load of 39,200 tons is expected to grow to nearly 60,000 tons. The firm campus chilled water capacity System Needs to be increased by approximately 15,000 tons.
 - **Power Outage:** Approximately 14,000 tons of chilled water capacity are currently on standby power systems for emergency chilled water production, but the emergency chilled water load is estimated to be 20,000 tons and will grow by another 5,000 tons. Additional standby power systems or other means of meeting emergency chilled water load are required with 6,000 tons needed now and another 5,000 tons needed by 2025.
 - **City Water Outage:** On-site non-potable water (NPW) reclamation systems provide approximately one million gallons per day to the chilled water system for cooling tower makeup via the reclaim pond and future water hub, but the demand on peak days will total two million gallons by 2025. A city water disruption will require all but the emergency cooling loads to be shed if there is not another source of one million gallons per day non-potable water.
- Heating
 - **Aging Infrastructure:** Steam Boilers 4 and 5 at the West Campus Steam Plant (WCSP) are nearing the end of their reliable life. A recent condition assessment of Boilers 4 and 5 suggest they should last at least ten years, but by 2025 with the expected load growth they will be the only means of redundant heating capacity. Boilers 4 and 5 can only fire on No 2 fuel oil.
 - **Aging Infrastructure:** The East Campus to West Campus steam and condensate interconnect is aging, wastes energy and requires significant investment to continue service. This pipeline currently provides up to 80,000 pph capacity from East Campus Steam Plant (ECSP) to loads on West Campus. Since the East Campus back-up fuel (propane) system is non-functional, the interconnect also provides heating fuel redundancy from oil-fired equipment at WCSP to loads on East Campus. It is estimated that \$10 million capital investment will be required over the next decade to keep the line in service, and \$350,000 per year in steam plant cost is lost each year due to heat loss because of degraded insulation integrity along the two-mile path.
 - **Single-Point Failure:** The North Pavilion is connected to a single steam and condensate pipeline without any local backup supply and it is not feasible to add a second pipeline to the area across Erwin Rd.

- **Aging Infrastructure:** The base West Campus summer steam load exceeds the capacity of the East Campus to West Campus steam and condensate interconnect, making it very difficult to ever schedule complete shutdowns for WCSP to modify or repair systems that are not fully redundant. Currently, to shut down WCSP during the summer, the campus load shedding plan must be enacted which requires significant time and attention from operations personnel, along with coordination with and impact to building occupants.
- **Load Growth:** The 2017 trended hot water system peak hourly load is 11,300 MBH, but additional conversions are planned on West Campus that will exceed the capacity of Hot Water Plant (HWP) 1, and conversions are planned on East Campus that will require a new separate hot water plant. By 2025, two or three additional hot water plants will be required.
- **Natural Gas Outage:** The WCSP fuel oil storage tank has a useable capacity of approximately 225,000 gallons of No. 2 fuel oil, which can only sustain less than three peak heating days or four 80% heating days (including campus load growth) in the event of a natural gas system outage. If six tanker truck deliveries of 6,500 gallons each can be added to the storage tank per day, then nearly a week of peak heating days can be sustained without natural gas. If the natural gas system outage lasted longer than a week, the six tanker truck deliveries per day will sustain the emergency heating loads indefinitely if the load shed plan is enacted.
- **Natural Gas Outage:** The ECSP propane fuel system is not in service and requires \$500,000 investment to repair. If the East Campus to West Campus steam and condensate pipeline is removed, then East Campus will need to have a redundant fuel source for heating.
- **City Water Outage:** The steam system requires 230,000 gallons per day of non-potable makeup water during peak conditions with campus load growth. Combined with the chilled water system non-potable makeup water demand, the total winter condition demand is approximately 650,000 gallons per day. This is expected to be within the capacity of the on-site water reclamation systems, but the portion required for heating system makeup is not currently piped to the WCSP.
- **Power**
 - **Power Outage:** The emergency chilled water capacity shortfall of 6,000 tons now and an additional 5,000 tons in the future requires additional standby power systems. An additional 6.5 MW firm capacity needs to be installed now and additional 3.25 MW firm capacity is needed by 2025. Previous campus planning leveraged the Duke Energy CHP plant to provide this capacity.

- **Power Outage:** Research buildings are not fully backed up by standby power systems. Approximately 12 MW of new standby power capacity is required now to fully back up these buildings during a power outage. If these buildings are fully backed up, then the standby chilled water capacity increases by another 15,000 tons at peak to align with these buildings being fully operational during a power outage, requiring a total of 25.5 MW of additional standby power systems to back up critical buildings 100% of the year. By 2025, an additional 5.6 MW of standby power systems is expected to be needed to fully back up expected growth which correlates to standby chilled water capacity increasing by 9,000 tons, requiring a total of 13.7 MW of additional standby power systems to back up critical buildings 100% of the year.
- **Substation Interconnect Capacity:** The brief overcurrent excursion rating capacity of the existing interconnect between substations 2 and 3 is 8.52 MVA, which is insufficient for Substation 2 to carry the total existing load of Substation 3 if both Substation 3 transformers are unavailable. This issue worsens when accounting for load growth at Substation 3.
- **Substation Interconnect Capacity:** The substation 3 to substation 4 interconnect is not complete.

Category	Cooling	Heating	Power
Load Growth	15,000 tons	2-3 Hot water plants	
Power Outage	11,000 tons Emergency CHW		20 MW Standby Power
City Water Outage	1 million gpd	230,000 gpd	
Natural Gas Outage		ECSP propane system is non-functional WCSP fuel oil tank will only last 3-4 days	
Single-point Failures		North Pavilion relies on single pipeline	
Substation Interconnect Capacity			SUB 2/3 Interconnect is undersized SUB 3/4 Interconnect is not complete
Aging Infrastructure		East-West Steam and Condensate Interconnect	

Category	Cooling	Heating	Power
		Boiler 4,5 near end of life	

Table 1.2 – System Needs Summary Matrix

1.2 OPTIONS AND CHALLENGES

There are several solutions that could be implemented to satisfy the System Needs identified previously. The basic description of these options is as noted below:

Separate Heating and Colling (SHC) – Business as usual case, with separate heating and cooling plants, plus continuous duty central generating plant for standby power System Needs.

Combined Heat and Power (CHP) – Simultaneous generation of heat and power to meet a large portion of the standby power System Needs as well as heating System Needs. Provide separate chillers to meet cooling System Needs.

Combined Heating and Cooling (CHC) – Simultaneous generation of heating and cooling using Heat Recovery Chillers (HRC) to satisfy heating and cooling need for a portion of campus. Additional heating, cooling and packaged generators are required to meet additional System Needs.

There are a series of limitations and challenges with these options, especially CHC for a campus wide system. These challenges include:

- CHC requires an extensive hot water distribution system to all buildings converted to hot water. Although much of this piping already exists, if large district CHC plants were to be implemented, this would require additional piping distribution, including a West-East campus interconnect to simplify operations and consolidate equipment.
- Many of the West Campus Buildings that have been converted to hot water utilizing high hot water temperatures (160°F to 180°F), due to the original selection parameters of point-of-use equipment in those buildings. Although they could be converted to a lower temperature system that is more in alignment with a highly efficient CHC system (110°F to 120°F), it would be very costly and disruptive.
- One of the keys to efficient campus thermal operation is the reduction of unnecessary simultaneous heating and cooling in the building HVAC systems. Although this can never be eliminated due to the complex and critical nature of the buildings at Duke University, it likely will not grow significantly as new buildings are brought on line. CHC relies of capturing this overlap and converting cooling loads into heating energy.
- Due to the challenges and limitations noted, the Central Campus (CC) and East Campus heating loads are best suited for the use of CHC. These systems will serve new buildings or buildings in which their heating systems will be replaced, so they will be compatible with lower temperatures of highly efficient CHC systems. Additionally, independent

systems in both these locations will eliminate the need for large bore hot water piping between the West and East Campuses.

- The east-west campus steam line interconnection results in extensive energy losses but is still required to provide bi-directional back-up heating. If this line is to be removed, additional West Campus steam production and an East Campus back-up fuel system are required.
- Boilers 4 and 5 at WCSP are nearing the end of their useful life but are currently required to meet firm capacity. Phase out should occur, but additional steam capacity must be in place before this can happen.

Based on these limitations, the following options in Figure 1-1 would be viable for meeting the capacity and resiliency System Needs:

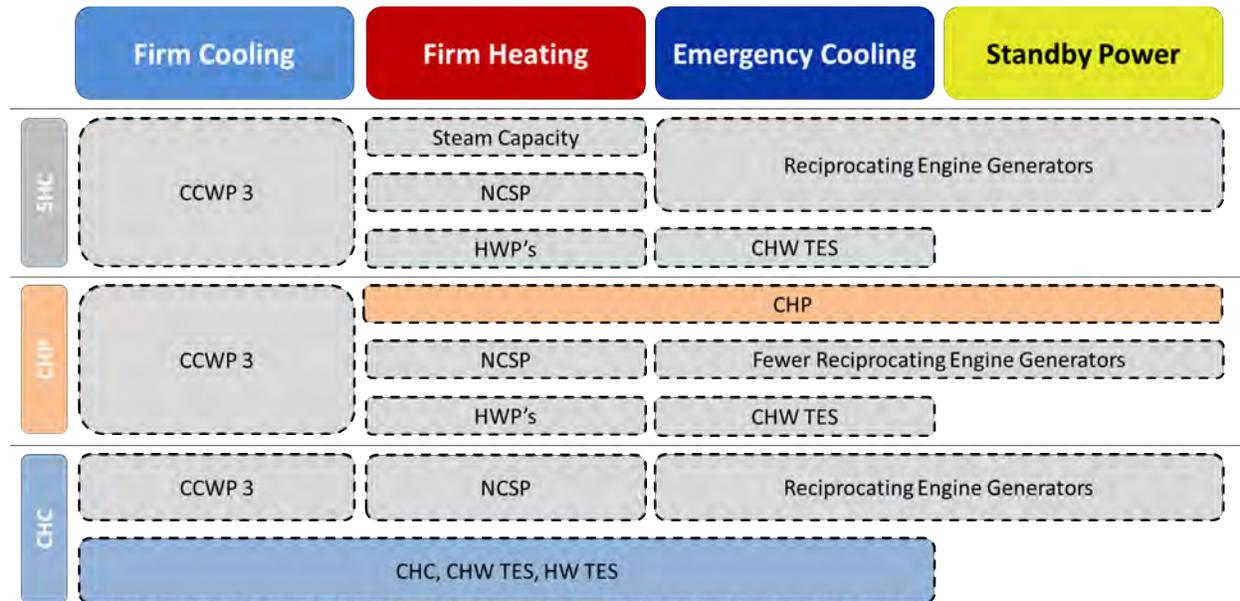


Figure 1-1 – Summary of System Needs and Recommendations with SHC, CHP and CHC

A further description of the components of the alternatives described above are:

- Cooling Options
 - Continue design and construction of Central Chilled Water Plant (CCWP) 3 with initially two 3,800-ton conventional chillers and ultimately four 3,800-ton conventional chillers. Heat recovery chillers are planned to meet the heating System Needs of the Central Campus development but can also be leveraged for 3,500 tons of peaking chilled water capacity initially and ultimately 7,000 tons of peaking chilled water capacity by providing equipment to reject surplus heating water produced.
 - Consider field-erected stratified thermal energy storage (TES) tank capacity to reduce the standby power system requirements for emergency chilled water capacity.
 - If chilled water TES is provided, the tank can also be leveraged for emergency non-potable makeup water capacity. Otherwise,

consider a two-million-gallon non-potable water storage tank to supplement the reclamation pond and water hubs in providing two peak days of makeup water capacity to the chilled water system.

- Heating Options
 - Design and construct a new North Campus Steam Plant (NCSP) in the North Pavilion area to alleviate dependency on the single steam and condensate pipeline to the area. Consider three to five modular, rapid response natural gas steam boilers to meet these System Needs. A secondary benefit of this remote steam plant would be the ability to back feed steam to the rest of West Campus during the summer to alleviate some of the WCSP load for scheduling shutdowns.
 - Abandon the East Campus to West Campus steam and condensate interconnect to avoid capital expenditures for repair and annual energy and water losses.
 - Plan for replacement of WCSP Boilers 4 and 5 with new steam capacity of approximately 80,000 pph.
 - Add steam boiler capacity to replace the capacity of the East Campus to West Campus steam and condensate interconnect and accommodate some future growth.
 - Add additional hot water plants to convert steam to hot water as buildings are converted.
 - Alternatively, add a Combined Heat and Power (CHP) system that meets standby power requirements using a Combustion Turbine Generator (CTG) and meets additional steam System Needs instead of adding additional steam boilers using a Heat Recovery Steam Generators (HRSG). Two sizes were analyzed: two 6 MW units or two 10 MW units. Additional hot water plants to convert steam to hot water are still required.
 - Continue negotiations with Duke Energy for construction of a 20 MW CHP plant that sells steam and hot water to Duke University. This plant is mutually beneficial because it relieves overload in the local utility grid for Duke Energy, while adding power resiliency and heating capacity for Duke University. It is assumed that Duke University would purchase enough biogas for use on site to generate a carbon offset equal to the regional emissions added by the Duke Energy CHP plant.
 - Alternatively, add a Combined Heating and Cooling (CHC) system that uses waste heat from the chilled water system to meet the load of the hot water system, which reduces the demand on the steam system, avoiding the need for Boiler 7 and additional hot water plants. Although there are economies of scale in combining the Central Campus hot water system with the East Campus and West Campus hot water system with a single CHC plant, the challenges previously noted make this very difficult.
 - Add non-potable water distribution from the reclamation pond and/or water hub to the WCSP. Alternatively, add a non-potable water surge tank at WCSP that would allow tanker trucks to offload makeup water during a city water outage and contract with

a water delivery company to deliver 230,000 gallons per day during peak winter conditions.

- For CHC options, use CHC at East Campus to meet primary heating and cooling System Needs.
- Power Options
 - Install a new 20 MW continuous duty central generating plant consisting of eight 3.25 MW reciprocating engine generators to power the emergency chilled water capacity, research buildings, and chilled water capacity for a portion of the remaining critical chilled water load. The exact capacity of this central generating plant will require further study, but since CHP options up to 20 MW have been analyzed, the options analysis is conducted based on each alternative having 20 MW of site generation. The cost assumptions for the central generating plant are based on Diesel fueled engines, but natural gas could also be considered as fuel at additional cost.
 - As an alternative to some or all of the new engine generator units, install an energy storage device to power the emergency chilled water capacity and the area of refuge load. Options considered include lithium-ion batteries, flow batteries, other chemical batteries, liquid air storage, or concrete block storage, among others, but thermal energy storage is the most viable option.
 - Add capacity to the substation 2 and 3 interconnect and complete the interconnect between substations 3 and 4.
 - If CHP is installed on campus, utilize planned interconnects to consolidate base load and distribute standby power.

1.3 RECOMMENDATIONS

Use this Energy System Needs Analysis as a basis for the development of a detailed Utility Master Plan that establishes the major projects, timeline, and costs for the following projects. Even though a very preliminary life cycle cost analysis with extensive sensitivity testing has been prepared comparing the options, there are still some undefined items that need to be resolved prior to developing an action plan. Therefore, the following next steps are recommended:

- **Emergency Chilled Water:** There is an immediate need to provide additional chilled water capacity to meet peak and emergency requirements. Chilled Water thermal energy storage (TES) provides the best solution to meeting emergency chilled water requirements, allowing for some operational cost savings and providing a source of water for cooling towers in the event of an extended domestic water outage. It is recommended to immediately start a study to define the TES tank location and size. This should include a chilled water TES tank connected to the chilled water system (location to be determined), as well as additional standby power generators.
- **Additional Hot Water Capacity:** There is an immediate need to provide additional hot water heating capacity for the West Campus. Implement the second steam to hot water generation plant, located at Central Chilled Water Plant 1 (CCWP 1). This would require steam and hot water distribution piping to be extended to this location, as well as the addition of a heat exchanger station. As part of this effort, modify the CCWP 1 master plan to include a site assessment which includes this heat exchanger, CHP or diesel generators, additional steam generation capacity, and/or chilled water TES.
- **North Pavilion Steam Redundancy:** There is a need to provide a redundant source of steam to the North Pavilion area due to the age and condition of the steam piping under Erwin Road and the difficulty of scheduling a preventative or reactive maintenance outage due to the impact to the operations at the facility. Immediately begin to plan and locate a small regional steam plant north of Erwin Road to serve the North Pavilion area.
- **On Campus Power Generation:** CHP alternatives provide a solution that meets both resiliency and capacity system needs with a single plant.
 - The initial arrangement of a Duke Energy owned CHP Plant would result in the greatest economic value to Duke University, but a Duke University owned plant is highly dependent on electrical rates for the purchased power. Until this is defined, detailed economic analysis of this option is not possible, although preliminary analysis indicates costs need to be close to the current electrical pricing to make this viable.
 - Advance conversations with Duke Energy to define a variable electrical rate structure if Duke University implements campus-owned power production in the form of CHP. Once a rate is established, determine the economic impact on the purchased

electricity and overall campus utilities and decide on implementation of CHP.

- **Chilled Water Capacity:** Continue with CCWP 3 design, including new conventional chillers to meet load growth and planning for future Central Campus (CC) CHC as well as additional standby power generators.
- **Potential East Campus CHC System:** The SHC and CHC options had similar economic value, although the CHC options offered energy and carbon savings and should be utilized where possible within the constraints previously described. Begin an investigative effort on East Campus to assess and review the hot water temperature limitations for the buildings and the impact on future implementation of a CHC system. Define temperature requirements and establish standards for design of the renovation of hot water heating systems in these buildings.
- **Domestic Water Backup and Storage:** Continue plans for adding a Water Hub on campus to provide reclaim water for cooling towers and possible steam make up. Evaluate domestic water storage tank in conjunction with TES.
- **Substation Interconnects:** Add capacity to the substation 2 and 3 interconnect and complete the interconnect between substations 3 and 4.

1.4 CONCLUSIONS

- Technology
 - No single technology or system approach effectively meets all of Duke University's energy needs.
 - Solutions should be tailored to the unique differences in energy needs of parts of campus.
 - Operability of selected technologies is critical to maintaining a high level of system reliability.
- Cost
 - Based on the analysis, all the options over a 30-year life cycle are within +3.1% to -1.5% of the baseline total present cost in the reference case and across all 1,260 sensitivity tests are within +10.4% to -4.0% of the baseline total present cost.
 - Annual investments can be best managed by making incremental improvements to systems versus a whole-sale implementation of a single system.
- Carbon Reduction
 - Based on the analysis, all the on-campus options are within +15% to -20% of the regional carbon emissions.
 - Only off-campus large-scale solar and methane-capture biogas can drive Duke University to carbon neutrality.

Note: the estimated savings and costs presented herein are based on historical weather data and projected system performance from previous tests and plant data. These energy values may vary widely year to year based on many factors such as weather, equipment performance, operational restrictions, etc. Therefore, the values presented herein should be used for comparison purposes only and not guarantees of actual system performance.

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5 INTRODUCTION

5.1 GOALS

The Duke Utilities and Engineering Services (DUES) goals are:

- **Safety:** Safety of Duke people, Duke systems and the Duke community is paramount
- **Reliability:** Design, install, operate & maintain systems such that they are always available and within specification to meet the critical demand of customers
- **Efficiency:** Continuously look to improve Duke systems operation to reduce cost and to minimize or reduce impact on our environment, pursuing climate neutrality in 2024 and beyond
- **Customers:** Provide timely & accurate consumption and cost information to Duke customers to support their efforts to understand utilities

5.2 PORTFOLIO

The Duke district energy system includes 229 buildings totaling 18,620,000 square feet. Cooling is provided to 123 buildings totaling 13,010,000 square feet through a network of 14 miles of underground chilled water piping up to 36" diameter supplied by two central chiller plants that have historically peaked at a load of 39,200 tons. Heating is provided to 145 buildings totaling 14,190,000 square feet through a network of underground steam piping supplied by two central steam plants that have historically peaked at a load of 331,200 pph. Power is provided to 220 buildings totaling 18,320,000 square feet through a network of underground ductbank supplied by five substations served by a redundant 44 kV utility grid owned by Duke Energy that have historically peaked at a load of 81,600 kW.

Buildings that are served include hospitals, clinics, laboratories, dormitories, classrooms, offices, libraries, athletics, assembly spaces, multiuse spaces, hotels, and vivaria.

The scale of the Duke district energy system is equivalent to over 8,000 average American households or about 10% the size of Durham.

Each of the three components of the district energy system are critical for campus operations.

- **Chilled Water System** provides building cooling, de-humidification, and process equipment cooling. Surgical operating rooms can go out of spec if chilled water supply rises more than 2°F, MRI machines cannot function without chilled water for cooling, and the East Data Center which houses medical records and critical OIT systems can see room temperature rise to 95°F in less than 30 minutes without chilled water for cooling.
- **Steam System** provides building heating, domestic hot water, humidification, de-humidification, and sterilization of surgical and lab equipment. Buildings begin seeing issues once pressure drops below 100 psig, hospitals normally have only one day supply of sterilized equipment on hand and building AHU coils can freeze in minutes without steam or hot water.

- **Power System** provides normal power for HVAC systems, lighting, equipment, computers, etc. Only portions of some buildings are provided with emergency and standby power systems.

5.3 BUDGET

The annual Duke utility budget is \$85 million. DUES pay for all new utility services to meet project System Needs and building projects pay for any relocated utilities. Utility expansion and renewal capital projects are debt financed and are recovered through the utility rates. Each utility is budgeted to pay for themselves. All rates are fixed (except electricity) for each fiscal year. All customers must pay the same rates per federal government grant requirements. Building usage is metered (mostly) and occupants pay for actual cost. DUES maintains a reserve account to cover unplanned overages.

DUES identified and implemented \$5.5M in cost reductions over the past five years. The average steam rate increase for the past three years was only 2.1% while converting and renovating plants. Operation and maintenance costs have been reduced by 23%, or \$1.7 million, since the 2009 fiscal year.

5.4 SUCCESS TO DATE

Five major measures have been accomplished since 2007:

- **Eliminated coal as fuel source** by 2011, reducing Duke carbon footprint by 11%. Refurbished, modernized, and converted to natural gas two steam plants. Improved steam system efficiency by 7%. Reorganized team redeploying 7 jobs that would have been lost.
- **Centralized chilled water production**, which improved chilled water system efficiency by 25%, reduced campus peak energy use by 11% on a normalized basis and reduced water use by 30% or 40 million gallons per year.
- **Installed Central Generating Plant** to provide emergency power to chilled water for critical facilities and to power the East Data Center.
- **Developed Hot Water Conversion** plan that will save Duke 25% in construction, maintenance, and operation costs over the next 20 years when compared with staying with steam distribution
- **Converted of 1200 site lighting fixtures to LED lamps**

5.5 CHALLENGES

Campus load growth will be explored in the next section, but even without growth there would be improvements needed in these areas of the district system:

- Cooling
 - Approximately 14,000 tons of chilled water capacity are currently on standby power systems for emergency chilled water production, but the emergency chilled water load is estimated to be 20,000 tons. Additional standby power systems or other means of meeting the remaining 6,000 tons of emergency chilled water load are required.

- On-site non-potable water reclamation systems provide approximately one million gallons per day to the chilled water system for cooling tower makeup via the reclaim pond and future water hub, but the demand on peak days totals 1.3 million gallons. A city water disruption will require some loads to be shed if there is not another source of 300,000 gallons per day non-potable water, assuming average output from the pond, assuming average output from the pond.
- Heating
 - Steam Boilers 4 and 5 at the West Campus Steam Plant (WCSP) are nearing the end of their economic life. A recent condition assessment of Boilers 4 and 5 suggest they should last at least ten years, but by 2025 with the expected load growth they will be the only means of redundant heating capacity. Boilers 4 and 5 can only fire on No 2 fuel oil.
 - The East Campus to West Campus steam and condensate interconnect is aging, wastes energy and requires significant investment to continue service. This pipeline currently provides 70,000 pph capacity from ECSP to loads on West Campus. Since the East Campus back-up fuel (propane) system is non-functional, the interconnect also provides heating fuel redundancy from oil-fired equipment at WCSP to loads on East Campus. It is estimated that \$10 million capital investment will be required over the next decade to keep the line in service, and \$350,000 per year in steam plant cost is lost each year due to heat loss because of degraded insulation integrity along the two-mile path.
 - The North Pavilion is connected to a single steam and condensate pipeline without any backup supply and it is not feasible to add a second pipeline to the area across Erwin Rd.
 - The base West Campus summer steam load exceeds the capacity of the East Campus to West Campus steam and condensate interconnect, making it very difficult to ever schedule complete shutdowns for WCSP to modify or repair systems that are not fully redundant. Currently, to shut down WCSP during the summer, the campus load shedding plan must be enacted which requires significant time and attention from operations personnel, along with coordination with and impact to building occupants.
 - The historical hot water system peak load is 11,300 MBH, but additional conversions are planned on West Campus that will exceed the capacity of Hot Water Plant 1, and conversions are planned on East Campus that will require a new separate hot water plant. By 2025, two or three additional hot water plants will be required.
 - The WCSP fuel oil storage tank has a useable capacity of approximately 225,000 gallons of No. 2 fuel oil, which can only sustain 3.6 peak heating days or four and a half 80% heating days in the event of a natural gas system outage.

- The ECSP propane fuel system is not in service and requires \$500,000 investment to repair. If the East Campus to West Campus steam and condensate pipeline is removed, then East Campus will not have a redundant fuel source for heating.
- The steam system requires 185,000 gallons per day of non-potable makeup water during peak conditions and is reliant on city water.
- Power
 - The emergency chilled water capacity shortfall of 6,000 tons requires an additional 6.5 MW firm capacity of standby power to be installed now.
 - Research buildings are not fully backed up by standby power systems. Approximately 12 MW of new standby power capacity is required now to fully back up these buildings during a power outage. If these buildings are fully backed up, then the standby chilled water capacity increases by another 15,000 tons at peak to align with these buildings being fully operational during a power outage, requiring a total of 25.5 MW of additional standby power systems to back up critical buildings 100% of the year.
 - The brief overcurrent excursion rating capacity of the existing interconnect between substations 2 and 3 is 8.52 MVA, which is insufficient for Substation 2 to carry the total existing load of Substation 3 if both Substation 3 transformers are unavailable.
 - The substation 3 to substation 4 interconnect is not complete.

6 SYSTEM NEEDS ANALYSIS

6.1 GROWTH ASSUMPTIONS

Table 6.1 below lists the planned construction projects for the next three years. North Pavilion is also listed because it was connected in fall of 2017 after the historical peak chilled water demand was recorded, so even though the building is already online, it will be added as future load for the chilled water system. After the next three years of planned construction, it is assumed the general growth will be 300,000 square feet per year.

Facility	Size (GSF)	Served by Substation	Year Online
North Pavilion	315,000		Fall 2017
Arts Building	68,000	3	2018
Trinity Dorm	48,000	3	
MSRB3	155,000	5	
Alumni Building	30,000	3	
Hollows Dorms	264,000	4	2019
Physical Therapy Building	101,000	2	
New Bedtower	250,000	2	
	250,000	2	2020
Basketball Legacy Building	26,000	4	
North Pavilion Addition	115,000	2	
Engineering Building	150,000	2	
Proton Building	75,000	5	
Future Growth	300,000/year		Beyond

Table 6.1 – Campus Growth Assumptions

A separate development is envisioned for the Central Campus area that will add up to 7,000 tons of load to the district cooling system between 2020 and 2025. The heating capacity for the Central Campus area is not planned to be connected to the district heating system. It is assumed the new construction

buildings will add cooling demand of 300 GSF/ton, heating demand of 25 Btu/hr/GSF, and power demand of 3.5 W/GSF.

All new buildings in the campus load growth are assumed to be added to the district energy system for cooling, heating, and power. There are additional renovation projects planned for buildings that are not currently on the district cooling system but will be added as part of the renovation. These buildings are listed in Table 6.2 below. It is assumed the cooling load for these buildings is less intense and only 500 GSF/ton.

Facility	Diversified Cooling Demand (tons)	Size (GSF)	Year Online
John Hope Franklin	70	33,000	Fall 2017
Smith Warehouse	410	206,000	
Southgate	100	51,000	2018
Craven Quad	250	127,000	
Crowell Quad	200	99,000	2019
Gilbert Adams	140	69,000	2020
Giles	90	46,000	2021
Alspaugh	90	46,000	2022
Pegram	90	46,000	2023
Wilson	100	48,000	2024
Brown	100	52,000	2025
Bassett	90	46,000	2026

Table 6.2 – Renovation Projects – New District Cooling Loads

6.2 SYSTEM NEEDS VS CURRENT CAPACITY

The existing district cooling system consists of two central chiller plants, CCWP 1 and CCWP 2. CCWP 1 historical capacity is 8,000 tons, but a current cooling tower replacement project will increase the capacity to 9,400 tons by 2019. CCWP 2 capacity with the final chiller installed summer of 2017 is 36,000 tons firm with a redundant capacity of 3,900 tons. A third central chiller plant, CCWP 3, is currently in design with space for four 3,800-ton conventional chillers and four 1,750-ton heat recovery chillers. The initial buildout will include two conventional chillers and two heat recovery chillers. The heat recovery chillers

will produce 120°F hot water to meet the heating System Needs of the Central Campus development. Equipment will be provided to reject surplus heat so that the cooling capacity of the heat recovery chillers can be utilized as needed for peak conditions. The historical district cooling peak demand is 39,200 tons for 13,010,000 square feet of connected buildings, but that is expected to increase to nearly 60,000 tons for over 20 million square feet by 2026. Figure 6-1 below shows the historical district cooling hourly load duration with percent of time on the horizontal axis and the corresponding load that can be exceeded for that percent of time on the vertical axis. Following, Figure 6-2 shows a histogram of the ambient enthalpy and the coincident total district cooling load at that time with the average as a solid line and the 5th to 95th percentiles as dashed lines. Finally, Figure 6-3 shows a shaded area representing the peak load growth for future years overlaid with the system capacity changes. As shown in Figure 6-3, there is potential for unmet loads in one to two years if CCWP 3 is not constructed.

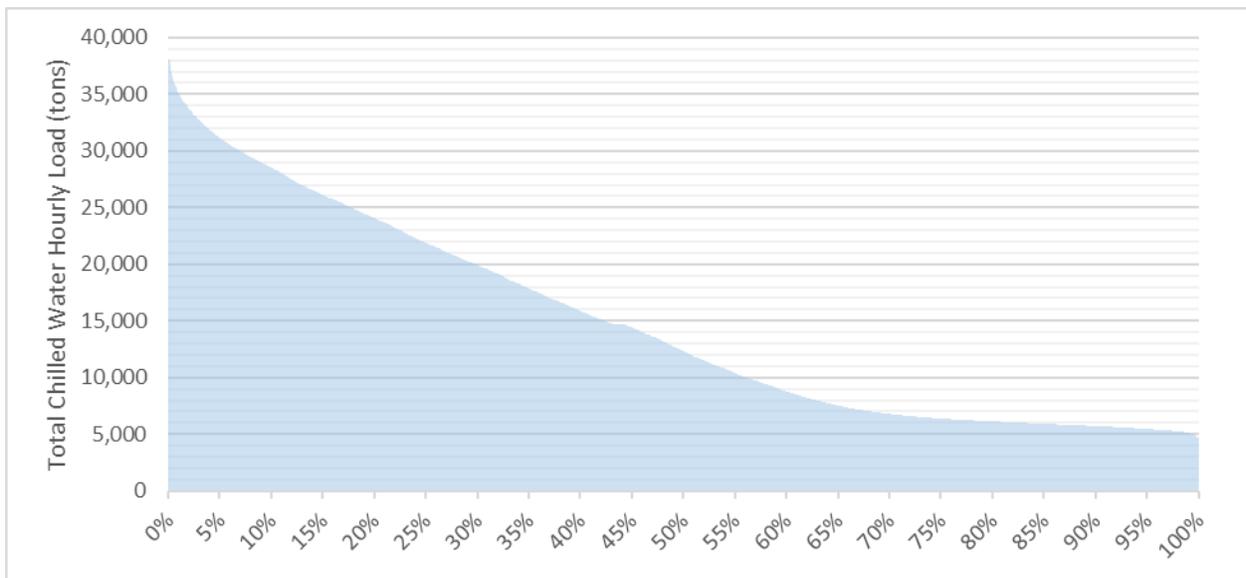


Figure 6-1 – Historical District Cooling Hourly Load Duration

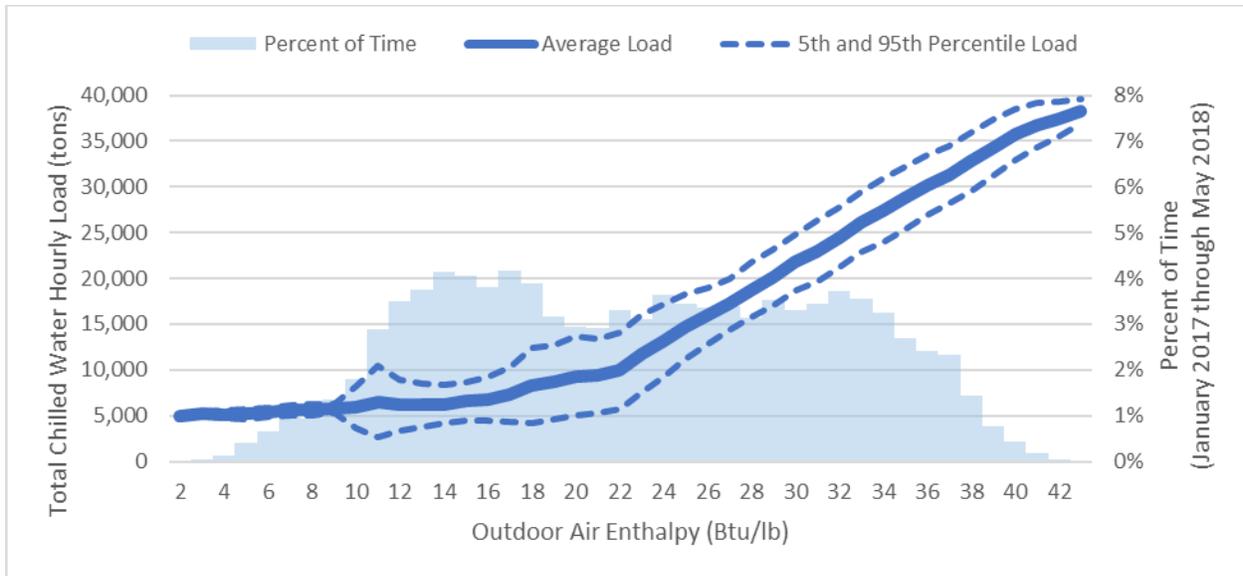


Figure 6-2 – Enthalpy Histogram with Coincident Historical District Cooling Load

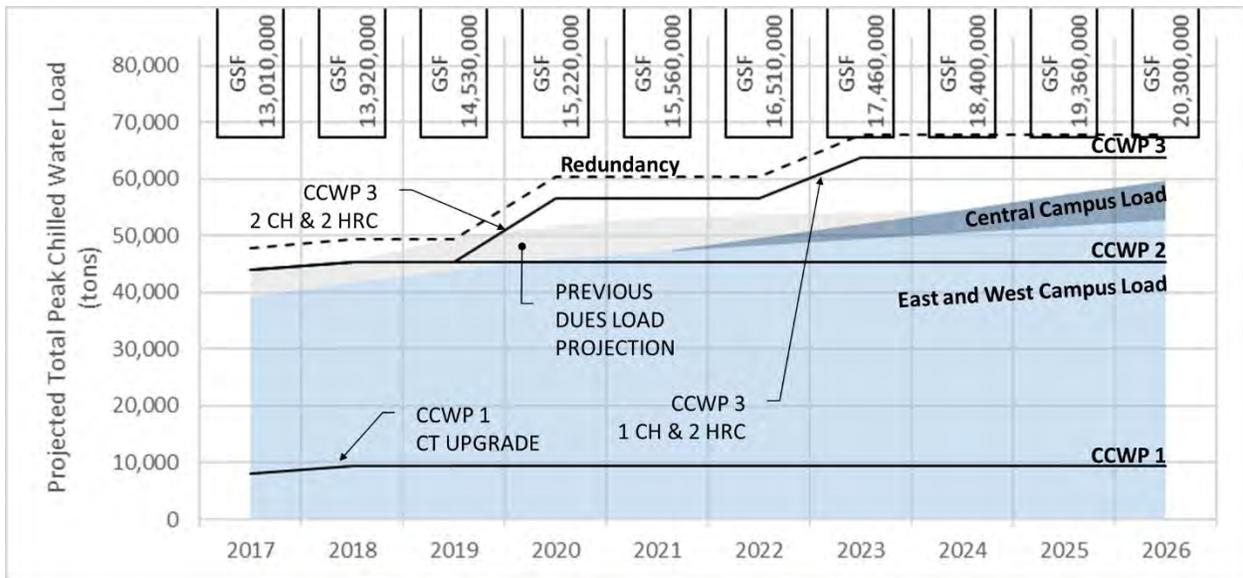


Figure 6-3 – Projected District Cooling Load and Capacity

The existing district heating system consists of two central steam plants, East Campus Steam Plant (ECSP) and West Campus Steam Plant (WCSP). ECSP capacity is 125,000 pph, but only about 90,000 pph of that capacity is useful because the East Campus load is 25,000 pph and the interconnect pipeline from East Campus to West Campus has limited capacity. The East Campus to West Campus steam and condensate interconnect is aging, wastes energy and requires significant investment to continue service. This pipeline currently provides 70,000 pph capacity from ECSP to loads on West Campus. It is estimated that \$10 million capital investment will be required over the next decade to keep the line in service, and \$350,000 per year in steam plant operating cost is lost each year due to heat, steam, and condensate losses. If the

line is abandoned, the West Campus steam capacity would be reduced by 70,000 pph. WCSP capacity is 320,000 pph firm with Boilers 4 and 5 as 100,000 pph of redundancy, but Boilers 4 and 5 are approaching the end of their economic life. The historical district heating peak demand is 331,200 pph for 14,190,000 square feet of connected buildings, but that is expected to increase to over 400,000 pph for over 17 million square feet by 2026. Figure 6-4 below shows the historical district heating hourly load duration with percent of time on the horizontal axis and the corresponding load that can be exceeded for that percent of time on the vertical axis. Following, Figure 6-5 shows a histogram of the ambient enthalpy and the coincident total district heating load at that time with the average as a solid line and the 5th to 95th percentiles as dashed lines. Next, Figure 6-6 shows a shaded area representing the peak load growth for future years overlaid with the system capacity changes. As shown in Figure 6-6, if Boilers 4 and 5 are removed by 2025, there will be a firm steam capacity shortage of 85,000 pph increasing at a rate of 8,000 pph per year. Finally, Figure 6-7 shows a shaded area representing the peak West Campus load growth for future years overlaid with the system capacity changes without the East Campus to West Campus steam and condensate interconnect. As shown in Figure 6-7, if the East Campus to West Campus steam and condensate interconnect is abandon, there will be an immediate firm steam capacity shortage that increases to approximately 100,000 pph by 2026 and increasing at a rate of 8,000 pph per year beyond that, plus additional 80,000 pph shortage when Boiler 4 and 5 are removed.

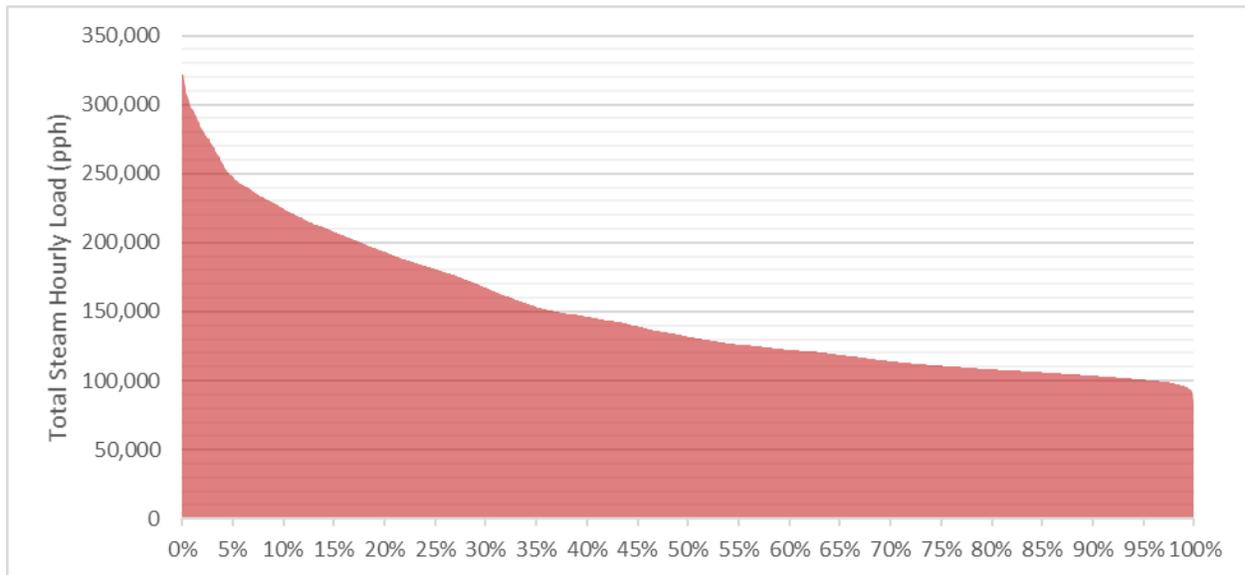


Figure 6-4 – Historical District Heating Hourly Load Duration

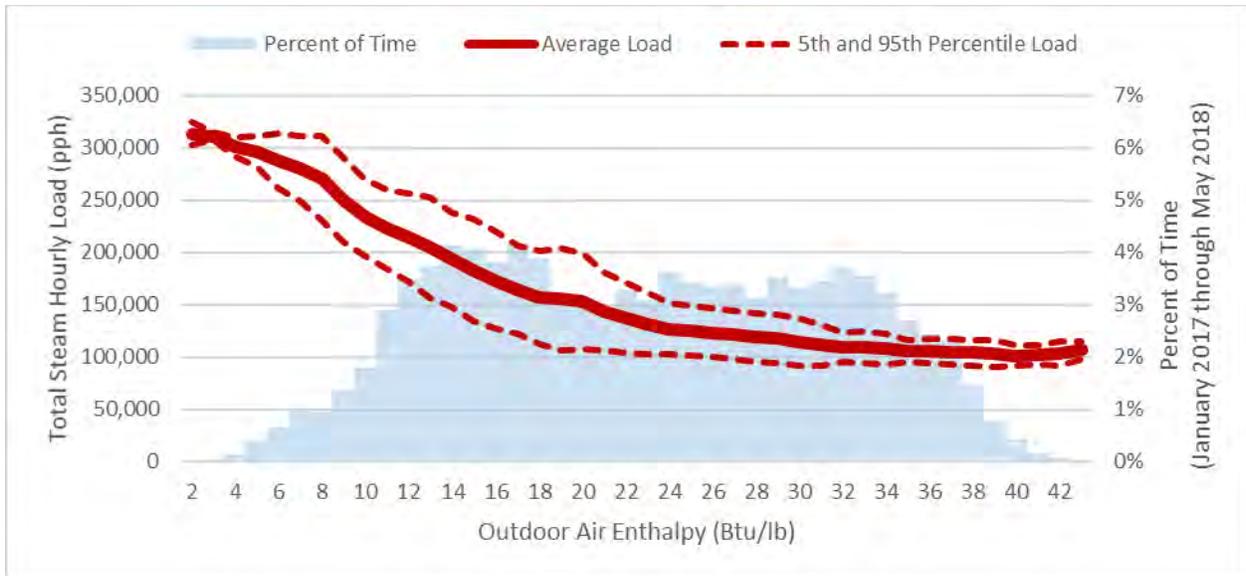


Figure 6-5 – Enthalpy Histogram with Coincident Historical District Heating Load

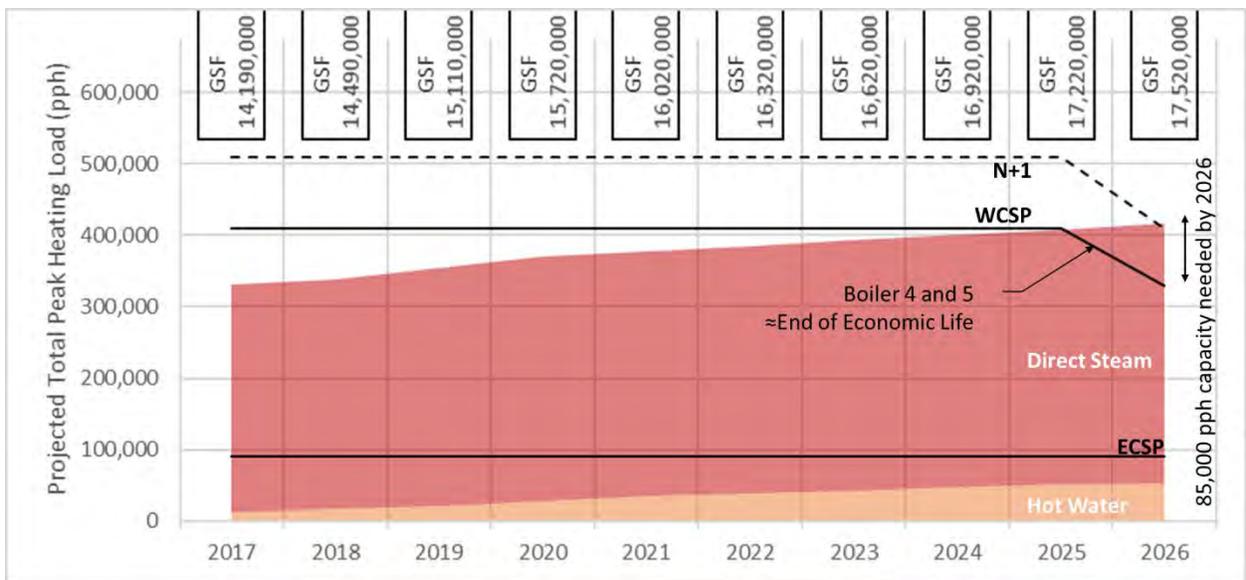


Figure 6-6 – Projected District Heating Load and Capacity

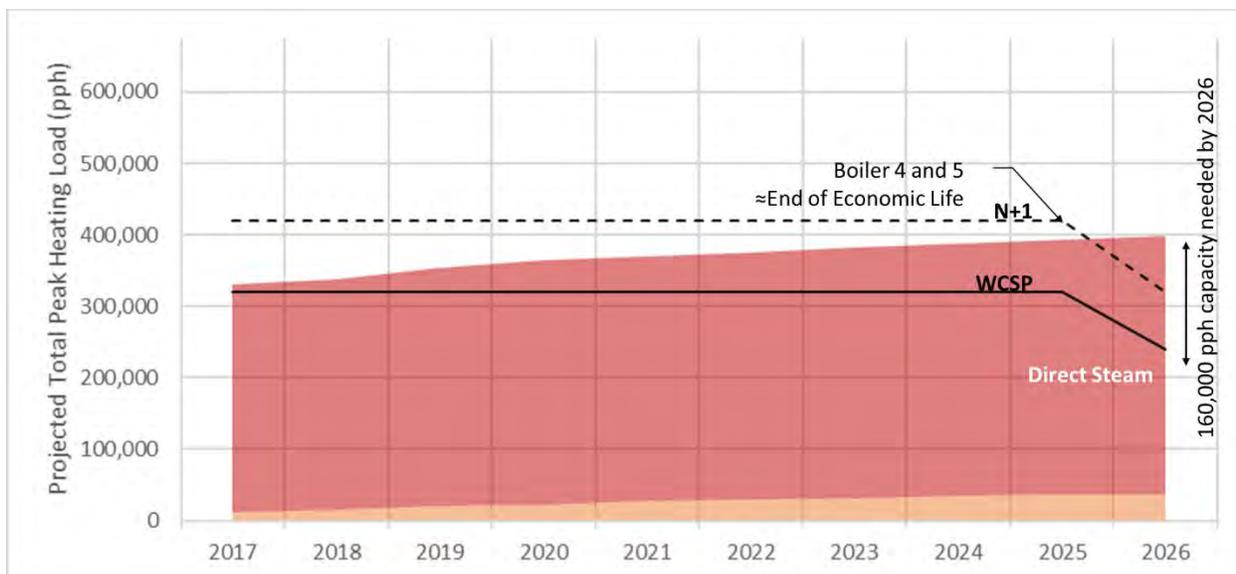


Figure 6-7 – Projected West Campus District Heating Load and Capacity without the East Campus to West Campus Steam and Condensate Interconnect

Duke has already embarked on a hot water conversion plan that will ultimately result in half of the district heating building square footage being served by a hot water distribution that is heated via three to four hot water plants with heat exchangers supplied from the district steam system. This plan will save energy by reducing steam distribution and condensate return losses, which will save operating cost, reduce regional carbon emissions by 16,000 MTCDE per year and reduce on-site non-potable water consumption by four million gallons per year. For new construction buildings and renovations, hot water is lower capital cost to install, and hot water systems are safer, lower cost to maintain, and have a longer expected life. Physical space requirements in building mechanical rooms are less for hot water mixing than for converting central steam to building hot water. The hot water conversions also open the door for other technologies to produce heating, removing the hot water load entirely from the district steam system and reducing regional carbon emissions by another 18,400 MTCDE per year and reducing on-site non-potable water consumption by another four and half million gallons per year.

The portion of district heating load planned to be converted to hot water during peak is shown in Figure 6-6 above, but some of the planned conversions are currently later than 2026. The ultimate steam to hot water conversion, and the impact to removing that portion of the steam system, is shown as a load duration curve in Figure 6-8 below. The hot water load duration curve is projected from historical data recorded at hot water plant 1 for buildings that are already converted and then extrapolated based on sizes and types of buildings that are planned to be converted in future years. As can be seen, the peak hot water load is approximately equivalent to one 80,000 pph steam boiler, so if another system produces the hot water then Boiler 7 is not required at WCSP yet. Also note the difference in shape of the steam and hot water load duration curve where the base hot water load is approximately 10% of the peak and the base steam load is approximately 25% of the peak. Some of this can be attributed to non-weather-

dependent process steam loads, but the remainder represents summer heat losses of a steam system that are avoided by a hot water system.

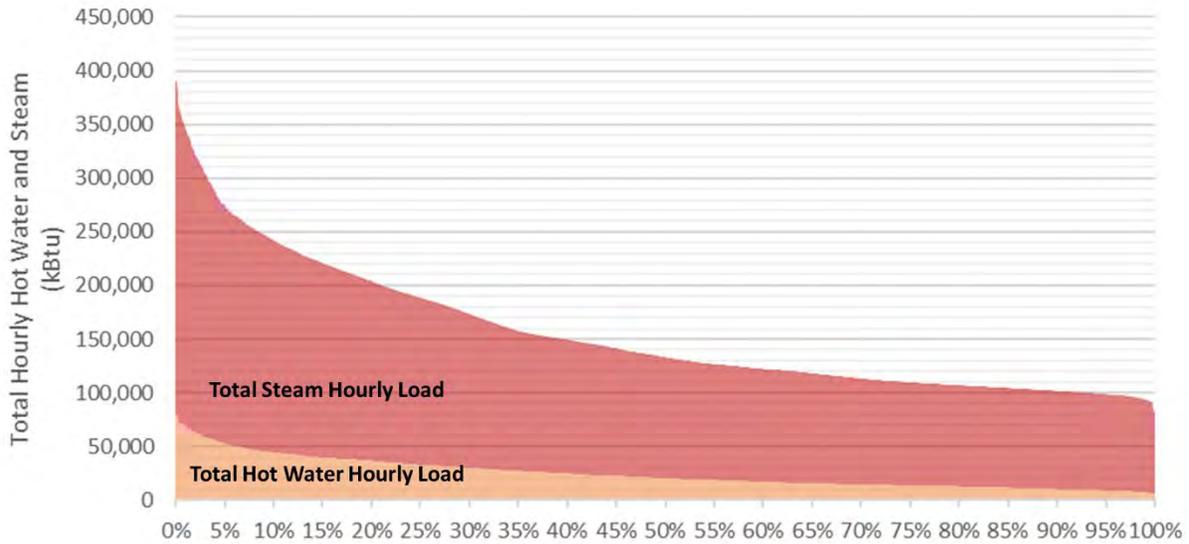


Figure 6-8 – Future Steam and Hot Water Hourly Load Duration for Planned Conversions

Both the district cooling and district heating systems have large demands for non-potable makeup water. The district cooling system requires non-potable makeup water to supply the evaporative cooling towers for heat rejection from the central chillers and peaks at a peak daily demand of 1.3 million gallons but that is projected to increase with increasing chilled water demand to 2 million gallons per day. The district heating system requires non-potable makeup water to supply the boilers in place of steam and condensate losses in the system at a peak daily demand of 185,000 gallons but that is projected to increase with increasing heating demand to 230,000 gallons per day. The peak cooling system non-potable makeup water demand occurs during the summer while the peak heating system non-potable makeup water demand occurs during the winter.

Figure 6-9 and Figure 6-10 below show shaded areas representing the peak load growth during summer and winter for the future years overlaid with the average capacity of the sustainable water project, and the water reclamation system. As shown in Figure 6-9, there is a one million gallon per day demand for city water in the future peak summer condition. As shown in Figure 6-10, there is potentially enough non-potable water available on-site for non-potable makeup water System Needs in the future peak winter condition, but that is not currently distributed from those sources to the WCSP.

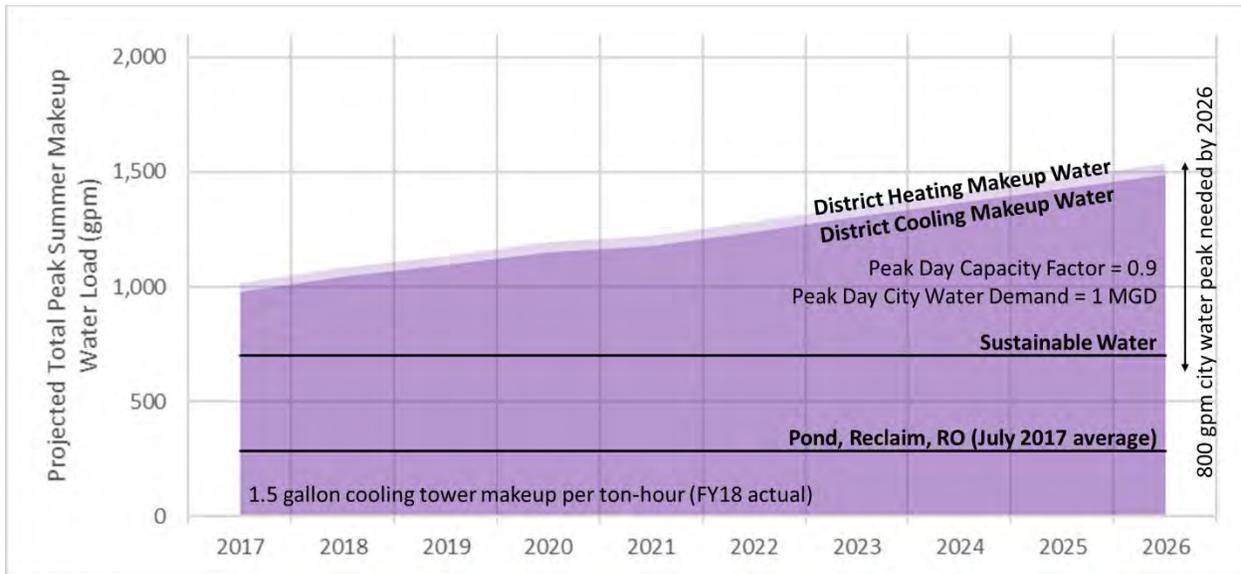


Figure 6-9 – Projected Peak Summer Non-potable Makeup Water Load

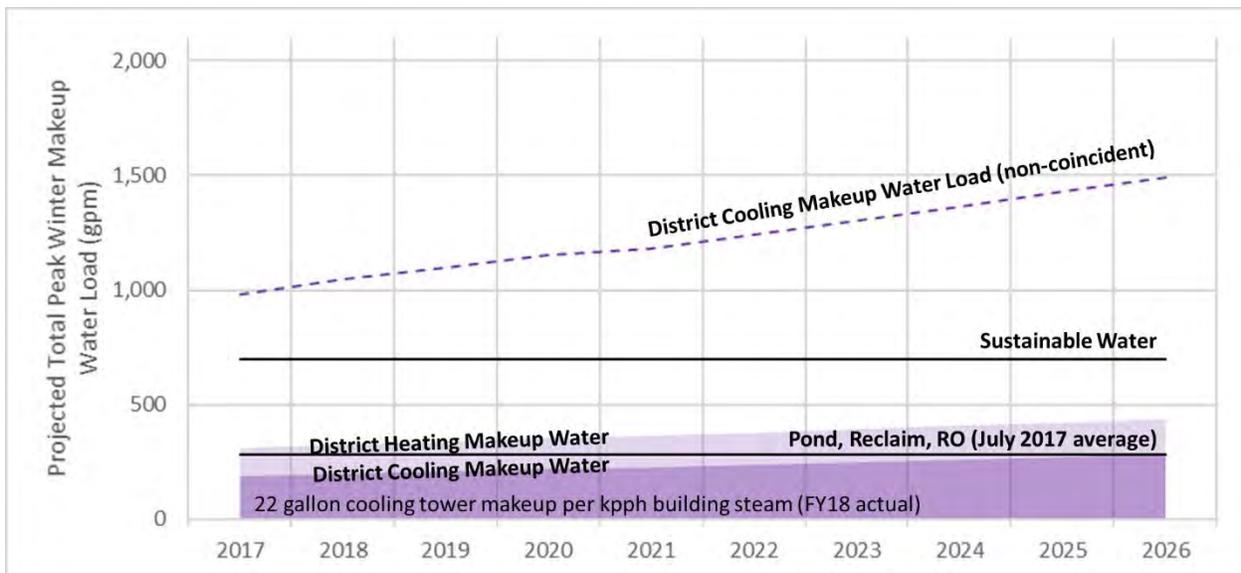


Figure 6-10 – Projected Peak Winter Non-potable Makeup Water Load

The existing district power system consists of five interconnected substations numbered one through five. Transformer capacities for each of the five substations are outlined below, along with the peak historical load:

- Substation 1
 - Bank 1 = 01408001 1 = 12 / 16 / 20 MVA
 - Bank 3 = 01408002 1 = 12 / 16 / 20 MVA
 - Total Substation Peak historical load: 10,600 kW

- Substation 2
 - Bank 1 = 12 / 16 / 20 MVA
 - Bank 2 = 12 / 16 / 20 MVA
 - Bank 3 = 12 / 16 / 20 MVA
 - Total Substation Peak historical load: 15,700 kW
- Substation 3
 - Bank 1 = 13.4 / 18 / 22.4 MVA
 - Bank 3 = 13.4 / 18 / 22.4 MVA
 - Total Substation Peak historical load: 6,100 kW
- Substation 4
 - Bank 1 = 13.4 / 18 / 22.4 MVA
 - Bank 3 = 13.4 / 18 / 22.4 MVA
 - Total Substation Peak historical load: 10,300 kW
- Substation 5
 - Bank 1 = 12 / 16 / 20 MVA
 - Bank 2 = 12 / 16 / 20 MVA
 - Bank 3 = 12 / 16 / 20 MVA
 - Bank 6 = 12 / 16 / 20 MVA
 - Total Substation Peak historical load: 40,900 kW

The historical district power peak demand is 81,600 kW for 18,620,000 square feet of connected buildings, but that is expected to increase to nearly 102,000 kW for nearly 22 million square feet by 2026. Figure 6-11 below shows the historical district power hourly load duration with percent of time on the horizontal axis and the corresponding load that can be exceeded for that percent of time on the vertical axis. Following, Figure 6-12 shows a histogram of the ambient enthalpy and the coincident total district power load at that time with the average as a solid line and the 5th to 95th percentiles as dashed lines. Finally, Figure 6-13 shows a shaded area representing the peak load growth for future years per substation.

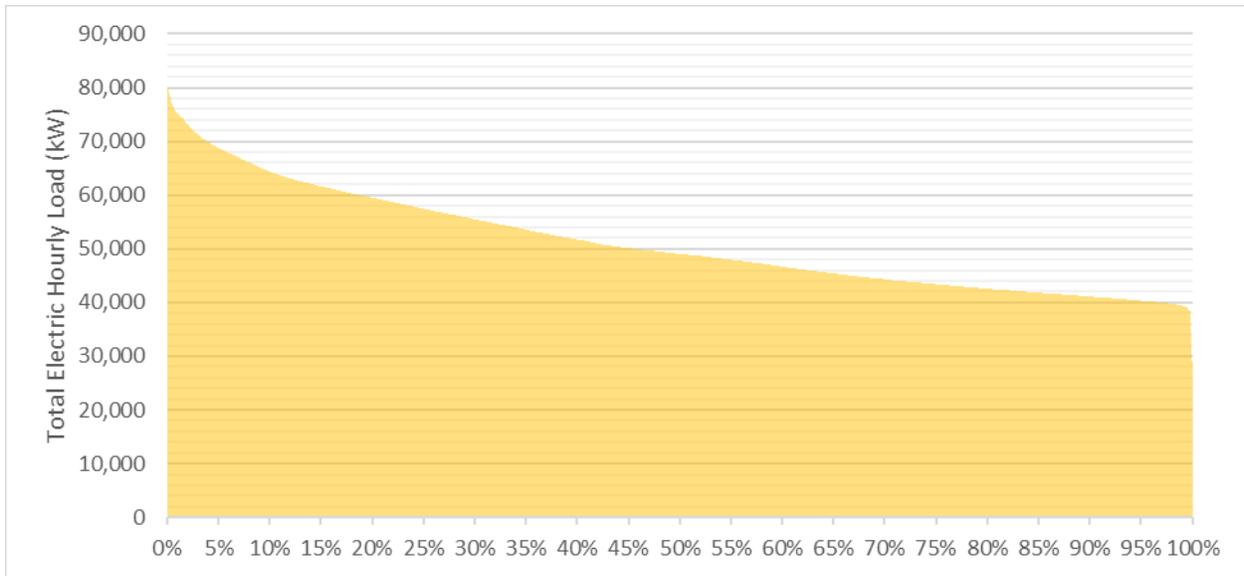


Figure 6-11 – Historical District Power Hourly Load Duration

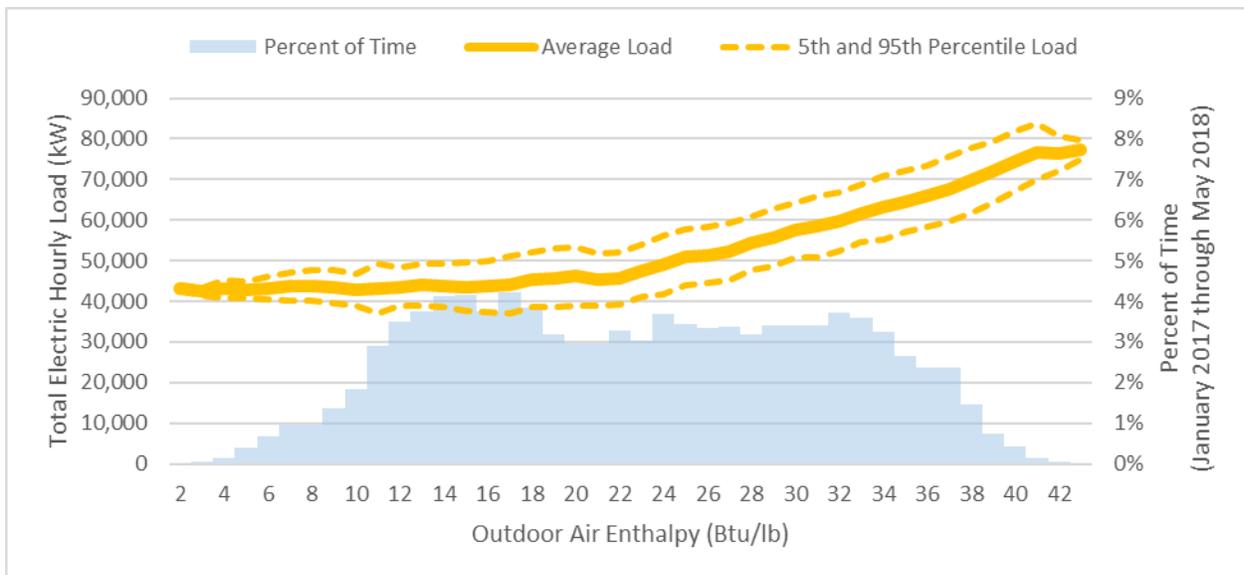


Figure 6-12 – Enthalpy Histogram with Coincident Historical District Power Load

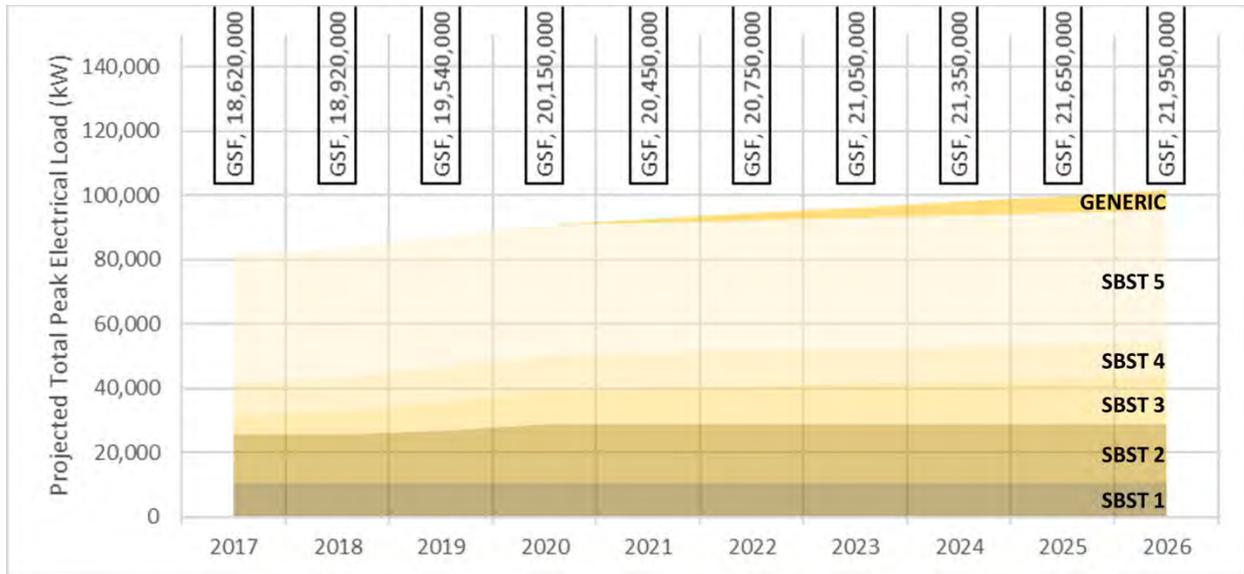


Figure 6-13 – Projected District Power Load and Capacity

The capacities of the existing and planned future campus substation interconnections are outlined below (switchgear (SGR)):

- SGR-1 TO SGR-5C
 - 1-350KCMIL Feeder
 - 7.1 MVA
 - 8.52MVA brief overcurrent excursion rating
- SGR-1 TO SGR-5B
 - 1-750KCMIL Feeder
 - 10.3 MVA
 - 12.36MVA brief overcurrent excursion rating
- SGR-1 TO SGR-2 (x2)
 - 1-750KCMIL Feeder
 - 10.3 MVA
 - 12.36MVA brief overcurrent excursion rating
- SGR-2 TO SGR-3
 - 1-350KCMIL Feeder
 - 7.1 MVA
 - 8.52 MVA brief overcurrent excursion rating
- SGR-2 TO SGR-4 (x2)
 - 1-350KCMIL Feeder
 - 7.1 MVA

- 8.52 MVA brief overcurrent excursion rating
 - SGR-3 TO SGR-4
 - Ductbank only, with dashed section installed by fiscal year 2020 or 2021

Three central generator plants, CGP 1, CGP 2 and CGP 3, produce standby power for a portion of the critical buildings and emergency chilled water. CGP 1 is located at CCWP 2 and has a capacity of 13 MW in four units to provide standby power to the East Data Center and 12,000 tons of emergency chilled water capacity. CGP 2 is located at WCSP and has a capacity of 3.25 MW in one unit with space for a second 3.25 MW unit to provide standby power to WCSP and emergency power to several other buildings in the area. CGP 3 is located at CCWP 1 and has a capacity of 3.25 MW in one unit to provide standby power for 2,000 tons of emergency chilled water capacity and emergency power to several West Campus buildings and athletics. Figure 6-14 below indicates the percentage of buildings on campus that have partial or full generator back up. This percentage includes buildings that are backed up by the central generator plants.

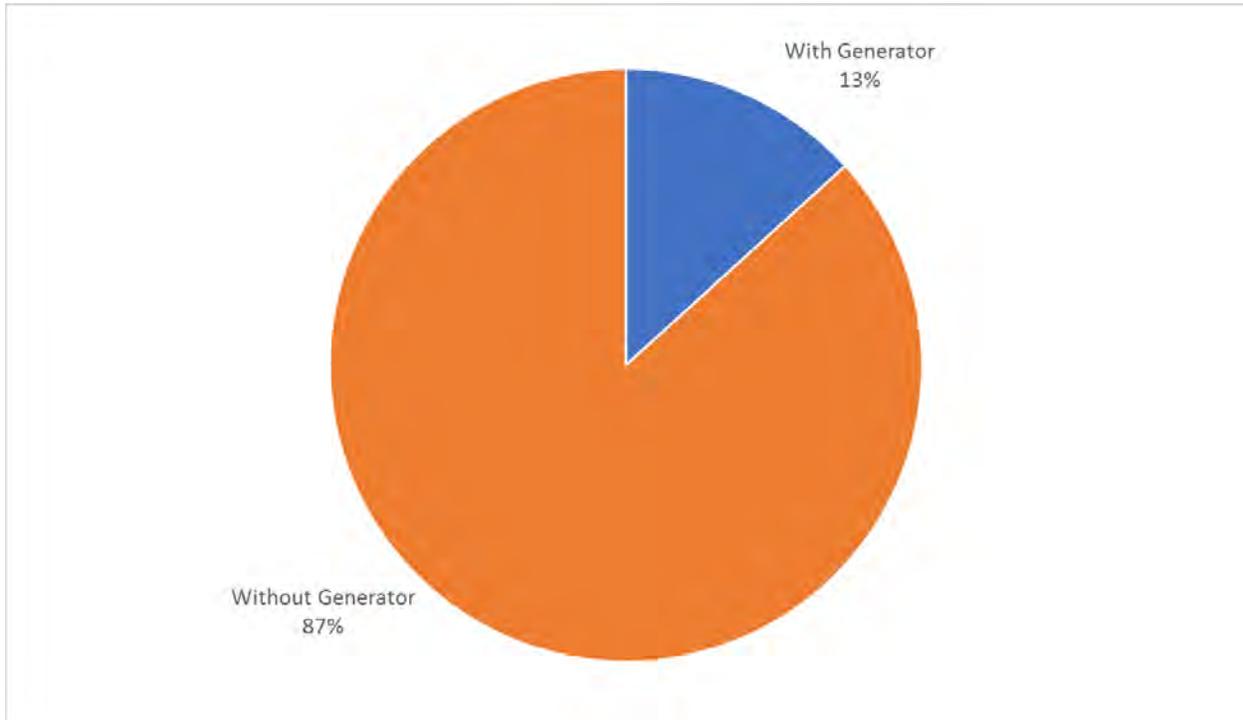


Figure 6-14 – Partial or Full Generator Backup to Buildings on Campus

Figure 6-15 below indicates the percentage of total power to Area of Refuge buildings on campus that has generator back up. The generators provide power to only 21% of these buildings' total power. It is assumed that during an extended outage to campus, these Area of Refuge buildings would need to operate at 100% load, requiring an additional 5.8 MW of generator backup.

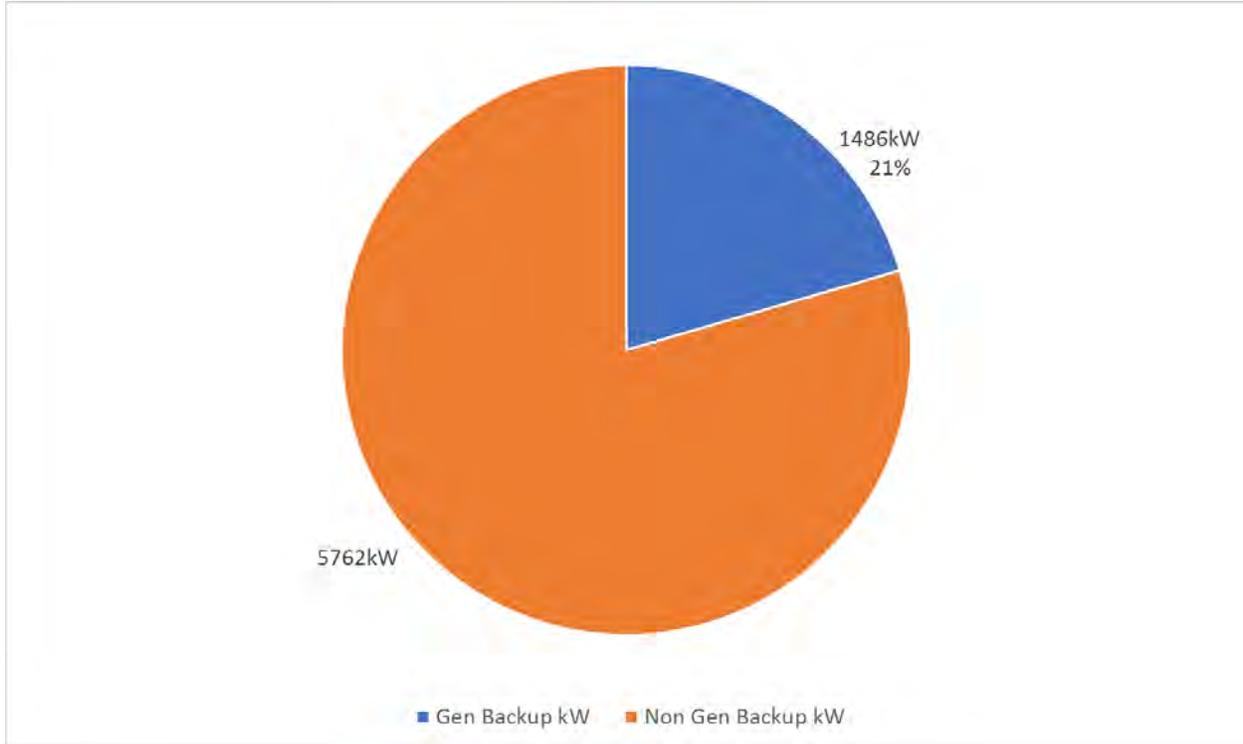


Figure 6-15 – Generator Backup to Research & Residential Buildings

Figure 6-16 below indicates the percentage of total power to critical buildings on campus that has generator back up. The generators provide power to only 37% of these buildings' total power. It is assumed that during an extended outage to campus, these buildings would operate at approximately 85% load diversity requiring an additional 12 MW of generator backup. Assuming the same percent breakdown on future buildings and at approximately 85% load diversity, by 2025 an additional 5.6 MW of generator back up is expected to be required.

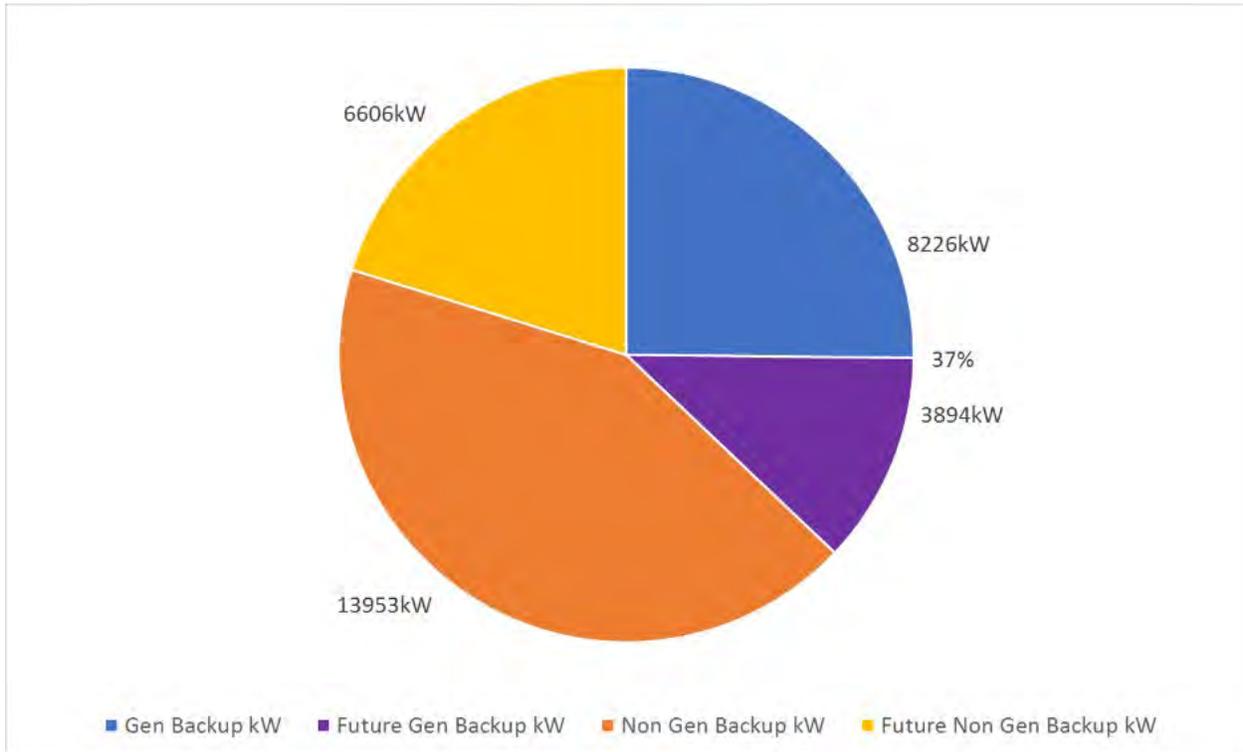


Figure 6-16 – Generator Backup to Critical Buildings

Only 14,000 tons total of chilled water capacity are provided with standby power but the peak emergency chilled water load is currently 20,000 tons and is expected to grow to 25,000 tons by 2025. Figure 6-17 below indicates the emergency chilled water for critical buildings in kW during the year and the available generator capacity to support this load. The existing generator plants CGP 1 and CGP 3 can serve the existing emergency chilled water 92% of the year. With approximately 10 MW of additional standby power, the expected emergency chilled water in 2025 would have generator back up 98.7% of the year.

Figure 6-18 below indicates the existing and future critical building load that is not currently backed up generator as well as the emergency chilled water load for these buildings in kW. Additionally, the non-emergency chilled water for these buildings is also plotted since if additional generator backup is provided to serve the total critical building load then the chilled water load for the buildings is expected to increase to normal operating levels. With approximately 20 MW of additional standby power, the expected critical buildings and their chilled water load would have generator back up 52% of the year.

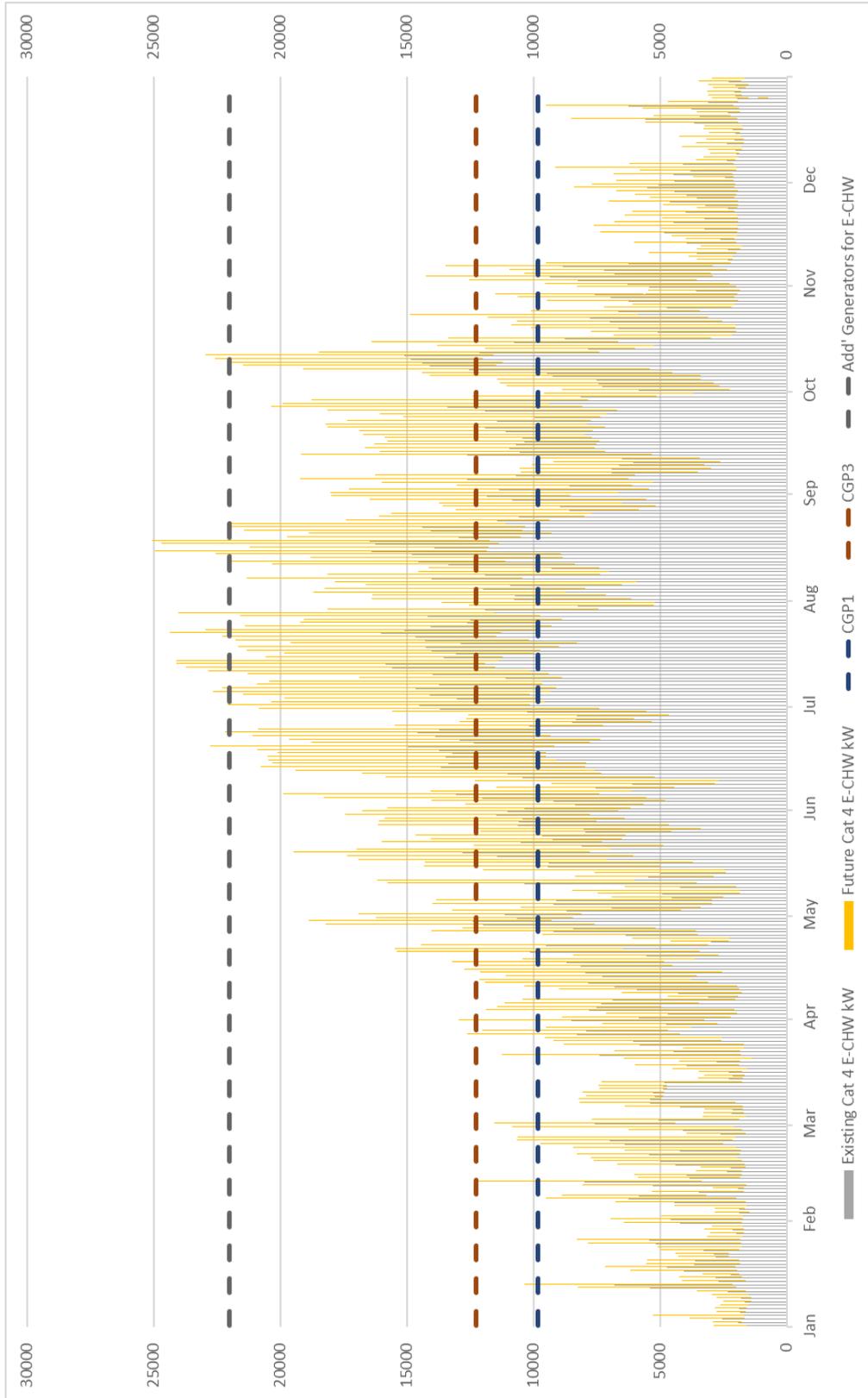


Figure 6-17 – Existing and Future Critical Building Emergency Chilled Water with Generator Backup in KiloWatts During a Year

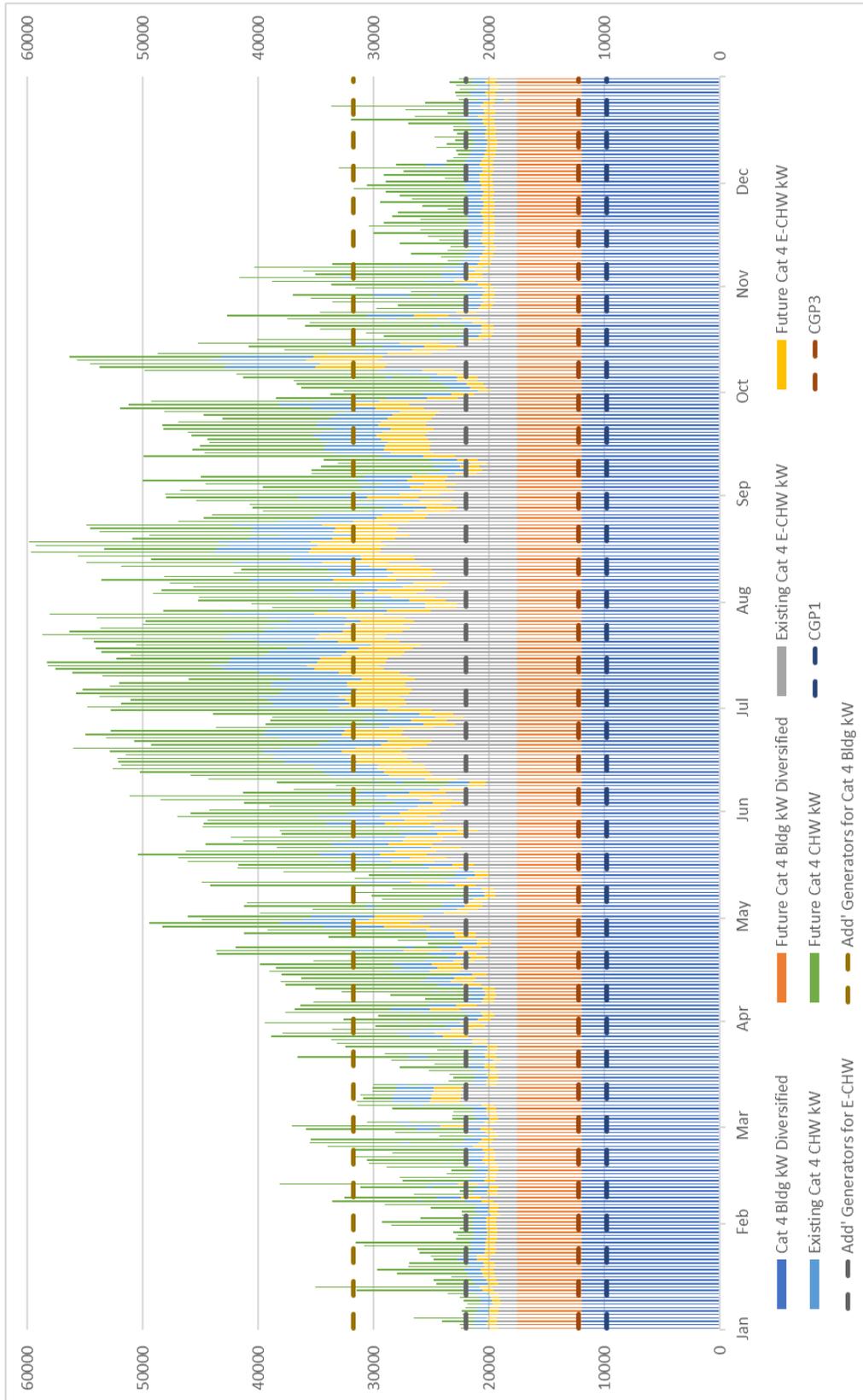


Figure 6-18 – Existing and Future Critical Building Load and Chilled Water with Generator Backup in KiloWatts During a Year

A total of 44 non-central engine generators are located on campus at individual buildings. All the central engine generators and 42 of the building engine generators operate on diesel fuel while two of the building engine generators operate on natural gas (having capacities of 100 kW and 250 kW). Figure 6-19 below indicates the maximum runtime in hours for the buildings on campus backed up by diesel generators on campus including the central generator plants.

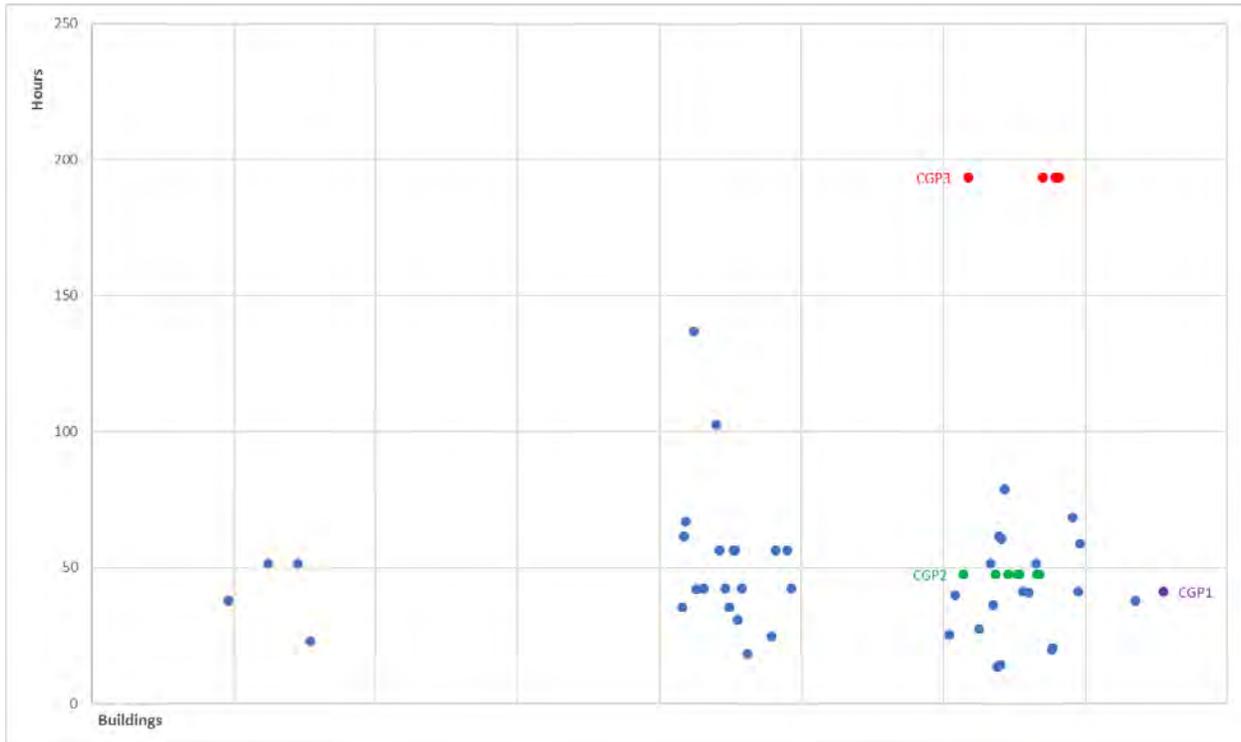


Figure 6-19 – Maximum Generator Runtime Based on Fuel Tank Capacity

The 250,000 gallon fuel oil storage tank at WCSP has a transfer truck filling station to transfer fuel to the distributed engine generator day tanks if it cannot be delivered by supplier. Duke should contract with a fuel oil delivery company to ensure access to a transfer truck is available during utility power outages.

7 RESILIENCY STUDY

7.1 INTRODUCTION, EXAMPLES OF EVENTS AND SUCCESS & FAILURES BY OTHERS

Superstorm Sandy made landfall with 80 mph winds in New Jersey at 8:00 pm on October 29, 2012 during a full moon high tide, leaving 8.5 million people without power across 21 states. Utility companies were only able to restore power for 95% of customers after ten days. This storm may have been the beginning of the buzzword “resiliency” for district energy systems as it was seen how some facilities in the area kept the lights on with CHP systems or other on-site generation. Princeton, NYU, and Fairfield University are just some of the examples that were able to continue limited supply of power to campus during the outage.

On Friday February 3, 2017, Orange Water and Sewer Authority (OWASA) had to reduce and then shutoff water services to customers in Carrboro and Chapel Hill. The incident was caused by a double failure where the Jones Ferry Water Treatment Plant had to be shut off because of a fluoride overfeed and a water line near Erwin Rd. ruptured because of high pressure. The University of North Carolina at Chapel Hill (UNC) was notified at 12:00 pm that day that they would be losing their water in 15 hours. UNC retained contractors to assist in getting water to their steam plant during this outage. They were told it was going to be a 48-hour duration. The 500,000-gallon OWASA water tower serving the hospital was isolated off to protect supply to the hospital. UNC used a 10,000-gallon existing surge tank at the steam plant to offload water truck deliveries and keep water to the steam plant. The tank had to be modified to receive water from an outside source. A total of 104,000 gallons of water were delivered to the UNC steam plant. OWASA repaired and tested the system and returned it to service after about 30 hours of impact to the University and the city. All public Facilities were closed during this crisis. Critical components that avoided a larger disaster were: the 500,000-gallon OWASA water tank near the hospital, 15 hours of notice, the 10,000-gallon surge tank at the steam plant, the ability of contractors to respond quickly with trucks and equipment, adjacent municipalities assisted OWASA in refilling their system where interconnections were available, and ambient temperatures were right for non-peak steam and little chilled water loads.

7.2 CURRENT INFRASTRUCTURE EVALUATION / SYSTEM NEEDS ANALYSIS

DUES have a load shed plan for both the district cooling and the district heating system to respond to conditions that render the available capacity less than the current demand.

The district cooling load shed plan could be required if multiple unit failures occur, if there are distribution line breaks in major distribution headers, if sufficient normal power is not available to fully operate chiller plants or if sufficient non-potable makeup water is not available to fully operate chiller plant cooling towers.

The district heating load shed plan could be required if multiple unit failures occur, if there are distribution failures in major distribution headers or the East Campus to West Campus interconnection, if natural gas is not available and sufficient fuel oil storage or fuel oil units are not available to fully operate steam

plants, or if sufficient non-potable makeup water is not available to fully supply the steam plant boiler feedwater system.

7.3 DISASTER / INTERRUPTION RESPONSE RECOMMENDATIONS

The following alternatives were identified to improve resiliency of the district energy system:

- Cooling
 - Consider field-erected stratified thermal energy storage (TES) tank capacity to reduce the standby power system requirements for emergency chilled water capacity.
 - If chilled water TES is provided, the tank can also be levered for emergency non-potable makeup water capacity. Otherwise, consider a two-million-gallon non-potable water storage tank to provide two peak days of makeup water capacity to the chilled water system.
- Heating
 - Design and construct a new remote steam plant (NCSP) in the North Pavilion area to alleviate dependency on the single steam and condensate pipeline to the area. Consider relocation of three to five of the 10,000 pph natural gas steam boilers that are currently located at ECSP but cannot be fully utilized because of limitations in the East Campus to West Campus steam and condensate interconnect. A secondary benefit of this remote steam plant would be the ability to back feed steam to the rest of West Campus during the summer to alleviate some of the WCSP load for scheduling shutdowns.
 - Plan for replacement of WCSP Boilers 4 and 5. Consider relocation of six of the 10,000 pph natural gas steam boilers that are currently located at ECSP. Only four or five boilers need to remain at ECSP to serve the East Campus load.
 - Continue business-as-usual Separate Heating and Cooling (SHC) system and add Boiler 7 at WCSP as an 80,000 pph steam boiler to replace the capacity of the East Campus to West Campus steam and condensate interconnect and accommodate future growth.
 - Add additional hot water plants to convert steam to hot water as buildings are converted.
 - Contract with a fuel oil delivery company to guarantee six 6,500-gallon tanker truck deliveries per day during winter conditions.
 - Add non-potable water distribution from the reclamation systems near CCWP 2 to the WCSP. Alternatively, add a non-potable water surge tank at WCSP that would allow tanker trucks to offload makeup water during a city water outage and contract with a water delivery company to deliver 230,000 gallons per day during peak winter conditions.

- Power
 - Install a new 20 MW continuous duty central generating plant consisting of eight 3.25 MW reciprocating engine generators to power the emergency chilled water capacity, research buildings, and chilled water capacity for a portion of the remaining critical chilled water load. The exact capacity of this central generating plant will require further study, but since CHP options up to 20 MW have been analyzed, the options analysis is conducted based on each alternative having 20 MW of site generation. The cost assumptions for the central generating plant are based on Diesel fueled engines, but natural gas could also be considered as fuel at additional cost.
 - Add capacity to the substation 2 and 3 interconnect and complete the interconnect between substations 3 and 4.

7.4 REDUNDANCY AND ENERGY DIVERSITY RECOMMENDATIONS

The following alternatives were identified to improve the resiliency of the district energy system, while also offering energy diversity and the potential for operational savings:

- Heating
 - Instead of continuing the SHC system, add a Combined Heat and Power (CHP) system that meets standby power requirements using a Combustion Turbine Generator (CTG) and meets additional steam System Needs instead of Boiler 7 using a Heat Recovery Steam Generators (HRSG). Two sizes were analyzed: two 6 MW units or two 10 MW units.
 - As an alternative to Duke University CHP, continue negotiations with Duke Energy for construction of a 20 MW CHP plant that sells steam and hot water to Duke University. This plant is mutually beneficial because it relieves overload in the local utility grid for Duke Energy, while adding power resiliency and heating capacity for Duke University.
 - As an alternative to SHC or CHP, add a Combined Heating and Cooling (CHC) system that uses waste heat from the chilled water system to meet the load of the hot water system, which reduces the demand on the steam system, avoiding the need for Boiler 7 and additional hot water plants.
 - Consider hybrid generation solutions that include both CHP and CHC systems.
- Power
 - Install an energy storage device to power the emergency chilled water capacity load. Options include lithium-ion batteries, flow batteries, other chemical batteries, liquid air storage, or concrete block storage, among others.
 - If CHP is installed on campus, utilize planned interconnects to consolidate base load and distribute standby power.

8 ENERGY PORTION OF CLIMATE ACTION PLAN

8.1 LIST OF POTENTIAL EFFORTS, PROS & CONS, FEASIBILITY

In 2007, Duke University signed the American College and University Presidents' Climate Commitment (ACUPCC) and set a target of achieving climate neutrality by 2024. Duke's climate neutrality goal includes the following categories:

- Scope 1
 - Steam plant fuel combustion, including upstream fugitive emissions for losses during production and distribution, which is included in this analysis and report
 - Duke-owned transportation fleet fuel consumption, but this component is not affected by or included herein
- Scope 2
 - Purchased electricity for buildings, chiller plants, and heating plants, including upstream losses in transformation and distribution, which is included in this analysis and report
- Scope 3 (not affected by or included herein)
 - Duke-financed air travel
 - Employee commuting
 - Solid waste

For the purposes of this report and analysis, the carbon impact fuel for heating, cooling, and building use are considered, where fuel can refer to natural gas, fuel oil, biogas or electricity.

Carbon neutrality is achieved as two main parts: reduction and offset. Carbon offsets come at a price, which varies based on the source region and type, and include a social component that favors reductions over offsets. Reduction of fuel use also comes at a cost, starting with low hanging fruit such as behavioral changes and awareness by users, but ranging to large-scale energy system changes on campus.

The Duke Carbon Offsets Initiative (DCOI) mission is to identify, create, and purchase the necessary carbon offsets for Duke to achieve carbon neutrality, but in a way that provides educational opportunities, prioritizes local, state and regional offsets, and facilitates new and unique offset projects. Current projects include a swine waste-to-fuel program that is piloted at Loyd Ray Farms collecting methane gas that would otherwise be released to the atmosphere and processing it for delivery through existing natural gas infrastructure. Another ongoing project is urban forestry which plants trees in urban areas of the local community, state, and other institutions around the country.

Through carbon offset projects like the ones mentioned above and a mix of purchased offsets a blended price for offsetting emissions that cannot be reduced is realized. The carbon offset price can be used to determine financial feasibility of on-site energy projects that reduce carbon footprint, such as solar photovoltaics, solar thermal, or Combined Heating and Cooling (CHC). The baseline carbon offset cost used in the report is \$20 per metric ton of carbon

dioxide equivalent (MTCDE). The sensitivity analysis also reports the results at \$10/MTCDE, and \$0/MTCDE.

Duke has already embarked on a hot water conversion plan that will ultimately result in half of the district heating building square footage being served by a more efficient hot water distribution that is heated via three to four hot water plants with heat exchangers supplied from the district steam system. This plan will save energy by reducing steam distribution and condensate return losses, which will save operating cost, reduce regional carbon emissions by 16,000 MTCDE per year and reduce on-site non-potable water consumption by four million gallons per year. The hot water conversions also open the door for other technologies to produce heating, removing the hot water load entirely from the district steam system and reducing regional carbon emissions by another 18,400 MTCDE per year and reducing on-site non-potable water consumption by another four and half million gallons per year.

One of the alternatives for producing the heating is a Combined Heating and Cooling (CHC) system which is described in more detail in the following section of this report. The CHC system saves operating cost and eliminates 18,400 MTCDE emissions associated with the steam plant but adds approximately 4,000 MTCDE emissions per year because of increased electricity purchases. To avoid the increased off-site emissions, the CHC system could be coupled with on-site solar photovoltaic (PV) energy.

Duke University has already installed over 1 MW of on-site solar PV with the recent completion of a 750-kW system on the top of the Research Drive parking garage, and the Climate Action Plan (CAP) proposes that another 3 MW will be installed across campus. Even though the peak output of these systems is more than 1% of the 81,600-kW campus demand, the campus needs electricity 24-7-365, or 8,760 hours per year. In Duke's climate, solar PV systems produce approximately 1500 Watt-hours per peak Watt. As a result, the current installed solar capacity equates to approximately 0.3% of all purchased electricity that is projected with growth through 2025.

The CHC system would consume approximately 16,400 Megawatt-hours per year. Based on RDU TMY3 data with fixed photovoltaic panels, 30 kWh per year can be collected per square foot of panel area, and assuming a 4 to 1 ratio for solar array size to useable panel area, and 18% panel effectiveness, the solar array size required is approximately 57 acres with a peak output of 11.5 MW. For a sense of scale, this is about the size of the Duke Gardens. This would quadruple the 4 MW CAP goal, and require a significant land area, because even if that top of every building on campus had solar panels added, that would only total 8 acres.

Utility-scale solar PV systems can take advantage of economies of scale, can more easily connect to high capacity transmission lines, and are easier to balance with regional energy demands versus energy use on a single campus meter. It is likely the most economical and feasible method for increasing Duke's solar energy portfolio beyond the 4 MW currently planned is via off-site production.

Another way to eliminate the additional scope 2 carbon emissions added by the CHC system is to instead produce the heat directly with solar thermal. Solar thermal cannot be done very far off-site like solar PV because the hot water

collected must be pumped and distributed to the loads. Based on RDU TMY3 data, with fixed vacuum tube solar collectors, 43 kBtu per year can be collected per square foot of panel aperture area at an annual average effectiveness of 0.661, but the irradiance profile does not align well with the heating demand profile, as shown in Figure 8-1 below.

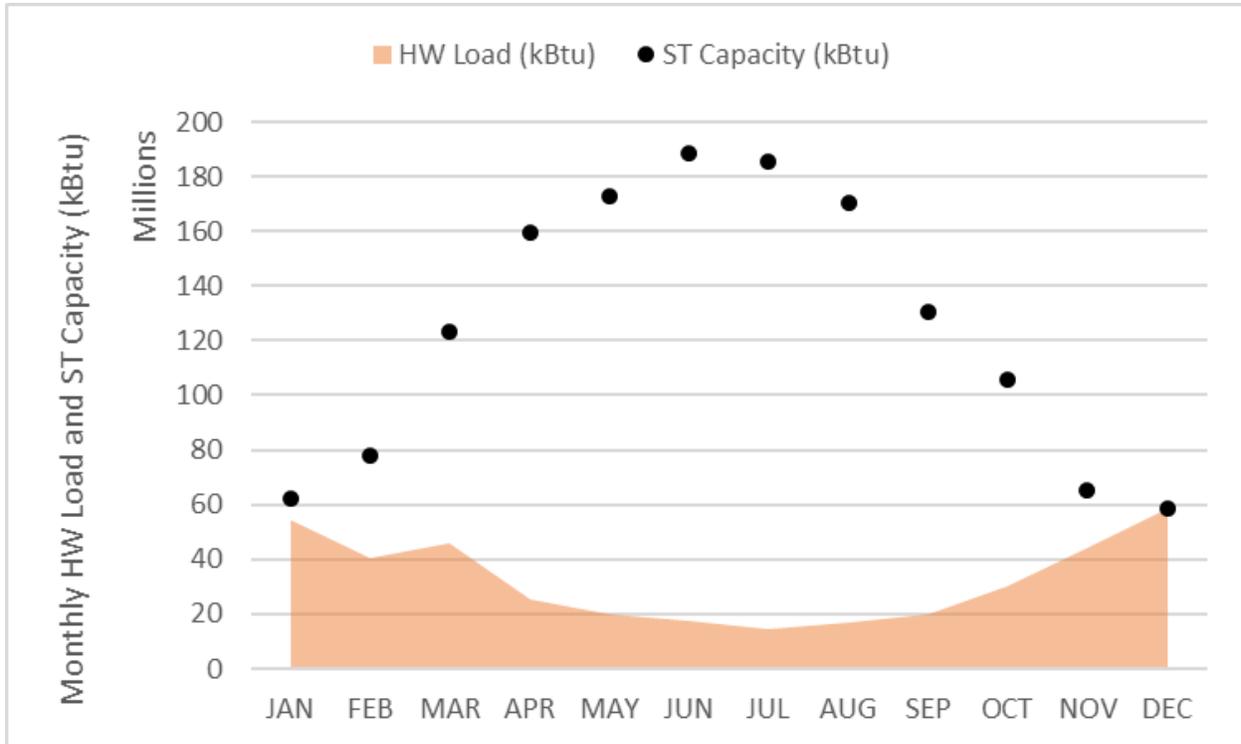


Figure 8-1 – Annual Heating Load and Solar Thermal Availability

As shown in Figure 8-1 above, during the peak HW load month of December, only 13 kBtu per month can be collected per square foot of panel aperture area at a monthly average effectiveness of 0.565. This highest load and lowest productivity month is what drives the required size of the array. Assuming a 4 to 1 ratio for the solar array size to the aperture area, the total size required is approximately 400 acres, or about 1/20th of the Duke Forest. To balance the daily profile of solar irradiance and hot water demand, a buffer tank of nine million gallons would also be required. A system like this would cost hundreds of millions of dollars and is not feasible financially. It would also be unfortunate to have such a surplus of available hot water in the summer that cannot be utilized. Some systems in Europe store excess solar thermal water in underground pits for use later in the winter, but those systems also require enormous land area and financial investment.

Large scale central solar thermal is not a viable alternative to central Combined Heating and Cooling (CHC). If there are smaller projects in the areas of campus that are not planned for steam to hot water conversion, it could still be studied to install a small rooftop solar thermal array to reduce central steam consumption. If there are hot water systems that are not planned to include CHC in the future, it could still be studied to install a small solar thermal array connected to the distribution system.

8.2 REGULATORY ENVIRONMENT & CONSTRAINTS

The regulatory environment in North Carolina currently prevents Duke University from entering into Power Purchase Agreements (PPA) for off-site solar or wind energy generation. Regulation proposed in late 2017 in the NC General Assembly may open new solar opportunities for Duke University by early 2019. University officials are closely following the North Carolina HB589 rule making process on renewable energy as it may be an opportunity for Duke University to build economically feasible, larger scale solar off-campus that has not previously been an option.

Duke Energy's Green Source Advantage (GSA) Program will be available to nonresidential customers who have energy demands of at least 1 MW of peak demand at a single location, or an aggregate of 5MW or more of peak demand across multiple locations. There will be up to 600 MW of total capacity, with 100 MW for military installations, 250 MW for The University of North Carolina institutions, and 250 MW set aside for other large nonresidential customers, such as Duke University.

Customers can choose to purchase any amount up to 125% of their maximum annual peak demand, which for Duke University would be 125% of 81.6 MW, or just over 100 MW. As previously described, this will equate to approximately 100 MW at 1500 W-h/W for an annual energy total of 150,000 MWh. In the baseline case, it is projected that Duke's purchased electricity demand will be 514,000 MWh per year by 2025. That could be increased by 16,400 MWh with CHC or reduced by 170,000 MWh with CHP, so in any case there would be enough demand to maximize the available purchase, and the impact will be a carbon reduction of 150,000 MWh by 0.22 MTCDE/MWh or about 33,000 MTCDE.

The program will be on a first-come-first-served basis, so it is not guaranteed that any of the 100 MW will be available. Beyond this program which would allow Duke University to source approximately a third of purchased electricity from renewable sources there are not currently any regulations that permit off-site renewable power purchases.

8.3 SUMMARY OF CARBON REDUCTION MEASURES

The 2017 CAP Update outlined measures to reduce carbon footprint at buildings, such as designing new buildings to be better than the energy efficiency code, replacing existing T-8 fluorescent lighting with LED's, and optimizing existing HVAC systems using retro-commissioning. These building measures total a carbon reduction of approximately 15,000 MTCDE per year. The update also outlined measures to reduce carbon footprint associated with utilities, such as the addition of 4 MW on-site solar PV, chilled water system improvements, some building solar thermal systems and steam to hot water conversion. These utility measures total a carbon reduction of approximately 8,000 MTCDE per year. Note the hot water conversion scope only included plans through 2021. The ultimate hot water conversion scope across West Campus and East Campus will provide an additional 11,000 MTCDE per year when complete in approximately 2030.

Other components that are new in this analysis or have changed since the 2017 update are the impact of biogas, the Duke Energy grid carbon intensity projections, the chilled water system expansion, the scope of CHC, and the scope of CHP. In the 2017 CAP Update, biogas was used as a one-to-one offset

as a carbon neutral fuel for boilers or CHP, but now credit has been applied to the carbon benefit of avoiding direct methane release which has 34 times the global warming impact as carbon dioxide per pound. When accounting for the direct methane release avoidance, a ratio of 11% biogas to natural gas makes a carbon neutral mixture. This means that the existing fuel consumption of the SHC system can easily exceed the amount of biogas reclaim that is needed to offset all of Duke’s Scope 1, 2 and 3 reported emissions.

In 2017, Duke Energy was projecting 0.27 MTCDE/MWh carbon intensity for the years 2025 through 2035, but the current projections show 0.22 MTCDE/MWh beyond 2025. The lower average grid carbon intensity increases the relative amount of carbon emissions for Duke University owned CHP options.

During the 2017 CAP update, a renovation and expansion of CCWP 1 was in design. After learning of the potential three million square foot development on Central Campus, the design was shifted to a new CCWP 3 instead. Constructing a new plant instead of renovating and expanding CCWP 1 is more efficient by approximately 0.05 kW/ton, which reduced Scope 2 carbon emissions by 700 MTCDE per year.

The 2017 CAP Update included an analysis of a CHC system, but only for the near-term hot water load projections. This analysis is broadened to include the full potential of CHC for the ultimate planned hot water conversion for West Campus and East Campus and studies the potential interconnections to the new Central Campus development CHC system.

The primary CHP option included in the 2017 CAP update was the 20 MW Duke Energy owned CHP, selling carbon neutral steam and hot water for heating to Duke University. That option is included in this analysis, but also two sizes of Duke University owned CHP with two 6 MW units or two 10 MW units. Even through the Duke University owned CHP options increase regional carbon emissions, the additional natural gas purchase by Duke University presents an opportunity to procure more biogas than could otherwise be burned on campus, to ultimately make Duke University a regional carbon sink.

This analysis has identified a path to eliminate the East Campus to West Campus steam and condensate interconnect, which currently loses heat, steam, and condensate. Eliminating this pipeline will reduce regional carbon emissions by approximately 1,600 MTCDE per year.

The eight alternatives considered in this analysis have the following impact to regional carbon emissions:

- (2) 6 MW CHP: 17,000 MTCDE per year increase
- (2) 10 MW CHP: 32,400 MTCDE per year increase
- 20 MW CHP (DE): 50,800 MTCDE per year decrease
- CHC: 14,700 MTCDE per year decrease
- CHC w/ CC: 13,900 MTCDE per year decrease

Note that although the CHC options result in carbon reductions, there are difficulties associated with their implementation, including the need for large pipelines, TES tanks and increased operational complexity.

9 OPTIONS

9.1 EXPLANATION OF ALTERNATIVES

The existing district energy system is Separate Heating and Cooling type (SHC). Central chiller plants produce chilled water that is distributed to loads and then returned to the chillers. The chiller condensers reject heat to the environment via evaporative cooling towers. The heating system is separate from the cooling system, with central steam boilers fired on natural gas distributing steam to buildings or hot water plants. Some buildings use the steam for heating or process directly, but most buildings and the hot water plants convert the steam to hot water for distribution to the loads. Power to the buildings and plants is also separate from the thermal systems, connected to the grid. A SHC system is illustrated in Figure 9-1 below and a simple schematic of the steam system follows in Figure 9-2.

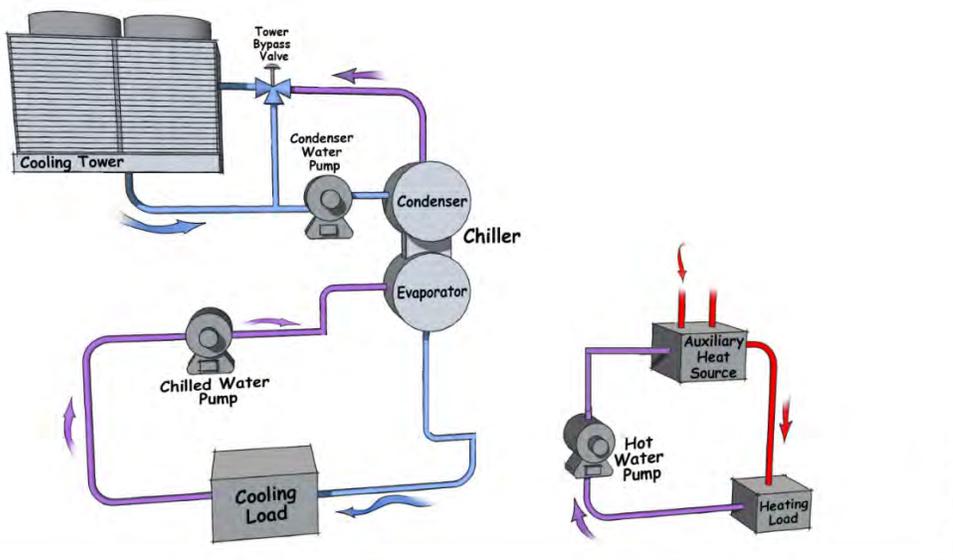


Figure 9-1 – Separate Heating and Cooling (SHC) System

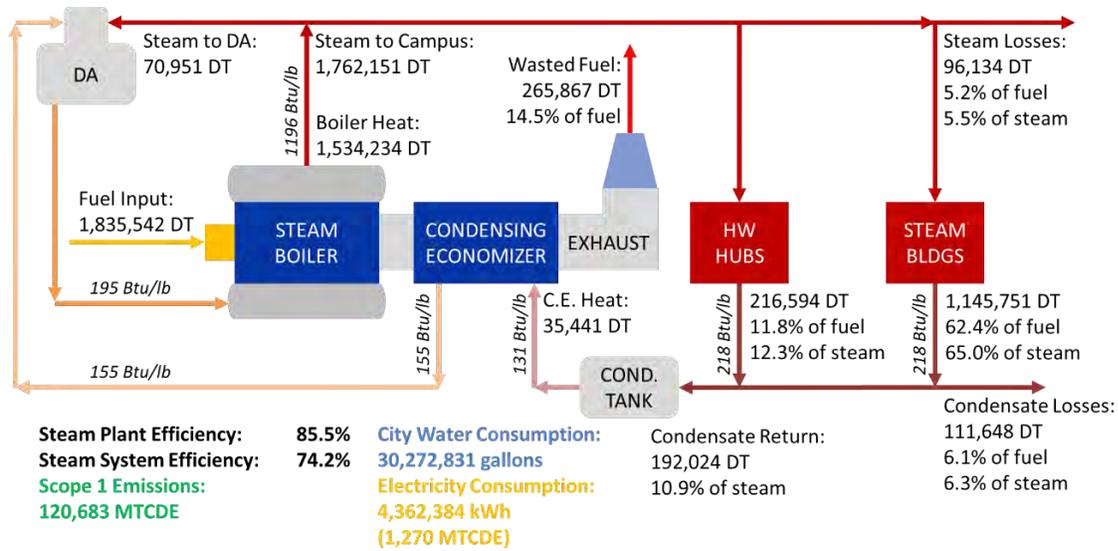


Figure 9-2 – Steam System Simple Schematic

A Combined Heating and Power (CHP) system uses a reciprocating engine or combustion turbine generator package to supply a portion of the power System Needs in parallel to the grid. The engine or turbine exhaust is routed to a heat recovery steam generator that produces useful heat in parallel to the steam plant. The heat recovery steam generator exhaust can then be routed to an economizer that produces useful hot water in parallel to the hot water plant. The combined electrical and thermal efficiency of a CHP system is greater than any natural gas fueled generation on the electrical grid but depending on the mix of fuel sources in the region is not necessarily more efficient than the averaged grid efficiency. A CHP system with a combustion turbine is illustrated in Figure 9-3 below.

For Duke, CHP defers the addition of Boiler 7 at WCSP and replaces an equivalent capacity of continuous rated standby generation.

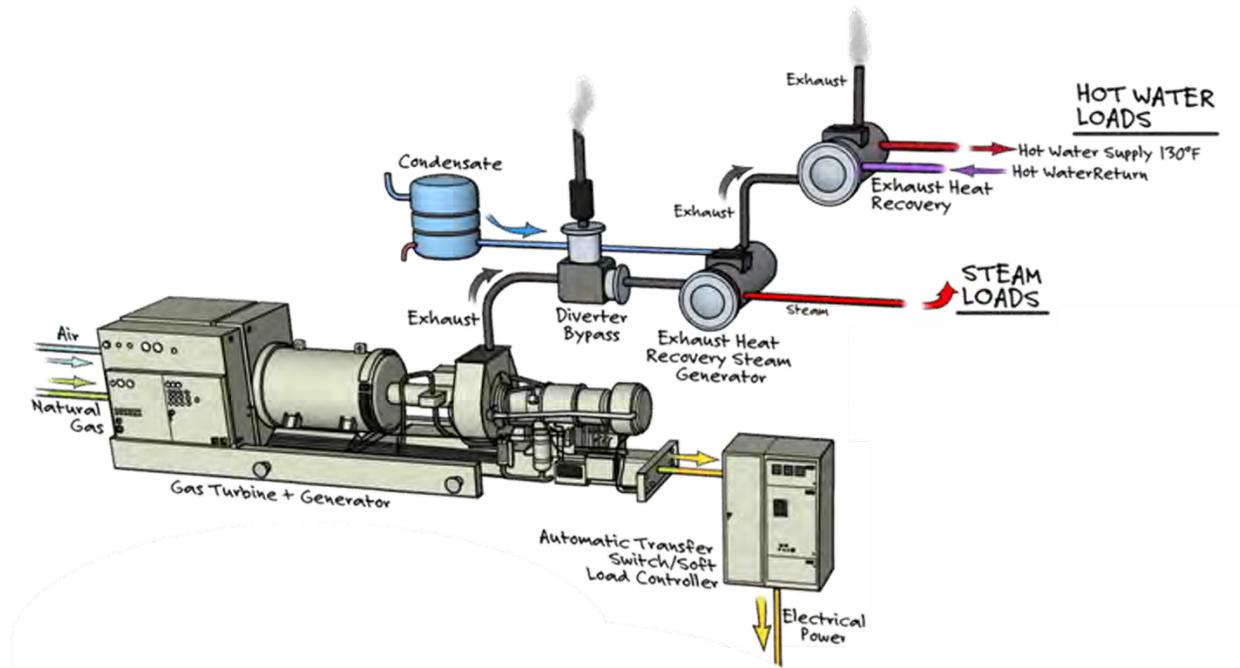


Figure 9-3 – Combined Heating and Power (CHP) System

A Combined Heating and Cooling (CHC) system uses a heat pump chiller to recover waste heat from the chilled water system and convert it to useful hot water heat. The evaporator of the heat pump chiller is paralleled with the evaporators of the conventional chillers in the existing plants and the condenser of the heat pump chiller is paralleled with the condensers of the hot water plant, which is reduced to backup heating capacity. The heat pump chillers cannot modulate in load as easily as conventional chillers, and the heating and cooling profiles vary differently throughout the day, so large thermal energy storage tanks are required on the heat pump chiller evaporator and condenser circuits to optimize operation of the system and base load the heat pump chillers. A CHC system is illustrated in Figure 9-4 below.

For Duke, CHC defers the addition of Boiler 7 at WCSP, defers some of the conventional cooling capacity at new CCWP 3, avoids the need for new non-potable water storage on campus, reduces the normal consumption of city water, lowers regional carbon emissions by using electricity as a fuel for heating instead of natural gas, and improves on site efficiency for conversion of fuel to useful heating. The CHC system requires new large bore hot water distribution piping, large thermal storage tanks and increases the operational complexity of the chilled water system.

A CHC system is already in design to serve the heating System Needs of the Central Campus development. Since the load will be all new construction, the heating system can be designed to accept 115°F heating water supply from the central plant, which can be produced in chillers very similar to the type already in use for conventional cooling on campus, because the temperature leaving the condenser is only about 20°F hotter than conventional evaporative heat rejection

during peak summer. The heat pump chiller at this heating temperature is very efficient for producing useable heat.

The hot water conversions in process on West Campus and East Campus are for buildings that currently utilized steam for heating. Some of the buildings use steam to hot water converters in a mechanical room and then distribute the hot water to hydronic preheat coils and terminal devices in the HVAC systems. This type of system was historically designed at 180°F because the steam at reduced pressure in the converter was condensing at approximately 220°F and more than 40°F approach temperature on that heat exchanger did not offer significant savings compared to the savings of having a high approach temperature on the heating coils that are supplied with 180°F. The approach for the hot water conversion scope has been to regionalize the steam to hot water conversion, for benefits that have already been described herein. Packaged heat pump chillers that are readily available can only produce 170°F heating water supply, so the hot water conversion buildings will need to be tested to ensure they can operate properly with 165°F heating water supply. It is likely that most of the buildings are slightly oversized and can operate satisfactorily with the lower supply temperature. Where issues are discovered, those building systems will need to be modified and some cost (\$500/ton) has been considered in the capital estimate for CHC to address those buildings.

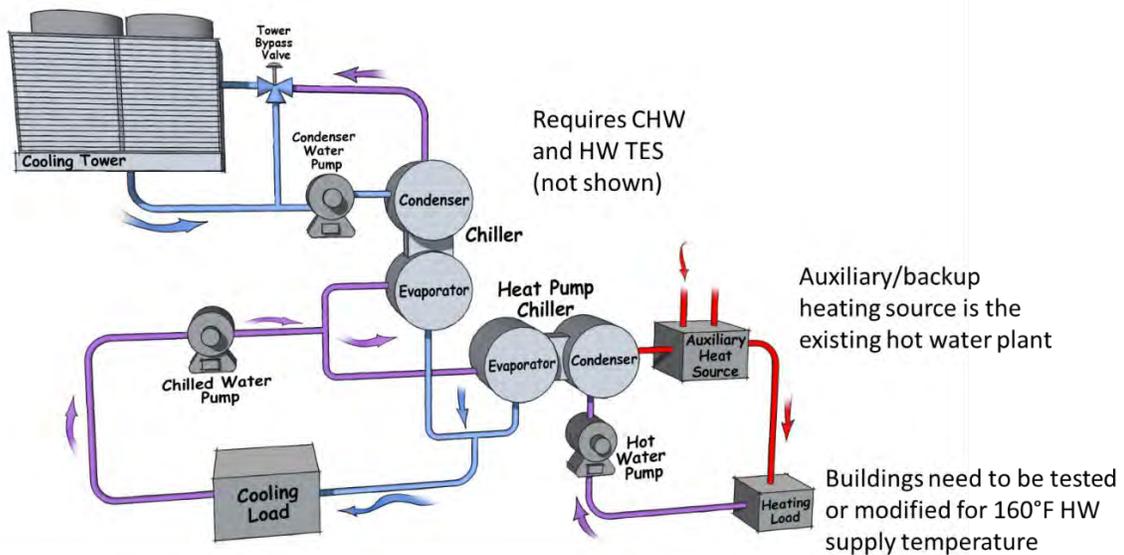


Figure 9-4 – Combined Heating and Cooling (CHC) System

There is currently only a single manufacturer that offers a packaged heat pump chiller at central scale capable of producing 170°F heating water while providing simultaneous cooling. The lift associated with moving saturated refrigerant gas in the evaporator at approximately 42°F to the pressure of the saturated condenser conditions above 170°F is much higher than conventional cooling applications. The package that is available to do this uses two centrifugal compressors in series with an intercooler. The energy consumption is near 1.7 kW per unit of useful cooling. For options that consider combining the East Campus and West Campus CHC alternative with the planned Central Campus CHC system, there is

an energy penalty for the portion of load that could have been produced for Central Campus at 120°F that has been accounted. The main advantage of combining the systems is capital cost reduction, and limitation of the number of campus system that need to be operated.

The hot water conversions planned for East Campus have a higher percentage of existing buildings that use steam directly for heating via radiators. It could be possible to design the entire East Campus hot water conversion to operate at a lower temperature, which would be advantageous if a dedicated heat pump chiller were provided for that load. This type of redesign on West Campus would likely prove too costly for just the benefit of reducing lift on the heat pump chiller, but could be studied further.

9.2 USE OF ENERGY STORAGE FOR EMERGENCY CHILLED WATER

The emergency chilled water load is projected to be 25,000 tons but only 14,000 tons of chilled water capacity is currently on standby power systems. Adding 11,000 tons of chilled water capacity on standby power systems requires three new 3.25 MW engine generator units and the necessary electrical interconnects between a suitable location for the units and either CCWP 2 or CCWP 3, because CCWP 1 only has 7,400 tons of additional capacity that is not already on standby power. It is estimated that each of these additional units will cost three million dollars.

An alternative to installing new engine generator units is an energy storage system that stores normal power for use as standby power during outages. To provide one day of capacity, the energy storage device would need to be approximately 150 MWh. Utility-scale chemical battery systems to date are mostly lithium-ion systems, like batteries in cars, laptop computers, and mobile phones. Costs are declining but this system would still cost approximately fifty million dollars, which cannot be justified relative to nine million dollars for standby engine generators. Emerging chemical energy storage technologies for grid applications such as flow batteries could substantially reduce cost but are not readily available at this time.

Traditional mechanical energy storage systems such as compressed air energy storage and pumped hydro are not viable on campus. Pumped hydro is the most common type of energy storage in the world but requires large reservoirs of water at different elevations that are most often modification of existing geography and not completely manufactured as would be required at Duke. There is a similar emerging technology that uses a crane to stack large concrete blocks when charging energy and then lowers the blocks to discharge the energy, but it is not readily available yet and not likely to be cost competitive for standby power. Grid-scale compressed air energy storage is rare and usually only utilized in combination with natural rock caverns that are air tight, which do not exist at Duke. There is an emerging technology that uses liquid air energy storage to reduce the capacity of the storage system required allowing for fabricated pressure vessels to be used, but again this is not readily available or cost-competitive for standby power systems.

There are not any known chemical or mechanical energy storage devices that are economically viable for a standby power system. These technologies are in use today as components in electric grid generation balancing every day. The everyday use of such systems can justify the high capital cost. These

technologies are not typically applied in lieu of generation systems for providing standby power on a limited-use basis.

Another type of energy storage to consider is thermal. A field-erected stratified chilled water thermal energy storage (TES) tank could be provided to load-level the emergency chilled water load as shown in Figure 9-5. The solid black line shows the average load for each hour of the day for the 98th percentile and above load days (worst-case emergency chilled water scenario). The dashed black line shows a levelized load that could be achieved with a chilled water TES tank. The dark blue region is when the chiller capacity exceeds the nighttime demand and charge the tank. The light blue region is when the daytime demand exceeds the chiller capacity. The total amount of stored chilled water requires approximately 2 million gallons of useable TES. This method reduces the emergency chilled water load from 25,000 tons to 22,000 tons and eliminates the need for one of the three 3.25 MW engine generator units.

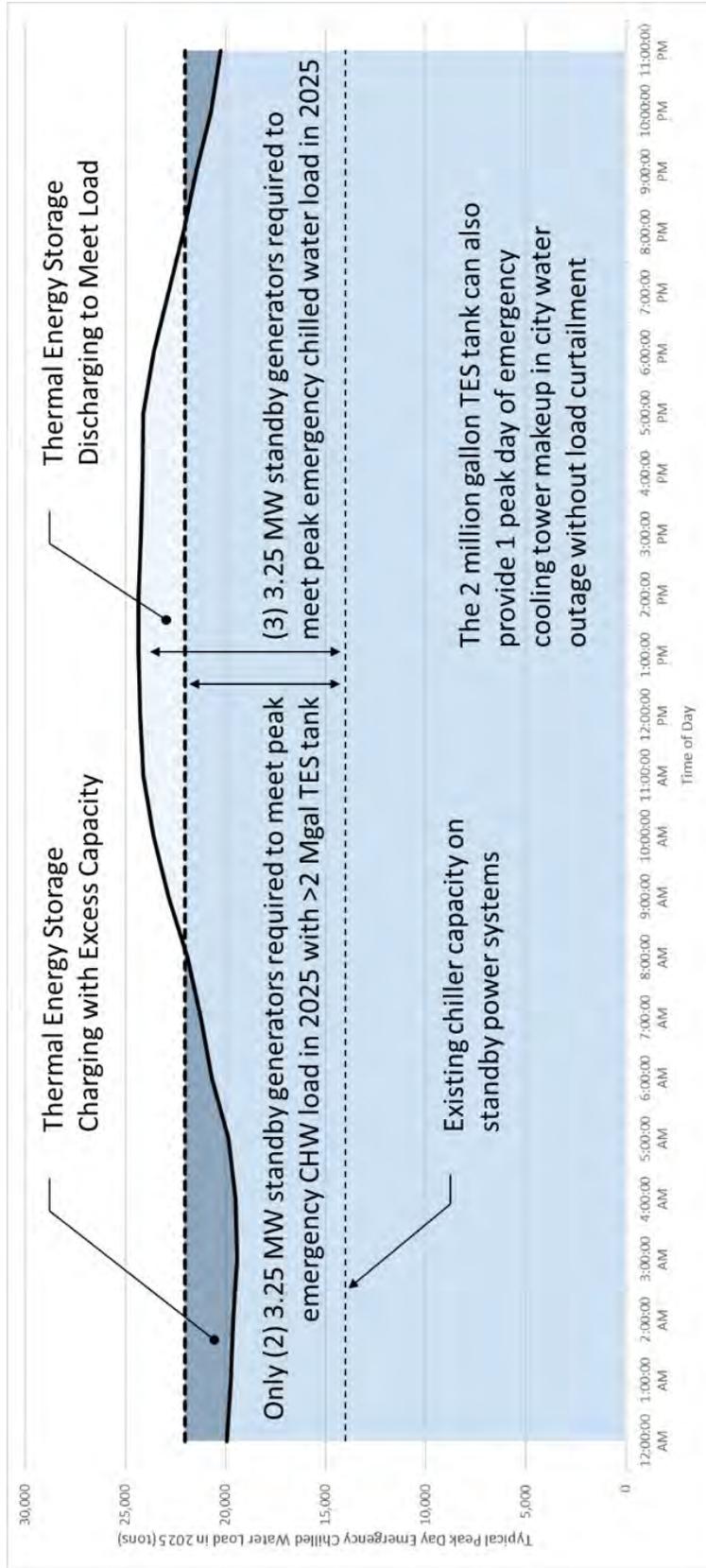


Figure 9-5 – Thermal Energy Storage for Emergency Chilled Water Capacity

Mechanical or chemical energy storage devices are not feasible for sustained standby power to supply emergency chilled water during normal power failure, but TES could be used to level the emergency chilled load and reduce the need for standby generation. The following summarizes the standby power required for each alternative considered:

- If TES is not provided and if there is no power from a CHP system:
 - Eight (8) 3.25 MW reciprocating engine generators to power the emergency chilled water capacity, the critical buildings, and chilled water capacity for a portion of the remaining critical building chilled water load
 - Approximate capital cost is \$24 million
- If TES is provided and if there is no power from a CHP system:
 - Seven (7) 3.25 MW reciprocating engine generators to power the emergency chilled water capacity, the critical buildings, and chilled water capacity for a portion of the remaining critical building chilled water load
 - Approximate capital cost is \$21 million
 - Approximately \$3 million capital cost can be reduced by avoiding a new 3.25 MW engine generator unit
- If TES is not provided and there is power from a two 6 MW CHP system:
 - Four (4) 3.25 MW reciprocating engine generators to power the emergency chilled water capacity, the critical buildings, and chilled water capacity for a portion of the remaining critical building chilled water load
 - Approximate capital cost is \$12 million
 - Approximately \$12 million capital cost can be reduced by avoiding four new 3.25 MW engine generator units
- If TES is not provided and there is power from a two 10 MW CHP system:
 - No additional reciprocating engine generators are needed to power the emergency chilled water capacity, the critical buildings, and chilled water capacity for a portion of the remaining critical building chilled water load
 - Approximately \$24 million capital cost can be reduced by avoiding eight new 3.25 MW engine generator units

9.3 ECONOMICS, CO₂ IMPACT, RESILIENCY & RELIABILITY IMPACT

The efficiency and regional emissions of the existing SHC system are dependent on four factors: efficient use of delivered fuel for conversion to useful heating, equivalent carbon content of delivered fuel for heating, efficient use of delivered fuel for conversion to useful cooling, and equivalent carbon content of delivered fuel for cooling. A major improvement was recently completed when Duke eliminated coal as fuel source in 2011, reducing Duke carbon footprint by 11%. Not only was the equivalent carbon content of delivered fuel reduced by using natural gas instead of coal, but the efficiency of converting that fuel to useful

heating was also improved by 7%. Another major improvement is currently in progress to improve the fuel conversion to useful heating by regionalizing steam to hot water heat exchangers for buildings and distributing hot water instead of steam which will improve heating system efficiency by 12%. On the cooling side, a major effort is nearly complete to centralize chilled water production, which has improved chilled water system efficiency by 25%, reduced campus peak energy use by 11% on a normalized basis and reduced water use by 30% or 40 million gallons per year.

Currently 99.7% of the fuel delivered to the campus is electricity from Duke Energy, with the remaining 0.3% from solar that was recently expanded five-fold with a 750-kW installation on the top of the Research Drive parking garage. Since 2005, Duke Energy has made major improvements in the equivalent carbon content of the delivered electricity and plans to continue moving in that direction, as shown in Figure 9-6. From 2005 to 2017 the percent of coal fired generation decreased from 61% to 33% and was replaced by expansions of natural gas fired generation and renewable energy from hydroelectric, wind and solar sources, which reduced equivalent carbon content of the delivered electricity by 31%. Duke Energy plans to invest \$11 billion in continued expansion of natural gas fired generation and renewable energy in place of coal fired generation. By 2030, Duke Energy projects coal fired generation to decrease from 33% to 16% and equivalent carbon content of the delivered electricity to be reduced by another 13%.



Figure 9-6 – Duke Energy is Expanding Natural Gas Infrastructure

The equivalent carbon content of delivered electricity is typically measured in units of metric tons of equivalent carbon dioxide emissions per megawatt-hour, or MTCDE/MWh. A metric ton is equivalent to 2,205 pounds and a megawatt is equivalent to 1,000,000 watts. Using some figures from the U.S. EIA to put this in perspective, the average American home uses 10.8 MWh per year (2016 data) and if the carbon content of that electricity was 0.4 MTCDE/MWh then the average American home emissions associated with delivered electricity is 4.3 MTCDE or 9,480 lbs of CO₂. About 19.6 pounds of CO₂ are produced from burning a gallon of gasoline that does not contain fuel ethanol. So, the emissions equivalent for the average American home with an electric grid equivalent carbon content of 0.4 MTCDE/MWh is like setting fire to 500 gallons of gasoline.

The historical and projected future equivalent carbon content of delivered electricity from Duke Energy is shown in Figure 9-7 below. Prior to 2011, the carbon intensity was greater than 0.4 MTCDE/MWh, but by 2017 the carbon intensity was 0.31 MTCDE/MWh. By 2023 and beyond, the average carbon intensity is projected to be approximately 0.22 MTCDE/MWh.

Something else to consider is that the published equivalent carbon content of delivered electricity from any utility company is in terms of the megawatt-hours generated, not the megawatt-hours that are used. Approximately 9% of the energy generated is lost in distribution and transformation before it is utilized. The only way to avoid these losses is by generating electricity at the point of use, such as with a CHP system. To make a better comparison of the regional emissions impact of a CHP system, the grid carbon intensity should be adjusted to account for losses. The 2017 carbon intensity of 0.31 MTCDE/MWh generated is really 0.34 MTCDE/MWh utilized and the projected future 0.22 MTCDE/MWh generated is really 0.24 MTCDE/MWh utilized.

Burning natural gas contributes to 117 pounds of equivalent carbon dioxide emissions per million Btu. Burning gasoline was mentioned above, so for comparison, the lower heating value of gasoline is 115,000 Btu per gallon, which means that burning gasoline contributes to 170 pounds of equivalent carbon dioxide emissions per million Btu, hence the conception that burning natural gas is cleaner, albeit only about 30% cleaner. Like how some generated electricity is lost before it is utilized, some natural gas is lost before it can be utilized, but there is a big difference when the natural gas is lost. When electricity is lost it is in the form of heat. When natural gas is lost it is a direct release of a greenhouse gas to the atmosphere. The current assumption is that 2% of natural gas that is extracted from the earth is lost in the extraction process, storage, or distribution. And when that natural gas is released it has a global warming potential of 34 times an equivalent amount of natural gas. The equivalent carbon impact of just burning the natural gas is 0.0531 MTCDE/MMBtu, but the total regional carbon impact of using natural gas is 0.0657 MTCDE/MMBtu when including the leakage impact.

The carbon content of delivered electricity from Duke Energy is important when evaluating alternatives, especially CHP. Although it is traditional to use average grid intensities when calculating grid efficiencies (as included in the baseline results of this report), Duke Energy plans to lower its grid intensity significantly through renewables and increased use of natural gas. One could argue that any local CHP use would offset only the natural gas component of Duke Energy's grid intensity, which is approximately 0.44 MTCDE/MWh.

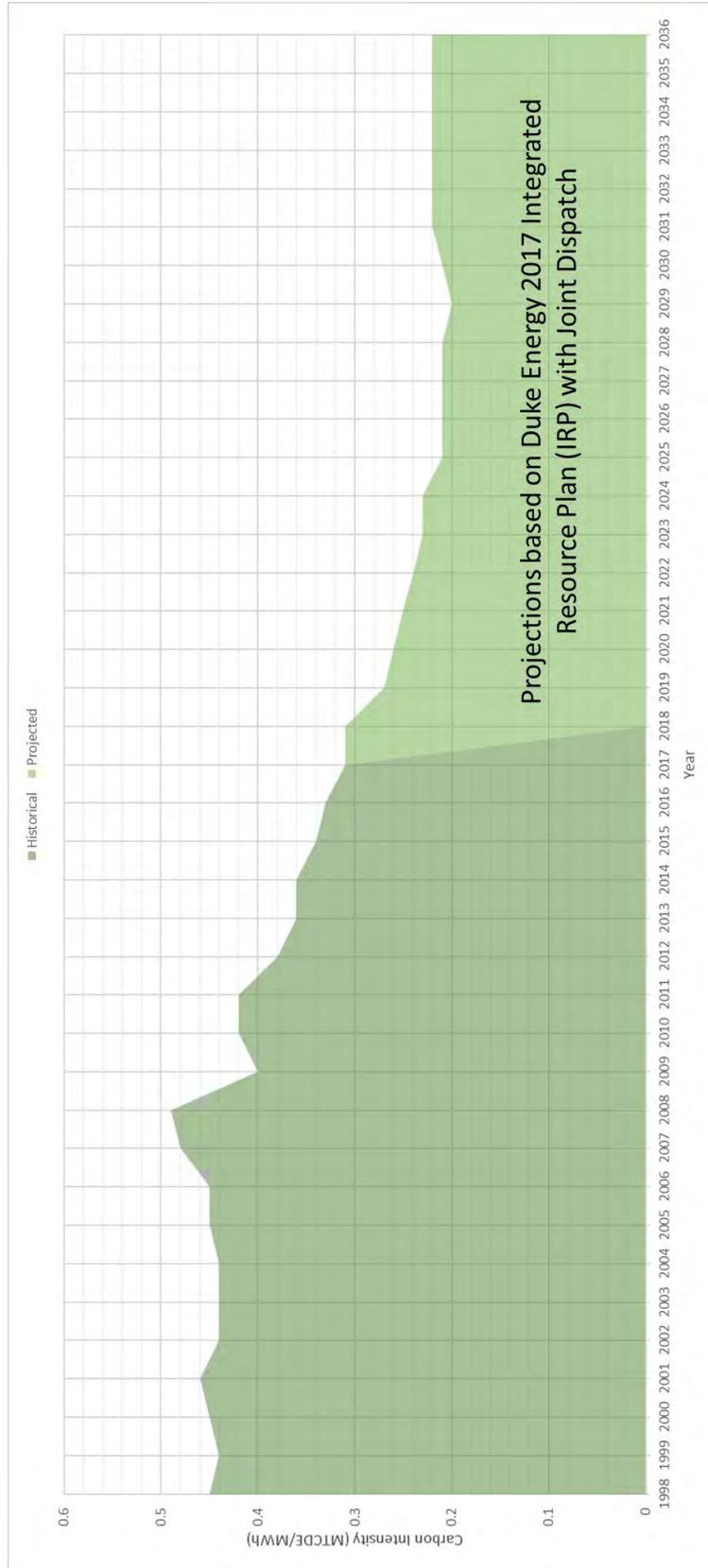


Figure 9-7 – Duke Energy Historical and Projected Carbon Intensity (MTCDE/MWh)

High level capital project costs have been estimated for comparing SHC, CHP, and CHC options. The unit cost factors are listed below:

- CCWP 3 CHC system for Central Campus: \$27 million
- 80 kpph steam boiler at WCSP: \$10 million
- Hot Water Plants: \$3.0 million each
- Parallel-unit CHP systems: \$3.0 million per MW
- 170°F CHC System: \$4,500 per ton
- HW or CHW TES: \$3 per gallon
- NPW storage: \$2 per gallon
- EC-WC HW connection: \$16 million
- EC-CC-WC HW connection: \$20 million
- 3.25 MW standby power unit: \$3.0 million each

Note that some capital investments are required in the same way for every alternative and are excluded from the analysis that compares alternatives. These additional capital expenditures are estimated to be \$54 million for the full buildout for the conventional portion of CCWP 3, \$5 million for NCSP, \$3 million for each additional 3.25 MW engine generator unit to expand above 20 MW of new standby power, \$20 million for electrical substation interconnects, chilled water, steam, and hot water distribution to new and renovated buildings, sustainable water project, and general maintenance and renewal.

Item	SHC	(2) 6 MW CHP	(2) 10 MW CHP	20 MW CHP (DE)	CHC	CHC w/ CC
Dedicated CC CHC?	Yes	Yes	Yes	Yes	Yes	-
WCSP Boiler 7	Yes	-	-	-	-	-
HW Hubs	3	3	3	3	-	-
CHP (MW)	-	12	20	-	-	-
CHC (tons)	-	-	-	-	5400	7200
CHW TES (Mgal)	-	-	-	-	2	2
HW TES (Mgal)	-	-	-	-	2	2.5
NPW Storage (Mgal)	2	2	2	2	-	-
Heating Connection (\$M)	-	-	-	5	16	20
Standby Power Units	8	4	-	-	7	7
Total (\$M)	74	88	100	45	100	87

Table 9.1 – Capital Cost Components for Alternatives

The alternatives under consideration will shift the balance of fuel supply for the district energy system. The future price of natural gas and electric pricing are variable and cannot be precisely predicted. The baseline results utilize the reference case projections for energy prices published by the U.S. Energy Information Administration in the 2018 Annual Energy Outlook for the South Atlantic region. Natural gas for boilers is assumed to be the price for industrial customers, electricity is assumed to be the price for industrial customers, and natural gas for CHP is assumed to be the price for electric power producers. Thirteen other cases of energy projections are included in the sensitivity analysis.

It is assumed the year that a new system would be constructed and placed in operation is 2025. All financial results are presented in 2017 dollars, using 3% fixed general inflation and 3% discount rate. Operating and maintenance costs, and the cost of water are assumed to increase equal to inflation. The 25-year present value factor for costs like this for the years of 2025 through 2049 in 2017 dollars is 25. Note that this factor equals the number of years because the discount rate and general inflation rate are equal in the model. The initial cost for water is \$0.01 per gallon. The initial cost for operating and maintenance are discussed below.

Construction cost estimates included in this report are all listed as 2017 dollars, but construction costs compared in the analysis are adjusted for inflation to 2025 and then discounted back to 2017 dollars. With the current inputs of equal discount rate and general inflation rate, the discounted future cost is the same as the 2017 cost.

Based on the reference case projections for energy prices published by the U.S. Energy Information Administration (EIA) in the 2018 Annual Energy Outlook for the South Atlantic region, and 3% general inflation with 3% discount, the present value factor for 25 years of each utility between 2025 and 2049 are:

- Industrial Natural Gas (for boilers): 27.7
- Electric Power Producer Natural Gas (for CHP): 28.7
- Industrial Electricity: 22.5

The above present value factors show that natural gas prices will escalate slightly more than general inflation and electricity prices will escalate slightly less than general inflation. The higher escalation for CHP natural gas prices relative to boiler natural gas prices is showing how the commodity cost and basis are expected to increase more than the local distribution charges. Overall the total present cost of natural gas for CHP is still less than the total present cost of natural gas for boilers because the current price is 20% lower.

Operating and maintenance cost are estimated for each alternative but only as a means of comparing the alternatives against each other. These estimates are not total operating and maintenance cost expectations for any system on campus, just the relative cost for items that are different in each option. This is important to include in the analysis because the CHP will cost more to operate and maintain than the other options. Unit factors are listed below for each component:

- CCWP 3 CHC system for Central Campus: \$4 per ton per year
- 80 kpph steam boiler or HRSG: \$800 per kpph per year
- Hot Water Plants: negligible
- CHP combustion turbine: \$0.009 per kWh per year
- 170°F CHC System: \$20 per ton per year
- HW or CHW TES: negligible
- NPW storage: negligible
- HW connections: negligible
- 3.25 MW standby power unit: \$10,000 each per year
- SUB Interconnects for CHP: negligible

The initial cost for carbon is based on Duke’s goal to be climate neutral by 2024. The only cost of carbon discussed in this report or included in the analysis is that associated with the district energy systems, including power for cooling, buildings, or heating, and natural gas for heating. Any fuel oil used for operating boilers or engine generators during testing or emergencies are excluded. Any fugitive emissions from refrigeration systems are excluded. Any transportation or

other reporting categories tracked by the Office of Sustainability are also excluded.

Duke's primary method for offsetting carbon emissions has been planned as reclaiming methane at swine farms in North Carolina and processing the biogas for addition to existing natural gas infrastructure. Using a global warming potential of 34 for the direct release of methane, 0.634 MTCDE/MMBtu emissions are reduced by capping lagoons and avoiding the release. The expected price of reclaiming and processing the biogas is \$20/MMBtu, so the effective carbon offset price is \$25.4/MTCDE. In this study, the initial price of carbon offsets has been selected as \$20/MTCDE with the assumption that Duke will ultimately purchase a mix of some lower priced offsets. It has been assumed that carbon offset costs will increase at the rate of general inflation. Other carbon offset prices are tested in the sensitivity analysis.

For Duke Energy CHP option, the model assumes that Duke University will purchase biogas for use on site equivalent to 11% of the CHP gas consumption to generate a carbon offset equal to the regional emissions added by the Duke Energy CHP plant. Avoiding 0.634 MTCDE/MMBtu methane release by capturing and using biogas versus typical 0.066 MTCDE/MMBtu for burning natural gas at a ratio of 11% biogas makes the CHP carbon neutral.

Table 9.2 below shows the first-year results for quantity of energy units and resulting operating costs for each option.

Item	SHC	(2) 6 MW CHP	(2) 10 MW CHP	20 MW CHP (DE)	CHC	CHC w/ CC
Regional Emissions Avoided (MTCDE)	Baseline	-17,000	-32,400	50,800	14,700	13,900
Site Water Consumption Avoided (MG)		0.7	1.4	1.1	23.4	23.4
Purchased Electricity Savings (GWh)		98.8	176.4	0	-13.2	-16.4
Gas Consumption Savings (DTx1000)		-622	-1,142	772	272	272
Carbon Cost (\$M)	4.9	5.2	5.5	3.9	4.6	4.6
Water Cost (\$M)	3.6	3.6	3.6	3.6	3.3	3.3
Electricity Cost (\$M)	30.2	26.1	22.6	30.2	30.8	30.8
Natural Gas Cost (\$M)	8.0	10.2	12.1	8.8	6.8	6.8
Maintenance Cost (\$M)	0.2	1.1	1.9	0.0	0.2	0.2
Annual Cost Savings (\$k)	-	550	1,120	390	860	790

Table 9.2 – Energy Quantity and Cost Results for First Year

Using the first-year results for quantity of energy units and resulting operating costs for each option from above, and the present value factors described previously, a 25-year life cycle cost comparison was developed, and the results are shown in Figure 9-8 below. For the baseline option and the eight alternatives, the total 25-year present cost of each component is presented as a stacked column chart, with gray for capital cost, orange for natural gas cost, yellow for electricity cost, blue for water cost, light orange for operations and maintenance cost, and green for carbon offset cost. The total 25-year present cost is labeled at the top of each column.

The chart also shows icons representing the relative amount of regional carbon emissions (green leaf icon), site water consumption (blue water droplet icon), electricity consumption from the grid (lightning bolt in yellow triangle icon), and site natural gas consumption (orange flame icon). All the icons in the SHC case are centered vertically on the chart. The icons move for the alternatives relative

to the baseline with 75% decrease at the bottom of the chart and 75% increase at the top of the chart.

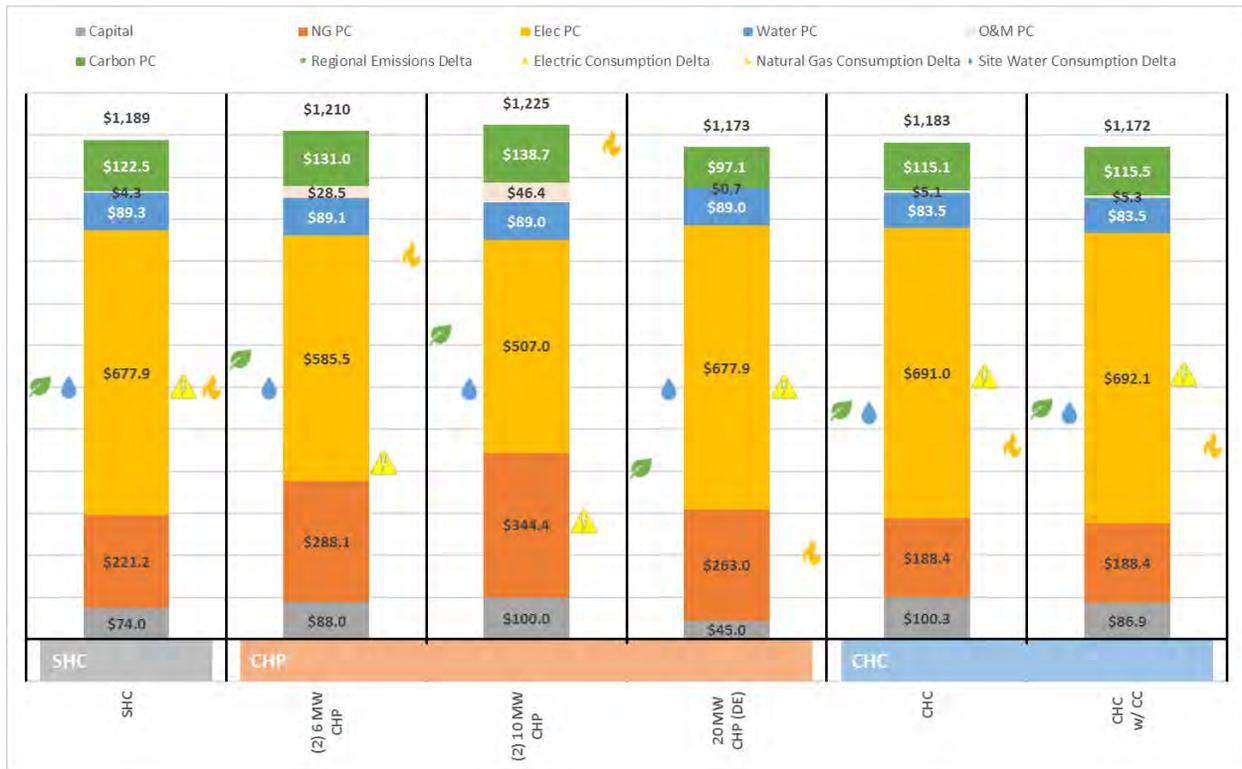


Figure 9-8 – Total Present Cost (million dollars) for Alternatives

The results of the total present value comparison are dependent on many factors, all of which are adjustable in the model. Some selected uncertain input parameters have been tested for sensitivity as listed below:

- The baseline results use the U.S. EIA reference case for future energy prices. It is impossible to accurately project these prices because of unknowns regarding economic growth, future oil prices, domestic energy resources, and technological change; therefore, the U.S. EIA has also included side case data in the 2018 Energy Outlook that was tested in the Duke alternatives life cycle cost analysis relative to the reference case. There are six side cases that are listed and described below in addition to the reference case. Each of the seven cases is also tested with or without the Clean Power Plan (CPP) included.
 - **Reference:** Includes population growth of 0.6%/year, nonfarm employment growth of 0.7%/year, and productivity growth of 1.6%/year. Real Gross Domestic Product (GDP) increases by 2.0%/year and growth in real disposable income per capita averages 2.2%/year. Real oil prices in 2017 dollars steadily rise from \$52/b in 2017 to almost \$114/b by 2050.
 - **High Economic Growth:** Includes population growth of 0.8%/year, nonfarm employment growth of 0.9%/year, and

productivity growth of 2.0%/year. Real Gross Domestic Product (GDP) increases by 2.6%/year and growth in real disposable income per capita averages 2.5%/year.

- **Low Economic Growth:** Includes population growth of 0.5%/year, nonfarm employment growth of 0.5%/year, and productivity growth of 1.2%/year. Real Gross Domestic Product (GDP) increases by 1.5%/year and growth in real disposable income per capita averages 2.0%/year.
- **High Oil Price:** Real oil prices in 2017 dollars steadily rise from \$52/b in 2017 to almost \$230/b by 2050.
- **Low Oil Price:** Real oil prices in 2017 dollars fall to \$27/b in 2017 and only rise to \$52/b by 2050.
- **High Oil and Gas Resource and Technology:** Oil and gas recovery per well drilled in the United States, including Alaska and offshore, is assumed to be 50% lower than in the reference case. Technological improvements reducing costs and increasing productivity for oil and gas drilling are also assumed to be 50% lower than in the reference case.
- **Low Oil and Gas Resource and Technology:** Oil and gas recovery per well drilled in the United States, including Alaska and offshore, is assumed to be 50% higher than in the reference case. Technological improvements reducing costs and increasing productivity for oil and gas drilling are also assumed to be 50% higher than in the reference case.
- **Clean Power Plan:** The Obama Administration unveiled the Clean Power Plan (CPP) on August 3, 2015, designed to lower carbon dioxide emissions from coal-fired power plants by 32% by 2030 by introducing renewable generation to the grid that decreases dependency on coal-fired plants. The Trump administration has argued the plan is not legal per current laws and has placed it under review. The U.S. EIA cases can be adjusted assuming compliance with the CPP or not. When testing with CPP compliance, the resulting escalation of electricity prices are higher, which may or may not be realized for Duke University as a customer of Duke Energy which already operates one of the cleanest electric generation fleets in the country.
- The baseline results assume that Duke Energy does not change Duke University's electric contract if CHP is added, but there would be an adjustment equivalent to 2.5% higher cost of electricity for the remaining power that is purchased. The sensitivity test results also include the current electric contract without any adjustment, or the current electric contract with a 5% increase. The sensitivity test results also include transition to one of the published Duke Energy electric tariffs, such as OPT-V, LGS, or PG. It is assumed for these other tariffs that only substation 4 where the CHP would be connected is affected by the rate structure change. The cost of the remaining electricity purchase is so high on the LGS or PG rate structures that these results are filtered out of the

sensitivity test results because CHP cannot be justified. Based on very preliminary conversations with Duke Energy, it appears likely that the existing rate structure can be maintained if CHP is added.

- The baseline results assume a carbon offset price of \$20/MTCDE. The sensitivity test results also include \$10/MTCDE and \$0/MTCDE. Since the relative amounts of regional carbon emissions are not significantly different among the alternatives, these sensitivity tests do not have much impact on the results.
- The baseline results assume an electric grid carbon intensity of 0.22 MTCDE/MWh as is projected by Duke Energy for the future. The sensitivity test results also include 0.31 MTCDE/MWh matching the 2017 average, and 0.44 MTCDE/MWh, which has been calculated as the emissions associated only with the natural gas fired generation plants on the grid since those are likely the net asset that would be reduced if a new generating source is added at Duke.
- The baseline results assume that the new CHP is connected on the campus side of the 44-kV substations. The sensitivity test results also include a CHP connection directly to the 44-kV distribution with a new 44 kV single meter for the entire site. This avoids the complexity on campus for electrical interconnections to consolidate enough load to operate CHP, but it also means that the electricity lost in transformation at the substations would have to be purchased from Duke Energy. There may also be additional facility charges applied by Duke Energy for this scenario that have not currently been included.

The above sensitivity test scenarios result in 1,260 combinations that the model calculates and returns the net present value, discounted payback, and annualized gain or loss for each of the eight alternatives to the baseline SHC system. Figure 9-9 below shows a box and whisker chart for 378 of the sensitivity scenarios, filtering out those that test CHP on the Duke Energy LGS or PG tariff because those create very negative results for the CHP options resulting in excessive annualized losses. The results as if the campus was metered at a single point on the 44 kV system are also filtered out because it is not certain if that option is agreeable to Duke Energy. As shown in the chart, at least three quartiles of the CHP scenarios result in increased annual operating cost. The Duke Energy 20 MW CHP shows annual operating cost decrease for more than half of the results and is the lowest risk because it is an upfront capital cost savings. The CHC systems show annual operating cost decrease for almost every scenario tested.

Complete tabulated results of the sensitivity analysis are available upon request.

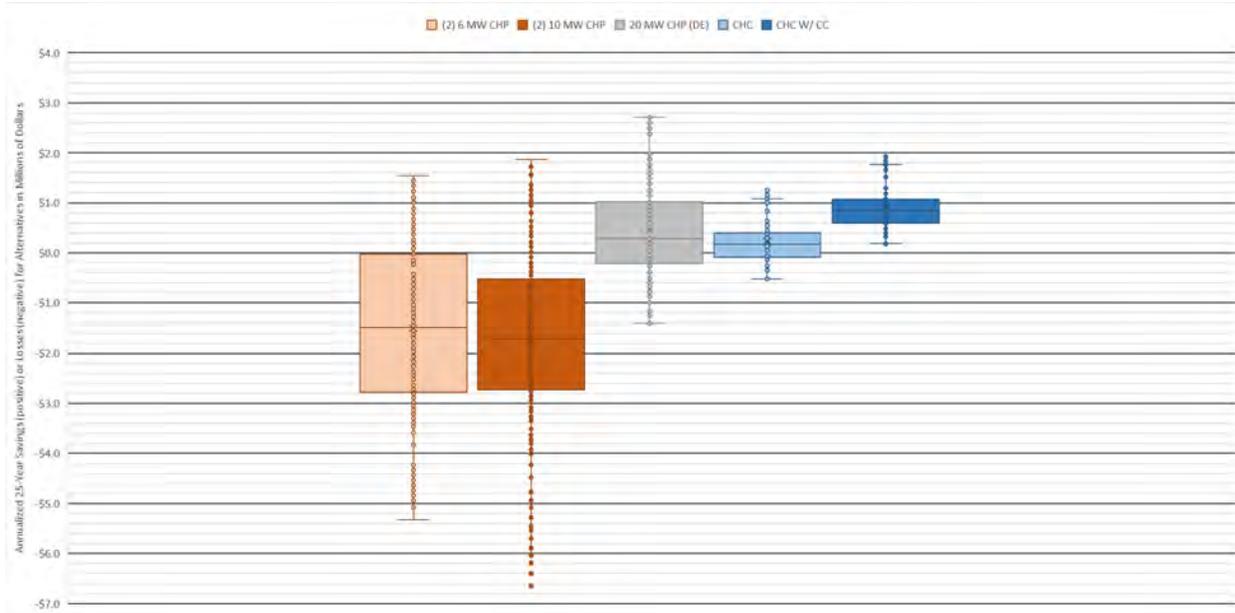


Figure 9-9 – Sensitivity Test Results: 25-Year Annualized Cost Gain or Loss (Boxes)

The box and whisker chart above is a quick visual representation of the result statistics but does not make it clear which inputs lead to which results. The bar chart shown in Figure 9-10 on the next page shows the same information but with the input results listed. The inputs are nested on the independent axis. The first input is a Yes or No for whether the CHP is connected to 44 kV. The second input is the electrical contract OPT-V or the OPT-V-DU to note the current electrical contract that is time-of-use similar to OPT-V. The next input is the grid carbon intensity, which has been filtered here to 0.22 MTCDE/MWh to limit the results. Following is the carbon offset price, which has been filtered here to \$20/MTCDE to limit the results. Next, is the percent adjustment to the electrical contract if CHP is added, followed by whether the CPP is included. Finally, are the seven U.S. EIA cases for future energy prices. The color-coding matches that of the box and whisker chart.

It can quickly be seen that all the CHC options (blue) result in annualized savings (positive). It can also be seen that the high oil and gas resource and technology side case or the low economic growth side case result in less CHP losses, but very few of the CHP scenarios generate annualized savings. The high oil and gas resource and technology side case lowers the cost of natural gas, and the low economic growth side case increases the cost of electricity.

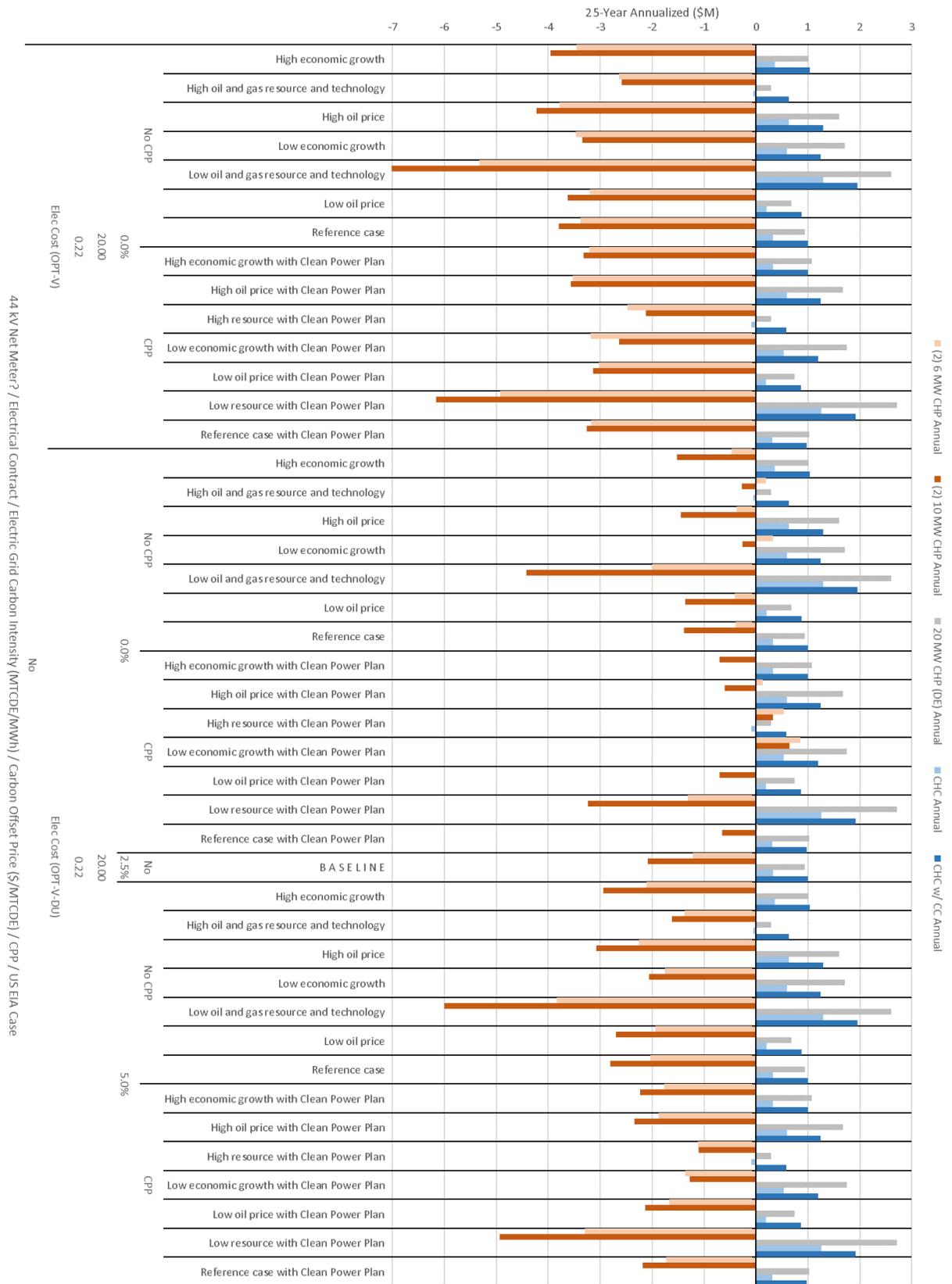


Figure 9-10 – Sensitivity Test Results: 25-Year Annualized Cost Gain or Loss (Bars)

9.4 CHALLENGES TO IMPLEMENTATION

A major challenge for installing a CHP system on campus is the district power system consisting of five interconnected campus substations. Even though there is a base power demand on campus of 40,000 kW, that load is only on the 44 kV Duke Energy distribution upstream of the substations and does not exist in any single location on Duke's campus. Note that the Duke Energy owned CHP is advantageous because of access to 44-kV distribution loop and they can utilize a single, more efficient, 20 MW or larger unit.

The current published rate structure (PG) that allows for direct connection from the CHP to the 44-kV distribution loop is not favorable and eliminates the potential for CHP payback. If Duke University installs their own CHP, they should attempt to negotiate a rate structure that provides access to the 44-kV distribution loop since it is the simplest way to distribute capacity amongst existing substations and it allows for a single, more efficient, 20 MW or larger unit.

If Duke University cannot negotiate a direct connection to the 44-kV distribution loop, then consolidating loads on Duke's campus limits the size potential for a CHP system to two 6 MW units to two 10 MW units, since the power distribution needs to occur through Duke University owned 12.47-kV substation interconnects:

To consolidate a base load for two 6 MW units:

- Utilize existing interconnect to shift the entire SUB 7 load to SUB 4.
- Utilize planned interconnect to shift half the SUB 3 building load to SUB 4.
- Utilized planned interconnect to shift half the SUB 5C load to SUB 4
- Parallel one unit with one existing substation transformer to maintain current system operations and maximize resiliency
- See Figure 9-11 for the new future SUB 4 load profile.

To consolidate a base load for two 10 MW units:

- Utilize existing interconnect to shift the entire SUB 7 load to SUB 4.
- Utilize planned interconnect to shift half the SUB 3 building load to SUB 4.
- Utilized planned interconnect to shift the entire SUB 5C load to SUB 4
- Parallel one unit with one existing substation transformer to maintain current system operations and maximize resiliency
- See Figure 9-12 for the new future SUB 4 load profile.

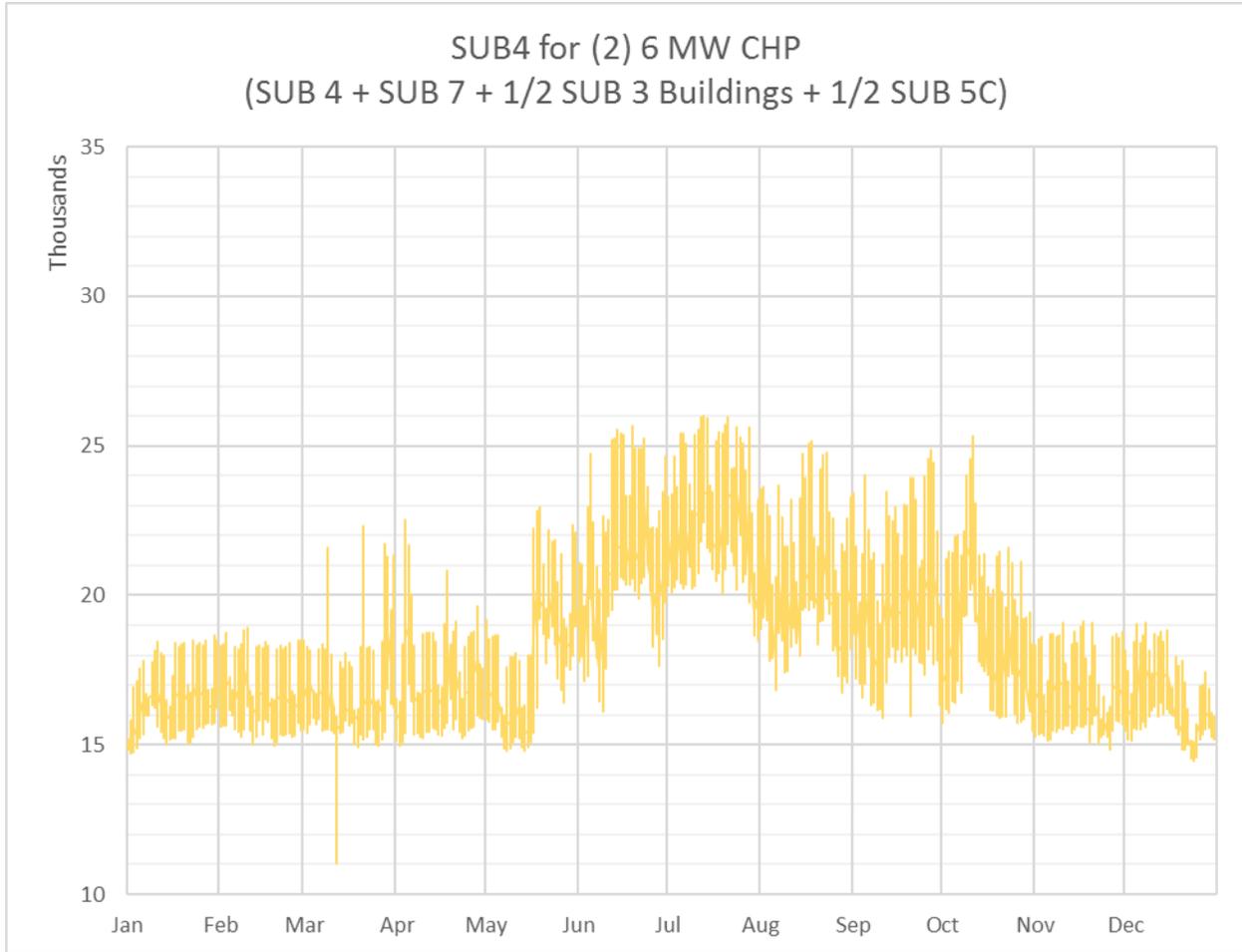


Figure 9-11 – SUB 4 Load for (2) 6 MW CHP Includes: SUB 4, SUB 7, 50% SUB 3 non-cooling, 50% SUB 5C non-cooling

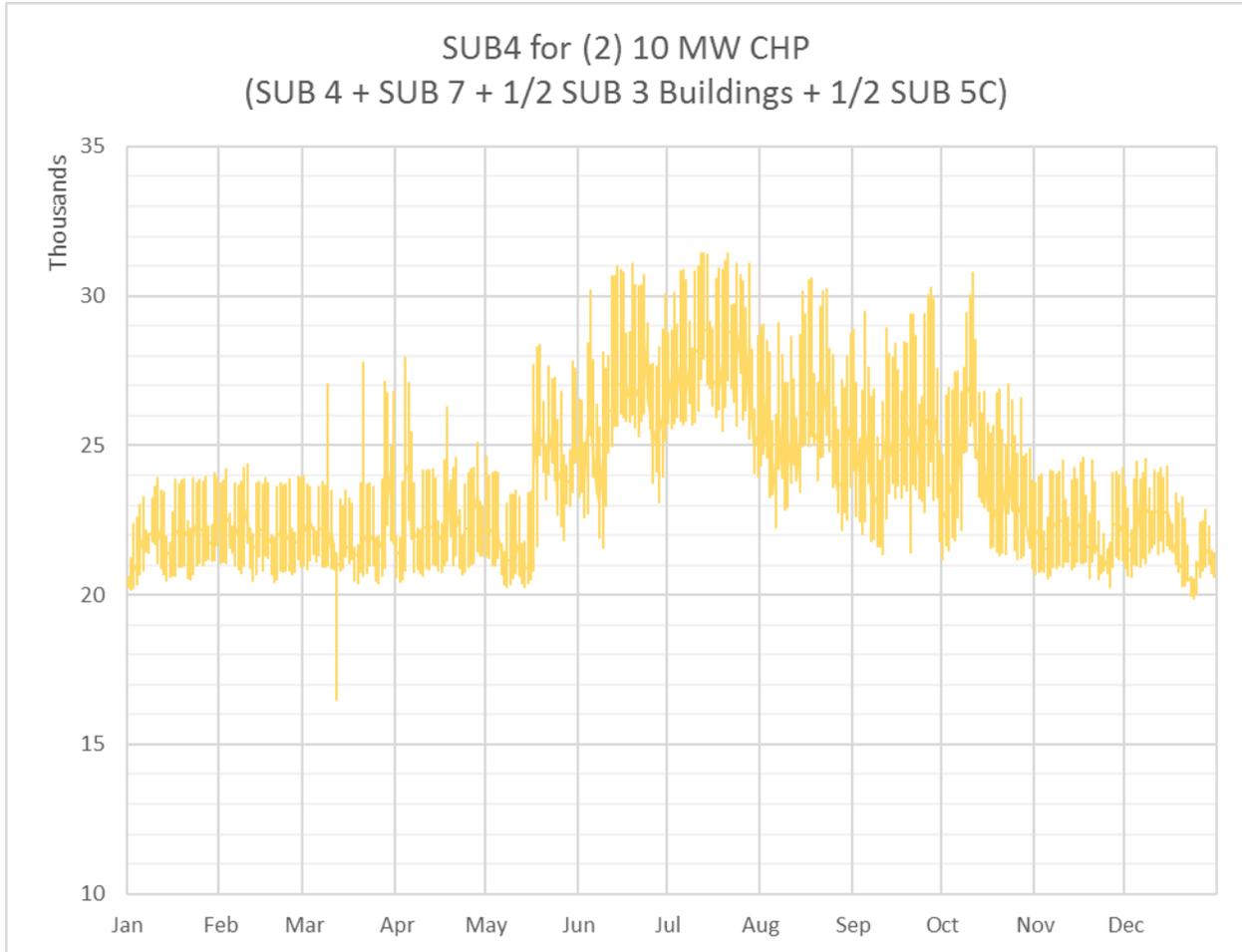


Figure 9-12 – SUB 4 Load for (2) 10 MW CHP Includes: SUB 4, SUB 7, 50% SUB 3 non-cooling, SUB 5C non-cooling

A larger single CHP output could be connected to the Duke Energy 44 kV distribution, but that is not behind the existing utility meter, and the applicable tariff for exporting site generation is not economically viable for operating CHP. Since Duke University is the only customer on the 44-kV distribution, if power could be metered at the 44-kV source instead of at each substation then a CHP on the 44-kV distribution would still be behind the meter. This arrangement could be favorable for CHP if it does not cause a change to the current time of use rate structure but would have to account for approximately 5% losses at the 44 kV transformers.

The current electric rate structure is based on time-of-use similar to the OPT-V tariff. It has not been determined how Duke Energy will adjust Duke University’s electric rate structure if CHP is added on campus. Based on very preliminary conversations with Duke Energy, it appears likely that the existing rate structure can be maintained if CHP is added. The sensitivity test scenarios include the current rate structure, the current rate structure with 5% penalty, the OPT-V tariff, the LGS tariff, and the PG tariff. Another option that has not been tested is the HP tariff where real-time costs of net generation are charged on an hourly basis with one day notice. HP has not been tested because the hourly pricing data was not available at the time of this report, but it is recommended this be studied in more detail. The baseline results use the current rate structure with a 2.5% penalty. The value of the electricity generated by the various CHP sizes on each tariff are listed in Table 9.3 below, where it is assumed that only substation 4 where CHP is connected might result in a different tariff requirement. These values are calculated as the total change in site electricity cost divided by the amount of energy produced at the CHP.

Electric Tariff	Value of Electricity Generated by CHP (\$/MWh)	
	(2) 6 MW	(2) 10 MW
Current	62	60
Current +2.5% (baseline)	54	56
Current +5%	45	52
OPT-V	32	46
LGS	22	44
PG	0	21
HP	TBD	TBD

Table 9.3 – Value of Electricity Generated by Various CHP Sizes per Tariff

There are also major challenges associated with the implementation of the CHC system. These challenges include:

- The best CHC arrangement interconnects the West Campus, East Campus, and Central Campus hot water systems. This requires large bore piping to connect CCWP 1 site, CCWP 3 site, and East Campus (along Campus Drive), which is very difficult and costly to install. Although CHC options that do not require these interconnections are available, they would be more operationally complex. As previously described, the CHC options are best suited for the East and Central Campuses.
- The use of CHC requires TES tanks, both hot and cold, to properly balance the loads and maintain the heat pump chiller operation at or near a fully loaded level. If TES tanks are not used, excess heat must be rejected to cooling towers, which is not as efficient.
- The use of fully loaded heat pump chillers in the CHC option will require starting and stopping these chillers unlike a typically conventional chiller that operates more continuously with load modulation. This cycling will create operational complexity with the existing chilled water plants, requiring them to react more rapidly.
- The use of heat pump chillers for the winter base cooling load will eliminate the need to operate the VFD chillers as much to meet low loads. Although they will still operate efficiently for the remaining load, this will impact their hours of operation and resulting savings, but the overall system will be more energy efficient.
- Commercially available heat pump chillers are limited to a hot water supply temperature of approximately 170°F, which requires an investigative effort at each connected building to assess and review the hot water temperature limitations for the existing HVAC equipment. Some of the building systems could require modifications to accommodate the lower heating supply temperature.