BEFORE
THE OHIO POWER SITING BOARD

In the Matter of the Application of The Ohio State University for a Certificate of Environmental Compatibility and Public Need for a Combined Heat and Power Generating Facility in Franklin County, Ohio	)))))	Case No. 19-1641-EL-BGN

DIRECT TESTIMONY OF

SERDAR TUFEKCI

ON BEHALF OF
THE OHIO STATE UNIVERSITY

July 6, 2020

I. INTRODUCTION, BACKGROUND, AND EXPERIENCE

Q. Please state your name, title, and business address.

A. My name is Serdar Tufekci. I am an employee of ENGIE North America, and I have been appointed as the CEO of Ohio State Energy Partners ("OSEP") since June 2017. OSEP is a 50/50 joint venture between ENGIE North America and Axium Infrastructure. OSEP is signatory to the Long-Term Lease and Concession Agreement ("Concession Agreement") for The Ohio State University ("Ohio State") Utility System. My business address is 2001 Millikin Rd, Suite 200, Columbus, Ohio 43210, which is on Ohio State's Columbus Campus, next to Ohio Stadium.

Q. What are your duties as the CEO of OSEP?

A. I am responsible and accountable for managing and delivering all requirements of the Concession Agreement to OSEP's customer, Ohio State. These requirements include:

- Efficient and reliable operations and maintenance of the utility system and services: providing electricity, steam, heating hot water, chilled water, and natural gas within the boundaries of the Columbus Campus of Ohio State.
- Reducing the total energy consumed per square foot on the Columbus Campus by at least 25% within 10 years through a series of energy conservation measure projects.
- Upon a request from Ohio State, providing market intelligence to Ohio State for procurement of natural gas and electricity commodity supplies.
- Managing the Academic Collaboration program, which includes faculty endowments, student scholarships, internships, and collaborative research. I am also a member of the committee that oversees the design and construction of the Energy Advancement and Innovation Center, which will be the cornerstone of the Innovation District being developed on Ohio State's Columbus Campus.

- Finally, and most important, I manage the design, development, and construction of all capital improvement projects on the utility system of Ohio State's Columbus Campus. The subject project for my testimony today is one of the many capital improvement projects I oversee on behalf of OSEP for Ohio State. Notably, OSEP receives no additional benefit connected to the type of technology utilized in capital improvement projects at Ohio State, including but not limited to the combined heat and power plant (CHP) proposed in the Application.

Q. What is your educational and professional background?

A. I graduated from Istanbul Technical University in 1992 with a B.S. degree in Mechanical Engineering, and received my M.S. degree from The Ohio State University in 1994, also in Mechanical Engineering. I received my executive MBA degree from Purdue University in 2010. I have a professional engineering license from the Commonwealth of Massachusetts since 2003, and have been a Fellow Chartered Engineer at the Institute of Mechanical Engineers in London, U.K since 2011.

After receiving my graduate degree from Ohio State, I worked in the manufacturing industry in Ohio and Japan for 3 years. I joined the power industry in 1997 and worked in design, construction, engineering, and operations functions of electricity generation projects in Turkey, the United Kingdom, and the United States for a global energy firm called International Power for fourteen years. I joined ENGIE North America in 2011 through its acquisition of International Power. Prior to my current role as OSEP CEO, I was the Vice President of Engineering and Construction for ENGIE North America, based in Houston, Texas. The last few projects that the team I led built for ENGIE North America are a wind farm on Vancouver Island, Canada, a solar farm in Holyoke, Massachusetts, a solar farm in Alpine, Texas, and a CHP in Mexico.

In 2017, upon the execution of the Concession Agreement, I moved to Columbus and began in my current title and role.

Q. On whose behalf are you offering testimony?

A. I am testifying on behalf of the Applicant, Ohio State, in my capacity as OSEP CEO.

Q. What is the purpose of your testimony?

A. I will provide background concerning the design and location of the CHP and the development and content of the studies submitted with the Application. I will sponsor the admission of those studies and portions of the Application into evidence.

Q. Is the Application, and all exhibits and appendices that you will be sponsoring for admission into evidence, true and accurate to the best of your knowledge?

A. Yes, they are. The Application and exhibits thereto were filed November 6, 2019 on the public docket in this matter and are incorporated herein by reference as Applicant Exhibit 1.

Q. Do you agree with Applicant Witness Scott Potter's direct written testimony as to the summary, overview, and purpose of the proposed project and facility?

A. Yes.

Q. Were you involved in the site selection process for the CHP?

A. Yes. In coordination with Ohio State, we viewed multiple sites on Ohio State's Columbus Campus, including sites east and west of the Olentangy River and State Route 315 as part of the selection process.

Q. Did you engage and oversee any study relative to the suitability of sites for the Project?

A. Yes, the site selection process was considered during the feasibility study and refined during the preliminary design phase. Each location was assessed for whether it enabled or restricted the CHP's ability to serve all of Ohio State's Columbus Campus with power and heat through a direct distribution system and tie into existing utility systems. The selected site is located just east of State Route 315 in roughly the middle of the Columbus Campus. This location – where a significant portion of Ohio States future growth is planned – provides access to the area west of Kenny Road for utility services via a new district heating and cooling network that is designed to be built concurrently with the CHP. Additionally, this location makes it possible to use existing distribution facilities, which enables the CHP facility to provide resiliency in the event of power outage events and which can only be addressed through an on-campus facility.

The proposed site was also studied for potential impacts on ecological and cultural considerations. The study results showed minimal impacts from disturbance and negligible expected impacts to soil, water, vegetation, cultural resources and wildlife.

Q. Were you involved in the design of the proposed facility?

A. Yes. I was involved in and led the development of the design for the CHP from concept to schematic design to presentation of the description and design in the Application. I was also involved in designing the building, facility layout, and major components of the facility, including but not limited to the types of generation equipment. See Exhibit D to Application: Preliminary CHP Architectural Design Plan; General Arrangement (attached hereto as Applicant Exhibit 2); and CHP Architecture Concept (attached hereto as Applicant Exhibit 3).

Q. Were alternative facility layouts and site designs considered?

A. Yes. A number of different configuration and combustion turbine generator (CTG) models were considered, with the goals of: providing the needed output capacities, fitting the CHP within a defined footprint to minimize impact on the surrounding roads, infrastructure, and buildings during construction, providing the highest level of thermal efficiency, enabling combustion of green hydrogen (H_2) blended into natural gas, and avoiding disruption to existing facilities once operational. The location of the CHP just east of the State Route 315 freeway means Ohio State can grow efficiently and economically in that location because each new building can be connected to the CHP.

We also prepared a detailed feasibility study for the facility, which includes consideration of a number of different layouts, components, and site designs. A redacted copy of the feasibility study is attached hereto as Applicant Exhibit 4. The confidential version of the feasibility study was previously provided to OPSB Staff.

Q. Were you involved in evaluating the CHP's planned interconnection to the existing regional electric grid?

A. Yes. Ohio State has an existing substation, called OSU Substation (referred to in the Application as Buckeye Substation). With the idea of minimizing Ohio State's required capital investment, the CHP design includes connection to the OSU Substation.

Q. Were you involved in assessing the economic impact of the proposed CHP?

A. Yes. We prepared all economic evaluations for the project relative to up-front costs and long-term operating costs and presented them to Ohio State. These calculations considered a variety of alternatives and sensitivities. All of the calculations demonstrated significantly positive economic impacts for Ohio State in terms of both decreased expenses and decreased carbon footprint.

Q. Were you involved in assessing the anticipated operation and maintenance expenses of the proposed CHP?

A. Yes. We provided all inputs to Ohio State used in operation and maintenance expense calculations based on industry norms and ENGIE North America's experience in operating and maintaining similar facilities across North America.

Q. Were you involved in engaging and overseeing any studies to assess the environmental effects of the proposed CHP, including whether it meets Air, Water, Solid Waste, and Aviation requirements under OAC 4906-4-07?

A. Yes. We were involved in the assessment of the potential environmental effects of the CHP. For a number of these studies, as detailed below and attached as Exhibits to the Application, we engaged TRC, a leading firm providing environmental and other consulting services, to assist with regard to review of data, modeling, and preparation of supporting studies for the Project. Based upon my knowledge, information, experience, and review of the applicable documentation and studies, I conclude Applicant has met, or will have met, all the appropriate environmental requirements for its proposed facility under OAC 4906-4-07.

Q. Describe the process and information considered to ensure the CHP meets the requirements in OAC 4906-4-07(B) relative to compliance with air quality regulations?

A. In coordination with Ohio State and TRC, we undertook comprehensive study of data and potential impacts of the CHP on air quality. Further information is set forth in detail in the Application. By way of example, we studied the ambient air quality data for Franklin County, Ohio. The CHP was designed to utilize state-of-the-art pollution control equipment. Specifically, each heat recovery steam generator (HRSG) will be equipped with an air emission control block consisting of an oxidation catalyst followed in series by a selective catalytic reduction (SCR) system. The oxidation catalyst will reduce carbon monoxide (CO) emissions by at least 85%. This unit will also reduce volatile organic compounds (VOCs) and organic hazardous air pollutants (HAPs) by at least 50%. The SCR system is designed to achieve a minimum of 85% nitrogen oxide (NOx) reduction. As set forth in the Application, the design and equipment selected for the CHP were done to ensure best available technology (BAT) to control air emissions.

The project was also reviewed for applicability of regulatory requirements, including Major New Source Review – Prevention of Significant Deterioration (PSD). In this regard, Ohio State followed the process for and the CHP has received an exemption from the Ohio Environmental Protection Agency (OEPA) from undergoing review under PSD regulations under OAC 3745-31-13(D)(1), applicable to non-profit health and non-profit educational institutions. During the process for seeking the applicable exemption with OEPA, opportunities for objection and public comment were provided, and none were submitted.

Further, an air quality analysis was prepared in accordance with Engineering Guide #69. The dispersion modeling clearly demonstrated protection of air quality in the areas within the 2,000-meter modeled area near the CHP facility.

The CHP was also analyzed and the plans comply with the requirements of:

- New Source Performance Standards (40 C.F.R. Part 60);
- National Emission Standards for Hazardous Air Pollutants (40 C.F.R. Part 63);
- Ohio NOx Budget Trading Program (OAC Chapter 3745-14); and
- Ohio NOx Reasonably Available Control Technology (RACT) Rules (OAC Chapter 3745-110).

All required permits have been obtained. See Exhibit I to Application: OPEA Air Permit to Install (PTI).

Additionally, analysis was conducted on the effects of both construction and operation of the CHP on air quality. With regard to construction, emissions will consist mainly of relatively minor emissions from construction equipment and from fugitive dust emissions. With regard to operation, OEPA operates an ambient air quality monitoring network in Franklin County, which will account for air emissions from the CHP. The modeling results, as shown in Table 18 of the Application, show that even using worst-case results, the CHP is modeled to have acceptable air quality impacts.

Since the filing of the Application, TRC performed an air quality modeling and analysis exercise regarding the impact of the CHP in order to review and address concerns raised by Sierra Club specifically about air quality for Franklin County and sensitive "neighbors." That modeling was done using a conservative approach, including using the National Ambient Air Quality Standards (NAAQS), which are reflective of protection of sensitive populations and considering a series of "highest" potential emission criteria, including:

- Location: The highest predicted impact within the air modeling grid and the highest predicted impact within the group of nearby sensitive receptors.
- Weather: The highest annual predicted concentrations based on 5 separate years of meteorological data; the highest 24-hour calendar day concentrations based on 1,826 days of meteorological data, the highest 1-hour concentrations based on 43,824 hours of meteorological observations.
- Operational: The CHP operating scenario (out of a group 12 CHP operating scenarios modeled) that produced the highest predicted impact(s).

The results showed:

- Franklin County is in attainment for all NAAQS. The CHP will have a negligible impact on the existing air quality in Franklin County and will not affect its attainment status for any pollutant.
- The air quality analysis has specifically targeted potential sensitive receptor locations surrounding the project site, including the OSU Wexner Medical Center. The highest predicted impacts at these locations are only minimally above the background concentrations and by themselves generally represent less than two percent at the highest impact location of the corresponding Primary NAAQS established to protect human health and particularly vulnerable populations on an annual basis.
- The impacts due to the CHP are predicted to be negligible at the OSU Wexner Medical Center.
- The model predicted project impacts are very small in comparison to the existing background concentrations and based upon current monitoring data would not be predicted to contribute to exceedances of any NAAQS. The model predicted impacts met OEPA's definition of *de minimis* impacts for air permitting.

Q. Describe the process and information considered to ensure the CHP meets the requirements in OAC 4906-4-07(C) relative to compliance with water quality regulations?

A. In coordination with Ohio State and TRC, we identified all required permits and programs for the installation and operation of the CHP. Incorporated into the Application are descriptions and plans relative to water pollution control equipment and treatment processes, erosion control, and monitoring during and after construction. Further, in May 2019, TRC conducted and prepared a Surface Waters Report, attached to the Application as Exhibit R. The Surface Waters Report concluded there are no wetlands or streams identified within the area to be disturbed for the project.

Q. Describe the process and information considered to ensure the CHP meets the requirements in OAC 4906-4-07(D) relative to compliance with solid waste regulations?

A. In coordination with Ohio State and TRC, we assessed the nature of solid waste associated with construction and operation of the CHP, as well as appropriate plans to deal with waste during both construction and operation. Further, Ohio State has a waste management plan for all new construction, which will be followed.

Q. Describe the process and information considered to ensure the CHP meets the requirements in OAC 4906-4-07(E) relative to compliance with aviation regulations?

A. In coordination with Ohio State and TRC, we assessed the location of the CHP proposed site relative to public use airports, helicopter pads, and landing strips. Notification letters to the owners of applicable facilities were provided. See Exhibit M to Application: Letter of Notification to The Ohio State University Medical Center Heliport Facility.

Since filing the Application, three FAA filings, one for each stack and one for the CHP building, have been submitted. No building or stack lighting requirements have been identified by the FAA. An additional FAA filing may be submitted for the construction crane, which will be handled by the crane subcontractor, as necessary.

Q. Were you involved in assessing whether the CHP meets the requirements in OAC 4906-4-08 relative to health and safety, land use, and ecological information?

A. Yes.

Q. Describe the process and information considered to ensure the CHP meets the requirements in OAC 4906-4-08(A) relative to health and safety?

A. In coordination with Ohio State and TRC, we assessed in detail all of the following factors, as set forth in the Application and Exhibits thereto: (1) Safety and Reliability of Equipment; (2) Failures of Air Pollution Controls; (3) Noise; (4) Water Impacts; (5) Geological Features; (6) Wind Velocity; and (7) Blade Sheer (N/A); (8) Ice Throw (N/A); (9) Shadow Flicker (N/A); (10) Radio and TV Reception (N/A); (11) Radar Systems (N/A); (12) Navigable Airspace Interference; and (13) Communication Interference (N/A).

Further, on May 16, 2019, TRC conducted a Baseline Ambient Sound Study and produced a report, which is Exhibit P to the Application.

Q. Describe the process and information considered to assess whether the CHP meets the requirements in OAC 4906-4-08(B) regarding ecological resources?

A. In coordination with Ohio State and TRC, we conducted mapping relative to the CHP. Additionally, on May 7, 2019, TRC conducted and prepared a report of its survey of wetlands, streams, vegetation, and ecological features, included as Exhibits R and S with the Application. TRC also performed a literature review survey of plant and animal life (Exhibit S).

A United States Fish and Wildlife Service (USFWS) Information for Planning and Conservation search was completed for the project study areas on February 1, 2019. An environmental review request was sent to the Ohio Department of Natural Resources (ODNR) on December 31, 2018 (Exhibit S). ODNR's response indicated no rare or endangered species, unique ecological sites, geologic features, animal assemblages, scenic rivers, state wildlife areas, nature preserves, parks or forests, national wildlife refuges, or other protected natural areas within a one-mile radius of the project area.

A Technical Assistance request was sent to USFWS on December 31, 2018, and USFWS's response indicated that there are no federal wilderness areas, wildlife refuges or designated critical habitat within the vicinity of the project.

A field survey was also conducted and showed that the entire proposed disturbance area is comprised of previously disturbed urban lands.

Q. Describe the process and information considered to assess whether the CHP meets the requirements in OAC 4906-4-08(C) regarding land use and community development?

A. In coordination with Ohio State, mapping was conducted and it was determined that the facility is located entirely within and adjacent to State of Ohio property, and that all adjacent structures are controlled by Ohio State. The CHP will have negligible impacts on land uses for land adjacent to and in the vicinity of the CHP. Few structures will be removed or moved.

The CHP plans are also compatible with regional plans and will have a negligible, if any, impact on regional development.

Q. Describe the process and information considered to assess whether the CHP meets the requirements in OAC 4906-4-08(D) regarding cultural and archaeological resources?

A. In coordination with Ohio State and TRC, this work consisted of mapping landmarks of cultural significance and recreational areas within a 10-mile radius, considering the estimated impacts on landmarks and recreational areas, and considering the visual impacts. Relevant correspondence and documentation is included with the Application as Exhibit T.

Q. Describe the process and information considered to assess whether the CHP meets the requirements in OAC 4906-4-08(E) regarding agricultural districts and potential impacts to agricultural land?

A. No agricultural districts or agricultural land are located in or near the project area.

Q. Has the CHP facility been designed to achieve minimum adverse impacts?

A. Yes. Ohio State has designed the CHP facility to minimize or eliminate potential impacts of construction and operation, as set forth in greater detailed in the Direct Testimony of Scott Potter. I have reviewed this testimony and concur.

Q. Are there any other matters you would like to bring to the Board's attention?

A. No.

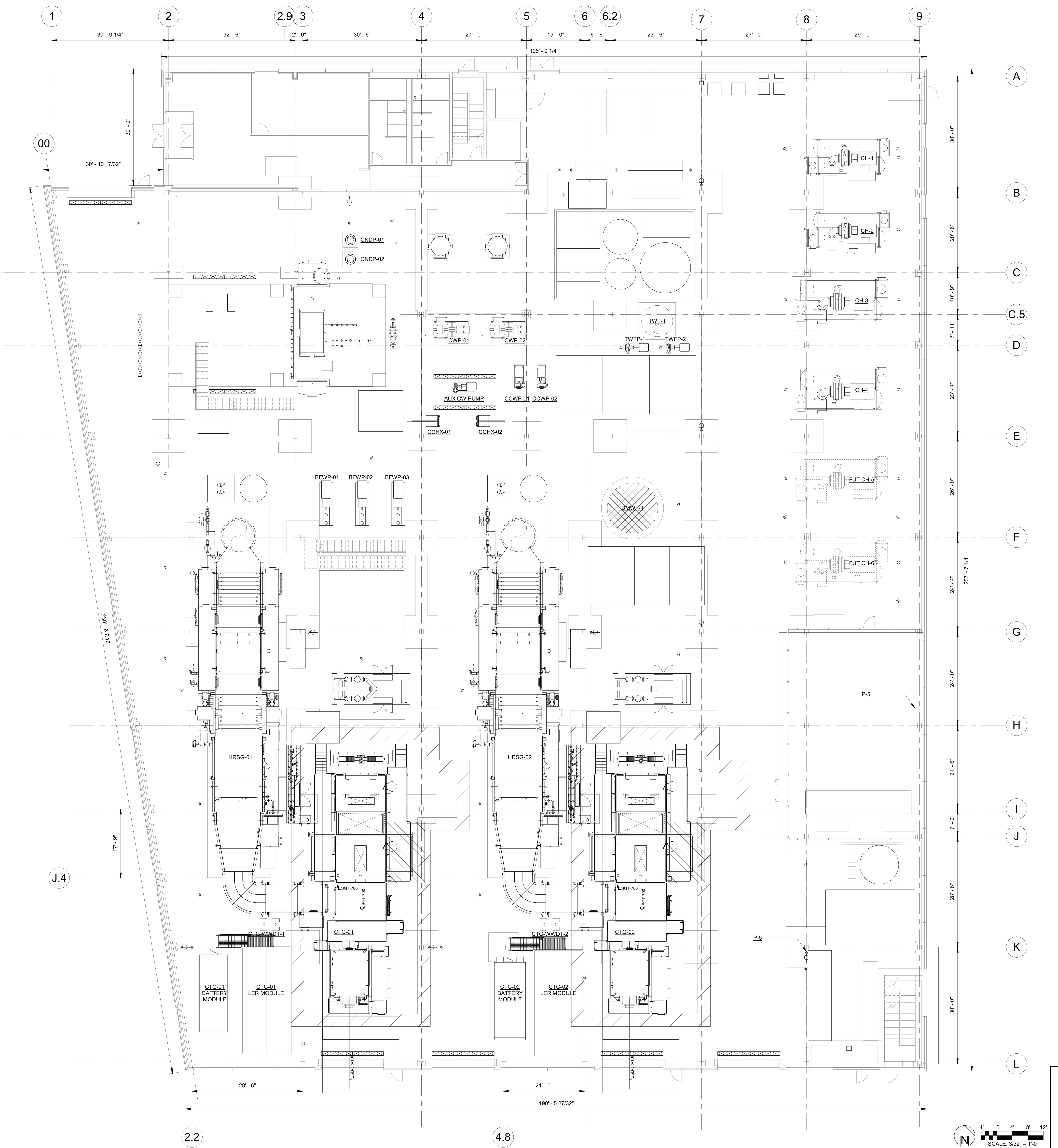
Q. What do you recommend that the Ohio Power Siting Board do in this case?

A. I recommend that the Ohio Power Siting Board grant the Application based upon the recommended conditions contained in the June 15, 2020 Staff Report of Investigation as modified by the revisions in the Direct Testimony of Scott Potter.

Q. Does this conclude your direct testimony?

A. Yes, it does. However, I reserve the right to offer testimony in support of any stipulation reached in this case.

Applicant Exhibit 2



EPC CONTRACTOR

FRANK LILL & SON INC.

ROCHESTER, NY
PROJECT NUMBER: 1-19-214

ENGINEER OF RECORD

RMF ENGINEERING INC.

BALTIMORE, MD
PROJECT NUMBER: 819533.A0

POWER ISLAND ENGINEER

CONCORD ENGINEERING GROUP

VOORHEES, NJ
PROJECT NUMBER: 2C19745.00

ARCHITECT OF RECORD

SMP DESIGN INC.

CINCINNATI, OH
PROJECT NUMBER: 019326

ISSUED FOR REVIEW

NO.	DATE	DESCRIPTION

REVISIONS

OSU PROJECT NUMBER: OSU-190883
ENGIE PROJECT NUMBER: 16-19-EXP

CHP / DHC Plant Smart Campus E Project

PREPARED FOR

ENGIE BUCKEYE OPERATIONS

COLUMBUS, OHIO

PREPARED BY

RMF ENGINEERING, INC.

5520 RESEARCH PARK DRIVE SUITE 300 BALTIMORE MD 21228

CHP - LEVEL 1 - GENERAL ARRANGEMENT PLAN

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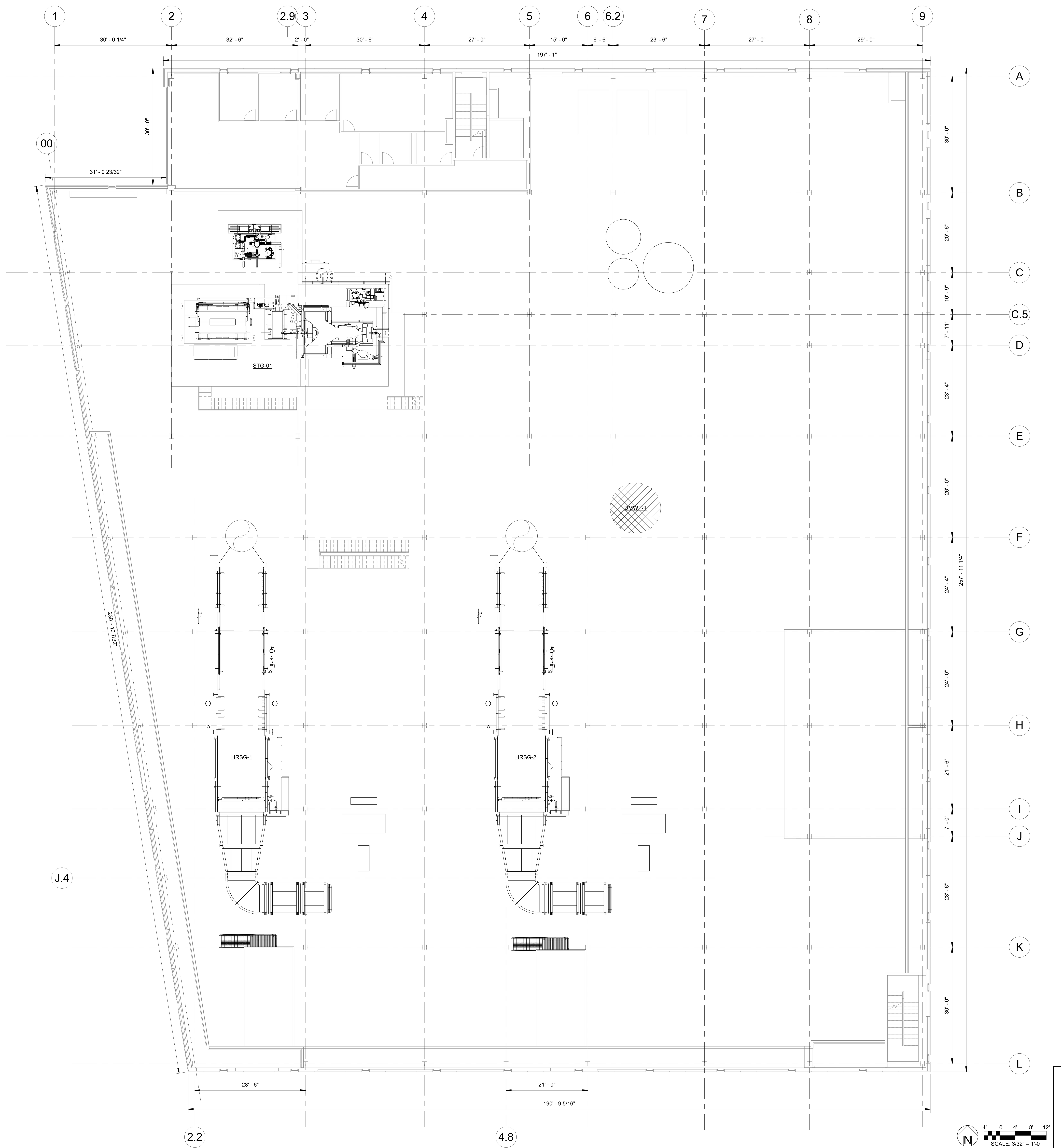

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CHP - LEVEL 2 - GENERAL ARRANGEMENT PLAN

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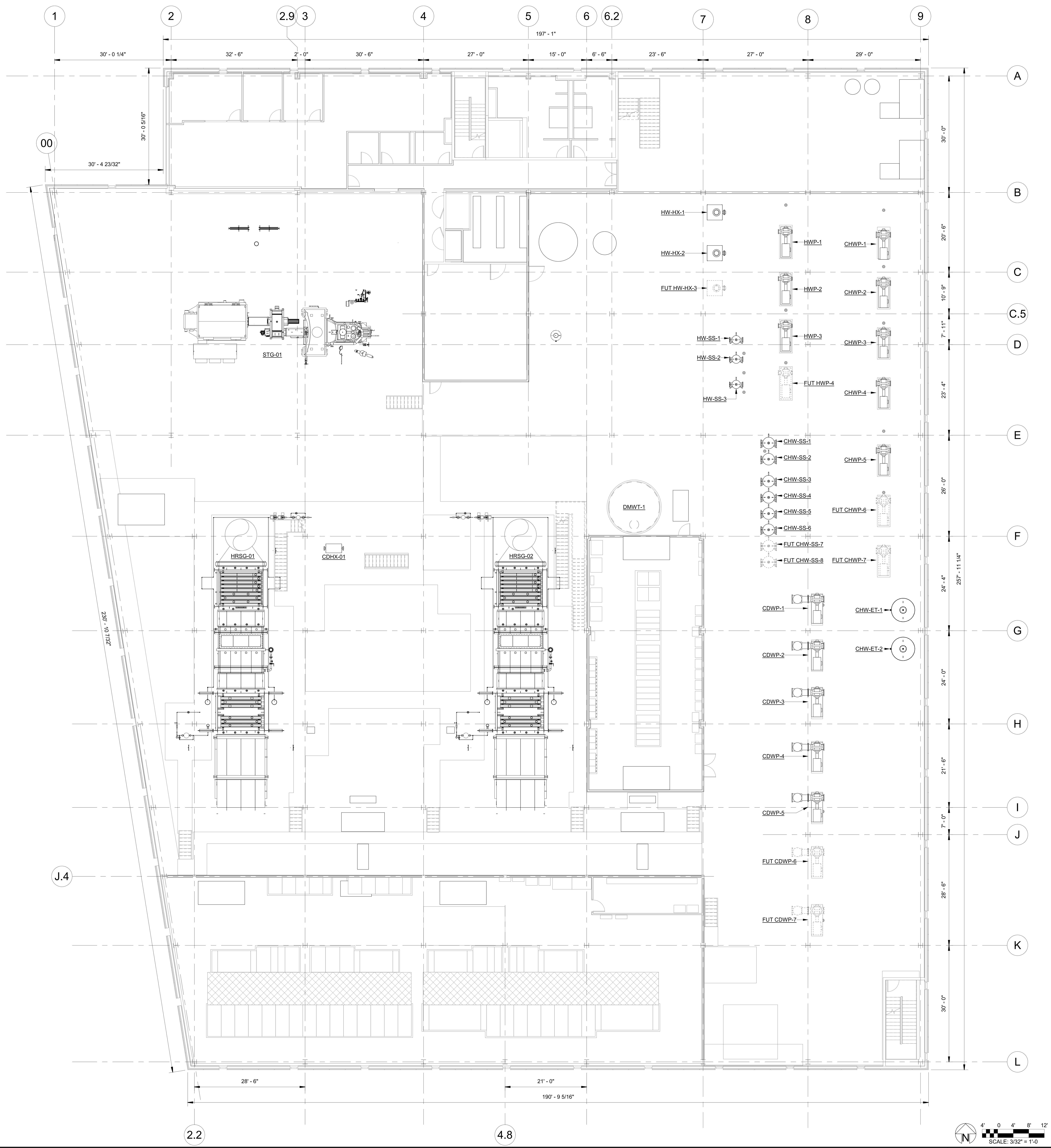

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CHP - LEVEL 3 - GENERAL ARRANGEMENT PLAN

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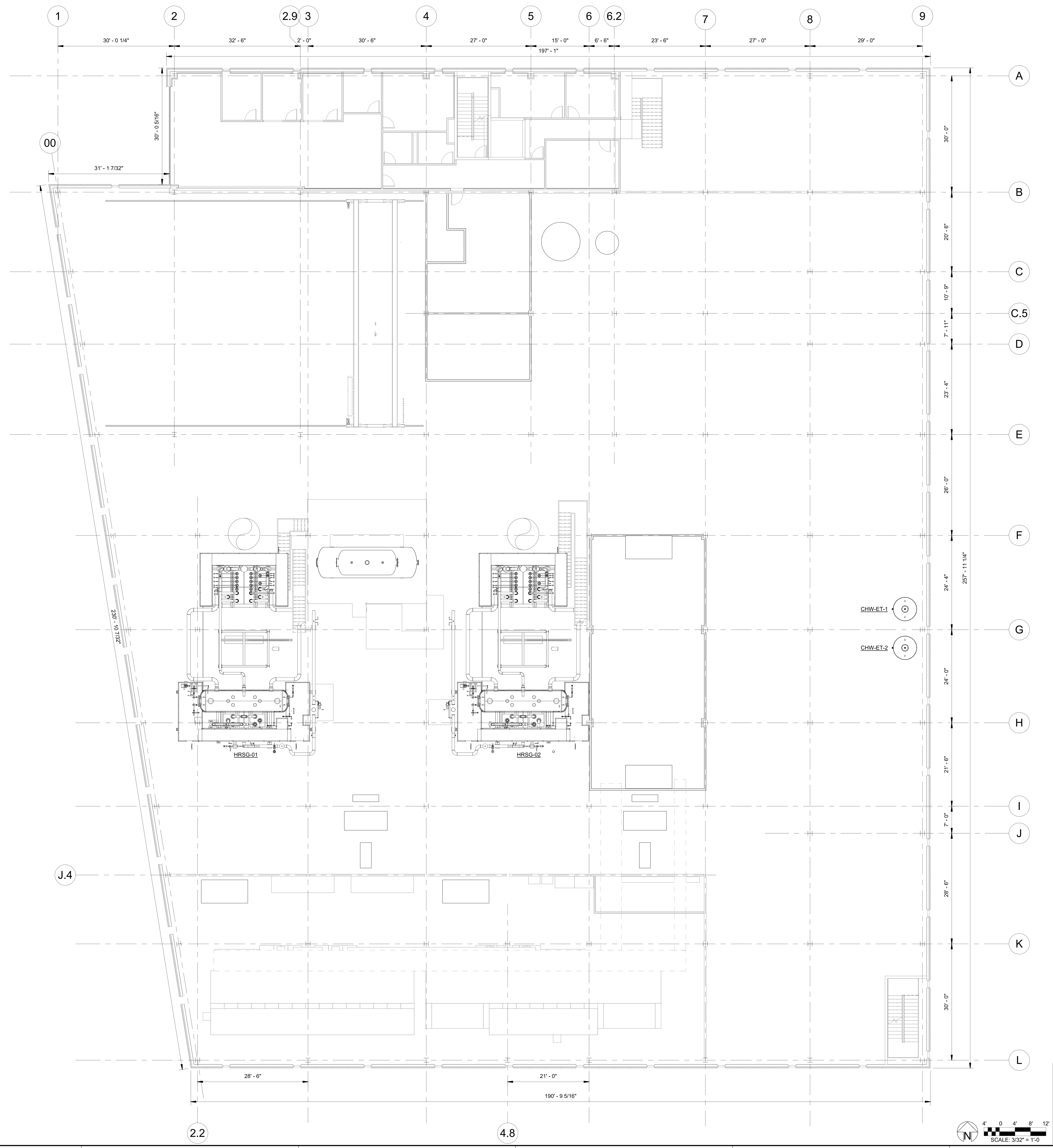

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CHP - LEVEL 4 - GENERAL ARRANGEMENT PLAN

SHEET NUMBER GA141

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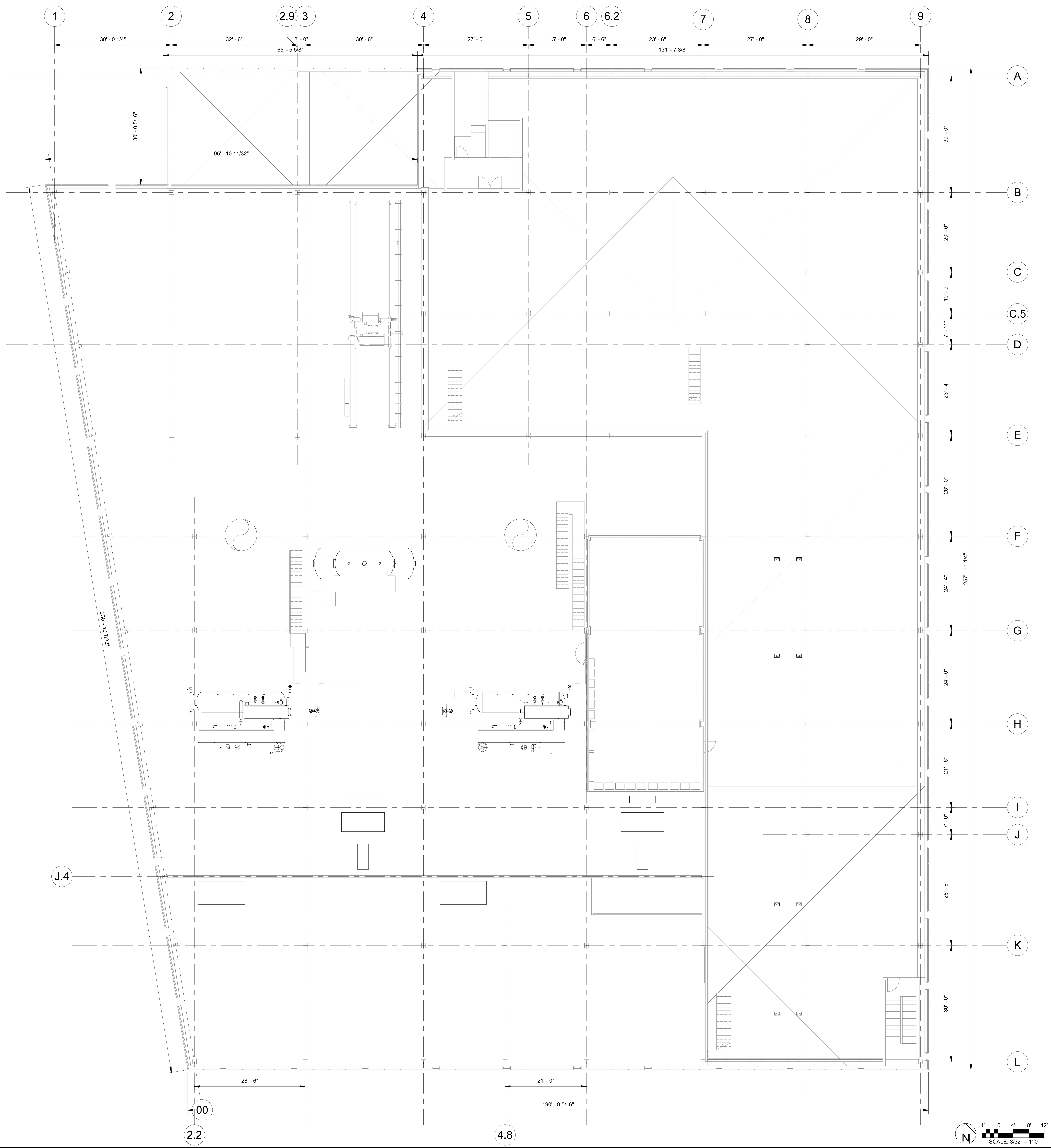

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CHP - LOW ROOF - GENERAL ARRANGEMENT PLAN

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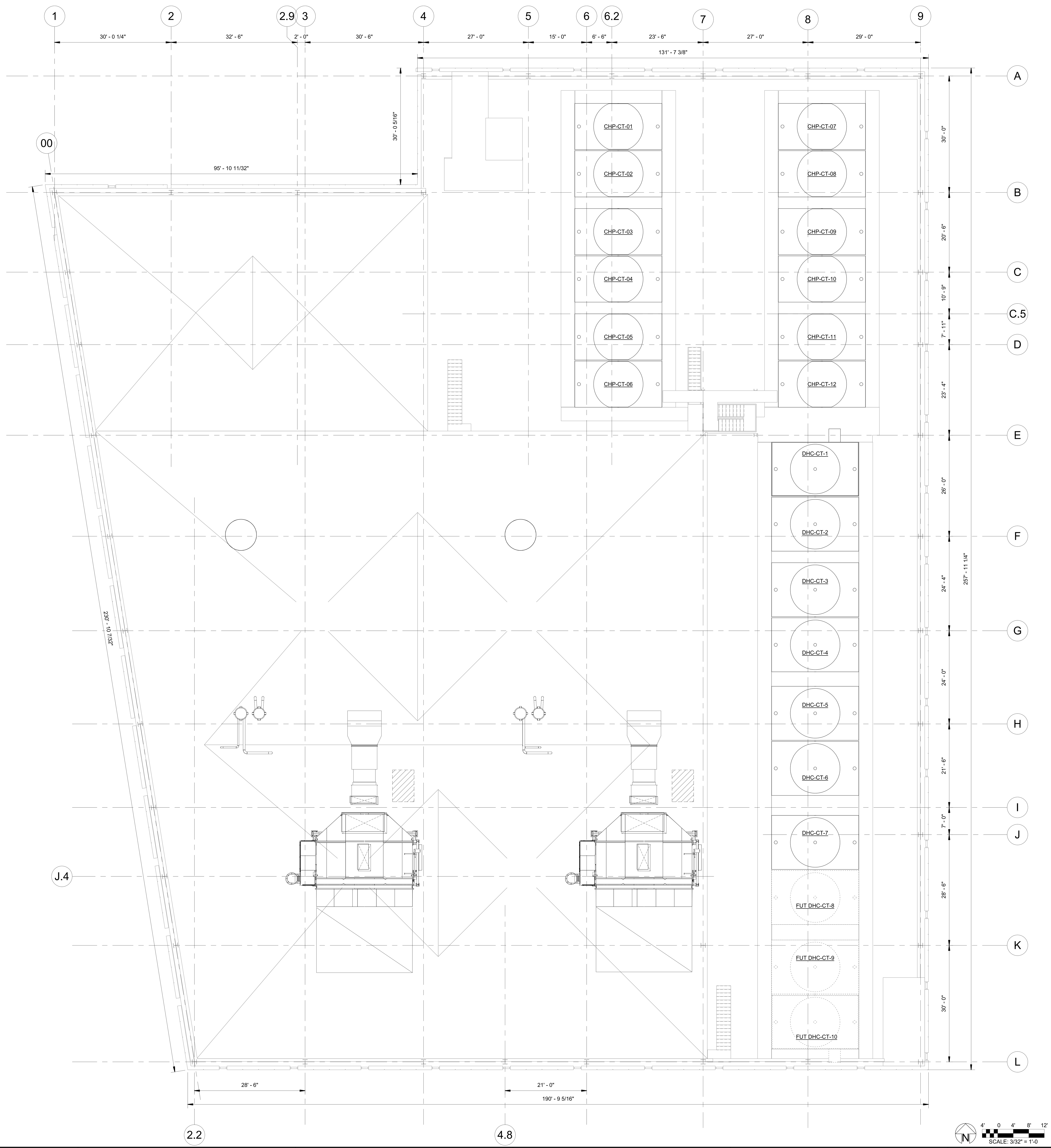

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ENGIE BUCKEYE OPERATIONS
COLUMBUS, OHIO

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CHP - HIGH ROOF - GENERAL ARRANGEMENT PLAN

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Applicant Exhibit 3

STREET LEVEL - **NW** CORNER - **SET BACK SCREEN OPTION**

Applicant Exhibit 4

THE OHIO STATE UNIVERSITY

CHP FEASIBILITY STUDY

February 20, 2018

OHIO STATE ENERGY PARTNERS

EXECUTIVE SUMMARY

The Ohio State Energy Partners (OSEP) is pleased to present the feasibility study results and recommendation for multiple Combined Heat and Power (CHP) configurations that will reduce the University's Levelized Cost of Energy (LCOE) by nearly [redacted]% over 25 years, reduce the University's carbon footprint by 38%, provide a path to carbon neutrality by 2050, and deliver a reliable source of energy.

Optimized CHP Combined Heat and Power Solution

The installation of a CHP forms the cornerstone of a strategy to help The Ohio State University reach its energy and environmental goals and realize significant energy supply cost savings similar to other major Universities that have implemented CHP facilities across the country listed in Appendix M. An on-site CHP facility can simultaneously generate heat (steam and/or hot water) and power in the most efficient thermodynamic cycle that cannot be matched by any other alternative technology. It can also reduce or even eliminate the reliance on high-priced retail electricity and mitigate the University's exposure to commodity price volatility, thereby making operating costs more predictable.

The philosophy underpinning our proposed designs is predicated on right-sizing the CHP facility to provide power generation to match the summer average electric load as measured at the OSU substation and taking into consideration the Blue Creek Wind generation as shown in Figure i-1 below. The CHP would be designed to meet the

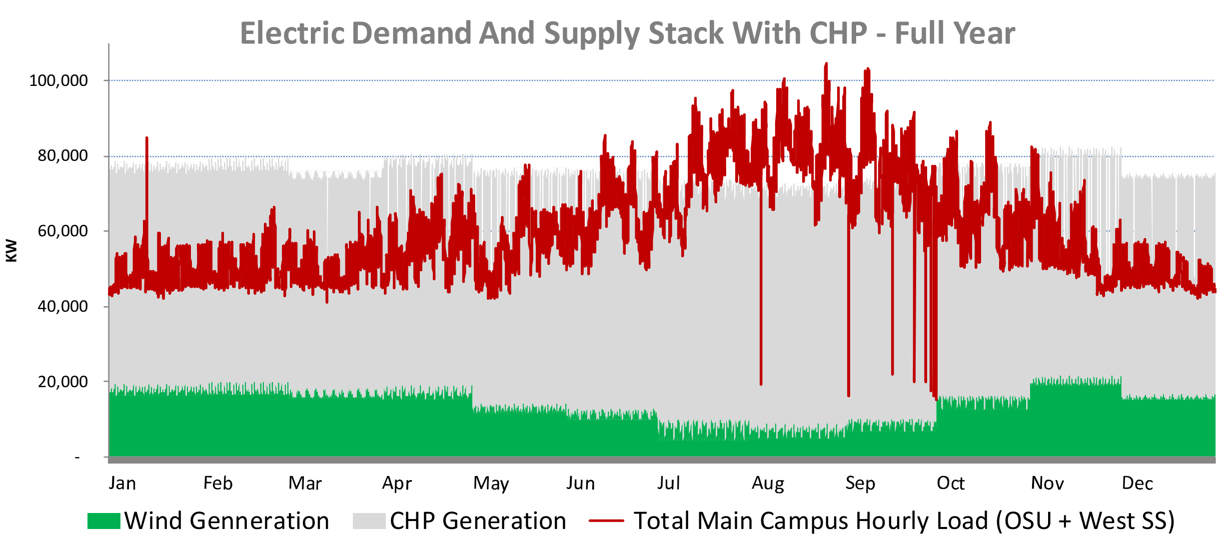

Figure i-1: Ohio State University's demand and supply stack with CHP and wind for the full calendar year

summer coincident steam demand and nearly all the average steam demand in the winter months. The external utility interconnection with AEP and the existing boilers at the campus will supply any shortfall in electricity or steam demand during normal operations, as well as provide necessary backup supply should the CHP be off-line for maintenance. To meet energy reliability standards required by the University, this facility will have the capability to supply the campus with power and steam in island mode[1] operation utilizing microgrid controls technology, to mitigate unplanned events such as regional power outages and weather-related disruptions. The CHP can also be configured to provide black start capability.

OSEP has assessed the financial and technical aspects of the CHP configuration originally developed by Burns & McDonnell for the University and determined that there is potential to further optimize the design. By configuring the facility with an extraction steam turbine which results in power capacity above the minimum campus load and considering critical loads[2], OSEP concluded that a higher capacity CHP facility with more steam/power output flexibility will be able to economically offset campus electric and thermal demand, while operating in a more fuel-efficient manner compared to the original design. Multiple CHP cases shown in Figure i-2 have been evaluated to ensure an optimized solution for the University.

All in 2020 $	*Burns & McDonnell*	*Case 1*	*Case 2*	*Case 3*	*Case 4*
Location	South of Smith	South of Smith	North of Smith	Midwest Campus	Midwest Campus (Exp)
Configuration	2x0 Titan 250	2x1 Titan 250	2x1 SGT 600	2x1 SGT 600	(2+1)x1 SGT 600
CHP Capex ($million)	$105	$128	$131	$147	$152
CHP and Midwest DHC* capex ($million)				$227	$232
NPV Savings to Ohio State** ($million)	$62	$117	$147	$161	$154
Real LCOE 2021-2045** (c/kWh) *(Compared to As-is LCOE)*	[redacted]				
Resiliency Improvement	68% of Critial Load	111% of Critial Load	116% of Critial Load	116% of Critial Load	116% of Critial Load
CO_2 Reduction (2021)	22%	33%	38%	38%	38%
Energy Efficiency Improvement (Source EUI)	14%	20%	24%	24%	24%
Procurement Risk Reduction	26%	36%	39%	39%	39%

** Midwest DHC : New chilled and heating hot water networks in the Midwest campus and a new central chiller plant.*
*** Net of Concessionaire's cost recovery (through incremental Variable Fee with 20 yr recovery); assuming 4% Discount Rate, 2% Inflation*

Note 1: Value of added resiliency has not been included in the NPV calculation
Note 2: Added value of a district heating and cooling network in Midwest campus supplying existing and future buildings is included in Case 3 and Case 4.
Note 3: Additional option value of adding a 3rd turbine of approximately [redacted] (resulting from West expansion) not included in the Case 4 NPV above
Note 4: All cases assumed Wind PPA to be expired in 2032 and replaced by grid purchase thereafter
Note 5: All cases assumed a reasonably higher estimate of grid procurement costs (relative to As-is) for residual electric demand (due to volume shrinkage) after the installation of the CHP. See section 1.4 for details

Figure i-2: Optimized cases to cover critical loads while providing economic benefit

[1] Continuous operation of the CHP disconnected from the grid, providing power and steam to the campus

[2] Critical load on campus is considered to be medical, research, and administrative facilities fed from OSU substation. A detailed definition and accurate calculation of critical loads to be serviced during an island operation will be established during the development phase. It should be noted that generation to supply critical load is different than "emergency generation", which is required by code for medical buildings and are typically supplied by diesel generators. In this case, the existing "emergency generation" equipment on campus would be maintained, and any new medical facility built on campus would still have its own emergency generation equipment. However, it is expected that the emergency generation equipment would be required to be operated only if the CHP is not available for a reason.

The detailed technical and commercial analysis provided within this report will result in customized CHP facility designs at each of the three locations considered – south of Smith Substation, north of Smith Substation and in the Midwest area of campus. In addition, the feasibility study will also highlight the enhanced energy savings, operational flexibility, reliability, grid resiliency, redundancy and touch on a risk-mitigating strategy for commodity (gas and power) procurement to the University.

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1.0 FEASIBILITY METHODOLOGY

Ohio State Energy Partners' approach and philosophy concentrates on meeting the needs of the University. OSEP is focused on providing a CHP design to create the greatest value and to bring the lowest energy costs to the University over the term. OSEP via ENGIE, brings its global CHP knowledge, operating experience and market knowledge to provide the best analysis for the selection of equipment and design configuration that leads to superior performance and reliability.

1.1 Guiding Principles

Ohio State Energy Partners has committed to provide a rigorous and continuous evaluation of the University's supply mix to optimize solutions and ensure the applied strategy will create value, reduce cost and utilize innovative technologies tailored to meet the objectives of the University. During this evaluation the following principles were used to address energy supply needs and risk resulting in an optimal CHP solution for the University.

- **Affordability**: Optimized CHP solution provides for Maximum Economic Value for the University vs the existing University utility cost "As-Is" baseline
- **Reliability:** Energy Resiliency to avoid disruption to critical and other campus load requirements
- **Sustainability:** Sustainable Solutions for long-term planning to mitigate risks and impacts related to the environment
- **Predictability:** Commodity Risk Management to allow for a cost-effective and risk-mitigating strategy for procurement of any supplemental retail electricity required by the campus

1.2 Cases

Figure 1-1: Locations for the North, South and Midwest CHP. While the North and South CHP locations are specific to the North and South of Smith Substation, the Midwest CHP location is rather flexible such that it can be located anywhere in the Midwest campus.

	Location	*Technology*	*Details*
Case 1	**South of Smith Substation**	**2x1 Titan 250**	• Two heat recovery steam generators • Condensing steam turbine with an extraction for process steam. • Supplemental duct burners for increased steam production. • The Siemens SGT 600 gas turbine model was not considered due to its footprint which is too large for this location.
Case 2	**North of Smith Substation**	**2x1 Titan 250 or 2x1 SGT 600**	• Two heat recovery steam generators • Condensing steam turbine with an extraction for process steam. • Supplemental duct burners for increased steam production.
Case 3	**Midwest Campus**	**2x1 Titan 250 or 2x1 SGT 600**	• Two heat recovery steam generators • Condensing steam turbine with an extraction for process steam. • Supplemental duct burners for increased steam production.

Case 4	**Midwest Expansion**	**(2+1) x1 Titan 250 or (2+1) x1 SGT600**	• Two heat recovery steam generators • Condensing steam turbine with an extraction for process steam. • Supplemental duct burners for increased steam production. • Provisions to expand with a third gas turbine and HRSG in the future

1.3 Cost

The Feasibility Study is based on indicative pricing based on ENGIE experience building and operating facilities similar in size and function to the proposed configurations conforming to Class 3 cost estimation per AACE. Black & Veatch Engineering (B&V), with its experience designing and building CHPs at several Big Ten Universities, provided technical support in the development of the capital cost (CAPEX) during the RFP and Feasibility Study. ENGIE developed the operational cost (OPEX) based on their experience operating CHP facilities in North America.

Capital Cost

The CAPEX estimate is based on the following

- Major Equipment quotes from original equipment manufacturer (OEM) for the gas turbine generators (GTG), steam turbine generator (STG) and heat recovery steam generator (HRSG).
- Major Equipment installation, balance of plant (BOP) equipment and material quantities from conceptual design and the cost estimate derived from B&V's cost database of recent similar project/proposal experience
- Labor man hours are based on B&V's experience on recent and similar projects. Labor rates are based on labor studies conducted in the area.

The following are the cost estimate assumptions/clarifications:

- Natural gas compression is required without redundancy. N+1 thermal redundancy achieved with utilization of existing boilers. Electric redundancy is achieved with import power from the grid.
- Islanding (continuous operation of the CHP disconnected from the grid, providing grid resiliency to the Campus) for critical loads will be included in the standard design. Black start capability (starting the CHP in an island mode after a complete blackout has occurred and the grid is not available) will be optional.

- Main control room, administrative offices and warehousing will remain inside McCracken in all cases.
- Construction is based on a facility located in Columbus, Ohio with union construction labor.
- Costs are in 2017 dollars with escalation unless otherwise specified
- Handling or removal of any hazardous material is not considered in the estimate.
- Construction Management & Indirects include costs associated all temporary utilities, temporary facilities, bonds and insurance.
- OSEP prepared the owner's cost which includes project development, offsite utility interconnects, environmental permitting, O&M team mobilization, costs, taxes, start-up and commissioning fuel and consumable materials, and IDC[3] is based on similar recent project/proposal experience.
- Project is assumed to be tax exempt (no State or Local taxes)
- Piling for foundation assumed not to be required in the Smith Substation vicinity locations based on Smith Substation soil borings. OSEP assumed piling will be required for Midwest location.
- Logistics and labor productivity cost adjustments are included in the CAPEX cost for both main campus and Midwest campus cases.
- No costs have been allocated for unknown underground issues in the CAPEX cost estimate.
- Project work schedule is assumed to be 10 hours a day, 5 days a week. Detailed project schedule will be finalized during development period.
- Interconnection to existing utilities will be performed during planned outages or utilization of hot tap processes

The CHP CAPEX cost is summarized in Figure 1-2 below. The detailed CAPEX estimate can be found in Appendix F.

[3] IDC: Interest During Construction

CHP CAPEX (2017 KUSD)										
	B&McD (2014$)	B&McD (2017$)	Case 1		Case 2		Case 3		Case 4	
	Solar	Solar	Solar		Solar	Siemens	Solar	Siemens	Solar	Siemens
Equipment subtotal	**$36,021**	**$38,226**	**$49,996**	**NA**	**$48,946**	**$50,096**	**$50,204**	**$51,421**	**$53,021**	**$53,875**
Civil	$683	$724	$3,863	NA	$4,247	$4,247	$8,947	$8,598	$8,847	$9,178
Mechanical	$5,479	$5,815	$16,100	NA	$17,225	$17,549	$22,953	$25,102	$23,846	$24,223
Electrical	$3,397	$3,604	$9,359	NA	$10,047	$10,047	$13,383	$13,385	$13,396	$13,389
Building	$9,449	$10,027	$12,853	NA	$12,814	$12,814	$9,671	$9,671	$11,171	$11,171
Engineering and Startup	$5,934	$6,297	$7,000	NA	$7,000	$7,000	$7,000	$7,000	$7,000	$7,000
Construction Mgt	$13,000	$13,796	$2,000	NA	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000
Contractor's Profit	$2,363	$2,508	$5,385	NA	$5,446	$5,523	$6,065	$6,225	$6,340	$6,421
Construction & Material subtotal	**$40,306**	**$42,773**	**$56,561**	**NA**	**$58,779**	**$59,179**	**$70,019**	**$71,982**	**$72,600**	**$73,380**
Concessionaire's Cost	[redacted]			NA	[redacted]					
Start-up Consumables	$41	$41	$41	NA	$41	$41	$41	$41	$41	$41
TOTAL COST W/O CONTINGENCY	[redacted]			**NA**	[redacted]					
Contractor's contingency	$10,300	$10,930	$6,532	NA	$6,643	$6,698	$7,150	$7,332	$7,519	$7,576
Concessionaire's Contingency -	[redacted]			NA	[redacted]					
Contingency subtotal				**NA**						
TOTAL COST W/ CONTINGENCY	**$94,923**	**$100,342**	**$121,174**	**NA**	**$122,506**	**$124,159**	**$136,101**	**$139,587**	**$142,093**	**$143,840**
Phase 2 Interconnection	$0	$0	$19,550	NA	$19,550	$19,550	$16,905	$16,905	$16,905	$16,905
Fuel Oil (backup sources)	$2,100	$2,100	$2,100	NA	$2,100	$1,200	$2,700	$1,800	$2,700	$1,800
LNG (backup sources)	NA	NA	NA	NA	NA	NA	$13,000	$13,000	$13,000	$13,000
LNG (backup sources) TIC	NA	NA	NA	NA	NA	NA	$13,000	$13,000	$13,000	$13,000

Figure 1-2: CAPEX Summary

Note 1: Midwest and West DHC capital cost not included in this table
Note 2: On all cases the capex figures include all equipment and installation cost for all tie ins (steam, electricity and natural gas)
Note 3: CHP building based on standard metal clad siding
Note 4: Annie and John Glenn Ave bridge extension cost not in the capital cost table (steam line is in the capital table)
Note 5: All other enabling project cost are covered in the cost

Operational Cost

The OPEX budget is based on ENGIE's experience operating CHP & district energy facilities on college campuses. The final OPEX budget will be determined after technology, location and final design are established during the Development period. The following are included in the Feasibility Study OPEX assumptions:

- Union O&M labor in the fixed operation and maintenance cost (FOM[4])
- Long term service agreement (LTSA) for the gas turbine generators
- Chemicals for water treatment and emissions control operations
- Difference in cost for equipment parts, consumables and utilities between operating and maintaining the boilers and CHP are included in the variable non-fuel operation and maintenance (VOM[5]) cost

The OPEX Cost is summarized in Table 1[6] below:

Table 1: LTSA: Long term service agreement for the gas turbines, based on $/FH (fired hours)

Incremental Annual O&M Costs for CHP	
Variable O&M Costs ($'000)	734
Fixed O&M Costs ($'000)	229
LTSA Costs ($'000)	1,357
Total Incremental Annual O&M Costs ($'000)	**2,320**

1.4 Market Assumptions

The PJM West Hub is one of the most liquid energy pricing points in the world and is used for financial and physical transactions in the PJM spot and long-term markets. The hub represents the weighted average price of approximately 95 generation and load nodal pricing points across the PJM system. It is viewed as the benchmark for long-term pricing within PJM due to its stability to the influence of system constraints and its location between large load areas and areas of generation within the PJM system.

Locational Margin Pricing (LMP) in the PJM is a result from the operation of a market that is based on system constraints and least-cost dispatch in which marginal resources determine system LMP's based on the offers. As shown in Figure 1-3, in the first nine months of 2017, coal units were 32.5 percent and natural gas units were 52.9 percent of marginal resources compared to the first nine months of 2016 where coal units were 46.2

[4] FOM: Operations and maintenance costs that are constant per year, and not a function of operating hours.
[5] VOM: Operations and maintenance costs that are a function of operating hours.
[6] Based on 2x8,195 hours of operation assumption per year.

percent and natural gas units were 41.4 percent of the total marginal resources[7]. Because of gradual coal shutdown, the fuel mix in Ohio is expected to lean more towards Natural Gas as the primary marginal fuel over time.

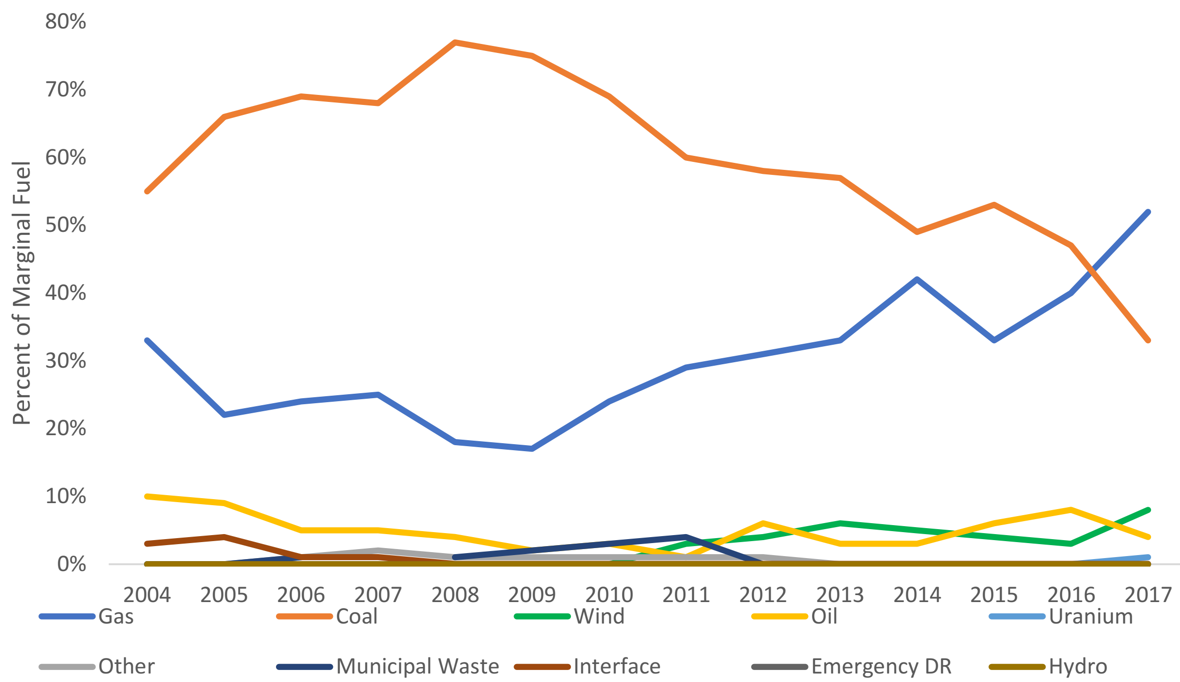

Figure 1-3: Type of fuel used in PJM market from 2004 to 2017

Base Case Market Projections

The all-in grid price encompasses largely two categories of charges – Retail Supply and Delivery charges. In the PJM market, Retail Supply charges include energy and non-energy components. These components are: (i) Energy: Wholesale Commodity Supply charges and (ii) Non-energy Supply charges: ICAP, ISO Ancillary charges, and suppliers' margin. The Delivery charges reflect AEP OH's wire charge tariffs to deliver the electricity to its customers. The wholesale supply charge depends on market conditions such as load growth, coal and nuclear retirement, generation mix, weather, and fuel prices (especially the marginal fuel).

The delivered natural gas price is primarily comprised of two elements: Commodity and Delivery charges. natural gas pricing is becoming the primary driver of electricity prices in PJM with changes in the fuel mix. At the national level, the seven major shale plays have and will continue to account for nearly all the incremental U.S. production over the long-term. Vast natural gas reserve and low production costs, on one hand, and some increased Power Sector Demand and LNG export, on the other, are the major drivers for

[7] http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2017/2017q3-som-pjm-sec3.pdf

low to moderate long-term natural gas price trends in the U.S. Considering natural gas becoming the long-term marginal fuel in the region, a somewhat similar trend can also be expected in the regional wholesale power price.

OSEP utilized a conservative market-forward based approach in developing its market projection in its evaluation. The market forwards for PJM AEP wholesale prices are available through 2025 (although outer years are not very liquid) whereas market forwards for natural gas prices are available through 2030 (generally liquid). In its long-term projection, OSEP utilized the market forwards, both power and natural gas, where available and took a conservative view thereafter, as provided in Figure 1-4 and Figure 1-5.

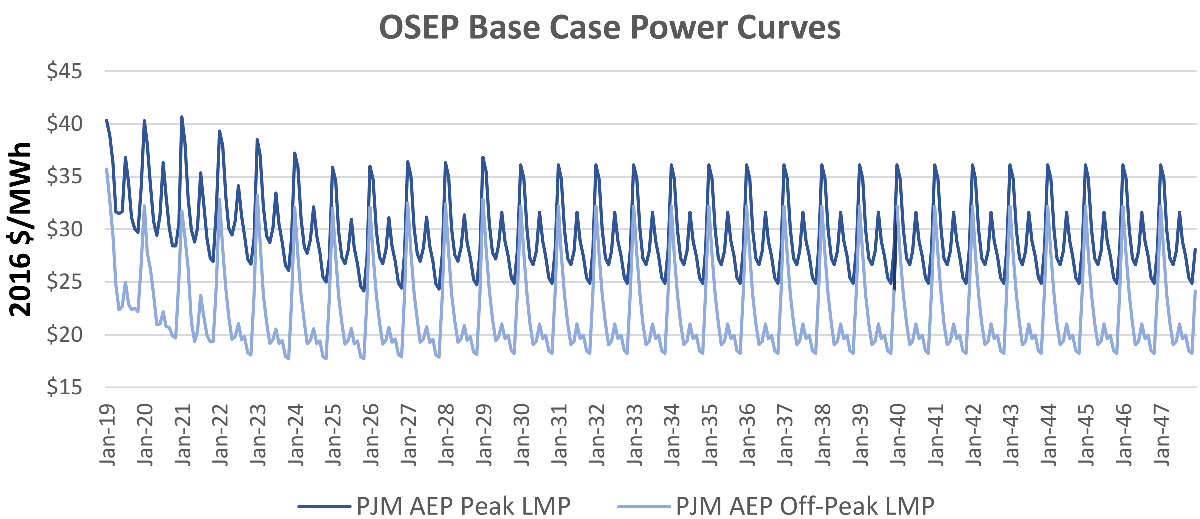

Figure 1-4: LMP forward price projection

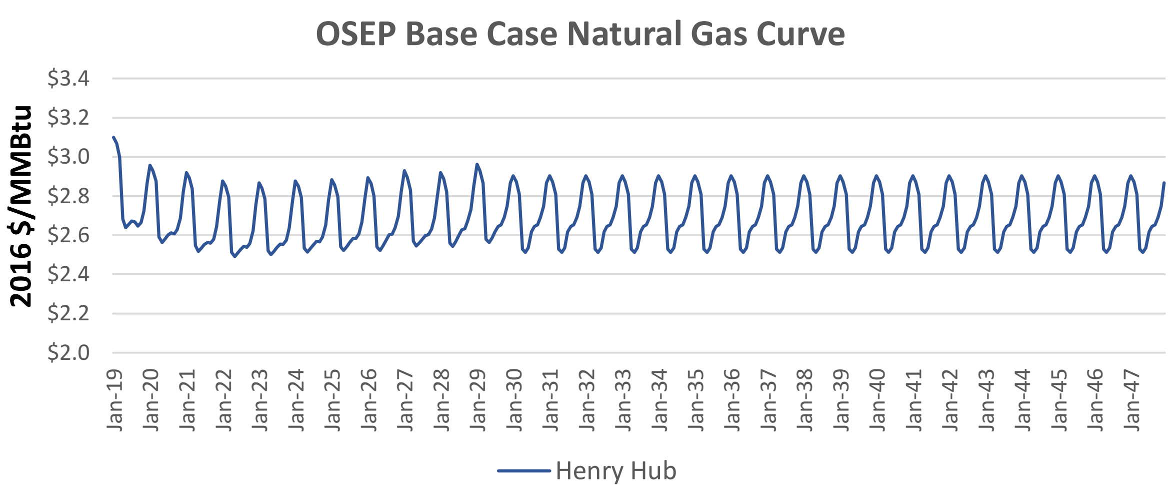

Figure 1-5: Henry Hub forward price projection

Finally, OSEP utilized the existing AEP OH tariff structure to estimate the Electric Delivery charges (based on the evolution of campus peak demand) to build up the final delivered electric grid prices for the "As is" and CHP cases for the university.

The resultant delivered nominal grid price in Figure 1-6 shows an annual growth of only 1.9% compared to historical growth of 2.4% in Ohio. See Appendix L for growth in historical Grid Electric price. The 1.9% annual growth in end-user retail grid price is less than the assumed annual inflationary measure of 2%. Considering the needed infrastructure investment in natural gas fired and Renewable driven generation in the region, OSEP believes this is a conservative market assumption for a base case; OSEP believes that the end-user retail grid price will grow higher than 1.9% per year.

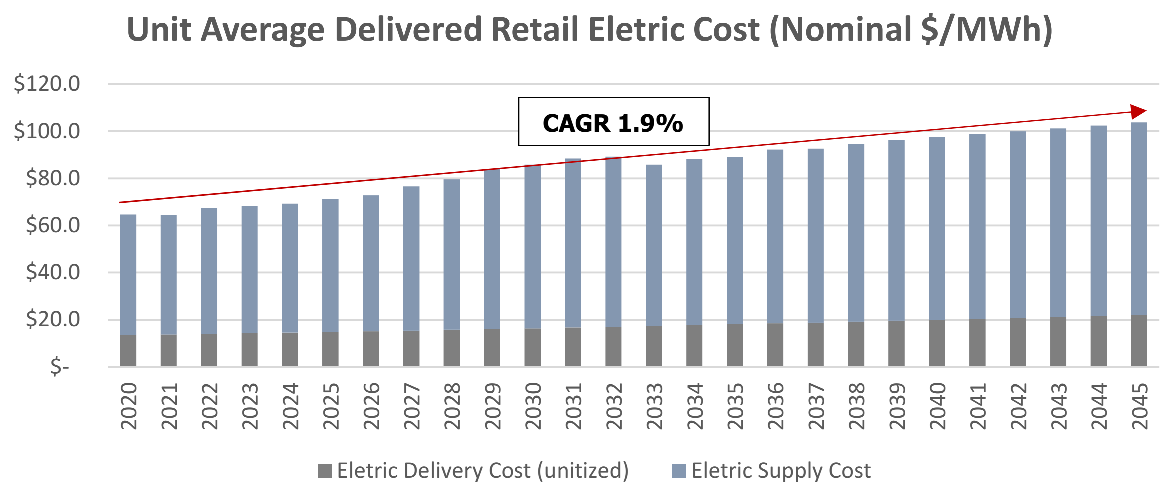

Figure 1-6: CAGR for delivered retail electric cost is less than inflation of 2% and historical growth of 2.4%

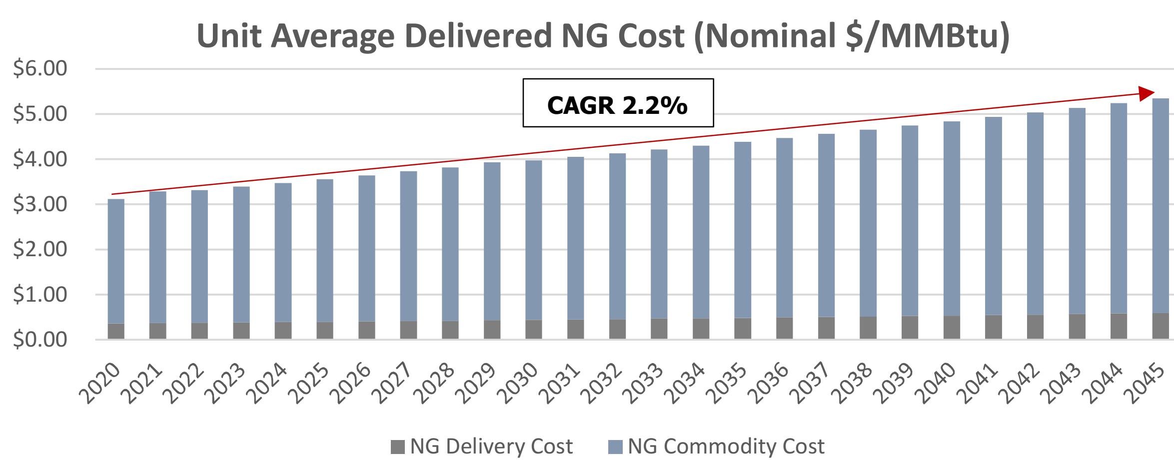

Figure 1-7: CAGR for natural gas is 2.2%; prices have come with vast natural gas reserve and Shale play in the U.S.

After the implementation of the CHP, University's unit cost of residual Retail Electric Supply as well as unit Delivery Charges are expected to go up relative to the "As is" unit procurement cost as depicted in Figure 1-8 below:

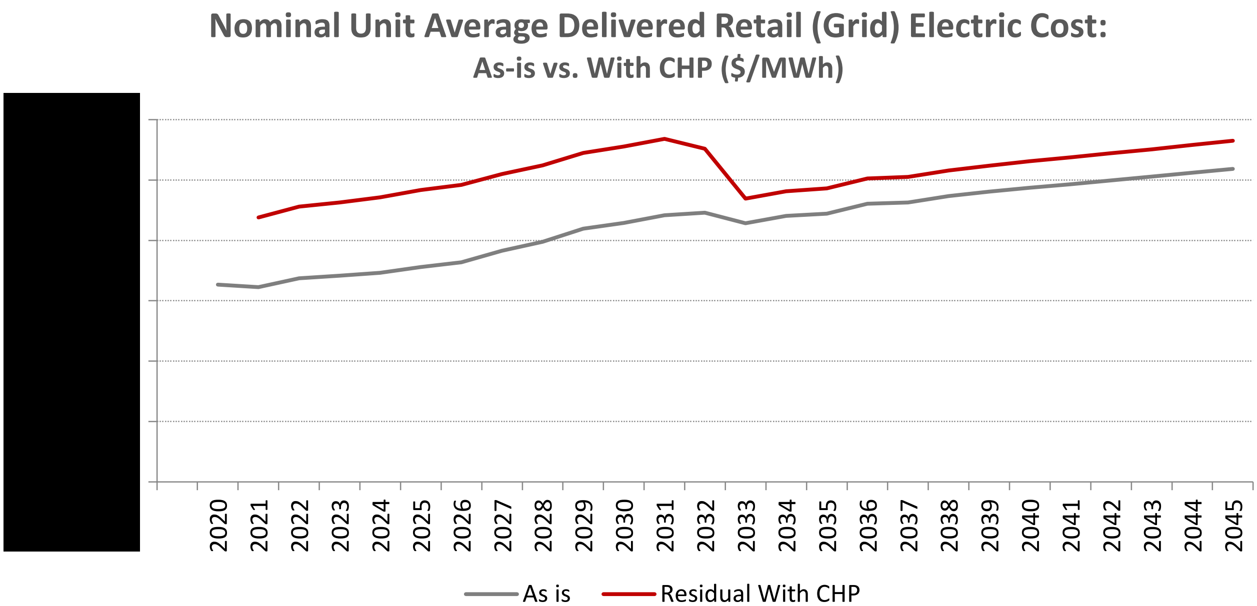

Figure 1-8: Residual grid supply costs expected to increase after implementation of CHP

3rd Party Market Projections

Apart from its own market projection, OSEP also utilized market projections developed by IHS CERA, an industry recognized leader and expert, in its valuation. However, OSEP chose to use the results from IHS CERA's market projection as a sensitivity case instead of the base case. A sensitivity analysis around OSEP's own market projections as well as results from CERA's market projection are discussed in section 3 of this study.

2.0 TECHNICAL EVALUATION

OSEP developed the technical configurations by establishing the current existing baseline utility system loads and projecting future loads based on campus growth and ECM implementation. The Gas Turbine Generator based configurations were established, and two equipment options were developed based on performance and cost. In addition, three locations were considered to provide University stakeholders the ability to evaluate the configurations based on their expectations for future campus growth.

Reciprocating engine-based configurations were also evaluated for the Feasibility Study however were not considered a good fit due to their lower exhaust energy, subsequent steam output, and much larger footprint.

Summary of Existing Conditions and Load Projections

Load projections used to size the CHP were based on campus historical load data, ECM implementation, campus growth and the Blue Creek Wind production.

As shown in Figure 2-1 through 2-3 below, the baseline electric and steam profiles were developed utilizing historical electric and steam data at OSU/West Campus Substations and McCracken Power Plant, respectively.

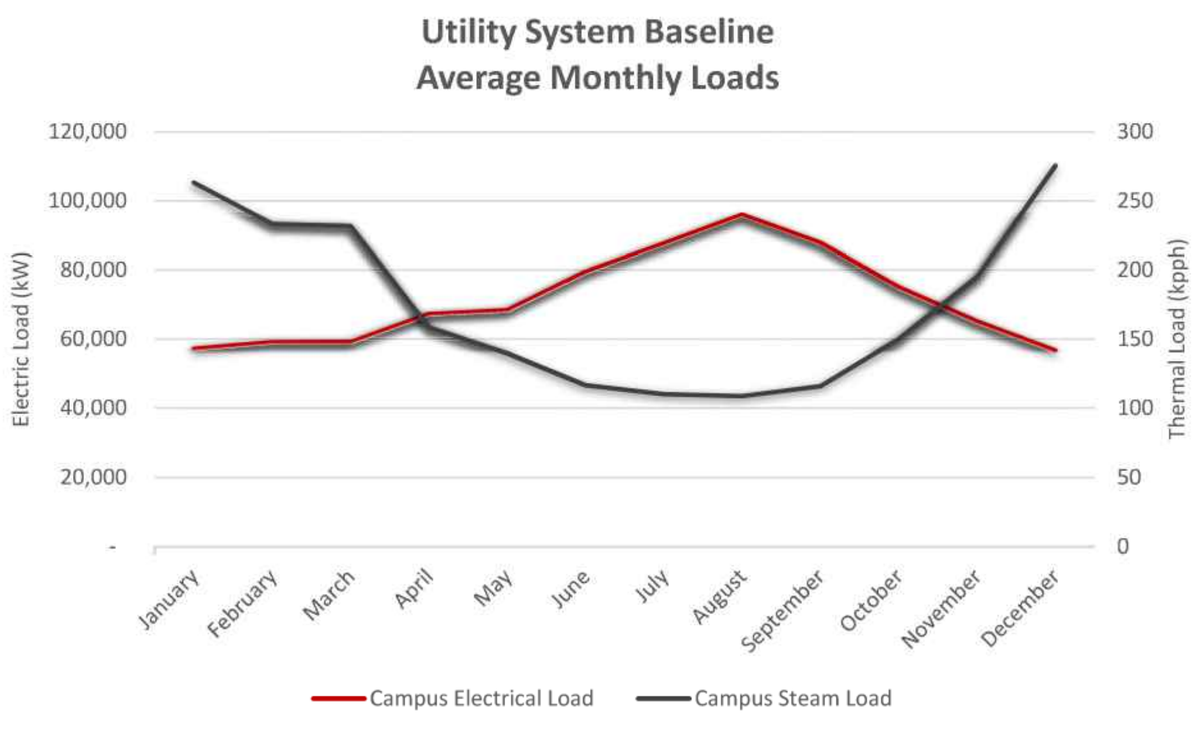

Figure 2-1: Historical electrical and steam loads

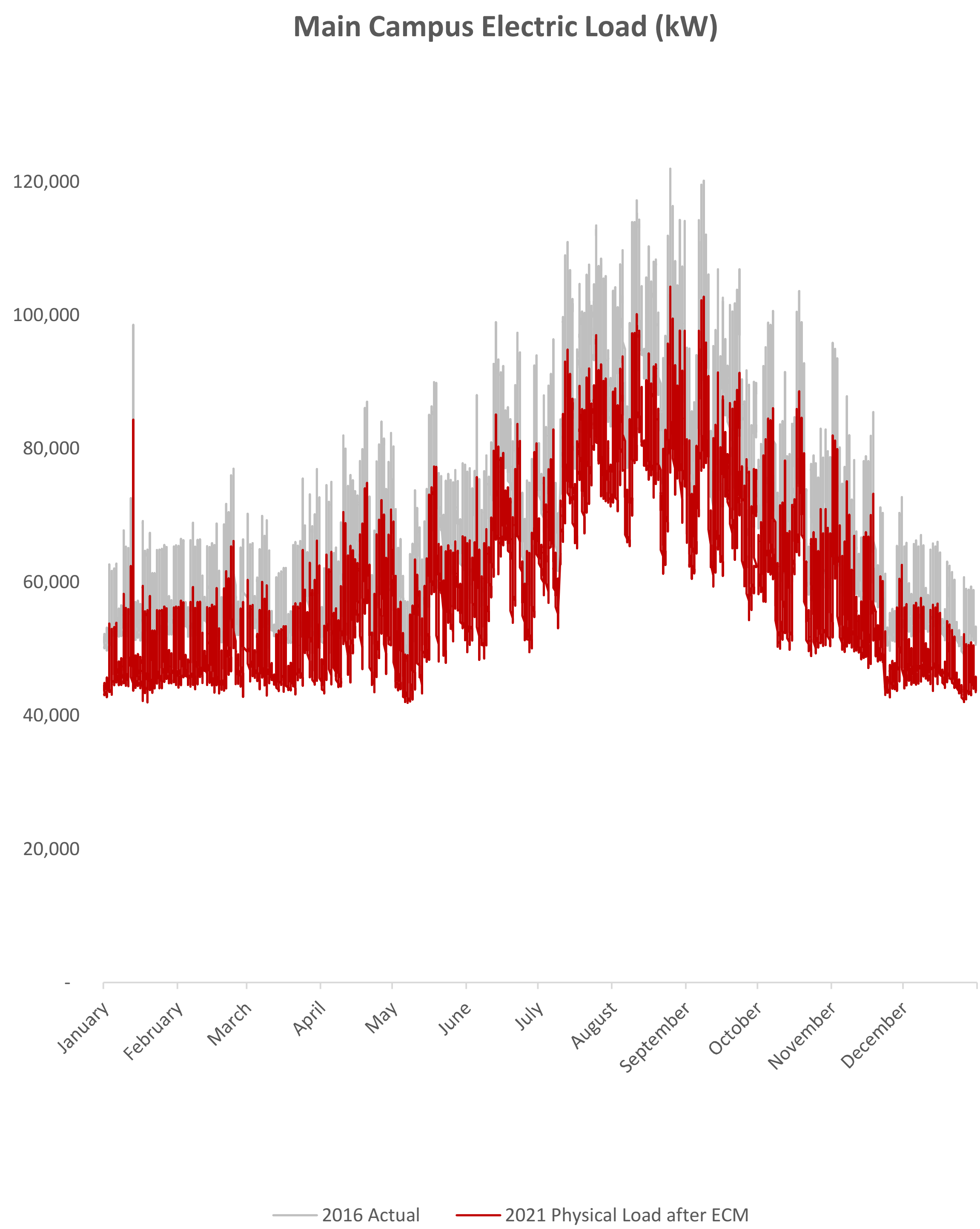

Figure 2-2: Historical electric profile Main Campus (OSU + West SS) and available physical load after ECM

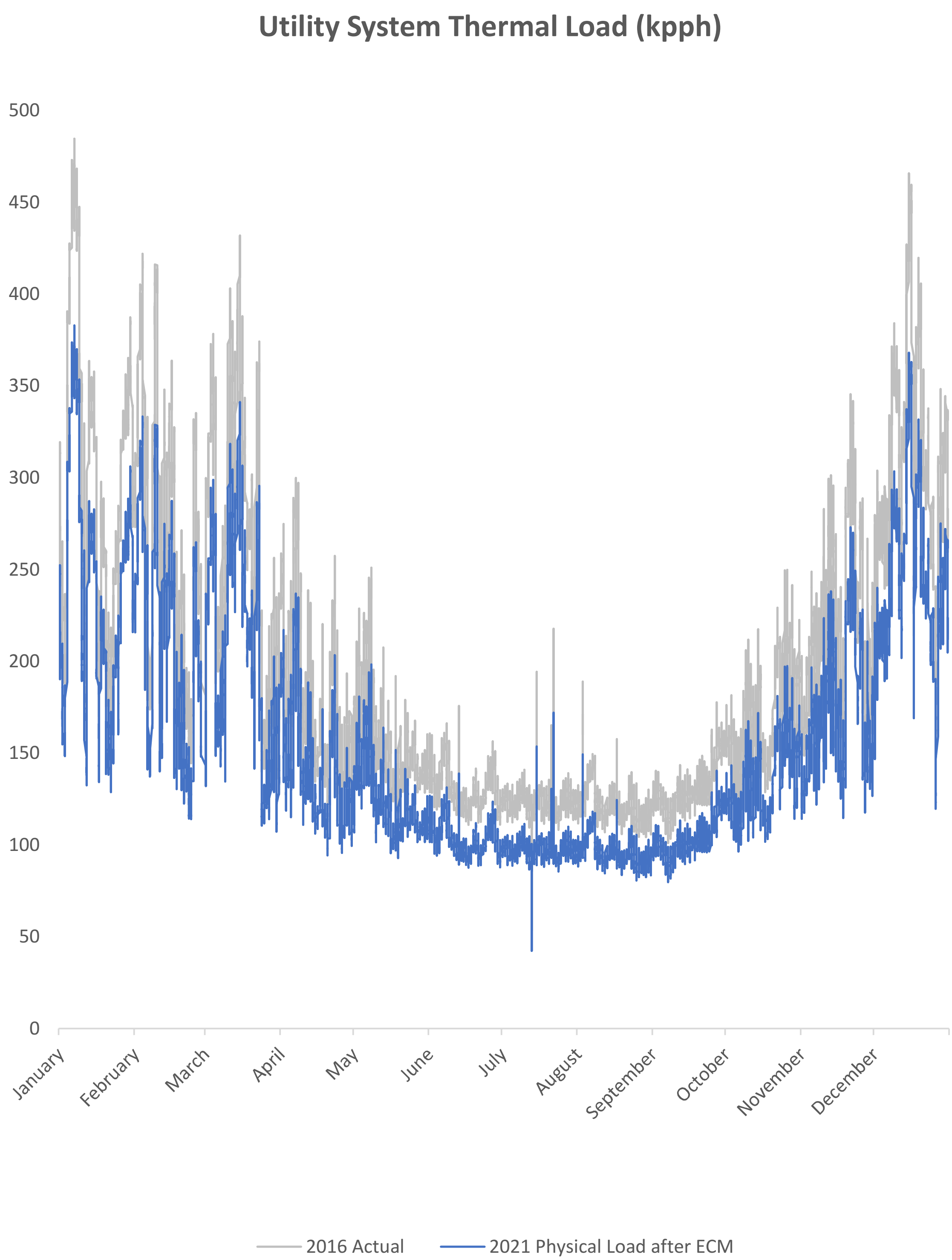

Figure 2-3: Historical steam profile and available physical load after ECM

In Figure 2-4, the average instantaneous Blue Creek Wind Production was modeled using historical data from 2014-2016 and fit to a 12x24 matrix (12 months by 24 hours).

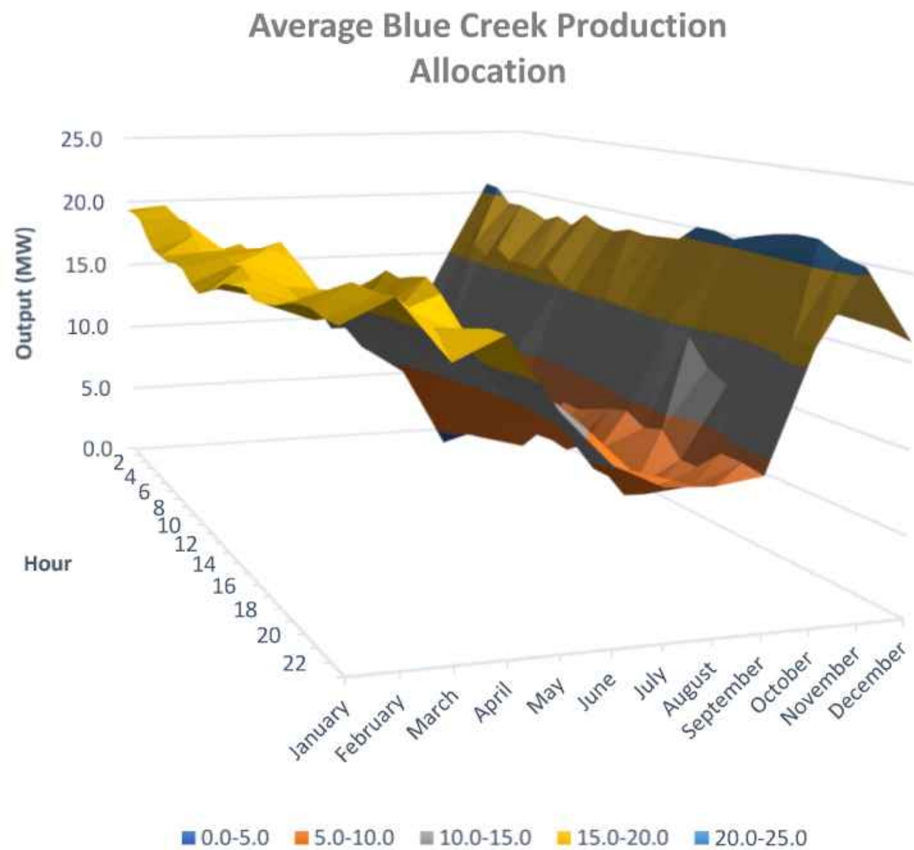

Figure 2-4: Average instantaneous Blue Creek wind production

From the baseline data, load projections were developed considering both campus expansion and reductions in the energy use intensity (EUI) through ECMs. Campus expansion was modeled as a linear annual increase in building footprint over the next twenty-five years for a total increase of ten million square feet; a 25% increase compared to the current campus footprint. Relationships were established to approximate the incremental electrical and thermal load associated with campus growth. Two-thirds of total campus electrical and thermal load growth is presumed to occur on Midwest and West Campus.

EUI reduction targets for electricity, chilled water, and steam consumption were incorporated into the estimates and are considered for the period from 2018 to 2027.

Steam and hot water utilization is expected to decrease with future buildings due to low temperature energy recovery and is considered in the projections shown in Figure 2-5.

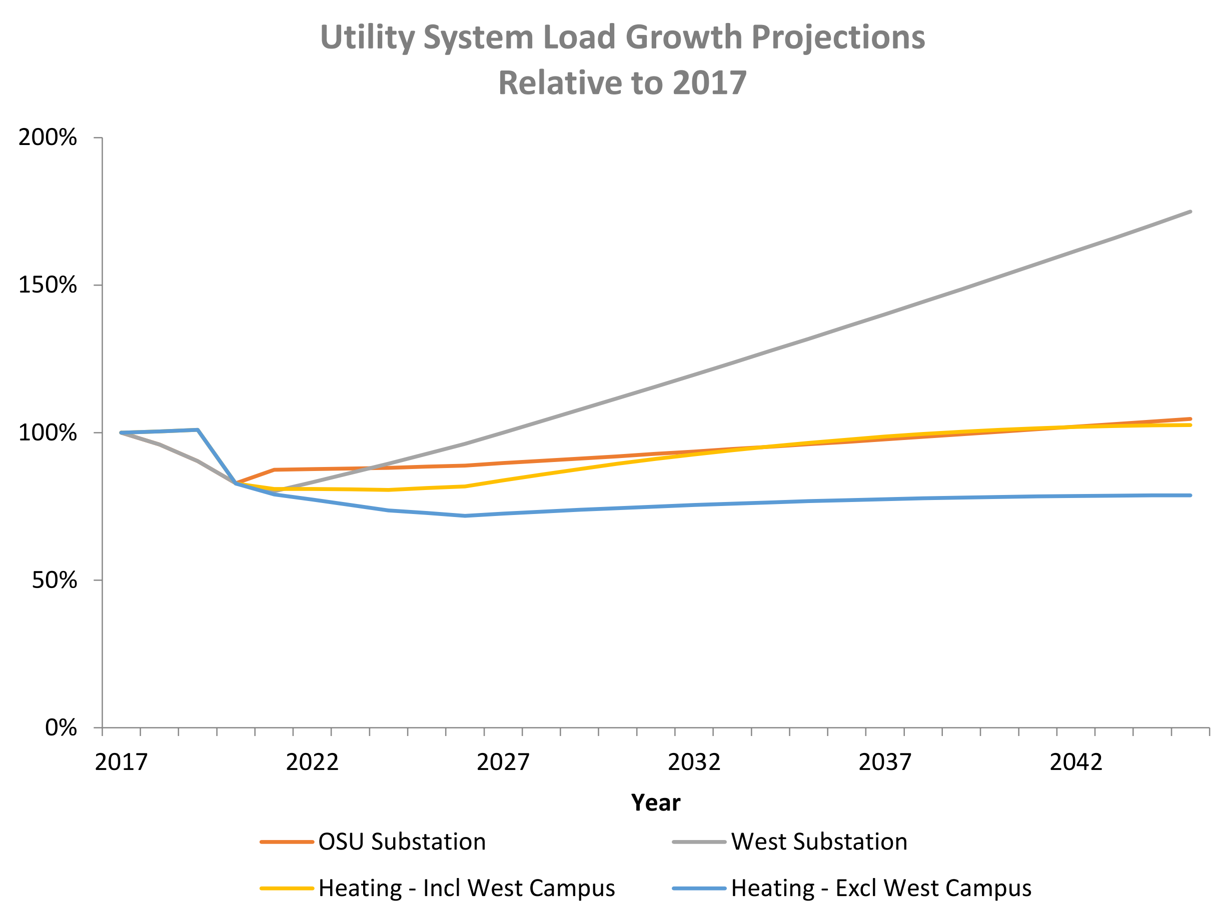

Figure 2-5: Load growth projections for the campus

Value-Added Idea to Utilize Existing Chiller Capacity

Excess capacity of the existing chillers at McCracken can be utilized to cool the GTG inlet air during the summer to increase CHP output and reduce the import of grid electricity[8]. The STG design allows steam to be extracted for campus heating or condensed in the steam cycle to provide additional electrical output of 28MW at ISO conditions. Due to the high variability in steam loads during winter and summer and from day to day, this design, as depicted in Figure 2-3, provides operational and commercial flexibility, which can be utilized on a real-time basis determining the process steam to power ratio, giving the

[8] GTG output decreases with increasing ambient temperature with lower air density. By cooling the gas turbine inlet air this loss in generation capacity can be mitigated.

University the optimum financial configuration. Duct burners installed within the HRSGs provide further flexibility by increasing the amount of steam that can be produced in the HRSGs. The amount of duct firing differs in the Titan 250 and SGT-600 cases to make the total plant output consistent between the cases. Cooling towers reject waste heat from the steam turbine exhaust to the atmosphere.

Plant outages will be scheduled to coincide with low load periods, typically in the spring or autumn months. The CHP will have the ability to maintain operation in the event of a single GTG outage or during an STG outage with the use of a steam bypass station.

Fuel gas compressors will be installed to pressurize natural gas above the current supply pressure of 60 psig. A single gas compressor will be installed per GTG, with a crossover line to the other GTG to increase availability. Due to the inclusion of a steam turbine, additional water treatment is required beyond what is provided currently for use in the existing boilers[9]. To reduce the water conductivity to the desired level, a second pass reverse osmosis (RO) and demineralizer system will be installed. All major mechanical and electrical equipment will be located within the CHP building. The building will help to reduce noise, improve aesthetics, provide freeze protection, and facilitate maintenance.

Electrically, the CHP will tie into the OSU Substation, either directly through OSU Substation or indirectly through Smith Substation depending on the plant location. The CHP will produce electricity at 13.2kV. In the event of a grid outage, the CHP can instantaneously disconnect from the grid and provide power to buildings connected to OSU and Smith Substations in island mode. As a future option, the CHP can also be connected to West Substation. A regulatory constraint for connecting to West Substation is that the load provided by the individual GTGs and STG cannot be split (i.e. each generator can only be connected to one substation at any given moment). If loads on west campus continue to grow, the connection to West Substation will provide further resiliency.

Adding steam production capability via the CHP in combination with steam demand reduction via ECM projects will allow for existing boilers to be retired at McCracken while maintaining N+1 thermal redundancy. In the base case, two boilers (Boilers #1 and #5) will be retired, reducing life cycle costs associated with maintaining and replacing these pieces of equipment. This retirement provides for a total savings of $15MUSD over 25 years.

Both GTG models are equipped with dry low NO_x (DLN) combustors. GTG and duct burner emissions will be further reduced in the HRSG with NO_x and CO/VOC catalysts. Urea will

[9] Steam turbines require feedwater with much higher purity than boilers.

be stored on site for use in the Selective Catalytic Reduction (SCR) process[10]. A Continuous Emissions Monitoring System (CEMS) will be installed in the HRSG stacks to monitor plant emissions levels and ensure compliance within the required operating limits.

Several features are included in the CHP design to protect the equipment and, more importantly, personnel in and around the facility. Fire protection will be designed per NFPA code. Campus water is considered as the source for fire protection, except for areas where water can exacerbate the conditions of a fire such as in the GTG enclosure or in the oil storage building. The CHP distributed control system (DCS) will have many protection functions built in which will automatically unload and shutdown the plant if unsafe conditions are detected via instrumentation.

The limiting factor for CHP production is natural gas consumption in the winter, which is restricted to 950 million BTU per hour (MMBTU/H).

Case 1 – South of Smith Substation

The area south of Smith Substation, at the intersection of Tuttle Park Place and Annie & John Glenn Avenue, is an ideal location for the CHP due to proximity with water, steam, and natural gas tie-points at McCracken and the Water Treatment Building. The small footprint of the site constrains the layout of equipment and requires the HRSGs to be placed on the second floor of the building, increasing structural costs. Due to the smaller area, the Siemens SGT-600, which requires a larger footprint, is excluded as an option.

The existing water treatment facility will be utilized with the addition of a 2nd pass RO system and a mixed-bed demineralizer.

The CHP will connect to Smith Substation via three 1500-amp (A) feeders. Existing connections between OSU and Smith Substations will distribute the electricity to buildings on the main campus utility network. If the option to connect the West Campus Substation is utilized, new duct banks will be required from the CHP site to the Olentangy River. Existing duct banks are available under the river near John Herrick Drive and will route the feeders to Olentangy River Road. Utilizing the existing duct bank will reduce the costs of crossing the river but will exhaust the duct bank's capacity. From Olentangy River Road to West Substation, new duct banks would be required along Kinnear and Kenny Road to make the final connection to West Campus Substation, crossing underneath Highway 315 and a set of railroad tracks on Kinnear Road.

While the location of the CHP is well-suited for the existing campus load profile, it is not an optimal fit with respect to campus expansion; most of which is considered in the Midwest and West campus based on Framework 2.0.

[10] SCR process uses ammonia as the chemical agent. Rather than bring ammonia to campus in road tankers and then store in tanks, ammonia will be produced in-situ and on-demand to eliminate hazardous material risk.

Case 2 – North of Smith Substation

North of Smith Substation is also a suitable location for the CHP for the same reasons listed for Case 1, but also has additional benefits. Water, steam, and electrical tie-points are the same for both proposed sites.

The advantage of Case 2 over Case 1 is the larger footprint (roughly 50% more area) allowing for improved equipment arrangement. The existing parking lot across from Ohio Stadium will be replaced in this scenario and existing electrical conduits will require relocation.

Case 3 – Midwest Campus

The Midwest Campus CHP is a solution capable of delivering the existing campus demands and leveraging its location to support Midwest and West campus expansion as detailed in Section 5 of this Feasibility Study. The CHP requires between 39k and 96k square feet of land and can be located anywhere within the Midwest campus. OSEP will collaborate with the University to minimize impact and optimize the footprint within an agreed upon location.

As an option, the cooling towers can be replaced with an air-cooled condenser (ACC). This would result in the following impact to price and performance of the CHP:

	Water-Cooled Condenser	Air-Cooled Condenser	Incremental Value	Percent Increase
CHP CAPEX (MUSD)	$139.6	$144.8	$5.2	3.7%
Summer Output (kW)	67,385	65,922	(1,463)	-2.2%
Summer Heat Rate (BTU/kWh)	8,755	8,949	194	2.2%
Footprint (acre)	2.14	2.37	0.23	10.6%
Water Consumption (gal/day)	606	365	(241)	-39.7%

Additional infrastructure investments will be required to tie-in to the existing utility system. A new gas pipeline would be installed between the CHP location and the gas house on Olentangy River Road between Lane Avenue and Woody Hayes Drive, which is the same line that feeds McCracken. Condensate return from campus buildings will still be routed to McCracken. There, the condensate will be treated and combined with RO make-up water prior to being pumped to the CHP. A 2nd pass RO system and demineralizer will improve water quality to the necessary level for use in the STG, prior to being stored in a new demineralized water tank located in the CHP building. A new steam line across the river would be necessary to maintain sufficient pressure at eastern campus buildings. The steam line is proposed to be routed along the planned extension of Annie and John Glenn Ave across the Olentangy River via a new bridge envisioned in the University's Master Plan Framework 2.0.

Electrically, the CHP would connect to OSU Substation via Olentangy River Road, utilizing the existing duct banks under the river near John Herrick Drive. The new duct bank from the CHP to John Herrick Drive would be installed with sufficient capacity to connect the CHP to West Campus. If the connection to West Campus Substation is considered, new duct banks would be installed south of John Herrick Drive on Olentangy River Road, then along Kinnear and Kenny Road to the substation.

Cost of this additional infrastructure is included in the CHP cost build up as shown in Figure 1-2, except for the Annie and John Glenn extension bridge.

Case 4 – Midwest Campus (Expandable)

A final case is proposed which offers the same benefits as Case 3, with even greater opportunity to support campus expansion. The configuration includes three GTGs, three HRSGS, and a larger STG designed to handle the increased steam load. At full capacity, this option produces 108 MW.

The CHP would be designed in two phases. The first phase would include two GTGs, two HRSGs, the STG, condenser, cooling tower, and corresponding balance of plant equipment (BOP) with provisions for a third GTG & HRSG. The building would also include space for subsequent expansion. The additional GTG and HRSG could be installed during the second phase – time to be decided by the University - to provide additional electrical and thermal output.

The utility infrastructure investment required during the first phase is $4.2 MUSD more than Case 3 due to increased cost of BOP equipment and a larger building to support the third gas turbine. Given the fuel supply limit of 950 MMBTU/h, the third gas turbine would require an upgrade to the campus gas supply system. A high-level cost to increase the natural gas supply to 1,300 MMBTU/h was estimated at $25 MMUSD by Columbia Gas.

Summary of Cases

In 2020 $'s	Burns & Mc	CASE 1	CASE 2		CASE 3		CASE 4	
			A	B	A	B	A	B
Location	South of Smith	South of Smith	North of Smith		Midwest		Midwest (Expansion)	
Turbine	Titan 250	Titan 250	Titan 250	SGT 600	Titan 250	SGT 600	Titan 250	SGT 600
Power output Summer (MW)	43	54	54	57	54	57	54	57
Steam output Winter (KPPH)	173	221	221	190	221	190	221	190
Emissions								
NOx (TPY)	*16.4*	*23.66*	*23.66*	*30.24*	*23.66*	*30.24*	*23.66*	*30.24*
CO (TPY)	*22.9*	*32.44*	*32.44*	*29.61*	*32.44*	*29.61*	*32.44*	*29.61*
Footprint (ksqft)	20	26	39	39	96	96	103	103
Heat Rate (BTU/kWh)	12,757	10,635	10,635	10,163	10,635	10,163	10,635	10,163
Overall CHP Efficiency	75.9%	60.3%	60.3%	62.0%	60.3%	62.0%	60.3%	62.0%
Total Capex ($ Million)	$105	$128	$129	$131	$144	$147	$149	$152
OPEX								
VOM ($/MWh)	*$1.5*	*$1.5*	*$1.5*	*$1.5*	*$1.5*	*$1.5*	*$1.5*	*$1.5*
FOM ($'000/Year)	*$229*	*$229*	*$229*	*$229*	*$229*	*$229*	*$229*	*$229*
LTSA ($/FH/unit)	[redacted]							
Variable Fee Amortization	20 year	20 year	20 year	20 year	20 year	20 year	20 year	20 year

Environmental - Water

Water consumption of the CHP can be broken into two major sources: Blowdown in the HRSGs and losses from the cooling tower system. HRSG blowdown losses are offset by avoided McCracken boiler blowdown losses. The net impact on water consumption is therefore a function of the cooling tower system, as shown in Figure 2-6. Cooling system losses can be mitigated by utilizing an air-cooled condenser in lieu of a water-cooled system.

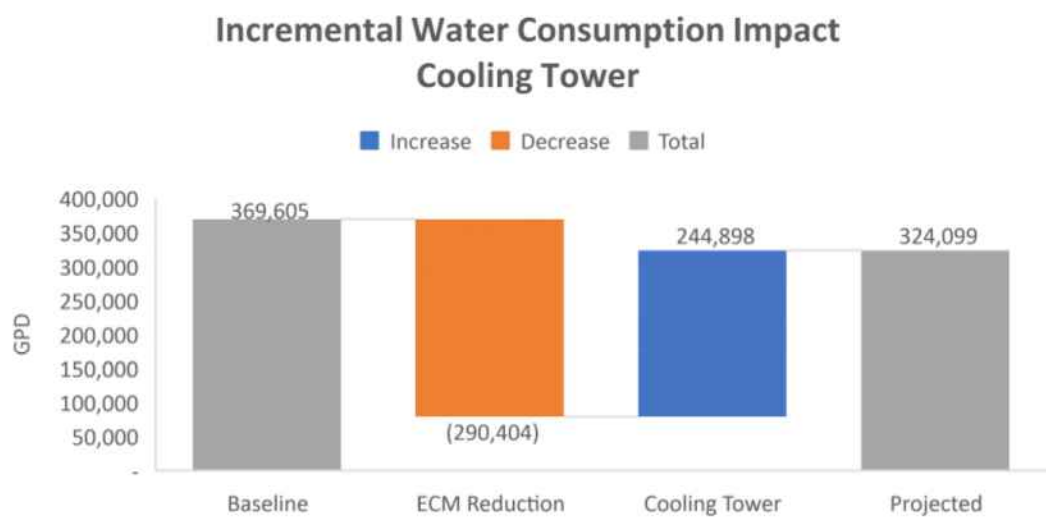

Figure 2-6: Water losses are minimum within the CHP steam cycle. "Baseline" illustrates current average water consumption at McCracken and the steam/condensate network.

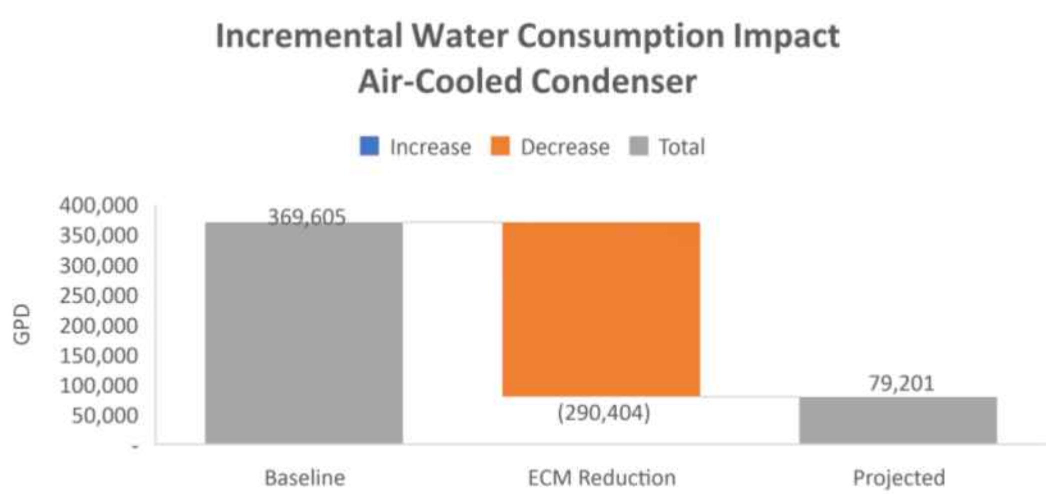

Figure 2-7: CHP water losses are minimal when utilizing an ACC, compared to the baseline water consumption of McCracken

Environmental - Noise

OSEP has considered OSHA regulations for sound emissions and proposes an incremental limit of 5 dB(A) for the increase at the CHP boundary relative to the current baseline. Additional University requirements regarding noise will be clarified during the development phase to determine the level of sound control necessary.

Environmental - Emissions

Potential to Emit (PTE) calculations were developed for particulate matter (PM), sulfur dioxide (SO_2), nitrous oxides (NO_x), carbon monoxide (CO), volatile organic compounds (VOC), and carbon dioxide (CO_2). The calculations estimate the tons per year (tpy) emitted assuming the CHP runs fully loaded year-round including duct firing (hypothetical highest emissions case). GTG and HRSG duct burner emissions factors were used to evaluate the emissions levels upstream of the NO_x and CO/VOC catalysts. To be conservative, the emissions are calculated at an ambient temperature of 30 °F, where the GTG exhaust flow and corresponding emissions flows would be the greatest. The effectiveness of the catalysts is assumed to be 85% for NO_x and CO and 50% for VOC. Additional emissions because of startup/shutdowns and use of secondary fuels are also considered. The PTE calculation for the Solar Titan 250 and SGT-600 is shown in Figure 2-8 below.

TOTAL POTENTIAL EMISSIONS, TPY	PM10	PM2.5	SO2	NOX	CO	VOC	CO2e
Solar Titan 250	17.53	17.53	7.11	23.66	32.44	8.67	335,321
Siemens SGT-600	15.28	15.28	8.64	30.24	29.61	7.15	334,302
Major NSR (PSD/NNSR) SER	15	10	40	40	100	40	75,000

Figure 2-8: Emissions calculations

Note that the CHP's PTE is below all Major New Source Review (NSR) significant emission rate (SER) thresholds except for particulate matter (PM10 and PM2.5) and greenhouse gases (represented as carbon dioxide equivalents). Exceedance of the CO_2 Major NSR SER threshold does not trigger a major modification if all other criteria pollutants do not exceed their respective Major NSR SER threshold. To avoid major NSR and to offset the PTE for PM10 and PM2.5, emission reduction credits would be required. The retirement of Boilers #1 and #5 provides a credit to the PTE values based on the Baseline Actual Emissions (BAE). The BAE credit is calculated from the greatest two-year average annual emissions in the 10-year lookback period for the two boilers to be retired. In 2013-2014, the total PM averaged 2.53 and 5.39 tpy for Boilers #1 and #5, respectively. The total emissions credit of 7.92 tpy for PM yields a net PM10 and PM2.5 emission increase of 9.61 and7.37 tpy for the Solar and Siemens configurations, respectively.

The Net PTE is below the Major NSR threshold for PM, hence the CO_2 NSR threshold is excluded from evaluation and based on our review of the permit approval process in Ohio, the allocated time for obtaining the required permit should be 9-12 months.

Project Implementation Strategy

There are several project delivery methods available which ENGIE considers and deploys globally based on project risk profile. OSEP, in consultation with the University, will develop the project implement strategy and delivery method prior to execution based on optimum risk profile. The CAPEX calculations in this Feasibility Report are based on a turnkey, EPC delivery method.

The campus being an active community with seasonal traffic and critical utility services will require complex coordination during the CHP implementation. ENGIE Services personnel on campus will be utilized to coordinate construction activities and minimize impact to the University. Construction sequencing and equipment/supplies shuttling has been proven in urban congested areas and will be utilized in the CHP construction. The project logistics cost and schedule have been considered in the feasibility study. A detailed logistics plan will be developed in advance of construction and shared/coordinated with the University to minimize impact to the campus. The logistical considerations include but aren't limited to the following:

- Offsite laydown and erection areas for equipment and materials
- Double handling and trucking during low volume traffic periods for transportation of small equipment and material for erection. Just in time delivery of OEM supplied large equipment directly to the site to minimize double handling.
- Craft productivity for double handling and delays due to campus event scheduling (i.e. home football games, graduation, and other special events),
- CHP steam/condensate, natural gas and electrical utility services will be tied into the existing campus facility system during planned outages which are scheduled during the off season (i.e. steam lines and natural gas during summer break)
- Construction fencing will be installed around the perimeter of the project to ensure public safety and secure the site
- A lifting plan will be developed to coordinate the use of stationary and mobile lifting equipment with campus activity
- Labor trailers to be off-site with shuttle transportation.
- A live-cam can be made available for live observation of construction activities to the campus community.

Project Implementation Organization

The Project organization with their respective functional responsibility is shown in Figure 2-9 below. The leadership team is structured for single point accountability with direct responsibility under the Project Manager. Except for the Operations Manager – who is going to be from the ENGIE Services team on campus – the project implementation team will be provided by ENGIE North America.

- **Project Manager** - direct responsibility for coordination with OSEP and the University administration, major equipment, EPC contracts and owner's engineer (OE) contracts required for the project. The subcontractor project managers will report directly to the Project Manager.
- **Construction Manager** - responsible for on-site monitoring project activities to assure the contractors' full compliance with performance, quality, safety, and environmental standards.
- **Project Engineer** - responsible for all aspects of the engineering and design of the project, including but not limited to selection of major equipment (technically), provide technical data for regulatory compliance (i.e. environmental permitting, interconnection), design of facility including interface to existing systems.
- **Contract Manager** - responsible for all aspects of contracting/procurement and administration of project contracts/POs, including but not limited to securing major equipment (commercial), EPC Contract (commercial), and OE.
- **Operations Manager** - responsible for coordinating with the University, staffing, training, and organizing the operations resources in preparation for the takeover of the facility on the Commercial Operation Date. The Operations Manager will also be responsible for administering all Post-COD obligations.
- **Corporate support** of the following areas will be administered from the ENGIE North American offices:
    - **Accounting/Finance** – cost control and reporting
    - **Environmental** – secure permits and develop permitting compliance process

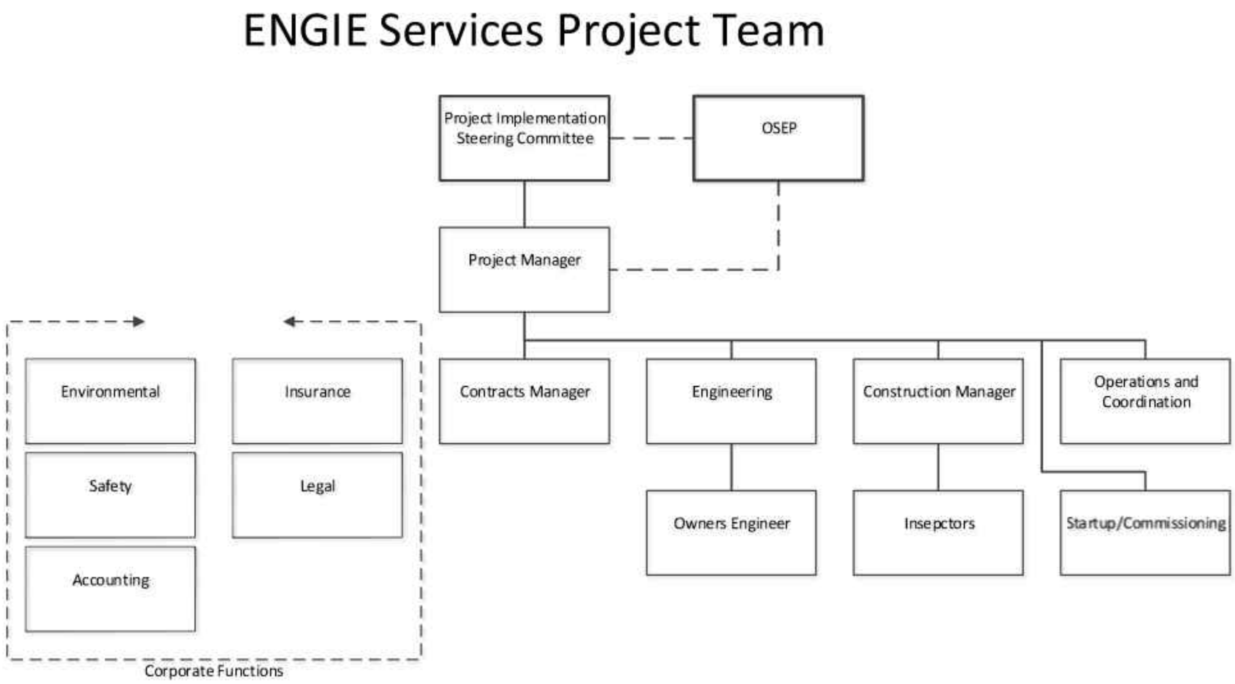

Figure 2-9: ENGIE Services CHP implementation team organization chart

Operations

ENGIE operates and maintains CHPs globally. In North America, ENGIE own portions of 12 combined cycle facilities (which are very similar to CHPs), 9 of which are operated by ENGIE. ENGIE North America and global O&M expertise will be utilized to develop the ENGIE Services training program. Personnel from ENGIE North America will be utilized to cross pollinate the ENGIE Services team to provide the necessary skills to efficiently operate and maintain the CHP in a safe and reliable manner.

The CHP Facility will be operated and maintained by the existing ENGIE Services team on campus. The facility will be completely automated with state of the art controls and requires minimal personnel to operate and maintain. Stationary engineers currently operating the McCracken boilers will be trained to operate the CHP.

Regular (day to day) maintenance will be performed by the existing maintenance team with two additional maintenance technicians added due to the additional equipment and expertise required for the gas and steam turbine sets, HRSGs and gas compressors. The bulk of CHP major maintenance required will be on the gas turbines, for which a long-term service agreement (LTSA) will be established with the OEM and is included in the OPEX. Remaining major maintenance beyond the scope of the ENGIE Services staff will be contracted out and this cost is included in the OPEX as variable O&M cost.

OSEP has taken the difference between operating and maintaining the boilers and CHP under consideration and based on a high-level assumption, determined the delta. The delta for equipment parts, consumables and utilities required to operate and maintain the CHP are included in the non-fuel variable operation and maintenance (VOM) cost. The incremental O&M labor is included in the fixed operation and maintenance cost (FOM).

Transmission services associated with the CHP operation is included in the ISO capacity/ancillary price.

Schedule

The CHP project schedule covers activities from development approval through start of commercial operation. Development process is in accordance with University requirements to provide a ready to execute package for approval. Project package will include but not be limited to firm CAPEX price, negotiated EPC or other construction contracts, financing, evaluation of non-environmental regulatory requirements, environmental permit (application, modeling, public notice (if required) and permit language, interconnection agreement (completion of the Facility Study which will identify risk) and detailed operation cost.

The total project schedule is 36 months which consist of a 14-month development period and 22-month implementation (including 12-month construction and 2 months commissioning). The 36-month detailed schedule provided in Appendix G is based on the following activities:

- Development Phase
    - Selection and negotiation of Owner's Engineer and Environmental Consultant
    - Identification of Implementation Contractors
    - Selection and negotiation of purchase contract for owner supplied major equipment (release contingent on the University's final approval) for selected site
    - Development of project delivery method and project schedule
    - Owner's Engineer development of sufficient design for firm pricing, or, project functionality development and selection of EPC contractor, depending on project delivery method.
    - Contractor selection and establishment of firm pricing, negotiations of all contracts to a "ready to sign" level.
    - Interconnection Agreement
    - Receive air and other environmental permits (Minor Permit Amendment)
    - Architectural design approval during development period
    - Develop and finalize detailed project schedule

- Assist/work with the University for communications, public outreach, and stakeholder management.
- Implementation Phase
  - Detailed design for construction
  - Detailed Commissioning and Testing Plan
  - Procurement of owner-supplied major equipment
  - Detailed safety, security and quality programs
  - Construction and project management teams site
  - Construction with 10-hour days, 5 days a week (5x10)
  - Stakeholder management
  - Local and state agency management in collaboration with related departments of the University

Activity	Start	Completion
University CHP Development Approval		Jun 2018
Owner Engineer Selection	Jun 2018	Jul 2018
Environmental Consultant Selection	Jun 2018	Jul 2018
Interconnection Process	Jun 2018	Aug 2019
Air Permitting Process	Jun 2018	Jul 2019
Implementation Contractor Selection	Sep 2018	Jan 2019
Final Package to the University		Aug 2019
University Approve CHP Implementation		Aug 2019
Order Major Equipment	Aug 2019	Oct 2019
Detailed Design	Aug 2019	Apr2020
Mobilization to Site		Mar 2020
Construction Period	Mar 2020	Jun 2021
COD		Jun 2021

Figure 2-10: Project milestone schedule

Comparison to Burns and McDonnell CHP Case

The CHP configuration proposed by Burns & McDonnell in the 2014 Infrastructure Master Plan Update includes two Solar Titan 250 GTGs and two HRSGs with supplemental firing to produce steam for process use. The key difference between the Burns & McDonnell configuration and OSEP's recommended configuration is the inclusion of an extraction-condensing STG and the additional equipment required for the steam turbine operations. Burns and McDonnell considered consistent wind energy production across all months in their analysis. Based on historical data, wind production from the wind PPA is lowest during the summer when campus electric load is highest. CHP without a STG would have to be turned down during the summer – when the demand for power is highest - to match campus steam load. The advantage of OSEP's recommendation for any of the 4 cases is highest economic value, operational flexibility, reliability and optionality.

Heating and power loads have opposite seasonal peaks on Campus. Heating is at a minimum during the summer while electric-driven cooling is at its peak. Conversely, when steam usage peaks in the winter, electric loads are at near minimum. Without an extraction-condensing STG the electric and thermal production of the CHP are chained together, restricting the ability of the CHP to produce one service independent of the other. The OSEP configuration is not encumbered by this restriction. When the campus heating demand is low, steam can be utilized to produce more power.

The importance of flexibility is compounded given the nature of the Concession Agreement. ECM implementation will steadily decrease campus energy consumption, while expansion and campus growth will act as a restoring force. Design versatility is required not only to handle variability in seasonal loads, but also the uncertainty of future demands. The Burns & McDonnell configuration's simplicity could be its fatal flaw in the situation of significant thermal load reduction. Because OSEP will be managing the EUI reduction, it has visibility into ensuring the CHP design is the best long-term fit for the University.

3.0 COMMERICAL EVALUATION

Ohio State Energy Partners developed multiple CHP configurations with the focus on maximizing value, increasing reliability and resiliency and mitigating supply cost risks while reducing the University's carbon footprint.

The summary of the results for the multiple solutions are provided in Figure 3-1 below. While Case 2 (North of Smith) provides substantial improvement to its predecessors, Case 3 provides a larger value creation and other incremental benefits including the establishment of a new anchor for the central utility plant on Midwest campus and economic viability of a more efficient district energy network considering expansion of the Midwest campus. Finally, Case 4 is an enhanced version of Case 3 with built in optionality that preserves substantial upside with respect to campus expansion.

All in 2020 $	Burns & McDonnell	Case 1	Case 2	Case 3	Case 4
Location	South of Smith	South of Smith	North of Smith	Midwest Campus	Midwest Campus (Exp)
Configuration	2x0	2x1	2x1	2x1	(2+1)x1
Gas Turbine	Titan 250	Titan 250	SGT 600	SGT 600	SGT 600
Steam Turbine		SST300	SST300	SST300	SST300
Summer Maxium Capacity (MW)	43	70	73	73	73
Winter Steam Capacity (kpph)	218	218	190	190	190
Footprint	0.6 Acres	0.6 Acres	0.9 Acres	2.2 Acres	2.4 Acres
Alt 1: Midwest Centralized DHC Capex				$80.2	$80.2
Alt 2: In-building utility capex for MidWest campus				$70.4	$70.4
CHP Capex ($million)	**$105**	**$128**	**$131**	**$147**	**$152**
Total Relavant Capex***	**$105**	**$128**	**$131**	**$227**	**$232**
RESULTS					
Total NPV of OSU Savings* ($million)	**$62**	**$117**	**$147**	**$161**	**$154**
Base Savings without Midwest DHC	*$62*	*$117*	*$147*	*$127*	*$121*
*Incremental Benefits From Midwest DHC***	*$0*	*$0*	*$0*	*$34*	*$34*
Real LCOE 2021-2045* (c/kWh) *(Compared to As-is LCOE)*	[redacted]				
CO_2 Reduction (2021)	**22%**	**33%**	**38%**	**38%**	**38%**
Procurement Risk Reduction	**26%**	**36%**	**39%**	**39%**	**39%**
Resiliency Improvement	43 MW Capacity vs. 63 MW Critical Load	70 MW Capacity vs. 63 MW Critical Load	73 MW Capacity vs. 63 MW Critical Load	73 MW Capacity vs. 63 MW Critical Load	73 MW Capacity vs. 63 MW Critical Load

* *Net of Concessionaire's cost recovery (through incremental Variable Fee with 20 yr recovery); assuming 4% Discount Rate, 2% Inflation*
** *Net of Incremental DHC Capex; Not considering other option values related to locating the CHP in MW and adding a 3rd turbine under Case 4*
*** *Sum of CHP and Midwest campus district heating and cooling system with a new central chiller located near the CHP*
Incremental cost difference between Alternative 1 and 2 are used in the total NPV benefit denoted in the "RESULTS" section

Note 1: Value of added resiliency has not been included in the NPV calculation
Note 2: Added value of a district heating and cooling network in Midwest campus supplying existing and future buildings is included in Case 3 and Case 4.
Note 3: Additional option value of adding a 3rd turbine of approximately [redacted] (resulting from West expansion) not included in the Case 4 NPV above
Note 4: All cases assumed Wind PPA to be expired in 2032 and replaced by grid purchase thereafter
Note 5: All cases assumed a reasonably higher estimate of grid procurement costs (relative to As-is) for residual electric demand (due to volume shrinkage) after the installation of the CHP. See section 1.4 for details
Note 6: The incremental benefits of $34 million from Midwest DHC under Case 3 and 4 assumed, and net of, an incremental investment of $10 million (total $80 million in DHC vs. $70 million investment in building level thermal under status quo)

Figure 3-1: Summary of optimized cases provided by OSEP

3.1 Maximized Economic Value

Utility Cost Savings and Maximum Value Creation for the University

An optimized cogeneration facility will be able to economically offset the campus electric and thermal loads, while operating in a more fuel-efficient manner compared to the original Burns and McDonnell design. The analysis concludes that the addition of an optimized cogeneration facility would decrease University's levelized cost of energy (LCOE) by [redacted]% and provide for an additional $55-99 million (location specific) of value creation over the Burns and McDonnell configuration. Apart from the offset in energy usage due to efficiency gain, part of these savings will be derived from reduction in the PJM demand and capacity charges.

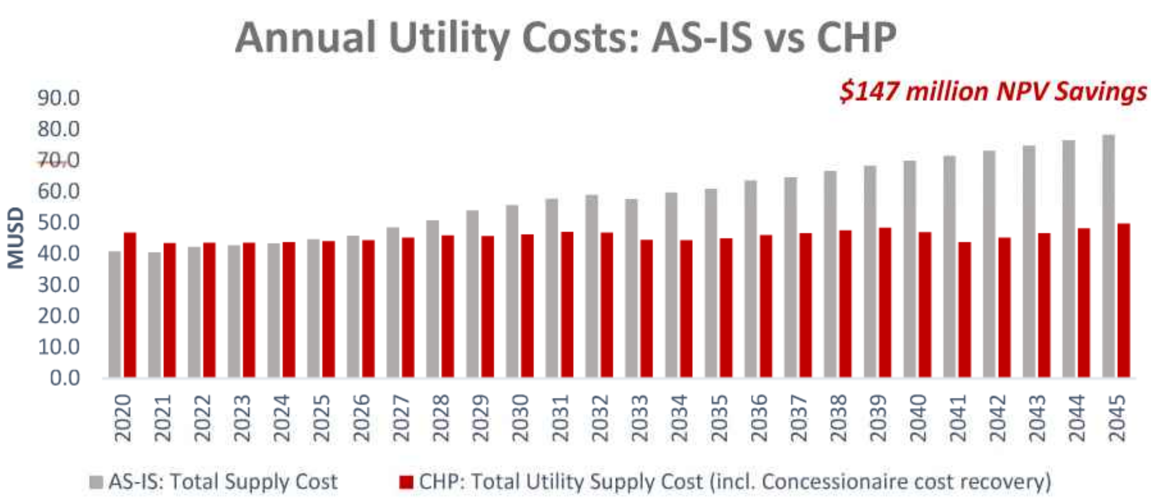

Figure 3-2: North of Smith substation (Case 2) provides $147M of NPV supply cost savings for the University

The optimized cogeneration solution for the North location in Figure 3-2 **yields $147 million of total Utility Savings over 25 years in NPV** at a 4% discount rate. This projected savings is net of University's incremental O&M costs as well as Concessionaire's cost recovery (through Variable Fee mechanism with a 20-year Recovery Period) over 25 years.

The real Levelized Cost of Energy (LCOE) of North location proposed by OSEP in Figure 3-3 realizes a [redacted]**% decrease over 25 years** compared to the University's LCOE over the same period. The detailed NPV supply cost savings, detailed procurement, performance and LCOE models are located in Appendix H and I for Case 2. The detailed NPV supply cost savings and LCOE models for Case 4 are in Appendix J.

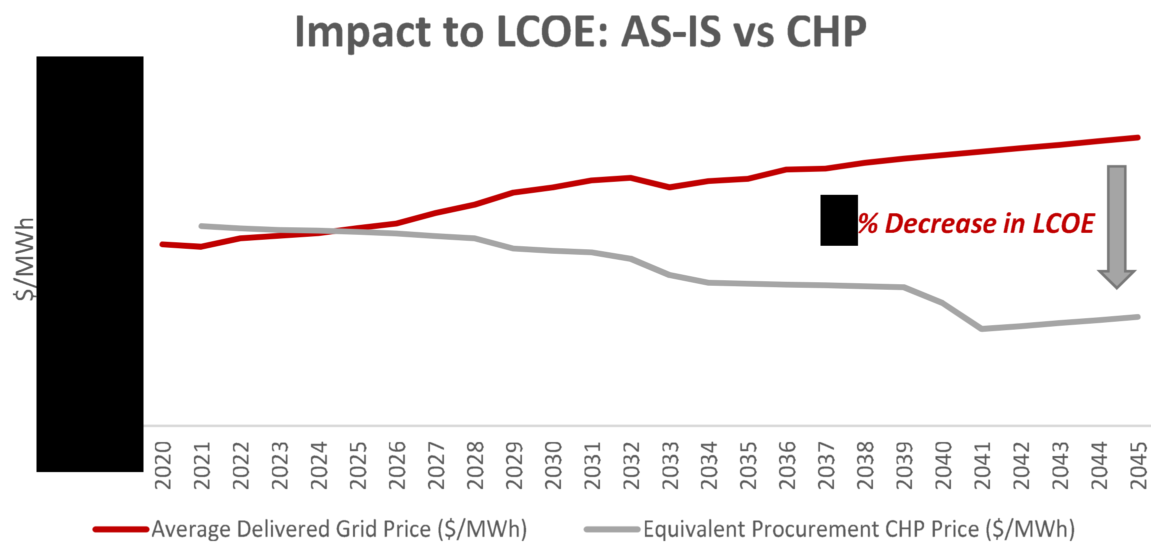

Figure 3-3: Both Case 2 and Case 4 provide the University with a [redacted]% reduction in LCOE compared to baseline

It should be noted that the LCOE numbers in Figure 3-1 represents the **fully-loaded delivered retail electricity price** for the University whereas in many standard market studies on competing technology, LCOE may represent the wholesale energy portion of the cost only and may exclude the delivery charges as well as some non-energy retail charges.

Payback Analysis

The cumulative net savings (including the incremental Variable Fee) shows a straight-line Payback Period, for Case 2 and Case 4 respectively, of approximately 9 and 11 years as described in Figure 3-4 and 3-5.

The relatively long payback period is because of how the Variable Fee mechanism works under the Concession Agreement (front-loaded, declining over time) - about 75-80% of the Concessionaire's cost recovery for the investment happens in that first 9-11 years period.

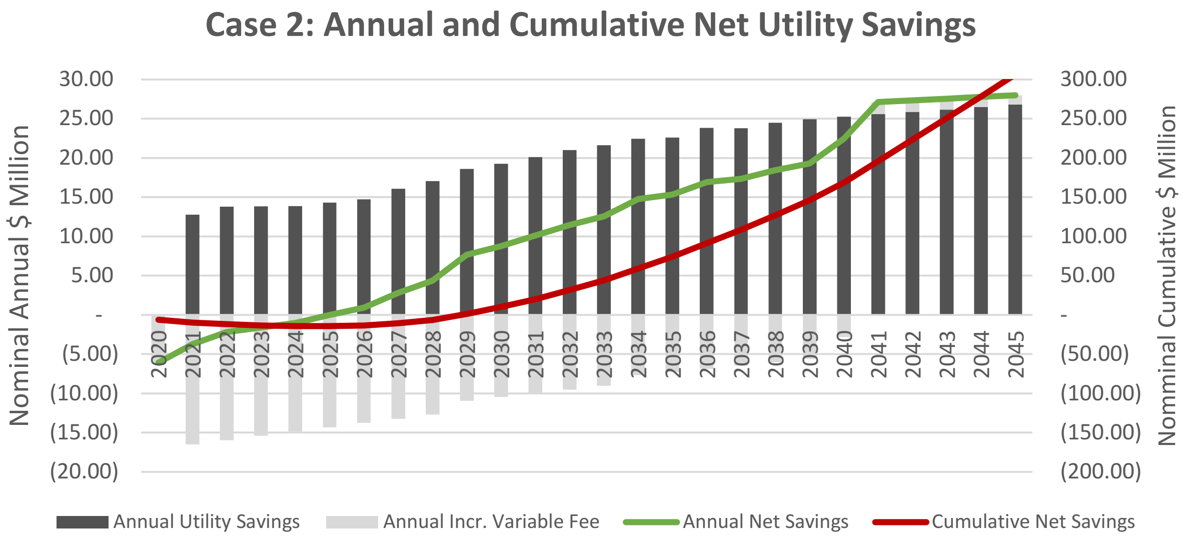

Figure 3-4: Payback Period for Case 2 is realized in approximately 9 years using 20-yr Recovery Period for the Variable Fee.

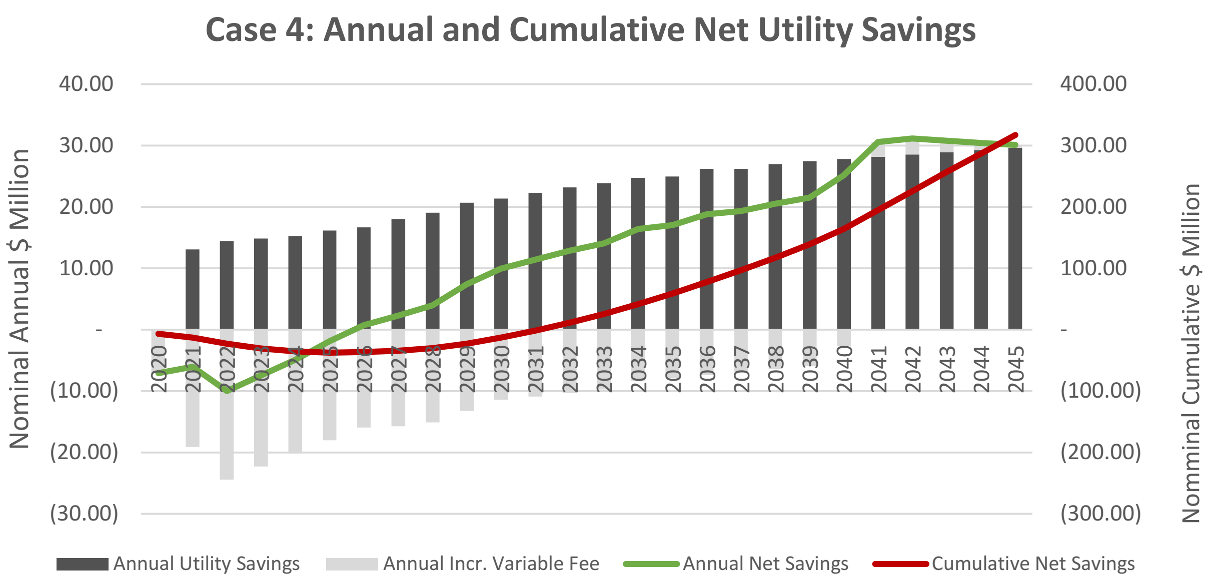

Figure 3-5: Payback Period for Case 4 is realized in approximately 11 years using 20-yr Recovery Period for the Variable Fee.

Sensitivity Analysis Around Market Curves

Figure 3-6 below provides a sensitivity analysis around the base case power and natural gas curves that OSEP utilized in its valuation. The analysis below concludes that the reduction in real LCOE is expected to be at least [redacted]% - under an ultra-conservative and unlikely pessimistic scenario, compared to "As is" case (assuming the commodity prices do not vary more than +/- 20% of the base case across 25 years).

OSEP utilized conservative market curves in its base case evaluation. However, the low case scenarios [redacted] by themselves project a much more conservative outcome than reality. The sensitivity analysis below assumed a complete disconnect or a negative correlation between power and natural gas prices (for example, [redacted] case assumed no change in power price) which is highly unlikely given the fuel mix in PJM is shifting more towards natural gas. In reality, a higher natural gas price would also result in a higher power price as a result of which the LCOE differential (between "As is" and CHP) would tend to be less pronounced and converge towards the base case differential [redacted] In addition, OSEP also incorporated a 3rd party market consultant's (IHS CERA) view in its valuation as a separate scenario which resulted into a similar reduction [redacted] in real LCOE as OSEP's base case.

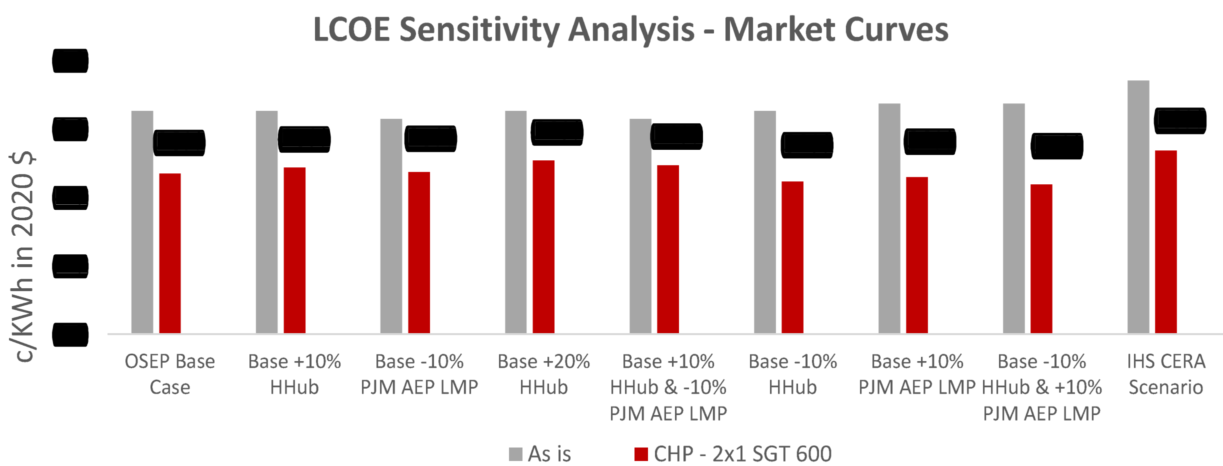

Figure 3-6 (a): Market sensitivities: shows a minimum reduction of [redacted] in real LOCE

As provided in Figure 3-6(b), to reach a break-even scenario (NPV=0), the entire Henry Hub price curve over 25 years would have to move upward <u>by about 95% compared to the OSEP Base Case, keeping all else constant</u>.

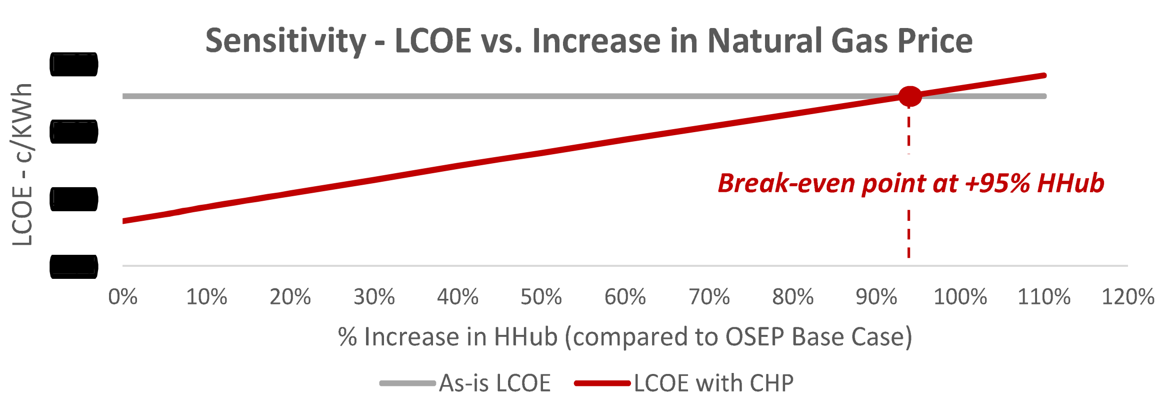

Figure 3-6 (b): A 95% increase in Natural Gas Price (compared to the Base Case) would result in a break-even scenario

Sensitivity Analysis around Campus Expansion Scenarios

As provided in Figure 3-7, OSEP provided analysis around campus expansion and market sensitivities that concludes the reduction in LCOE is expected to be at a minimum [redacted] under an extreme pessimistic scenario with very minimal campus expansion (only interdisciplinary research building on mid-west, ambulatory on west, replacement hospital on main campus, and college of medicine buildings on main campus) as well as [redacted] increase in fuel price. On the other hand, the natural gas forecast used in the base case with minimal campus expansion scenario will still result in a reduction in LCOE by [redacted].

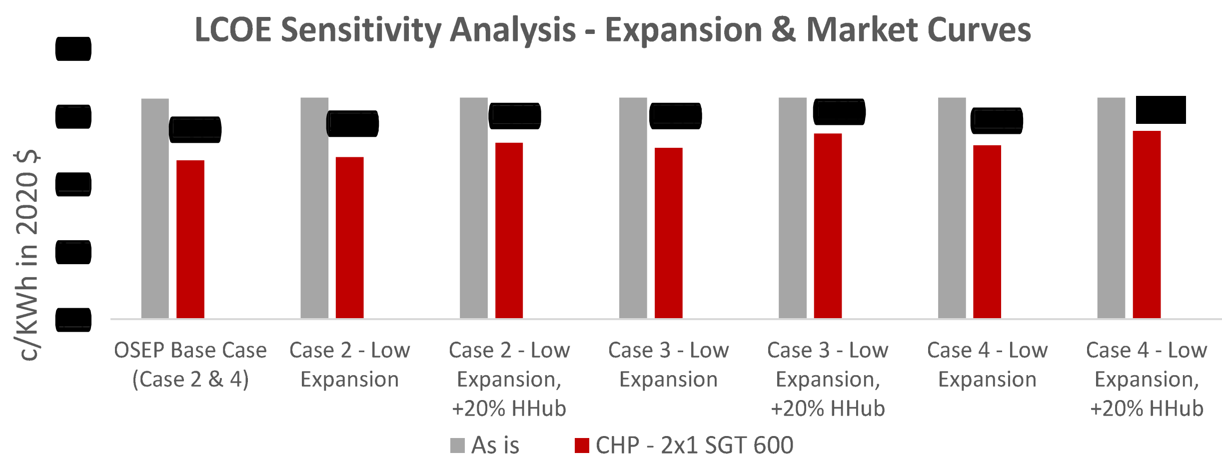

Figure 3-7: Minimal Campus Expansion coupled with very high Natural Gas price yields a minimum reduction in LCOE of [redacted]

The Full Expansion scenario (Midwest plus West campus; see section 5 for more details) provides significant additional upsides under Case 3 and 4, as shown in Figure 3-8.

Case 3 & 4 - Expansion Sensitivities and Upsides

	Case 3			Case 4 Upside
	Base Expansion	Low Expansion	Full Expansion	Full Expansion
Expansion Scenario	Midwest only	Four buildings only*	Midwest + West	Midwest + West
Added 3rd Turbine**?	No	No	No	Yes
NPV Savings ($million)	161	111	214	269
LCOE (c/KWh)	[redacted]	[redacted]	[redacted]	[redacted]
LCOE Reduction %	[redacted]	[redacted]	[redacted]	[redacted]

** Interdisciplinary research building on mid-west, ambulatory on west, replacement hospital on main campus, and college of medicine buildings on main campus. See Section-5 for more details*
*** Needs additional capex of ~$25 million, on top of the Case 4 capex of $152 million, to add the 3rd Turbine*

Figure 3-8: With Full Expansion (Midwest and West Campus), Case 4 provides significant optionality and upside compared to all cases analyzed

Operational Flexibility to Respond to Market Conditions

Equally as important as supply cost savings, the design of the CHP facility, with supplemental duct firing and a condensing/extracting steam turbine, lends itself to significant operational flexibility to independently balance the power and steam demands. The facility will be dispatched in an economic manner, factoring the marginal cost of electrical and thermal production and market prices of energy and ancillary products, while also adequately satisfying campus thermal demands. In a high electricity price environment, the CHP facility can throttle down the amount of process steam extraction so that the same steam can be routed through the steam turbine to produce electricity. This mechanism can be used as a peak-shaving strategy which reduces the exposure to more expensive electricity purchased from the market and can also be offered for sale, as an additional stream of revenue, in the PJM markets to take advantage of these high prices. The steam shortfall resulting from this diversion can be supplemented by existing boilers.

As an example, for the given month of June with low thermal demand, during the of-peak hours when the CHP has a surplus capacity, the CHP dispatch can be turned down, as shown in Figure 3-9 below.

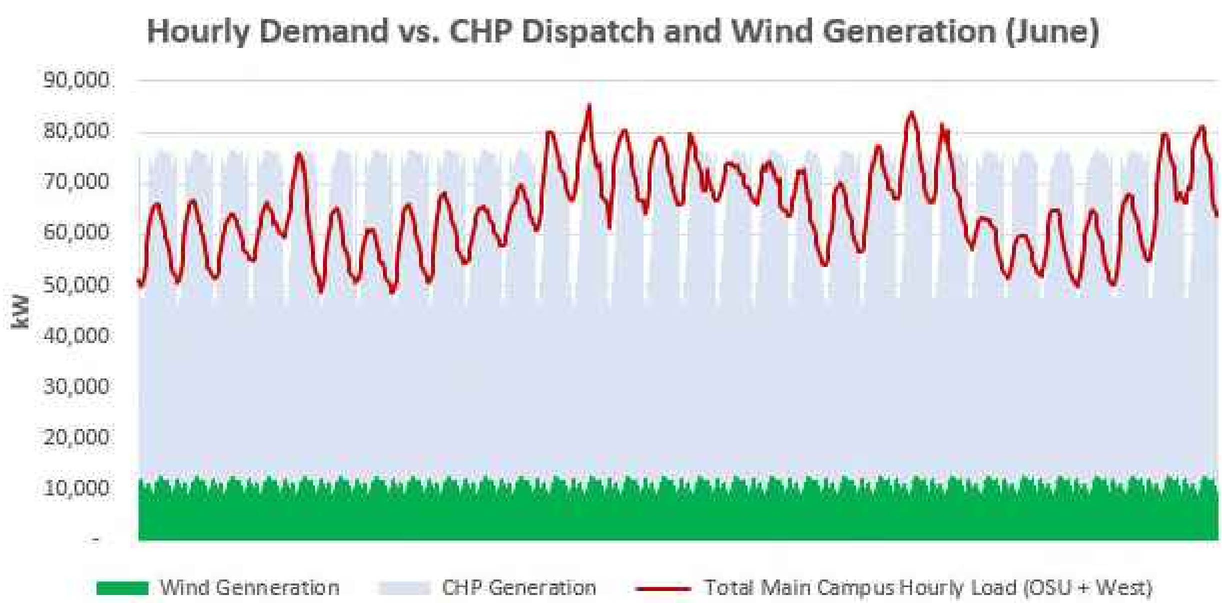

Figure 3-9: Wind generation for the month of June

3.2 Reliability and Energy Resiliency

Reliability and energy resiliency are a must to serve the University's critical loads and campus infrastructure. The proposed CHP solutions will provide with certainty, a reliable and secure source of generation should the supply of electricity from the grid to the University be disrupted due to unforeseen events, such as natural disasters and/or terror threats. The implementation of the proposed CHP project will form the cornerstone of a strategy that will provide for a reliable and resilient energy solution with the ability to operate disconnected from the PJM grid and the ability to re-synchronize to the grid.

Electrical Resiliency & Reliability

The abundance of inexpensive natural gas and its low carbon footprint allows for dispatchable generation using proven gas turbine CHP technology. By optimizing the size of the CHP facility, the minimum critical electrical loads (medical, research, administration defined as critical loads) can be met while essentially fulfilling the utility system's entire thermal load throughout the year as shown in Figure 3-10 below.

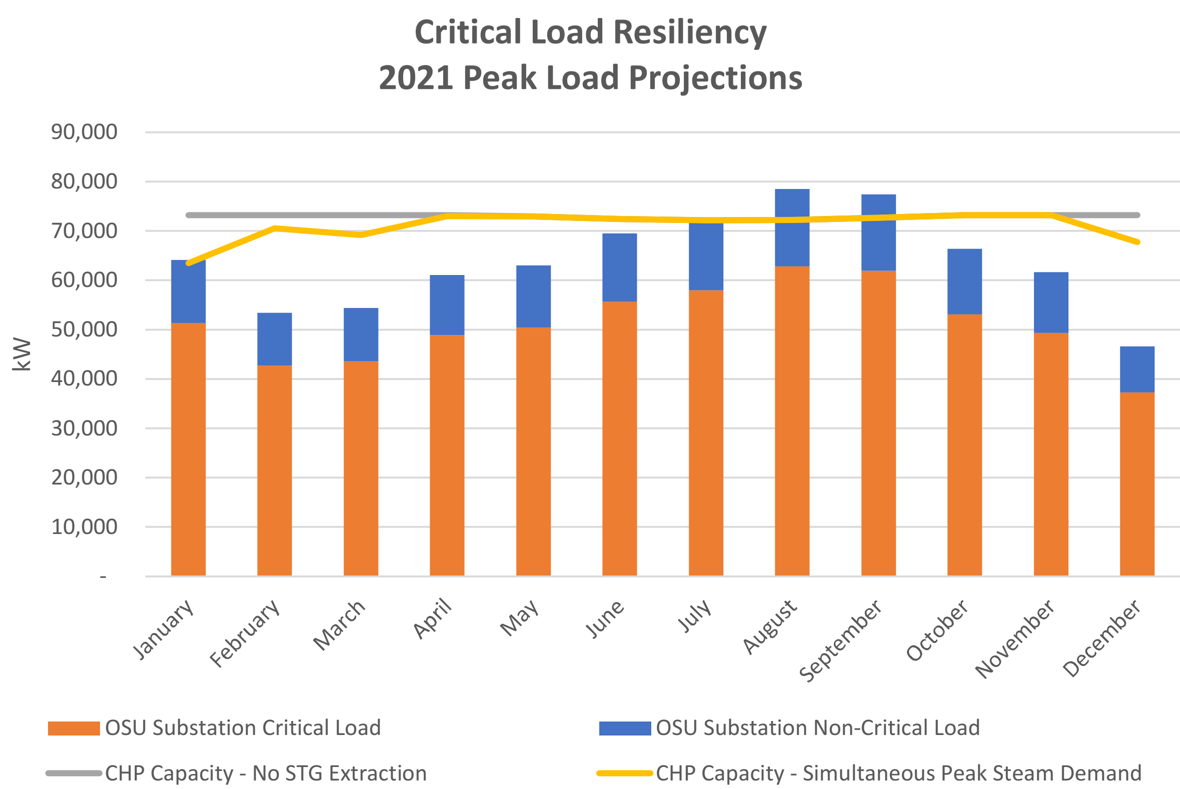

Figure 3-10: Critical loads are met using optimized CHP solution

Unlike the Blue Creek Wind generation (which is accounted for in the generation stack), the CHP facility will be operated in a dispatchable and flexible basis for continuity of supply.

Thermal Resiliency & Reliability

As for thermal demand, the proposed CHP solutions will first produce steam from efficiently recuperating waste heat energy from the gas turbines' exhaust via the HRSGs. If the steam demand is higher than what can be recuperated, then the HRSGs duct burners may be operated to make up the balance up to their operating limit. The existing McCracken boilers can be used to supplement any thermal needs beyond that provided by the alternates. In addition, the duct burners can also be used to increase steam flow through the steam turbine for increased power production when it is economical. Figure 3-11 below shows the detailed breakdown of process steam generated in the CHP and boilers to meet peak loads, as well as the avoided steam consumption due to ECMs implemented between 2017 and 2021. Given the historical peak steam load at McCracken and the projected offset from ECMs, N+2 redundancy can be maintained even with the retirement of two boilers.

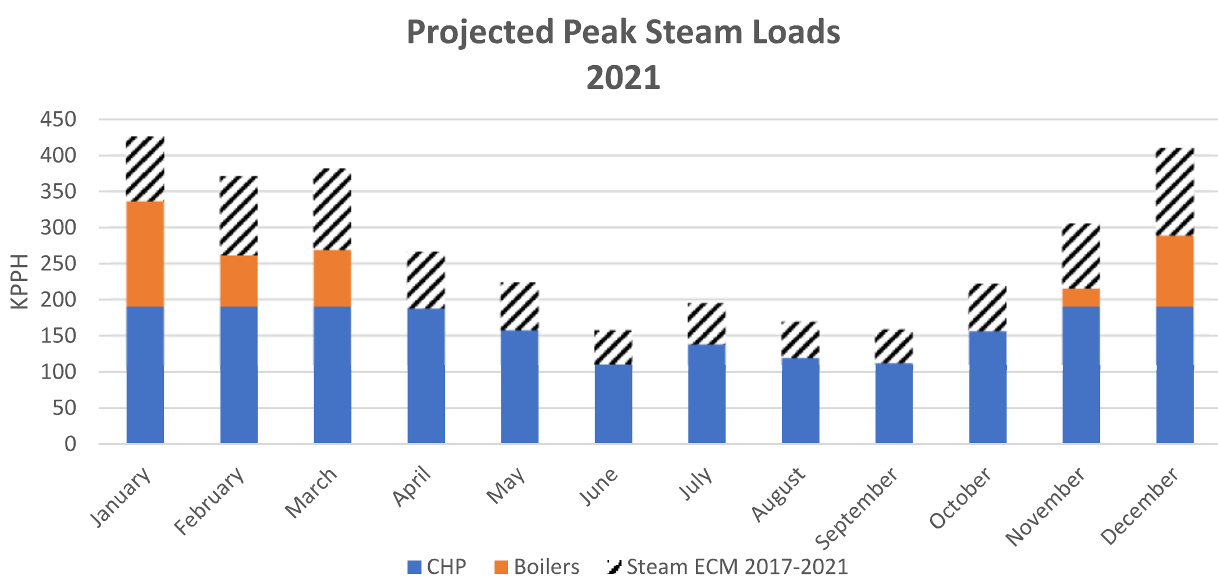

Figure 3-11: CHP and existing boilers provide steam to operate at N+2 levels

Back-up Generation Avoided costs

The CHP solution provides a reliable and secure source of generation should the supply of electricity from the grid to the University be disrupted due to unforeseen events. The CHP will be able to displace a portion of the University's critical electrical loads. OSEP evaluated the possibility of the CHP displacing critical loads currently served by onsite back-up generation. The OSU Generation Inventory Master list dated January 22, 2014 was used to determine the back-up generation capacity. University onsite back-up generation is summarized in Table 1.

Table 1: University onsite back-up generation

University on Campus Back-up Generation			
Building Services	**Number of Buildings**	**Total Capacity**	**Fuel Type**
Medical (Emergency Generation)	26	31 MW	Diesel
Non-Medical (Back-up Generation)	47	30 MW	Diesel
	73	17 MW	Natural Gas

The medical facilities are the most critical loads on campus as they provide life critical services. The facilities represent the University's emergency generation at 31 MW. Medical facility emergency electric services are governed by NFPA 110 Emergency Generations Level 1. NFPA states that Level 1 systems shall be installed where failure of the equipment to perform could result in loss of human life or serious injuries. **Error! Reference source not found.** summarizes the main NFPA requirements regarding emergency generation.

Table 2: NFPA Requirements - Emergency Generation

NFPA Level 1	
Requirements	**CHP Configuration**
Permanently installed emergency generation	CHP meets criteria
Onsite fuel to allow 48 hours of continuous operation	Fuel oil operation option included in CHP study. Medical Center expansion project architect indicated University Medical Facilities would require 96-hour onsite storage.
Emergency generation starts within 10 seconds of loss of electric power	If CHP is down for any reason it cannot start within the 10 sec criteria.
Temporary emergency generators in place when emergency generators out of service	Temporary electric generator can be provided during full plant outages

Based on the current configuration the CHP is unable to meet the NFPA 110 level 1 requirements. Therefore, we are assuming that all current and future medical facilities will have emergency diesel generation equipment.

Non-medical critical load requirements are governed by the individual University entity's necessities. Except for extraordinary circumstances, the CHP should be able to provide back-up electric power to the non-medical critical load, thereby replacing the existing back-up generators.

The main operating cost for any generation is fuel and equipment major maintenance, the remaining OPEX is minimal. For this evaluation OSEP makes the following assumptions:

- Reciprocating engine heat rates are 10 MMBTU/MWh regardless of size or fuel.
- Back up diesel generators operate 60 hours per year. One-hour back-up generator test per week and 8 hours of Back up operations
- Diesel fuel $22/MMBTU
- Natural gas $3/MMBTU
- Diesel back-up generator average size 600 kW
- Natural gas back-up generator average size 222 kW
- 600 kW unit major maintenance cost per unit $1k/yr
- 222 kW unit major maintenance cost per unit $0.350k/yr

Since the current CHP configuration does not meet the medical facility regulatory requirements, OSEP assumes only non-medical critical load back-up generators will be displaced by the CHP.

Table 3 is a summary of the cost savings of displacing non-medical back-up generators with the CHP on existing buildings.

Table 3: Existing Building Back-up Generator Cost Savings

Existing Building Back up Generator Cost Savings (2017 $'000)		
Diesel during test	[redacted]	$ 322 KUSD
Diesel during back up operations	[redacted]	$ 1KUSD
Annual Major maintenance	[redacted]	$ 47 KUSD
Natural gas during test	[redacted]	$ 26 KUSD
Natural gas during back up operations	[redacted]	$ 0 KUSD **(Note 1)**
Natural gas during back up operations	[redacted]	$ 26KUSD
Total Annual Cost		**$ 422 KUSD**

Note 1 – natural gas price during back-up operations is considered to be negligible

The CHP will not require weekly testing. During the eight hours of back-up operation, the fuel cost would be:

[redacted] = $ 8KUSD

Based on the OPEX cost (adjusted for CHP fuel cost during back-up operations) the University would have a net savings of around $414 KUSD annually by utilizing the CHP to serve the non-medical critical loads for existing buildings.

The University Master Plan indicates new buildings in Midwest Campus and several building expansions on Main Campus that will require back-up generation. The CHP will be able to meet theses loads, avoiding capital expenditure to the affected buildings. OSEP has made the following assumptions to calculate capital expenditure:

- 3 buildings classified as critical load buildings
- Average electrical load of each building 1445 kW
- Capital cost for installing 1445 kW diesel back-up generator $384 KUSD

Capital avoided cost for new and expansion buildings:

[redacted] = $1.2 MUSD

OSEP used the same assumptions as existing building OPEX except average back-up generation capacity of 1445 kW and $3000/unit annual major maintenance cost. Operational expenditure savings on new and expansion buildings is summarized in Table 4 below.

Table 4: New and Expansion Back up Generator Cost Savings

New and Expansion Back-up Generator Cost Savings (2017 $'000)		
Diesel during test	[redacted]	$ 50 KUSD
Diesel during back up operations		$ 3 KUSD
Annual Major maintenance		$ 9 KUSD
Total OPEX		**$ 62 KUSD**

The CHP will not require weekly testing. During the eight hours of back up operation, the fuel cost would be calculated using the following formula:

[redacted] = $ 0.710 KUSD

Based on the avoided CAPEX and OPEX cost savings (adjusted for CHP fuel cost during back up operations) the University would have an avoided $2.11 million CAPEX cost and a net savings of around $61kUSD annually by utilizing the CHP to serve the new and expansion critical loads.

It should be noted that this is a minimal growth case considering only three buildings. Any additional non-medical building will increase the avoided Capex and Opex savings.

Additional Resiliency Through Alternative Technologies

Combining a cogeneration facility with renewable energy and energy storage technology that can be deployed in the future could offer the University the ability to become energy independent, completely removing Ohio State's exposure to the price movements of the regional electricity market. The CHP and the associated electrical distribution and control system will establish the first microgrid or "smart grid" on campus for resiliency. Any future on site renewable generation, or smart demand response load reduction scheme can be added into the framework of this microgrid.

Additionally, this microgrid platform will unlock a new value potential for implementation of small, packaged CHP units that can be deployed in remote buildings – those that are far from the heating or cooling networks, but on the electricity grid – on a building by building, or cluster of buildings concept. Without the microgrid, a packaged CHP can be sized to the minimum or lower half of the power demand, which in many cases provides minimal heating value with a sub-optimal design at best, or a financially unfeasible design at worst. With the microgrid, the packaged CHPs can be sized according to the heating load, eliminating the capital needs for heating equipment.

3.3 Commodity Risk Management

As one of the largest commercial and industrial retail energy providers in North America with a significant presence in the PJM and Ohio power markets, ENGIE North America will continue to provide the University a cost-effective and risk-mitigating strategy for procurement of any supplemental retail electricity required by the campus.

One critical consideration supporting the OSEP recommended CHP facility is the transition of the Utility System from a retail-heavy electricity market exposure to a predominantly natural gas price risk as illustrated in Figure 3-12 below.

	As is (net of ECM)			With CHP			Decrease (Increase)		
2021 $million	Supply Cost	Highly Manageable *	Less Manageable **	Supply cost	Highly Manageable	Less Manageable	Total Change	Highly Manageable	Less Manageable
Electricity Commodity - Wind PPA***	6.7	6.7		6.7	6.7		0.0	0.0	
Electricity Commodity - Retail Supply	[redacted]			[redacted]			[redacted]		
Utility Delivery Charges	[redacted]		[redacted]	[redacted]		[redacted]	[redacted]		[redacted]
Fuel Costs	[redacted]			[redacted]			[redacted]		
Natural Gas Commodity	[redacted]	[redacted]		[redacted]	[redacted]		[redacted]	[redacted]	
Gas Transport/LDC charges	[redacted]		[redacted]	[redacted]		[redacted]	[redacted]		[redacted]
Total Supply Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
% Decrease (Increase) in Supply Procurement Risks							39%	-75%	89%

* Procurement risk long-term Manageable (5-10 years)

** Procurement risk short-term Manageable (2-3 years) or not manageable at all

*** Price fixed but subject to volumetric risks

Figure 3-12: Better manageability of supply risk by shifting unmanageable risk by 89%

The natural gas market poses inherently more manageable risks than regional electricity markets due to their liquidity. This allows customers to efficiently tailor strategies to their individual risk tolerance and to achieve a balance between cost savings and budget certainty.

The CHP solutions shift the University's supply risk into a more manageable natural gas risk that ENGIE can help the University manage over 5-10 years in advance. Additionally, given ENGIE's strong retail presence in the market, ENGIE can effectively advise the University on the appropriate products, counterparties, and terms for procuring any supplemental retail electric power.

The University's customized power energy hedge plan could include energy, capacity, ancillary components priced at market, hedged on a rolling 5-year basis, net of CHP and generation. Based on the hourly electricity load profile and the projected output of the CHP plant ENGIE could provide a solution to hedge the residual power exposure (~30%of requirement). The University could also consider hedging forward blocks of power for a rolling 1 month to five-year period. This Block & Index™ (Figure 3-13) strategy is useful for those customers that want some level of price certainty without incurring a risk premium associated with load-following, fixed price supply contracts.

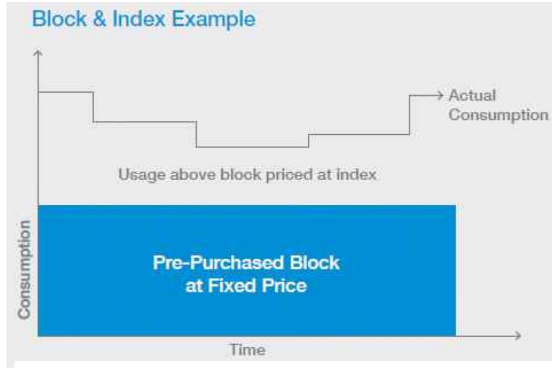

Figure 3-13: Hedge solution to reduce the University's exposure to commodity pricing

Based on the OSEP's due-diligence to date, it believes that a combination of medium-term to long-term customized rolling natural gas hedges, combining both physical and financial, could achieve economic budget certainty and a compelling supply risk management solution for the University.

3.4 Sustainability

Current "State" of Ohio

According to a study released by the US Energy Information Administration, the state of Ohio is the 5th largest producer of CO_2 emissions and the 20th largest producer of CO_2 emissions per capita shown in Figure 3-14 below. Ohio's grid reliance on coal-fired electricity – 59% of net electricity generation as of June 2017 – drives the production of air pollution that negatively affects the environment and the quality of life for current and future Ohio residents.

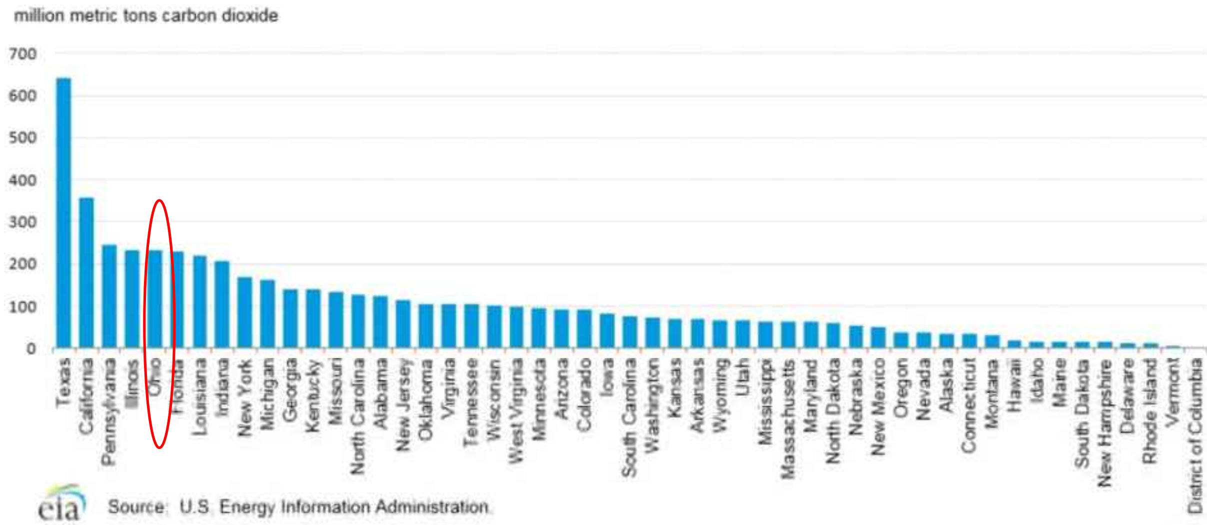

Figure 3-14: State of Ohio is 5th largest producer of CO_2 emissions

Installation of the clean and efficient natural gas fired CHP will significantly reduce the carbon footprint of the University. The reduction comes from two sources: 1) Improved efficiency in the production of steam and electricity through cogeneration, and 2) Offset of carbon-intensive (coal) Ohio grid electricity with natural gas. The CO_2 reduction estimate considers net effects of campus EUI reduction, campus expansion, and the procurement of wind from Blue Creek. Over the first twenty-five years of the project, the CHP is expected to reduce the University's carbon footprint by 21%.

The 2015 Energy Information Administration (EIA) CO_2 emission factor for the state of Ohio, in pounds of CO_2 generated per MWh produced, determines the carbon footprint of imported electricity. Annual grid emission factors are interpolated between the 2015 value (1,511 lb. CO_2/MWh) and the targeted 2030 value (1,190 lb. CO_2/MWh) from the Public Utilities Commission of Ohio (PUCO). Subsequent values after 2030 assume the same linear reduction for the duration of the analysis. Imported electricity associated with the Blue Creek wind contract is considered CO_2 neutral.

Reduction in imported electricity is offset by an increase in fuel consumption in the CHP. The carbon footprint of natural gas combustion is 117 lb. CO_2 per MMBTU of fuel. Fuel usage has been broken into two components for comparison, fuel chargeable to steam and fuel chargeable to power. Fuel chargeable to steam is the measure of the fuel that would be consumed in a boiler to produce a specified amount of steam. Because the steam load is the same regardless of whether a CHP is installed, the fuel chargeable to steam is also the same. For the CHP, additional fuel consumed above the fuel chargeable to steam is denoted as fuel chargeable to power.

A summary of the analysis for the first year of operation of the CHP is detailed in Figure 3-16 below.

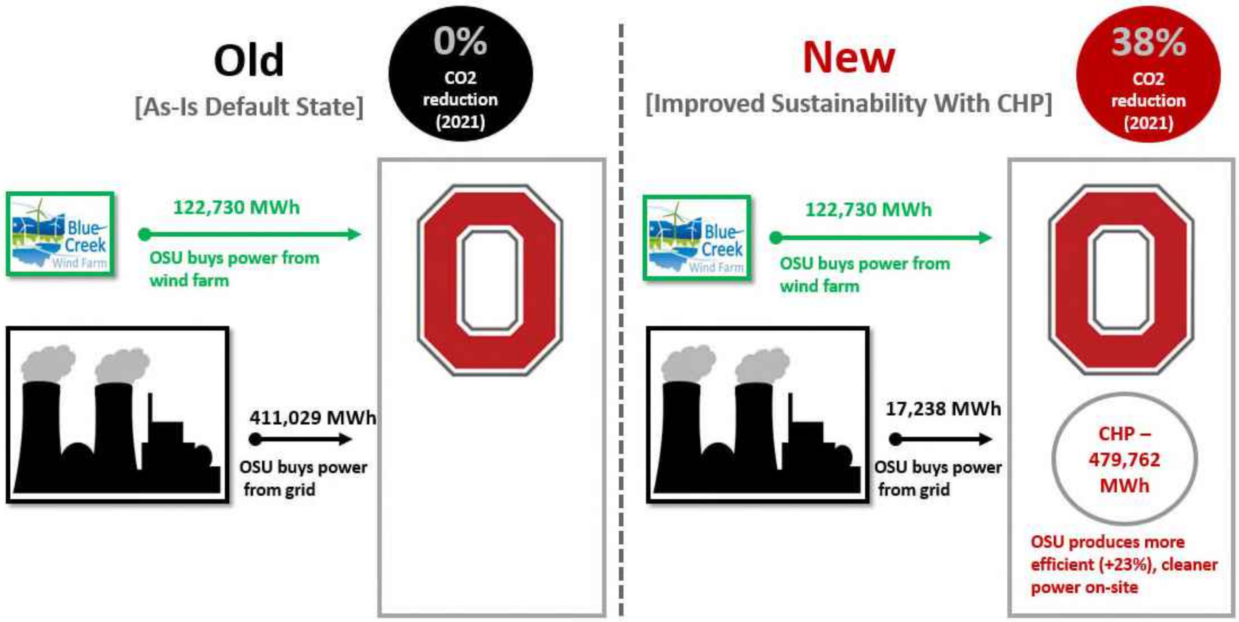

Figure 3-15: 38% CO_2 reduction by 2021 with CHP

Campus Energy Consumption

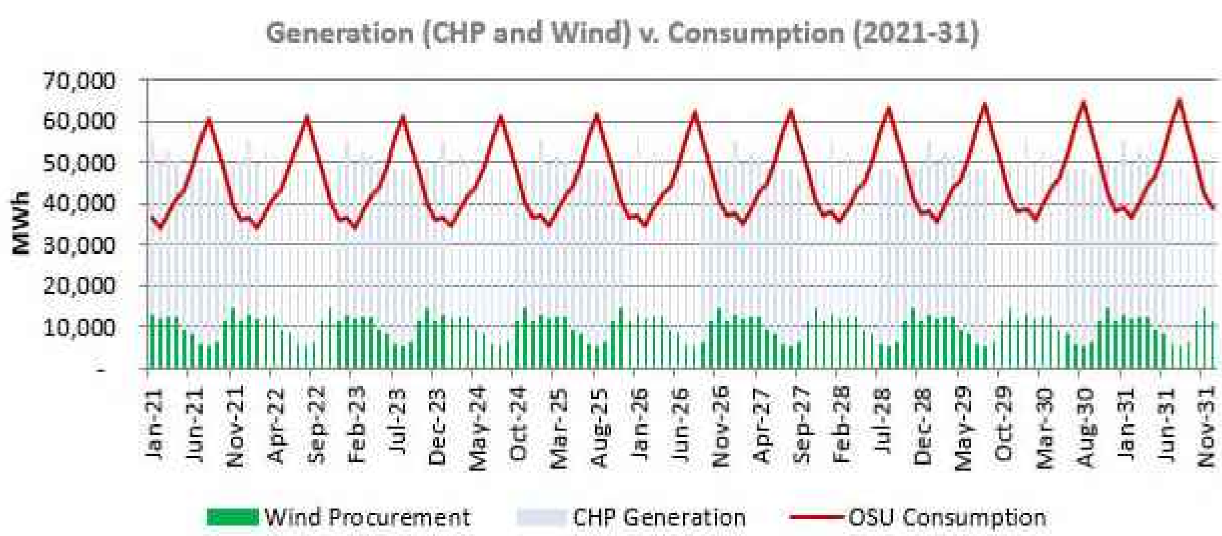

Figure 3-16: Wind procurement is not sufficient to offset campus load

Wind procurement is not sufficient to supply more than 25% of the power the University consumes as illustrated in Figure 3-16 and is not dispatchable. As a result, the campus must draw a large majority of its current power from the PJM grid. The CHP Project allows the University to take control of the campus' carbon footprint by switching to natural gas, a fuel source that is not only more economical than coal, but also cleaner, producing up to 48% less CO_2 emissions for the same amount of electric production. The proposed CHP is expected to reduce CO_2 emissions by 1.3 million tons by 2032 and 2 million tons by 2045, which is equivalent to the following:

Figure 3-17: EPA greenhouse equivalencies (https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator)

The Peak campus loads as illustrated in the table above can be filled with the procurement of green energy and/or the procurement of Green E-REC's to further reduce the campus carbon footprint.

Offsite Renewable Procurement

An Offsite Renewable procurement strategy by itself provides less carbon offset than a strategy combined with a CHP solution (Table 5), is not economically attractive (Table 6), and lacks other benefits:

- Does not provide for the reliability or resiliency that the University desires due to the intermittent nature of renewable generation
- Wind generation is high in the winter and low in the summer which is opposite of campus electrical load requirements
- Renewables have a much lower energy generation intensity (i.e. generation is not base load)
- Renewable projects do not provide for thermal generation
- Renewable projects are not dispatchable into the market
- In front-of-the-meter commercial scale renewable generation does not eliminate the delivery as well as other non-energy charges (such as ICAP and ancillary) for the University. For example, the delivered cost of energy for solar with $35/MWh PPA price would be around $64/MWh compared to a CHP LOCE of ~ $47/MWh

Table 5: Carbon Reduction Totals CO_2 compared to "As is" in year 2021

Carbon Offset Comparison (2021) by Alternative Energy Sources	
As-is + incremental 50 MW Offsite Solar*	15%
As-is + incremental 50 MW Offsite Wind*	21%
Proposed CHP Solution + Grid Procurement	38%
Proposed CHP Solution + REC Procurement**	**41%**

* As-is includes existing Blue Creek wind contract

** Renewable Energy Credit

Table 6: Delivered Cost of Energy for Solar PPA, assuming a $35/MWh PPA price, much higher than $50/MWh

Solar: All-in Delivered Cost of Energy	$/MWh
Solar Commodity PPA	$35.0
PPA Capacity Tag	$5.2
Ancillary, RPS, Shape costs, others	$10.1
Utility Delivery Costs	$13.7
Estimated Delivered Cost of Electric Energy	**$64.0**

As demonstrated above, the proposed CHP solution, coupled with REC (Renewable Energy Credit) procurement for the residual energy (net of CHP), provides for largest carbon offset in the most economical way. OSEP does understand the importance of the University's carbon goals and will continue to look and advise on the use of alternative energy when technically and economically feasible. The section below further discusses a more long-term viable path to a complete carbon neutrality.

Bridge to Achieving Carbon Neutrality

The University has set a goal to achieve carbon neutrality by 2050. Implementing this ambitious goal is currently cost prohibitive due to a lack of affordable and scalable technology (e.g. alternative energy solutions for thermal energy storage) capable of meeting the University's critical energy needs. A CHP plant can provide a bridge to the future by balancing the trade-off of emissions reductions while achieving long-term economic returns and providing the campus with reliable energy. The CHP solution, coupled with ECM, can provide **about 50% carbon reduction most economically in the near term**. Integration of CHP will also enable the ability to convert from steam to hot water system for heating as detailed in Appendix N. However, to meet the carbon reduction goal, OSEP in collaboration with the University, will develop creative solutions such as a second phase of ECM implementation[11] beyond the requirements in the

[11] Phase II: After the current 10-year, 25% EUI reduction plan is completed.

Concession Agreement and explore alternative energy sources beyond current technologies throughout the course of the term as illustrated in Figure 3-18 below.

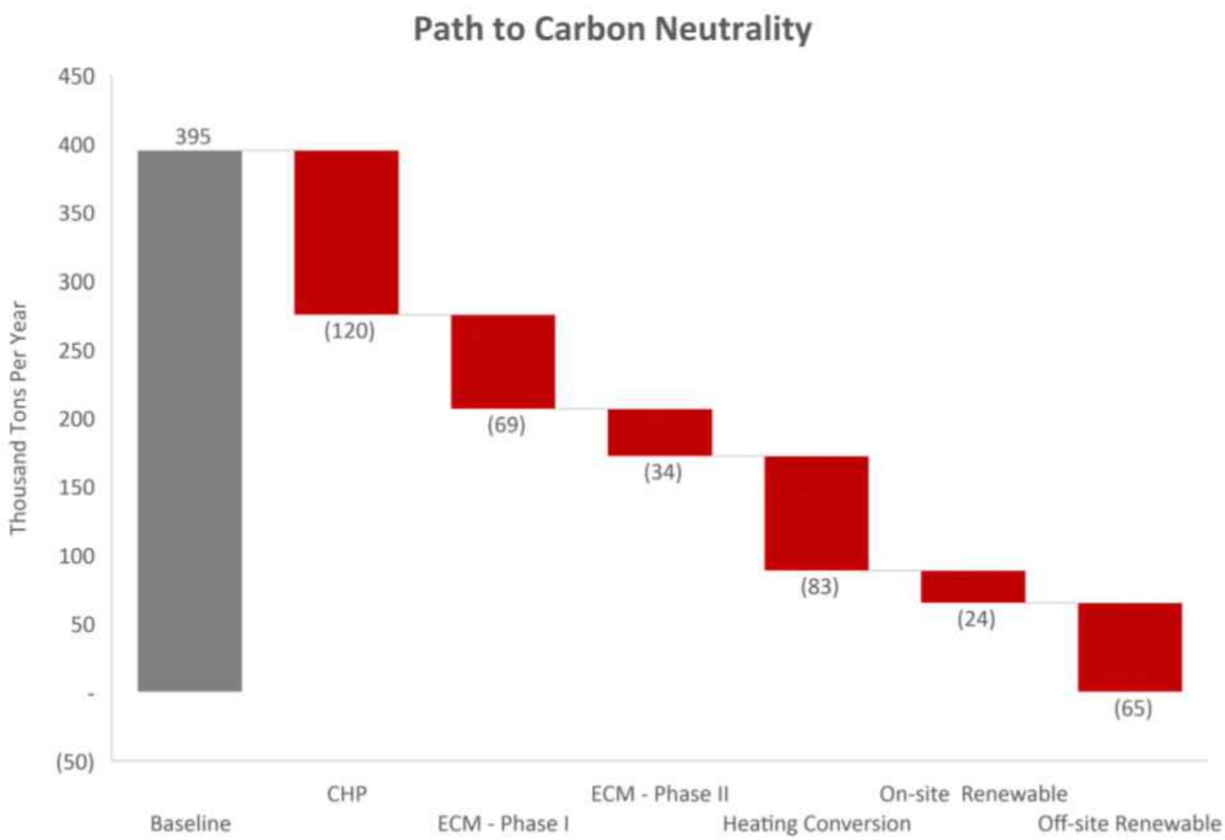

Figure 3-18: CHP and ECM Phase I implementation allow the University to reach nearly 50% of their goal

4.0 OTHER TECHNOLOGIES

4.1 Behind the Meter Solutions

Onsite Renewables

Onsite natural gas fired cogeneration represents the optimal solution to meet the energy demands of the university in a cost-efficient manner. Alternative energy sources either cannot meet the capacity demands of the university or are not financially viable. Behind-the-meter solar generation is limited in capacity and would not be able to meet campus electricity demands. A solar farm with the same capacity as the average campus load would require a footprint of 700 acres of land (and circa $300m worth of battery storage system). Systems such as fuel cells lack maturity and scale, so they are limited in capacity and are twice as expensive on a $/kW basis compared to a natural gas CHP. The key advantage of a CHP is the ability to deliver significant electrical and thermal energy simultaneously in an efficient and dispatchable manner. While renewable options must be oversized due to low capacity factors and require batteries to circumvent dispatch concerns, a CHP can be optimally sized to match a specified load.

Storage

In recent years, battery storage has been coupled with other technologies to help store renewable and conventional energy to increase energy availability when generation is greater than demand; however, this is a nominal increase due to market viability (see illustration below). Currently, these renewables plus storage systems is a capital-intensive solution on a $/kW basis to maintain resilient and continuous operation and is only viable in certain markets with significant state and local subsidies as illustrated in Fi

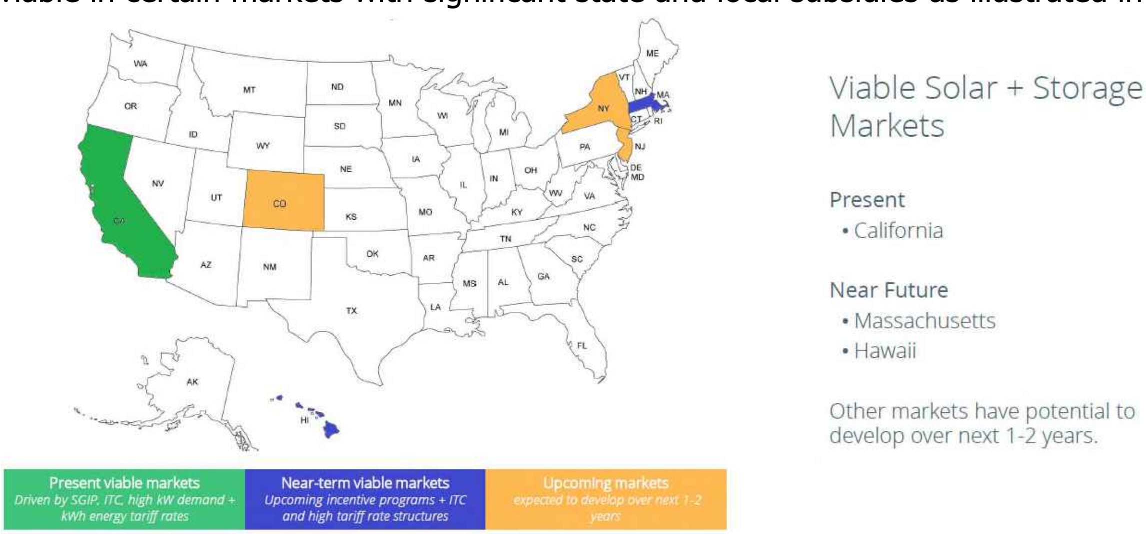

Figure 4-1: Combination of storage and solar are viable in certain markets

5.0 MIDWEST & WEST CAMPUS DHC

Considering the University's growth plans with Framework 2.0, a district heating and cooling network (DHC) in the Midwest and West campuses would generate significant savings as well as carbon reduction compared to in-building heating and cooling solutions.

The following methodology was used to compare "no DHC" vs "DHC" cases for Midwest and West campuses, separately. Detailed cost build-up and calculations can be found in Appendix K.

Table 5-1: Impact of DHC on CAPEX and OPEX

	No DHC	DHC	Net Result
Existing buildings	As is	Capital cost of heat exchangers and necessary piping added to calculation	+Δ CAPEX added to DHC solution
Existing buildings	O&M cost	DHC will reduce O&M costs	-Δ OPEX subtracted from DHC solution
Existing buildings	As is	Optimized chilled & hot water network	+Δ thermal efficiency savings subtracted from fuel and power cost
Network	As is	CAPEX cost of installing new piping. $25m existing steam pipe replacement avoided. **(Note 1)**	+Δ added to DHC solution, $25m avoided cost subtracted
Network Connections	N/A	Costs of crossing Olentangy River & 315 are included in CAPEX	+Δ CAPEX added to DHC solution
New buildings	Heating & cooling equipment CAPEX	New central chiller plant adjacent to CHP	+Δ CAPEX added to DHC solution
New buildings	O&M cost	DHC will have minimal incremental O&M cost	-Δ significant savings with DHC solution
New Buildings	Latest thermal efficiency equipment	Optimized chilled & hot water network	+Δ thermal efficiency savings subtracted from fuel and power cost
New Buildings	Back up Diesel Generation	DHC and CHP provide electricity in back up situations	Avoided CAPEX of diesel generators
New technology	Very limited potential	Significant potential to take advantage of solar, geothermal, or any new technology that can be applied to the low temp hot water network, or chilled water network.	Very high potential but quantification is subjective. Therefore, financial value not included at the moment.
Peak load	In-building equipment sized for peak load, operating at part load most of the year with suboptimal efficiency	System operates at high efficiency with incremental central equipment going in and out of service as needed.	+Δ thermal efficiency savings subtracted from fuel and power cost.
Redundancy	In-building equipment requires 2N redundancy, resulting in rarely utilized capital investment	N+1 redundancy	-Δ capital investment savings for DHC

Note 1: Existing steam and condensate lines will be abandoned in place and vaults decommissioned

The methodology used for the West Campus DHC is also very similar to the one used for Midwest campus.

A Midwest campus-located CHP coupled with a new chiller plant would be the anchor for this infrastructure. The CHP would provide sufficient thermal capacity to heat all existing and planned buildings on Midwest and West campus, while still delivering steam to main campus in the amount specified in the table below This integration unlocks synergies in O&M cost reduction, EUI reduction (although will not count toward OSEP's contractual EUI calculation) and lays the groundwork for the conversion of existing Midwest campus steam networks to hot water[12]. The alternative to a West Campus DHC is building-level heating and cooling which is sub-optimal in terms of carbon footprint, energy costs, and O&M costs. Detailed cost calculations along with network map for the West Campus DHC is illustrated in Appendix K.

Excess Capacity – Main Campus (kpph / million sq. ft)		
Configuration	2x1	3x1
Average Conditions	137 / 18.6	234 / 31.8
Peak Conditions	45 / 6.1	142 / 19.3

Although a total expansion of 5.8 million square feet during a fifteen-year period to Midwest and West Campus is possible, only the Midwest campus expansions (Interdisciplinary Research and Academic Research in Midwest Phase I and Phase II) are considered for the evaluation of Case 3 and Case 4. Average building electrical, heating, and cooling loads were projected using EIA guidelines and historical data from representative buildings on campus.

The structure of capital injection also differs between the two options. Upfront investment is required for the centralized DHC system, while building-level heating and cooling leverages a linear employment of capital as campus expands (see Figure 5-1).

Centralized utilities provide major savings in the ongoing Operation and Maintenance cost with lower staffing, maintenance and lifecycle cost than individual building utilities. Fulltime equivalent employees (FTE) for centralized utilities will be 33% of the individual building utility systems as most of the O&M activities will be performed by existing employees. While centralized heating and cooling equipment have higher upfront costs, they provide higher economies of scale and have longer useful life resulting in lower cost over the life of the facility.

[12] Hot water heating networks have been the choice of technology for the recent past and the foreseeable future as opposed to steam networks. Due to its lower temperature and pressure, hot water networks allow for low cost, non-metallic piping to be utilized which can be laid in the same trench or tunnel with the condensate return and chilled water piping.

Centralized heating and cooling unlocks additional value through efficiency improvements and corresponding EUI reductions. A centralized system can sequence the operation of equipment such that the load is carried by units near base load capacity. An estimated 30% reduction in chilled water electrical consumption is expected when compared to building-level cooling.

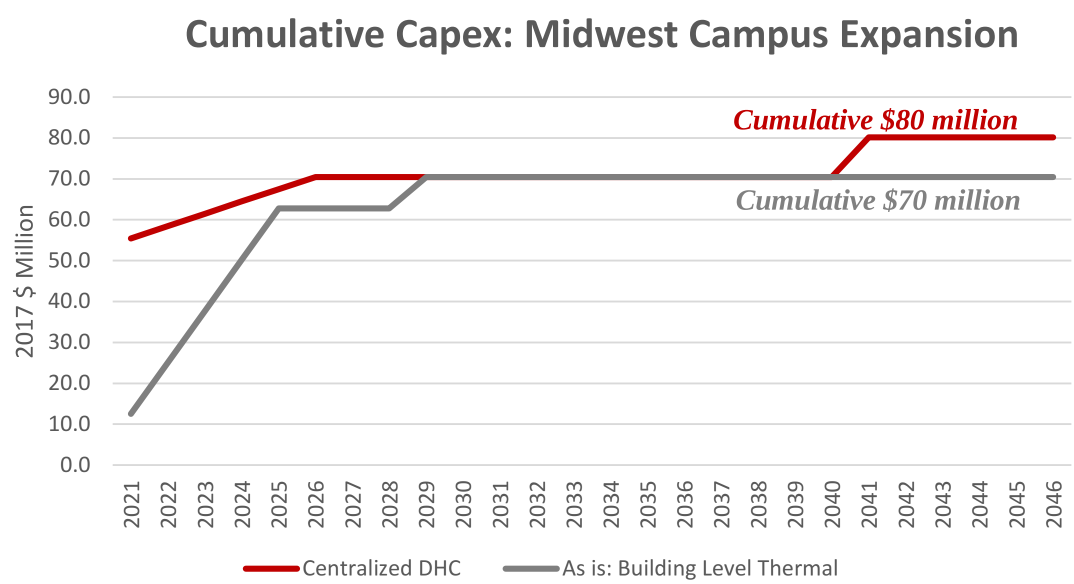

Figure 5-1: Cumulative CAPEX over time: Centralized DHC system vs. Building Level Thermal (Case 3 & 4)

Figure 5-2 below shows the benefits of a Centralized heating and cooling system in terms of operational savings that makes Case 3 & 4 (an enabler of a centralized heating and cooling system) more economically attractive, despite higher CAPEX, than other cases.

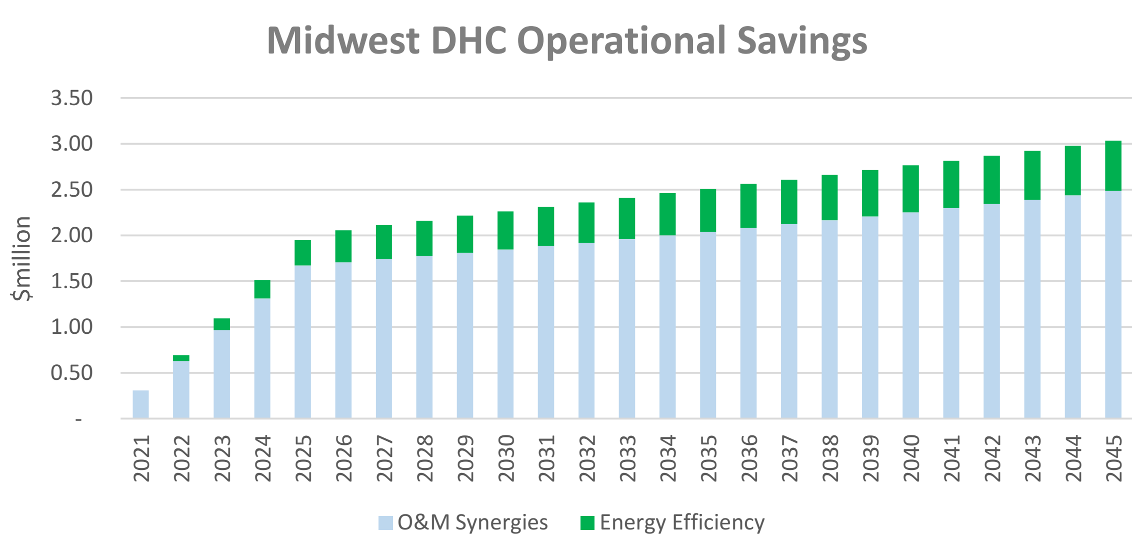

Figure 5-2: Annual O&M Savings & Synergies: Centralized DHC system vs. Building Level Thermal (Case 3 & 4)

6.0 MCCRACKEN RETIREMENT EVALUATION

McCracken Utility Facility Retirement

McCracken Power Plant (McCracken) is the oldest utility facility on campus housing boilers, chillers, air compressors, and office space for staff. OSEP evaluated the feasibility of retiring utility equipment in McCracken such that the facility can be repurposed by the University. Two strategies are explored:

1) Retirement of equipment either at the end of lifecycle, or sooner if practicable, or,
2) Accelerated retirement of equipment for earlier repurposing of McCracken.

Load growth was projected by considering future campus expansions and the impact of ECMs. The necessary Utility System upgrades to enable retirement in each scenario while maintaining system redundancy are detailed in the following sections.

Chilled Water Evaluation

Currently, the three utility chilled water networks (McCracken, South, East) are operated independently of one another. The McCracken and East networks are connected, however the point of interconnect is isolated. Connecting the networks (in Five-Year Plan as 38-22-LFC Chilled Water Optimization) will enhance the system redundancy, improve production efficiency, and will help enable the retirement of McCracken chillers by displacing lost capacity with the two remaining chilled water plants. The East and South Chilled Water Plants have space provisions available to increase capacity by 2,500 and 10,000 tons, respectively. In combination with the connection of the chilled water networks, additional ECMs will reduce the chilled water load of existing buildings by 18% over the next ten years. Increases in chilled water load for the Academic Core, Advanced Materials Corridor, Arts District, Northeast Oval, and Medical Center expansions are accounted for in the analysis. Chilled water loads due to expansion on Midwest and West campus will be covered by the future installation of chillers on Midwest campus.

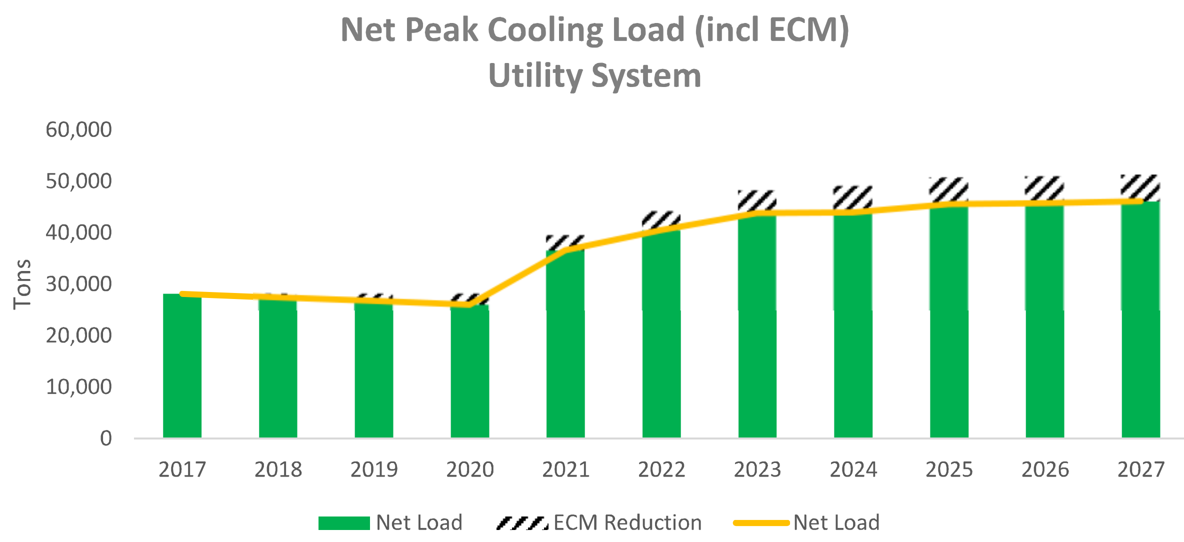

Figure 6-1: Net Peak Cooling Load

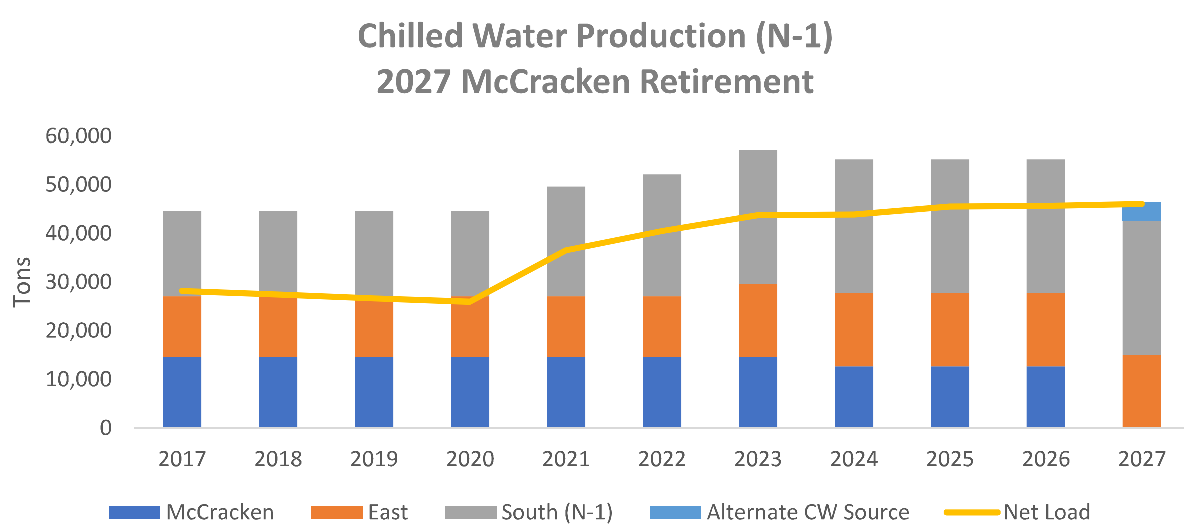

Figure 6-2: Chilled Water Production (2027 Retirement Strategy). N-1 denotes total chilled water capacity when one of the largest chillers is out of service.

Most of the capacity lost by the retirement of McCracken chillers is recovered by the expansion of the East and South Chilled Water Plants. To fully retire all nine McCracken chillers, an alternate source of 4,000 tons of cooling will be necessary.

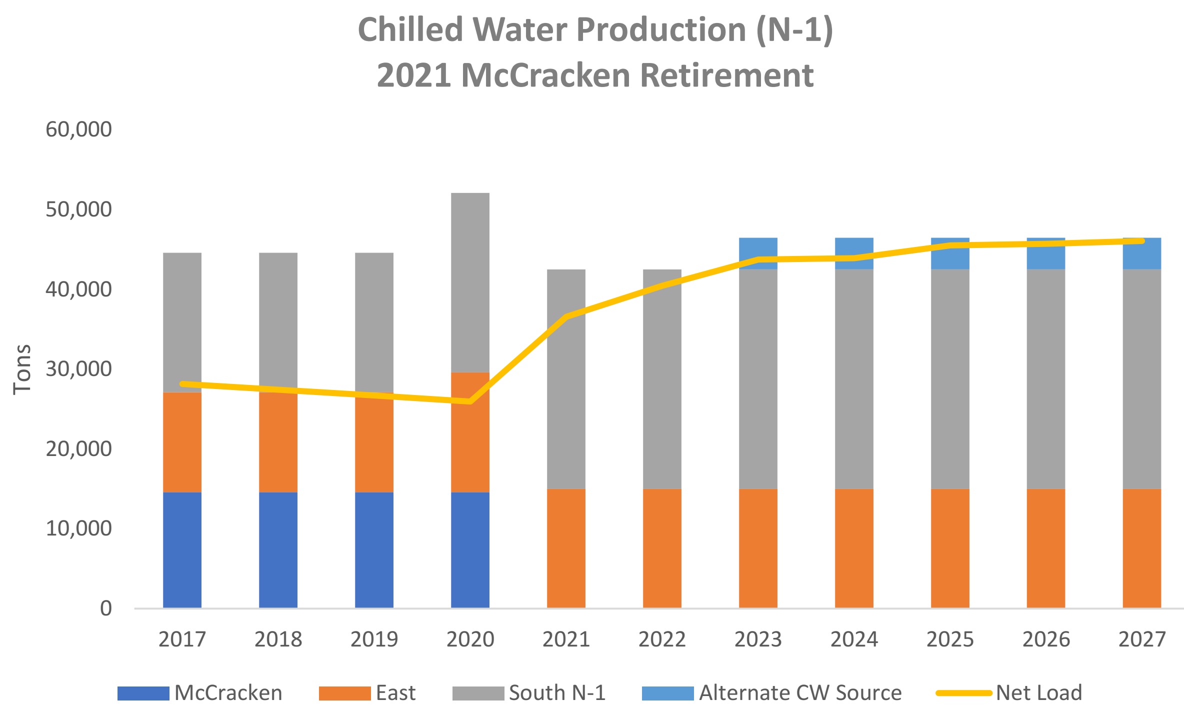

Figure 6-3: Chilled Water Production (2021 Retirement Strategy)

Chilled Water Evaluation Conclusion

As can be seen in Figure 6-2 and Figure 6-3 above, only 4,000 tons of additional cooling capacity will be required to enable the retirement of McCracken after building East and South Chiller plants up to their design capacity. This additional 4,000 tons of chilled water can be produced with a new chiller elsewhere on campus, geothermal wells, chilled water storage, or a combination of the above. Therefore, the chilled water analysis concludes that McCracken can be retired in 2027 or even earlier, in 2021 (accelerated).

Heating Evaluation

McCracken is the primary heating source for the Utility System. The proposed CHP facility will add 250 MMBTU/h of heating capacity, allowing the retirement of two boilers while maintaining N-1 capacity. ECMs for steam consumption will greatly offset the increase in steam load expected due to the Medical Center, Arts District, and Cannon Drive expansion projects as shown in Figure 6-4 below.

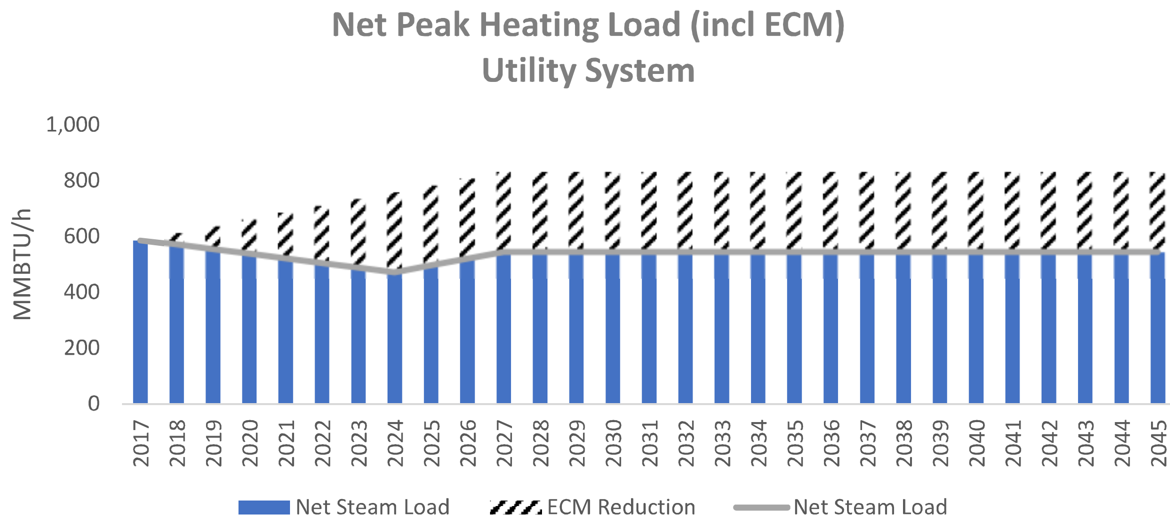

Figure 6-4: Net Peak Heating Load

Due to the offset in ECMs and expansion load growth, the net steam load of the Utility System is expected to be equivalent to current conditions. As additional McCracken boilers are retired following the commissioning of the CHP, new heating sources must be installed to maintain redundancy.

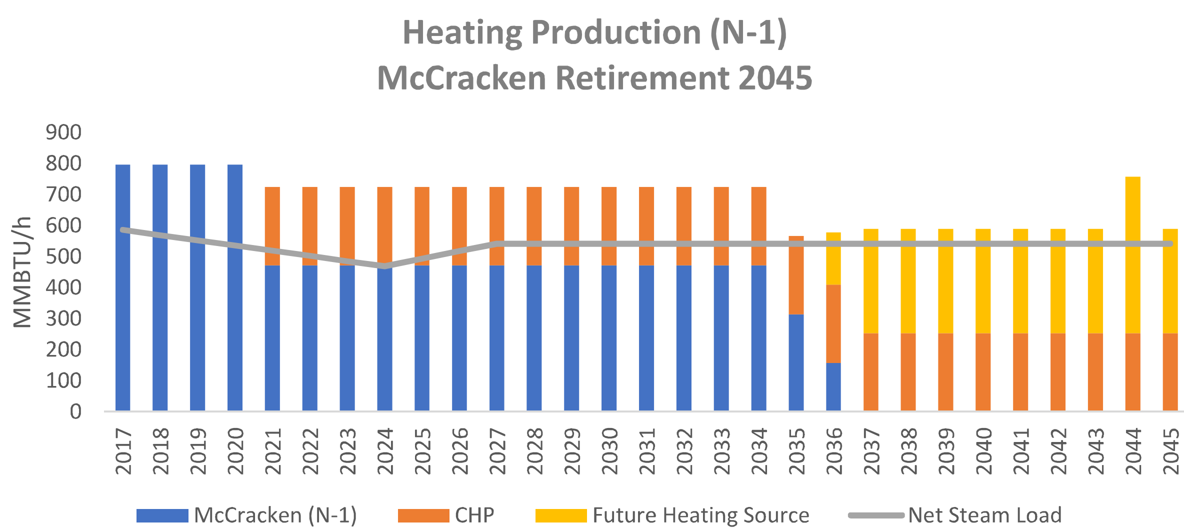

Figure 6-5: Heating Production (2045 Retirement Strategy)

Per Figure 6-5, additional heating capacity must be installed prior to 2036 to meet redundancy requirements. Note that the N-1 criteria is applied to the largest active McCracken boiler and that in 2037 McCracken contains a single boiler which is later retired in 2045. Once the final McCracken boiler is retired, the N-1 criteria is based on the future heating sources.

Similar to the McCracken chillers, the retirement of boilers can be completed prior to the exhaustion of equipment life. Figure 6-6 displays the required installation timing to facilitate the retirement of McCracken in 2035. This process will be more difficult than the chilled water retirement acceleration due to a lack of existing assets to provide for the remaining heating load.

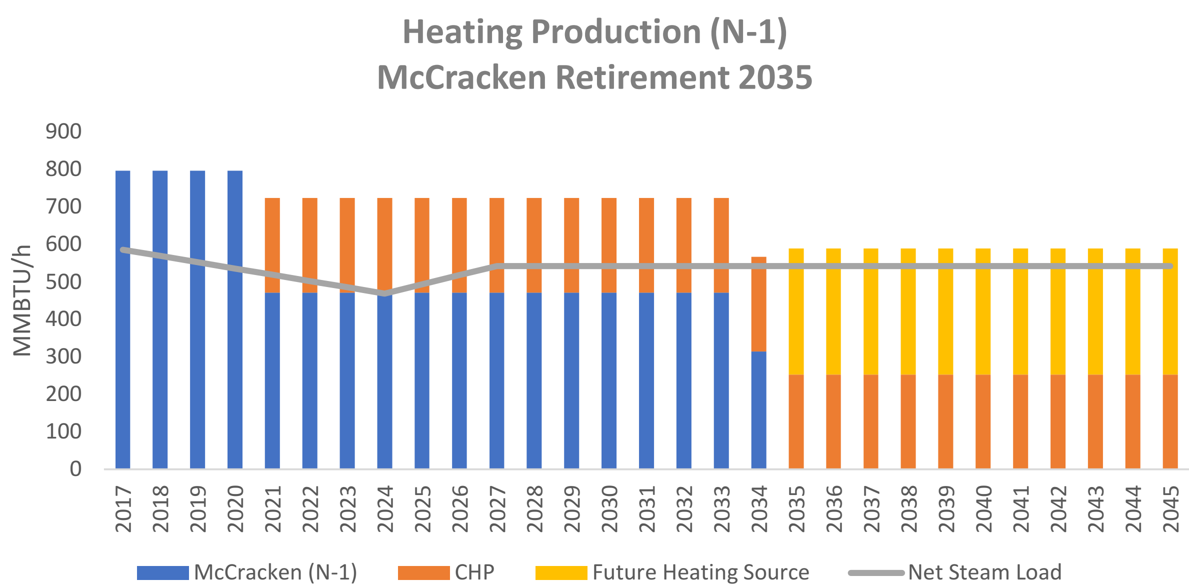

Figure 6-6: Heating Production (2035 Retirement Strategy)

Heating Evaluation Conclusion

Figures 6-5 and 6-6 illustrate the need to install 290[13] MMBTU/h of heating capacity to retire the McCracken boilers. This capacity can be generated by a diverse set of technologies including hot water heaters, geothermal wells, heat pump chillers, and hot water storage. Under a natural retirement scenario, this would occur in 2045. An accelerated retirement in 2035 is also viable.

[13] 540 – 250 = 290 MMBTU/h needed to meet demand, and an additional 125 MMBTU/h needed to provide N+1 redundancy, totaling additional 415 MMBTU/h. If 3rd GTG is installed in the CHP, then the additional heating capacity need would reduce to 290 MMBTU/h.

Cost Estimate

To fully realize the capability to repurpose McCracken, the following cost considerations are necessary:

McCracken Retirement Cost Summary ($ million)	
Replacement of McCracken steam boilers with hot water heaters at Midwest campus facility	$6.30
Chilled water storage tank with distribution piping	$2.00
Interconnection of chilled water loops	$6.00
Conversion of steam to hot water distribution	$25.00
Conversion of existing primary steam heat exchangers to primary hot water heat exchangers	$16.90
Conversion of Schottenstein arena from central steam/hot water to local gas water boiler	$2.00
Conversion of building steam humidification systems	$4.00
Replacement of steam heat tracing and cooling tower basin heaters	$0.38
Total	**$ 62.58**

Note 1: Hot water boiler total installed cost is $10.6MUSD, the cost to install steam boilers is $21.2 for a net savings of (-$10.6)

Accelerating the retirement of McCracken assets prior to the end of their lifecycle will incur value loss. Complete retirement of McCracken chillers in either 2021 or 2027 would result in a loss of 6.0 and 2.7 MUSD, respectively. McCracken boiler retirement in 2035 or 2045 would cause a loss of 5.0 or 3.0 MUSD, respectively.

Summary and Recommendation

As detailed in this section, many options exist to replace the existing heating and cooling capacity installed in McCracken. Retirement of the chilled water system is achievable as early as 2021, or in 2027. Retirement of the steam system on the other hand requires investment in new heating sources and possibly conversion of campus steam system to heating hot water.

To evaluate the feasibility of the repurposing of McCracken in more detail and certainty, a more detailed study is required. OSEP proposes performing a feasibility study to develop a long-term strategy for the Utility System that delivers the greatest value for the University.

7.0 CONCLUSIONS AND RECOMMENDATION

7.1 Results and Value Proposition

The detailed feasibility study for the University concluded that the on-site CHP facility is a much more resilient and sustainable solution to the University's energy needs that can simultaneously reduce or even eliminate the reliance on high-priced retail electricity providing for maximum economic value and mitigating the University's exposure to commodity price volatility, thereby making operational costs more predictable. The analysis conducted by OSEP took into consideration the case provided by Burns and McDonnell and further optimized the configuration based on size and location to address future campus expansion.

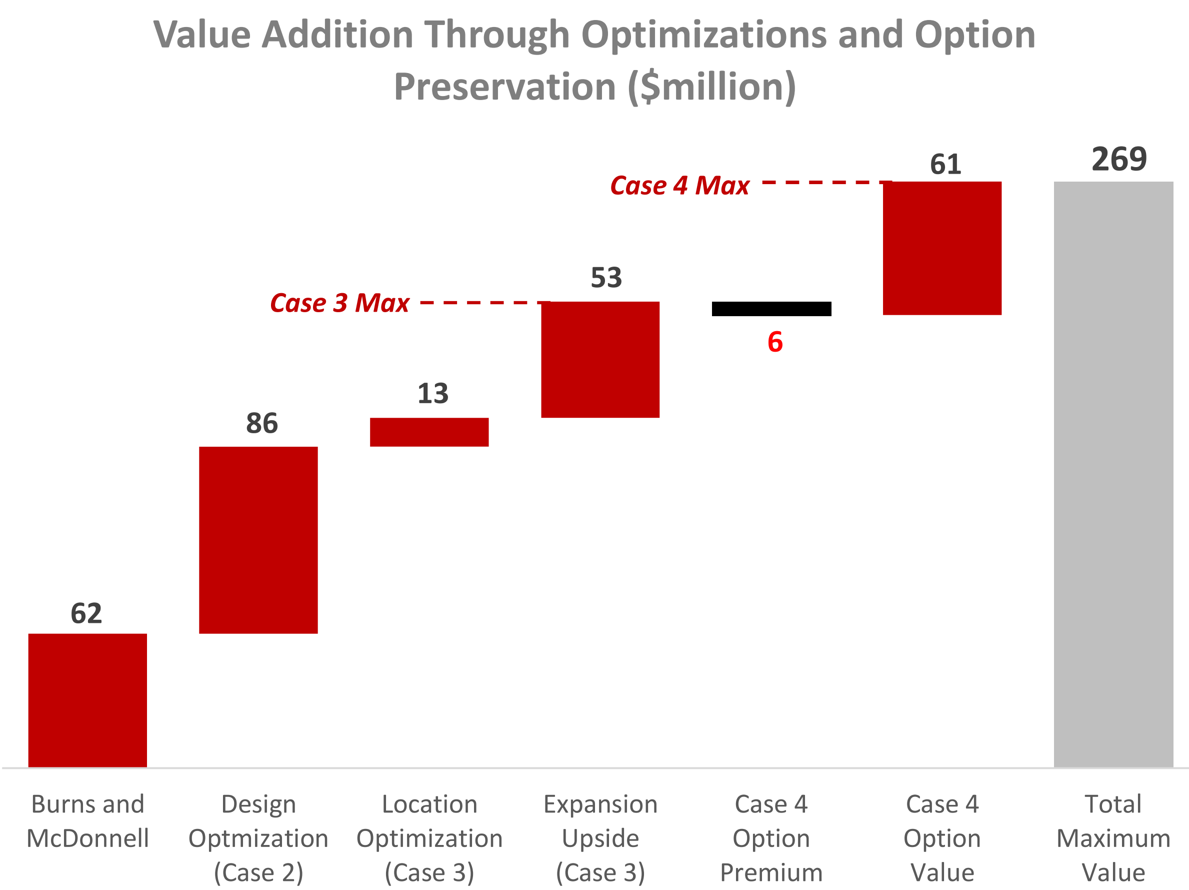

Figure 7-1: Full Expansion with addition of a 3rd turbine could create value up to $269 million in NPV savings

A full expansion (Midwest plus West) will result in $214 million NPV savings under Case 3. The Case 4 has an "option premium" of $6 million over the Case 3; however, Case 4 would preserve an additional upside of $61 million NPV savings ($55 million net of additional Case 4 option premium over Case 3) or a total realizable value of $118 from West campus expansion, as shown in Figure 7-1 above. To conclude, the Case 4 can create up to a total of $269 million in value considering the West Campus expansion and addition of a 3rd turbine (net of addition of 3rd turbine capex).

	Cases				
	Burns & Mc	Case 1	Case 2	Case 3	Case 4
Location	South – Smith Sub	South – Smith Sub	North– Smith Sub	Midwest	Midwest Expansion
Configuration	2x0	2x1	2x1	2X1	(2+1)x1
Summer (MW)	43	70	73	73	73 → 108
CAPEX (MUSD)	$105	$128	$131	$147	$152
CO_2 Reduction	● ○ ○	● ● ○	● ● ●	● ● ●	● ● ●
Resiliency	◐ ○ ○	● ● ○	● ● ●	● ● ●	● ● ●
Expansion and modularity	○ ○ ○	● ○ ○	● ◐ ○	● ● ○	● ● ●
LCOE	[redacted]				
NPV (Savings)	◐ ○ ○	● ◐ ○	● ● ◐	● ● ●	● ● ◐
Results	Basic	Enhanced Design	Optimized Design	Optimized Location	Preserved Upside
			Recommended		Recommended

Figure 7-2: Recommended cases based on technical and economic viability

Figure 7-2 above illustrates that all cases provide varying degrees of resiliency and reliability regardless of size, configuration or location. The Burns and McDonnell solution, albeit reliable, lacks commercial and operational flexibility and less economic benefit than Cases 1-4. Case 1, due to lower efficiency, higher $/KW CAPEX and higher LTSA costs from the Solar Turbine (Titan 250) does not provide the University with the most economic benefit.

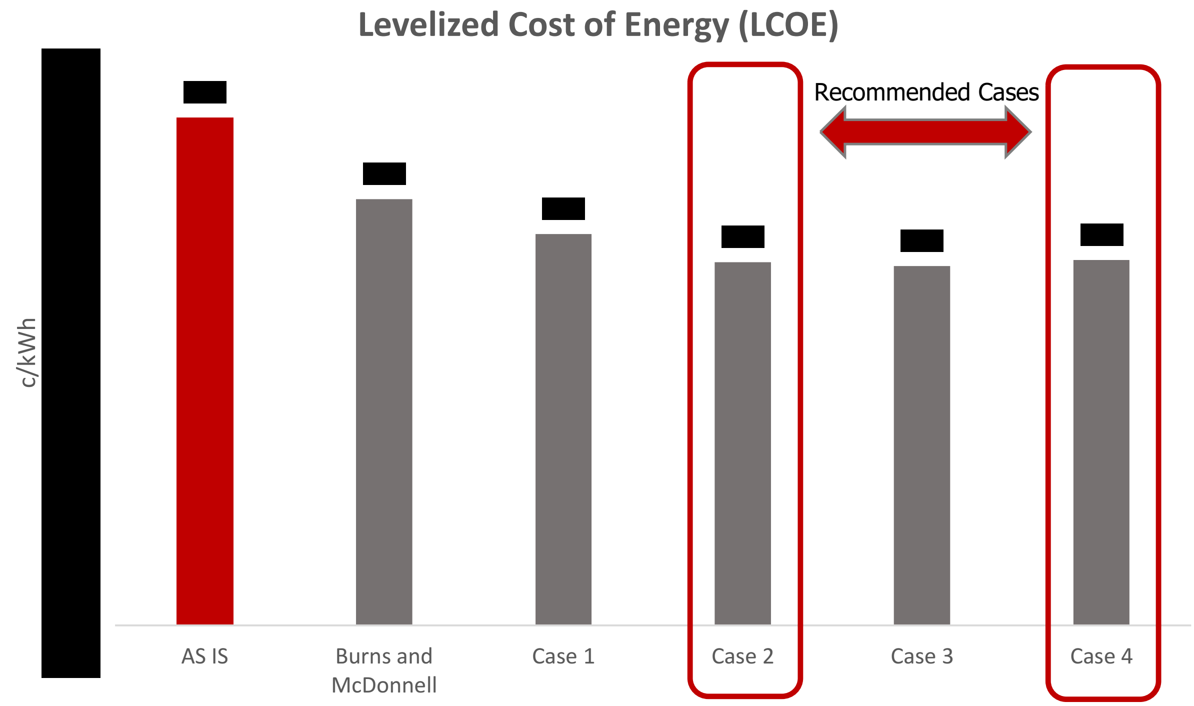

Figure 7-3: Recommended cases provide for best LCOE

To conclude, from a Levelized Cost of Energy (LCOE) viewpoint in Figure 7-3, all options are less than the as-is baseline case that the University is currently achieving**. LCOE for the recommended cases 2 and 4 are around [redacted] lower than the University baseline. The utility cost savings (in NPV) the University will realize ranges from $147M to $154M (Recommended Cases 2 and 4) over the life,** net of incremental O&M costs as well as Concessionaire's cost recovery through incremental Variable Fees. In additional to the above, **Case 4 preserves the full upside of $114 million NPV** from West Campus expansion.

OSEP has provided an analysis for different cases that include multiple configurations, technologies and locations toto offer the University a holistic view on reliable and resilient CHP solutions. The cases allow for optionality, enhanced energy savings and operational flexibility while also having a **substantial positive impact on the CO_2 footprint (38% reduction)** compared to the University's baseline.

OSEP is well aligned with the University with their vision of the future. The development and implementation of an optimized CHP facility is a major achievement and will be the steppingstone for the University to achieve its overall energy and carbon goals.

The Ohio State University

Combined Heat and Power Project

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APPENDIX

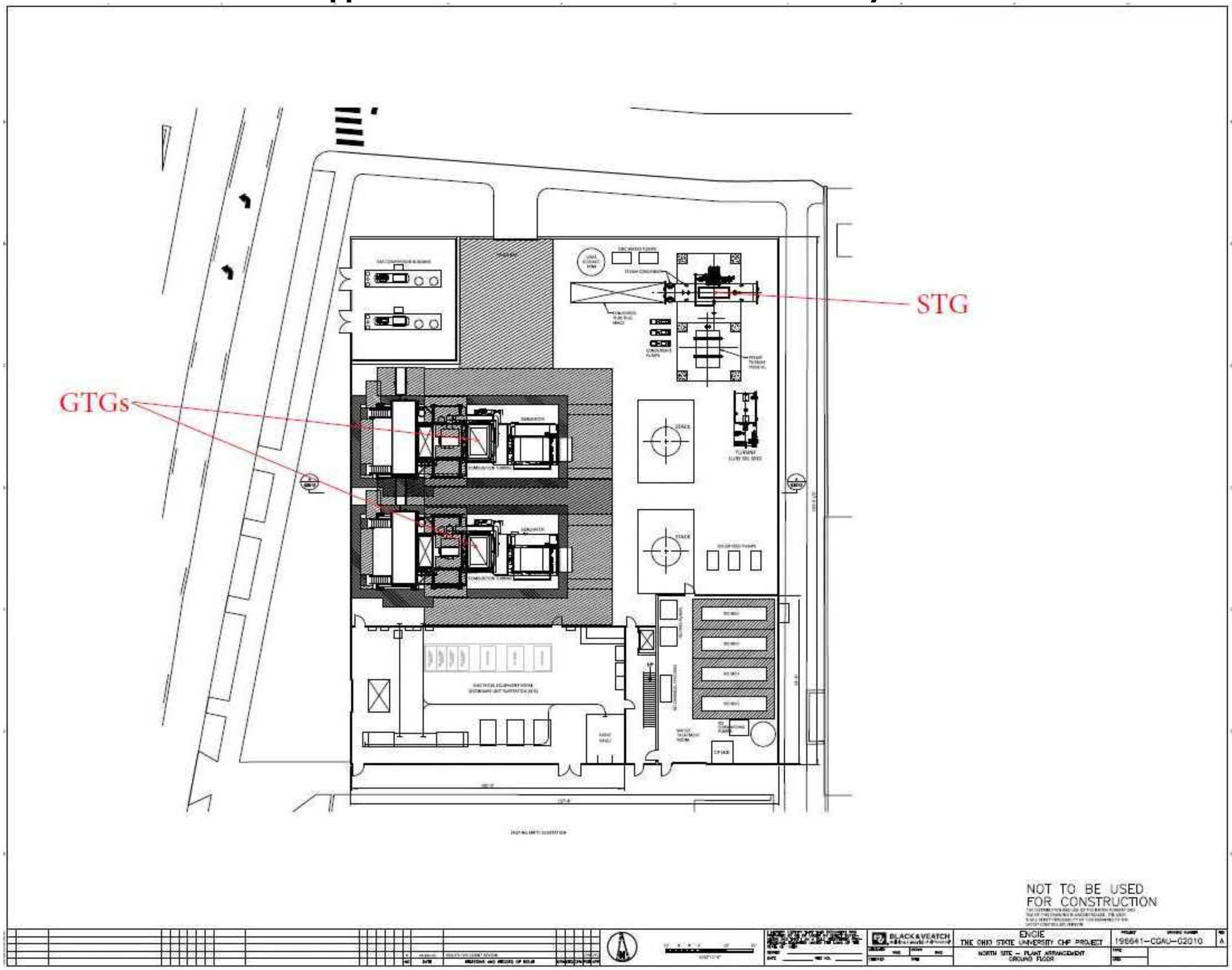
FEBRUARY 20, 2018

Appendix A – Detailed Performance

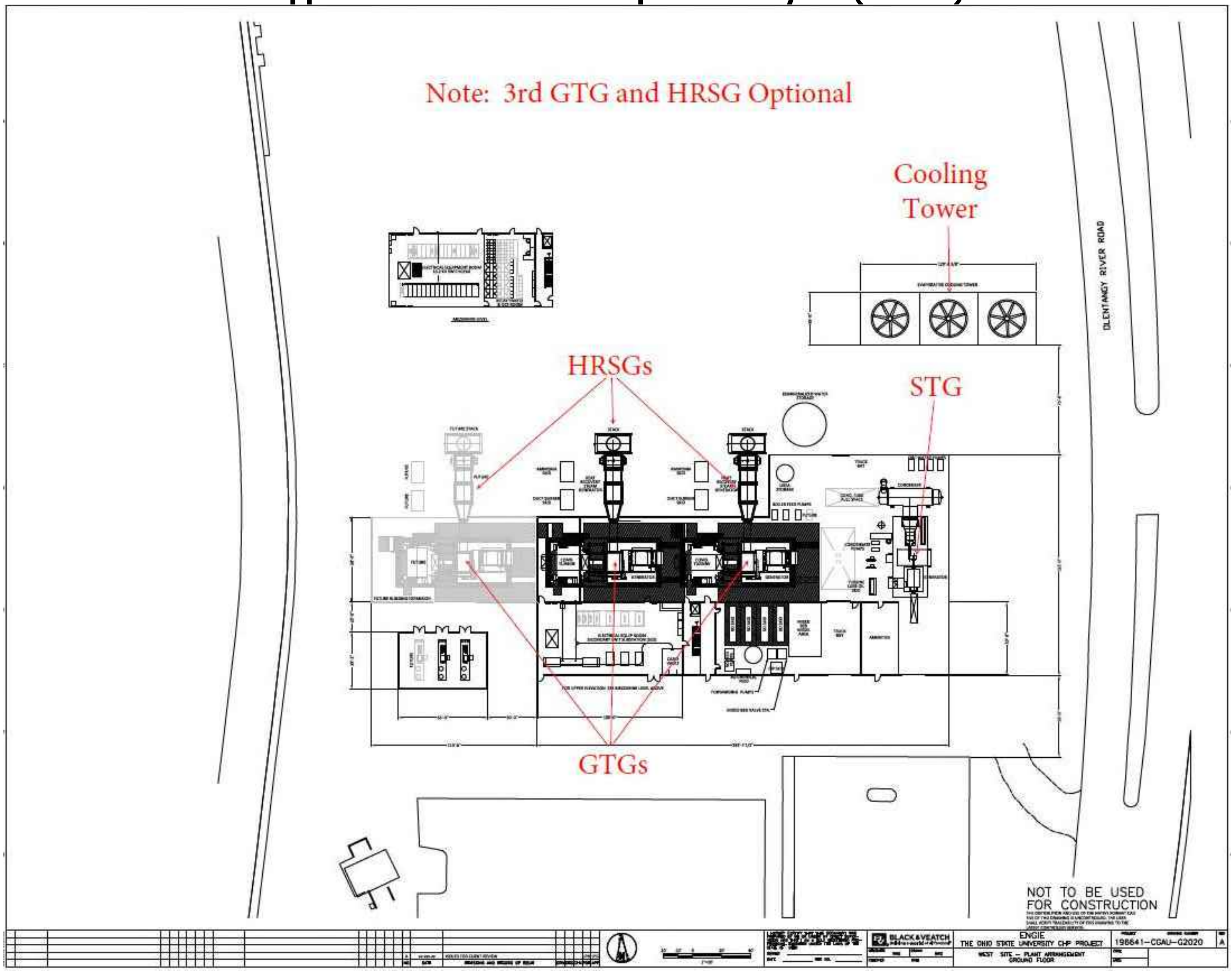
2x1 Titan 250		January	February	March	April	May	June	July	August	September	October	November	December
Power	Net Plant Output (kW)	57,017	58,787	57,452	59,337	60,144	60,885	60,985	61,114	61,161	59,311	59,388	55,940
	Average OSU electric demand (kW)	39,949	41,522	41,370	45,002	45,414	52,953	57,547	61,719	56,718	48,085	42,687	39,648
Fuel consumption	GT (MMBtu/h) HHV	436	437	432	420	420	420	420	420	420	418	430	437
	Duct Burner (MMBtu/h) HHV	217	215	205	199	199	199	199	199	199	196	204	213
	Auxiliary boilers (MMBtu/h) HHV	0	0	0	0	0	0	0	0	0	0	0	0
	Total Fuel (MMBtu/h) HHV	653	651	637	619	620	620	620	620	620	614	634	650
Steam	Steam from CHP (kpph)	208	184	183	125	110	92	87	86	92	119	154	218
	Steam from Aux boilers (kpph)	0	0	0	0	0	0	0	0	0	0	0	0
	Total steam (kpph)	208	184	183	125	110	92	87	86	92	119	154	218
	Average OSU steam demand (kpph)	208	184	183	125	110	92	87	86	92	119	154	218
Water Consumption	Condensate Return (kpph)	62	55	55	38	33	28	26	26	27	36	46	65
	Steam Cycle Make-up (kpph)	145	129	128	88	77	64	61	60	64	83	108	152
	RO Make-up (kpph)	194	172	171	117	103	86	81	80	85	111	144	203
	Cooling Tower Make-up (kpph)	54	77	77	136	157	180	187	188	178	141	107	45
Efficiency	Net Steam Energy (MMBTU/h)	268	237	236	162	142	119	112	111	118	153	199	280
	CHP Efficiency, HHV (%)	70.8%	67.3%	67.8%	58.8%	56.1%	52.7%	51.7%	51.5%	52.7%	57.9%	63.3%	72.5%
	PURPA Efficiency (%)	55.7%	54.3%	54.6%	50.7%	49.4%	47.7%	47.2%	47.2%	47.9%	50.3%	52.8%	56.5%

2x1 SGT-600		January	February	March	April	May	June	July	August	September	October	November	December
Power	Net Plant Output (kW)	59,314	59,601	58,229	61,529	62,729	63,894	64,108	64,261	64,162	62,088	60,842	58,853
	Average OSU electric demand (kW)	39,949	41,522	41,370	45,002	45,414	52,953	57,547	61,719	56,718	48,085	42,687	39,648
Fuel consumption	GT (MMBtu/h) HHV	561	559	549	534	534	534	534	534	534	534	546	558
	Duct Burner (MMBtu/h) HHV	87	87	84	80	80	80	80	80	80	80	84	87
	Auxiliary boilers (MMBtu/h) HHV	28	0	0	0	0	0	0	0	0	0	0	44
	Total Fuel (MMBtu/h) HHV	677	646	633	614	614	614	614	614	614	614	630	688
Steam	Steam from CHP (kpph)	190	184	183	125	110	92	87	86	92	119	154	190
	Steam from Aux boilers (kpph)	18	0	0	0	0	0	0	0	0	0	0	28
	Total steam (kpph)	208	184	183	125	110	92	87	86	92	119	154	218
	Average OSU steam demand (kpph)	208	184	183	125	110	92	87	86	92	119	154	218
Water Consumption	Condensate Return (kpph)	62	55	55	38	33	28	26	26	27	36	46	65
	Steam Cycle Make-up (kpph)	145	129	128	88	77	64	61	60	64	83	108	152
	RO Make-up (kpph)	194	172	171	117	103	86	81	80	85	111	144	203
	Cooling Tower Make-up (kpph)	35	41	42	86	106	128	134	135	124	91	63	36
Efficiency	Net Steam Energy (MMBTU/h)	268	237	236	162	142	119	112	111	118	153	199	280
	CHP Efficiency, HHV (%)	72.5%	68.2%	68.7%	60.5%	58.0%	54.8%	53.9%	53.7%	54.8%	59.4%	64.5%	74.7%
	PURPA Efficiency (%)	57.5%	55.2%	55.4%	52.4%	51.4%	50.0%	49.6%	49.5%	50.1%	52.0%	54.0%	58.7%

Appendix B – North of Smith Substation Layout



Appendix C – Midwest Campus Site Layout (Case 4)



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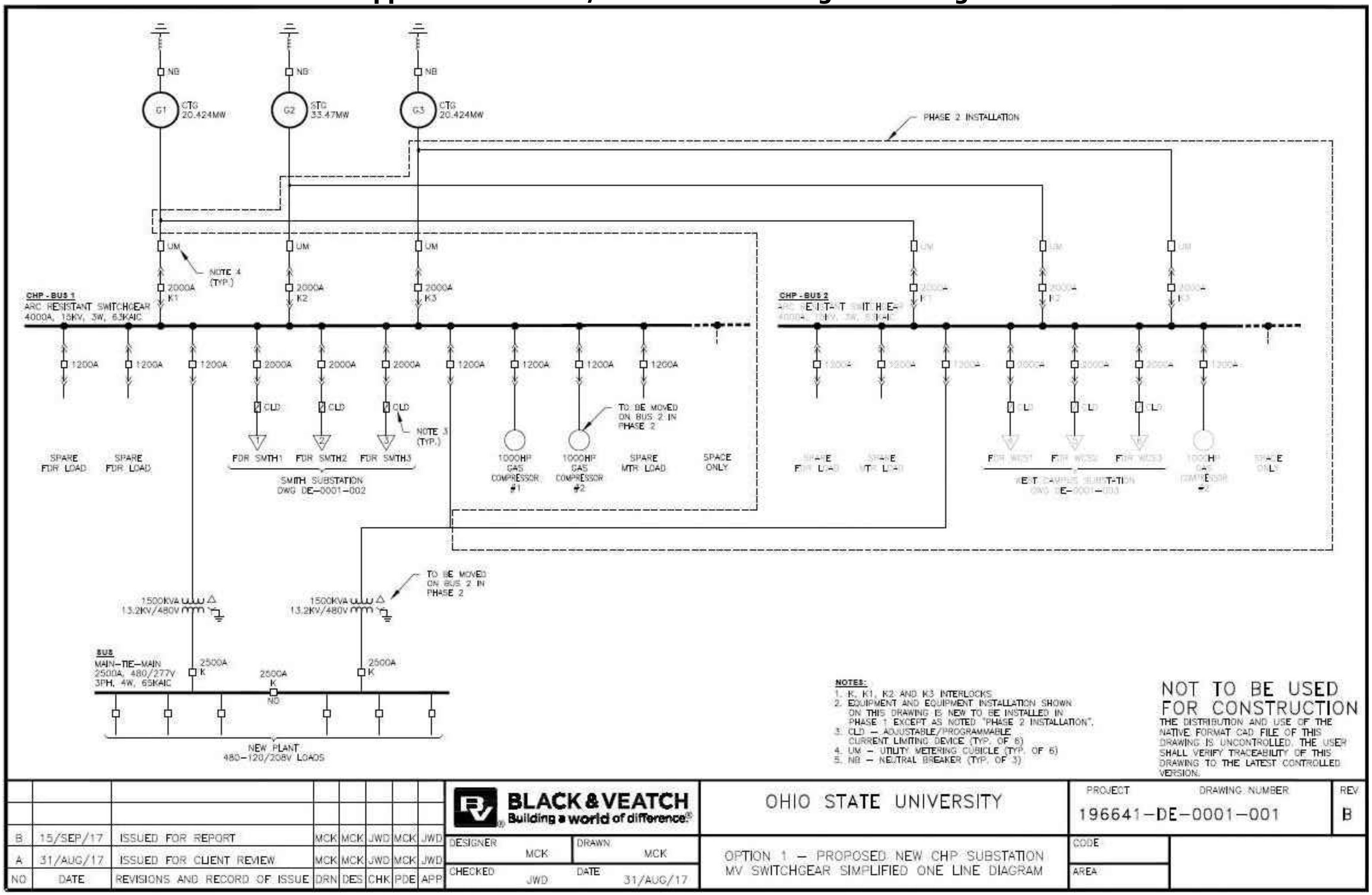
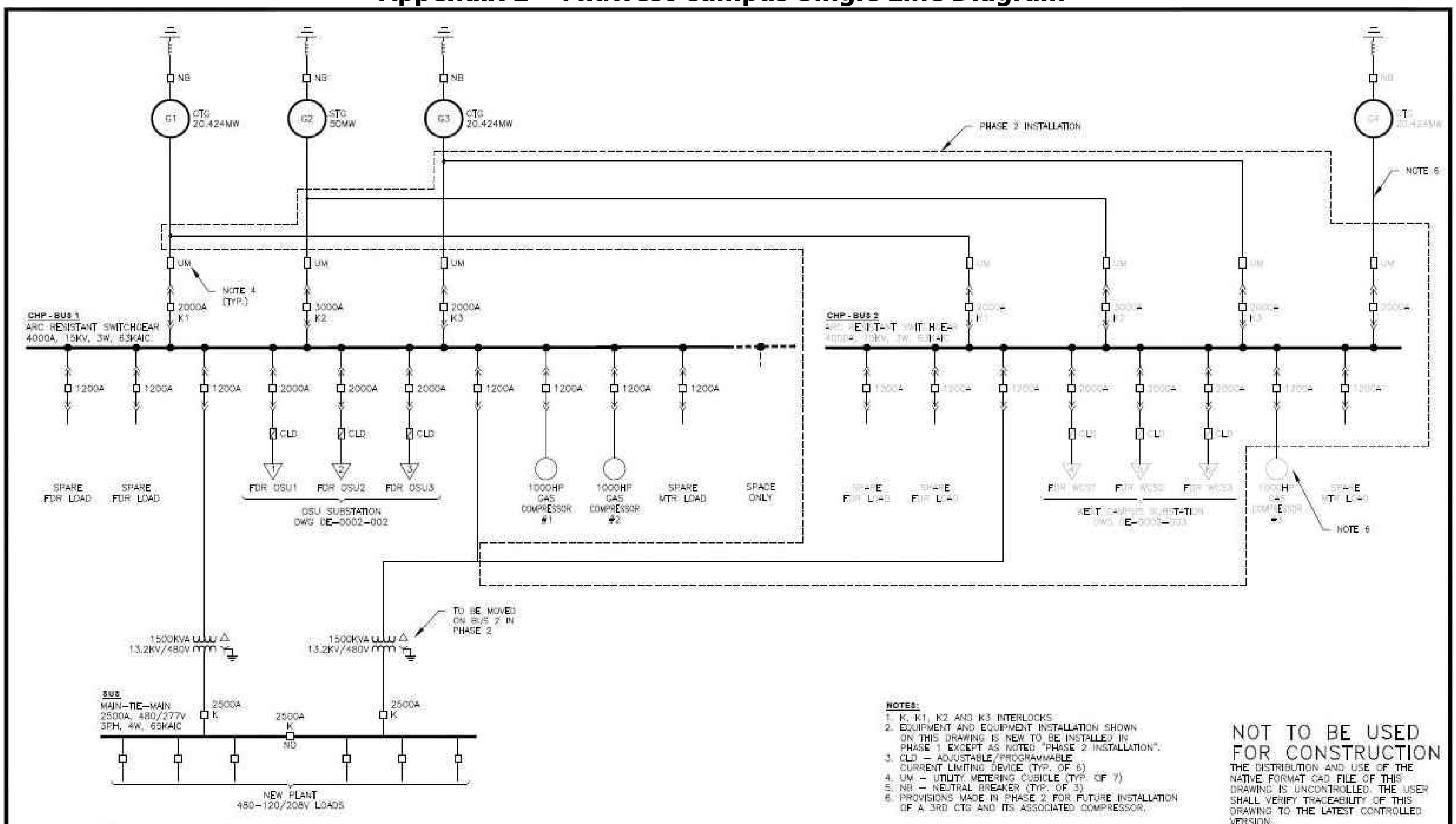
Appendix D – North/South Location Single Line Diagram



Appendix E – Midwest Campus Single Line Diagram



NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
B	15/SEP/17	ISSUED FOR REPORT	MCK	MCK	JWD	MCK	JWD
A	31/AUG/17	ISSUED FOR CLIENT REVIEW	MCK	MCK	JWD	MCK	JWD

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DESIGNER MCK | DRAWN MCK | CHECKED JWD | DATE 31/AUG/17

OHIO STATE UNIVERSITY
OPTION 2 – PROPOSED NEW CHP SUBSTATION
MV SWITCHGEAR SIMPLIFIED ONE LINE DIAGRAM

PROJECT 196641 | DRAWING NUMBER DE-0002-001 | REV B
CODE
AREA

Appendix F – Detailed Capex Estimate

	B&McD (2014$)	B&McD (2017$)	South Smith Substation	North Smith Substation		Midwest 2x1		Midwest 2x1 (exp)	
	Solar Turbine	Solar Turbine	Solar Turbine	Solar Turbine	Siemens	Solar Turbine	Siemens	Solar Turbine	Siemens
Gas Turbine Package	[redacted]								
Steam Turbine Package									
Heat Recovery Boiler									
Cooling Tower									
Fuel Gas Compressor									
Mechanical Equipment									
BOP Electrical Equipment									
Equipment subtotal	**$36,021,250**	**$38,226,039**	**$49,995,898**	**$48,945,560**	**$50,095,560**	**$50,204,293**	**$51,420,560**	**$53,020,960**	**$53,874,693**
Construction									
Civil	$682,500	$ 724,274	$3,863,459	$4,246,567	$4,246,567	$8,946,633	$8,598,421	$8,847,223	$9,177,906
Mechanical	$5,479,134	$ 5,814,501	$16,100,116	$17,224,746	$17,548,764	$22,953,452	$25,102,464	$23,846,042	$24,222,763
Electrical	$3,396,500	$ 3,604,393	$9,358,822	$10,047,185	$10,047,185	$13,382,534	$13,385,445	$13,395,775	$13,388,657
Building	$9,448,682	$ 10,027,017	$12,853,084	$12,814,074	$12,814,074	$9,670,567	$9,670,557	$11,170,567	$11,170,567
Engineering and Startup	$5,934,000	$ 6,297,208	$7,000,000	$7,000,000	$7,000,000	$7,000,000	$7,000,000	$7,000,000	$7,000,000
Construction Mgt	$13,000,000	$ 13,795,704	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000
Contractor's Profit	$2,363,000	$ 2,507,635	$5,385,178	$5,446,049	$5,522,520	$6,065,371	$6,225,470	$6,339,962	$6,420,533
Construction & Material subtotal	**$40,305,750**	**$42,772,784**	**$56,560,659**	**$58,778,621**	**$59,179,110**	**$70,018,557**	**$71,982,357**	**$72,599,569**	**$73,380,426**
Concessionaire's Cost	[redacted]								
Start-up Consumables	$41,000	$41,000	$41,000	$41,000	$41,000	$41,000	$41,000	$41,000	$41,000
TOTAL COST W/O CONTINGENCY	[redacted]								
Contractor's contingency	$10,300,000	$ 10,930,442	$6,532,178	$6,642,853	$6,698,255	$7,149,933	$7,331,959	$7,518,683	$7,576,078
Concessionaire's Contingency -	[redacted]								
Contingency subtotal	$12,783,395	$13,413,838	$8,049,274	$8,184,502	$8,248,004	$8,968,758	$9,195,176	$9,427,859	$9,498,836
TOTAL COST W/ CONTINGENCY	**$94,922,875**	**$100,341,936**	**$121,174,050**	**$122,506,093**	**$124,158,846**	**$136,101,484**	**$139,587,471**	**$142,093,207**	**$143,839,639**

Appendix G – CHP Project Schedule

Task Name	Start	Finish
Milestone Schedule	Wed 9/27/17	Mon 8/16/21
OSU CHP Project	Wed 9/27/17	Mon 8/16/21
Feasibility Study Project Schedule	Wed 9/27/17	Fri 6/8/18
Start Project	Wed 9/27/17	Wed 9/27/17
CHP Feasibility Study Phase	Wed 9/27/17	Tue 2/20/18
Deliver Feasibility Study To OSU	Tue 2/20/18	Tue 2/20/18
Prepare CHP Development Approval Package	Tue 2/20/18	Mon 5/14/18
OSU Development Approval	Mon 5/14/18	Fri 6/8/18
CHP Development Phase	Fri 6/8/18	Tue 9/24/19
ENGIE released to begin Development Process	Fri 6/8/18	Fri 6/8/18
Select Third Party Owner's Engineer	Fri 6/8/18	Thu 7/5/18
Select Third Party Environmental Consultant	Fri 6/8/18	Thu 7/5/18
Establish Cogeneration Project Requirements	Mon 6/11/18	Thu 7/26/18
Major Equipment Selection	Mon 6/18/18	Mon 7/23/18
Develop Execution Technical Bid Package	Fri 7/6/18	Fri 9/21/18
Regulatory Requirements (OSEP and University)	Tue 7/24/18	Thu 7/25/19
Interconnection Process (OSEP and University)	Mon 6/18/18	Mon 7/22/19
Interconnection Service Agreement Negotiation	Tue 7/23/19	Tue 9/24/19
Develop Project Implementation Program	Tue 7/24/18	Thu 8/1/19
Prepare CHP Execution Approval Package	Fri 5/24/19	Mon 8/5/19
OSU Execution Approval	Tue 8/6/19	Fri 8/30/19
CHP Project Execution	Fri 8/30/19	Wed 6/30/21
COD	Wed 6/30/21	Wed 6/30/21
Final Completion	Thu 7/1/21	Mon 8/16/21

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Combined Heat and Power Project

Appendix H – LCOE Impact Model (North of Smith SS)

Annual Performance Summary for Case 2 - SGT 600 2x1: North of Smith

Year	Average Delivered NG Price ($/MMBtu)	As is Energy Procurement: Fuel (MMBtu)	As is Energy Procurement: Wind Purchase (MWh)	As is Energy Procurement: Other Grid Purchase (MWh)	As is Energy Procurement: Average Delivered Grid Price ($/MWh)	Energy Procurement With CHP: Fuel (MMBtu)	Energy Procurement With CHP: *CHP Generation (MWh)*	Energy Procurement With CHP: Net Proc from CHP (MWh)	Energy Procurement With CHP: Plus: Wind Purchase (MWh)	Energy Procurement With CHP: Plus Other Grid Imports (MWh)	Energy Procurement With CHP: Average Delivered Grid Price ($/MWh)	Energy Procurement With CHP: Equivalent Procurement CHP Price ($/MWh)
2020	[redacted]	1,900,249	122,730	411,029	[redacted]	1,900,249	*0*	0	122,730	411,029		
2021	[redacted]	1,900,249	122,730	411,029	[redacted]	5,134,997	*489,562*	393,792	122,730	17,238	[redacted]	**$71.8**
2022	[redacted]	1,848,912	122,730	412,851	[redacted]	5,082,791	*489,269*	394,435	122,730	18,416	[redacted]	**$71.0**
2023	[redacted]	1,797,326	122,730	414,721	[redacted]	5,004,173	*484,442*	395,097	122,730	19,624	[redacted]	**$70.5**
2024	[redacted]	1,745,492	122,730	416,639	[redacted]	4,936,778	*479,918*	395,775	122,730	20,864	[redacted]	**$70.3**
2025	[redacted]	1,717,223	122,730	419,924	[redacted]	4,905,115	*477,975*	397,178	122,730	22,746	[redacted]	**$69.8**
2026	[redacted]	1,688,706	122,730	423,258	[redacted]	4,894,453	*478,492*	398,572	122,730	24,686	[redacted]	**$69.2**
2027	[redacted]	1,699,629	122,730	428,838	[redacted]	4,903,732	*478,986*	401,108	122,730	27,730	[redacted]	**$68.2**
2028	[redacted]	1,710,303	122,730	434,467	[redacted]	4,915,737	*479,732*	403,616	122,730	30,851	[redacted]	**$67.4**
2029	[redacted]	1,720,729	122,730	440,144	[redacted]	4,936,488	*481,780*	406,114	122,730	34,030	[redacted]	**$63.8**
2030	[redacted]	1,730,907	122,730	445,868	[redacted]	4,946,154	*482,260*	408,618	122,730	37,250	[redacted]	**$63.0**
2031	[redacted]	1,740,837	122,730	451,641	[redacted]	4,955,673	*482,739*	411,089	122,730	40,552	[redacted]	**$62.4**
2032	[redacted]	1,750,519	96,575	483,616	[redacted]	4,967,715	*483,448*	413,529	96,575	70,087	[redacted]	**$60.1**
2033	[redacted]	1,759,952	0	586,060	[redacted]	4,977,327	*483,933*	415,939	0	170,120	[redacted]	**$54.2**
2034	[redacted]	1,769,137	0	591,976	[redacted]	4,993,878	*485,315*	418,330	0	173,646	[redacted]	**$51.5**
2035	[redacted]	1,778,074	0	597,940	[redacted]	5,005,809	*486,041*	420,650	0	177,290	[redacted]	**$51.2**
2036	[redacted]	1,786,762	0	603,953	[redacted]	5,019,772	*486,971*	422,918	0	181,035	[redacted]	**$50.8**
2037	[redacted]	1,795,203	0	610,013	[redacted]	5,032,998	*488,090*	425,147	0	184,865	[redacted]	**$50.5**
2038	[redacted]	1,803,395	0	616,121	[redacted]	5,041,649	*488,559*	427,337	0	188,783	[redacted]	**$50.2**
2039	[redacted]	1,811,339	0	622,277	[redacted]	5,050,160	*489,032*	429,515	0	192,761	[redacted]	**$49.9**
2040	[redacted]	1,819,034	0	628,481	[redacted]	5,058,533	*489,508*	431,657	0	196,823	[redacted]	**$44.1**
2041	[redacted]	1,826,482	0	634,732	[redacted]	5,067,684	*489,987*	433,749	0	200,983	[redacted]	**$34.8**
2042	[redacted]	1,833,681	0	641,032	[redacted]	5,078,247	*490,470*	435,814	0	205,218	[redacted]	**$35.9**
2043	[redacted]	1,840,632	0	647,380	[redacted]	5,092,940	*491,598*	437,861	0	209,519	[redacted]	**$37.0**
2044	[redacted]	1,847,334	0	653,775	[redacted]	5,103,016	*492,082*	439,890	0	213,885	[redacted]	**$38.1**
2045	[redacted]	1,853,789	0	660,219	[redacted]	5,112,861	*492,568*	441,916	0	218,303	[redacted]	**$39.2**
CAGR	[redacted]				[redacted]							
LCOE* (Real 2020$, 2020-2045)					$ [redacted]							$ [redacted]

** Assuming 4% nominal discount rate, 2% inlfation*

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Combined Heat and Power Project

OHIO STATE ENERGY PARTNERS

Appendix I – NPV Savings Model (North of Smith SS)

Annual Financial Summary for Case 2 - SGT 600 2x1: North of Smith

Contract Year #	Year	Annual Utility Cost As is ($ million)						Annual Utility Cost With CHP ($ million)									Annual Net Utility Savings
		Wind PPA Prourement Cost	Other Retail Electric Supply Cost	Electric Utility Delivery Cost	Fuel Cost	O&M Costs (Emergency Gen Maint.)	Total Utility Supply Cost	Wind PPA Prourement Cost	Residual Electric Supply Cost	Electric Utility Delivery Cost	Fuel Cost (inl. CHP)	Incremental Variable Fee (Concession)*	O&M Costs (incl. CHP LTSA)	Utility Standby Charges	MW DHC O&M Synergies & Efficiency	Total Utility Supply Cost	
0	2020	6.58	[redacted]	7.16	5.53	0.44	[redacted]	6.58	[redacted]	7.16	[redacted]	6.10	0.44	0.00	0.00	[redacted]	-6.1
1	2021	6.72	[redacted]	7.29	5.71	0.45	[redacted]	6.72	[redacted]	2.02	[redacted]	16.50	2.32	0.28	0.00	[redacted]	-2.9
2	2022	6.85	[redacted]	7.46	5.60	0.46	[redacted]	6.85	[redacted]	2.09	[redacted]	15.96	2.36	0.29	0.00	[redacted]	-1.4
3	2023	6.99	[redacted]	7.64	5.56	0.47	[redacted]	6.99	[redacted]	2.15	[redacted]	15.42	2.40	0.30	0.00	[redacted]	-0.8
4	2024	7.13	[redacted]	7.82	5.54	0.48	[redacted]	7.13	[redacted]	2.21	[redacted]	14.88	2.44	0.30	0.00	[redacted]	-0.4
5	2025	7.27	[redacted]	8.02	5.58	0.49	[redacted]	7.27	[redacted]	2.30	[redacted]	14.33	2.48	0.31	0.00	[redacted]	0.5
6	2026	7.41	[redacted]	8.23	5.62	0.49	[redacted]	7.41	[redacted]	2.38	[redacted]	13.79	2.54	0.31	0.00	[redacted]	1.5
7	2027	7.56	[redacted]	8.48	5.80	0.50	[redacted]	7.56	[redacted]	2.49	[redacted]	13.24	2.59	0.32	0.00	[redacted]	3.3
8	2028	7.71	[redacted]	8.74	5.98	0.51	[redacted]	7.71	[redacted]	2.61	[redacted]	12.70	2.65	0.33	0.00	[redacted]	4.9
9	2029	7.87	[redacted]	9.01	6.19	0.53	[redacted]	7.87	[redacted]	2.73	[redacted]	10.97	2.71	0.33	0.00	[redacted]	8.2
10	2030	8.03	[redacted]	9.28	6.29	0.54	[redacted]	8.03	[redacted]	2.86	[redacted]	10.49	2.77	0.34	0.00	[redacted]	9.3
11	2031	8.19	[redacted]	9.57	6.45	0.55	[redacted]	8.19	[redacted]	2.99	[redacted]	10.00	2.83	0.35	0.00	[redacted]	10.7
12	2032	6.54	[redacted]	9.86	6.62	0.56	[redacted]	6.54	[redacted]	3.13	[redacted]	9.52	2.88	0.35	0.00	[redacted]	12.0
13	2033	0.00	[redacted]	10.16	6.79	0.57	[redacted]	0.00	[redacted]	3.27	[redacted]	9.03	2.94	0.36	0.00	[redacted]	13.1
14	2034	0.00	[redacted]	10.46	6.96	0.58	[redacted]	0.00	[redacted]	3.42	[redacted]	7.68	3.01	0.37	0.00	[redacted]	15.3
15	2035	0.00	[redacted]	10.78	7.13	0.59	[redacted]	0.00	[redacted]	3.58	[redacted]	7.28	3.08	0.37	0.00	[redacted]	15.9
16	2036	0.00	[redacted]	11.11	7.31	0.60	[redacted]	0.00	[redacted]	3.74	[redacted]	6.87	3.14	0.38	0.00	[redacted]	17.5
17	2037	0.00	[redacted]	11.45	7.49	0.62	[redacted]	0.00	[redacted]	3.91	[redacted]	6.45	3.21	0.39	0.00	[redacted]	17.9
18	2038	0.00	[redacted]	11.79	7.68	0.63	[redacted]	0.00	[redacted]	4.09	[redacted]	6.04	3.28	0.40	0.00	[redacted]	19.0
19	2039	0.00	[redacted]	12.15	7.86	0.64	[redacted]	0.00	[redacted]	4.27	[redacted]	5.62	3.35	0.41	0.00	[redacted]	19.8
20	2040	0.00	[redacted]	12.52	8.06	0.65	[redacted]	0.00	[redacted]	4.46	[redacted]	2.82	3.42	0.41	0.00	[redacted]	23.0
21	2041	0.00	[redacted]	12.89	8.25	0.67	[redacted]	0.00	[redacted]	4.66	[redacted]	-1.57	3.49	0.42	0.00	[redacted]	27.7
22	2042	0.00	[redacted]	13.28	8.45	0.68	[redacted]	0.00	[redacted]	4.87	[redacted]	-1.47	3.56	0.43	0.00	[redacted]	27.9
23	2043	0.00	[redacted]	13.68	8.65	0.69	[redacted]	0.00	[redacted]	5.08	[redacted]	-1.38	3.64	0.44	0.00	[redacted]	28.1
24	2044	0.00	[redacted]	14.10	8.86	0.71	[redacted]	0.00	[redacted]	5.30	[redacted]	-1.29	3.71	0.45	0.00	[redacted]	28.3
25	2045	0.00	[redacted]	14.52	9.06	0.72	[redacted]	0.00	[redacted]	5.53	[redacted]	-1.20	3.79	0.46	0.00	[redacted]	28.5

** 20 yr Variable Fee Amortization period; negative Incremental Variable Fee represents capex savings related to Boiler retirement and DHC (Case 3)*

Assumed Discount Rate (Nominal)	4.00%
NPV of Savings ($ million)	**147**

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Appendix J – NPV Savings Model (Midwest Campus)

Annual Financial Summary for Case 4 - SGT 600 2x1: Midwest Campus (Expandable)

		Annual Utility Cost As is ($ million)						Annual Utility Cost With CHP ($ million)									
Contract Year #	Year	Wind PPA Procurement Cost	Other Retail Electric Supply Cost	Electric Utility Delivery Cost	Fuel Cost	O&M Costs (Emergency Gen Maint.)	Total Utility Supply Cost	Wind PPA Procurement Cost	Residual Electric Supply Cost	Electric Utility Delivery Cost	Fuel Cost (inl. CHP)	Incremental Variable Fee (Concession)*	O&M Costs (incl. CHP LTSA)	Utility Standby Charges	MW DHC O&M Synergies & Efficiency	Total Utility Supply Cost	Annual Net Utility Savings
0	2020	6.58	[redacted]	7.16	5.53	0.44	[redacted]	6.58	[redacted]	7.16	[redacted]	7.07	0.44	0.00	0.00	[redacted]	-7.1
1	2021	6.72	[redacted]	7.29	5.71	0.45	[redacted]	6.72	[redacted]	2.02	[redacted]	19.13	2.32	0.28	-0.31	[redacted]	-5.2
2	2022	6.85	[redacted]	7.46	5.60	0.46	[redacted]	6.85	[redacted]	2.09	[redacted]	24.44	2.36	0.29	-0.69	[redacted]	-9.2
3	2023	6.99	[redacted]	7.64	5.56	0.47	[redacted]	6.99	[redacted]	2.15	[redacted]	22.29	2.40	0.30	-1.10	[redacted]	-6.6
4	2024	7.13	[redacted]	7.82	5.54	0.48	[redacted]	7.13	[redacted]	2.21	[redacted]	20.16	2.44	0.30	-1.51	[redacted]	-4.2
5	2025	7.27	[redacted]	8.02	5.58	0.49	[redacted]	7.27	[redacted]	2.30	[redacted]	18.03	2.48	0.31	-1.95	[redacted]	-1.2
6	2026	7.41	[redacted]	8.23	5.62	0.49	[redacted]	7.41	[redacted]	2.38	[redacted]	15.93	2.54	0.31	-2.06	[redacted]	1.4
7	2027	7.56	[redacted]	8.48	5.80	0.50	[redacted]	7.56	[redacted]	2.49	[redacted]	15.75	2.59	0.32	-2.11	[redacted]	2.9
8	2028	7.71	[redacted]	8.74	5.98	0.51	[redacted]	7.71	[redacted]	2.61	[redacted]	15.09	2.65	0.33	-2.16	[redacted]	4.7
9	2029	7.87	[redacted]	9.01	6.19	0.53	[redacted]	7.87	[redacted]	2.73	[redacted]	13.26	2.71	0.33	-2.22	[redacted]	8.1
10	2030	8.03	[redacted]	9.28	6.29	0.54	[redacted]	8.03	[redacted]	2.86	[redacted]	11.43	2.77	0.34	-2.26	[redacted]	10.6
11	2031	8.19	[redacted]	9.57	6.45	0.55	[redacted]	8.19	[redacted]	2.99	[redacted]	10.87	2.83	0.35	-2.31	[redacted]	12.1
12	2032	6.54	[redacted]	9.86	6.62	0.56	[redacted]	6.54	[redacted]	3.13	[redacted]	10.32	2.88	0.35	-2.36	[redacted]	13.6
13	2033	0.00	[redacted]	10.16	6.79	0.57	[redacted]	0.00	[redacted]	3.27	[redacted]	9.77	2.94	0.36	-2.41	[redacted]	14.8
14	2034	0.00	[redacted]	10.46	6.96	0.58	[redacted]	0.00	[redacted]	3.42	[redacted]	8.35	3.01	0.37	-2.46	[redacted]	17.1
15	2035	0.00	[redacted]	10.78	7.13	0.59	[redacted]	0.00	[redacted]	3.58	[redacted]	7.87	3.08	0.37	-2.51	[redacted]	17.8
16	2036	0.00	[redacted]	11.11	7.31	0.60	[redacted]	0.00	[redacted]	3.74	[redacted]	7.39	3.14	0.38	-2.56	[redacted]	19.5
17	2037	0.00	[redacted]	11.45	7.49	0.62	[redacted]	0.00	[redacted]	3.91	[redacted]	6.91	3.21	0.39	-2.61	[redacted]	20.0
18	2038	0.00	[redacted]	11.79	7.68	0.63	[redacted]	0.00	[redacted]	4.09	[redacted]	6.43	3.28	0.40	-2.66	[redacted]	21.3
19	2039	0.00	[redacted]	12.15	7.86	0.64	[redacted]	0.00	[redacted]	4.27	[redacted]	5.94	3.35	0.41	-2.71	[redacted]	22.2
20	2040	0.00	[redacted]	12.52	8.06	0.65	[redacted]	0.00	[redacted]	4.46	[redacted]	2.69	3.42	0.41	-2.76	[redacted]	25.9
21	2041	0.00	[redacted]	12.89	8.25	0.67	[redacted]	0.00	[redacted]	4.66	[redacted]	-2.40	3.49	0.42	-2.82	[redacted]	31.3
22	2042	0.00	[redacted]	13.28	8.45	0.68	[redacted]	0.00	[redacted]	4.87	[redacted]	-2.62	3.56	0.43	-2.87	[redacted]	31.9
23	2043	0.00	[redacted]	13.68	8.65	0.69	[redacted]	0.00	[redacted]	5.08	[redacted]	-1.87	3.64	0.44	-2.92	[redacted]	31.5
24	2044	0.00	[redacted]	14.10	8.86	0.71	[redacted]	0.00	[redacted]	5.30	[redacted]	-1.15	3.71	0.45	-2.98	[redacted]	31.1
25	2045	0.00	[redacted]	14.52	9.06	0.72	[redacted]	0.00	[redacted]	5.53	[redacted]	-0.47	3.79	0.46	-3.04	[redacted]	30.8
26	2046											0.18			-3.09	-2.9	2.9
27	2047											0.05			-2.59	-2.5	2.5
28	2048											0.11			-2.64	-2.5	2.5
29	2049											-1.19			-2.69	-3.9	3.9
30	2050											-0.63			-2.74	-3.4	3.4
31	2051											-0.61			-2.80	-3.4	3.4
32	2052											-0.58			-2.86	-3.4	3.4
33	2053											-0.55			-2.91	-3.5	3.5
34	2054											-0.18			-2.97	-3.2	3.2
35	2055											-0.20			-3.03	-3.2	3.2

10 Year DHC Savings

20 yr Variable Fee Amortization period; negative Incremental Variable Fee represents capex savings related to Boiler retirement and DHC (Case 3)

Assumed Discount Rate (Nominal)	4.00%
NPV of Savings ($ million)	**154**

The Ohio State University
Combined Heat and Power Project

OHIO STATE ENERGY PARTNERS

LCOE Impact Model (Midwest)

Annual Performance Summary for Case 4 - SGT 600 2x1: Midwest Campus (Expandable)

Year	Average Delivered NG Price ($/MMBtu)	As is Energy Procurement: Fuel (MMBtu)	Wind Purchase (MWh)	Other Grid Purchase (MWh)	Average Delivered Grid Price ($/MWh)	Energy Procurement With CHP: Fuel (MMBtu)	*CHP Generation (MWh)*	Net Proc from CHP (MWh)	Plus: Wind Purchase (MWh)	Plus Other Grid Imports (MWh)	Average Delivered Grid Price ($/MWh)	Equivalent Procurement CHP Price ($/MWh)
2020	[redacted]	1,900,249	122,730	411,029	[redacted]	1,900,249	*0*	0	122,730	411,029		
2021	[redacted]	1,900,249	122,730	411,029	[redacted]	5,134,997	*489,562*	393,792	122,730	17,238	[redacted]	$77.7
2022	[redacted]	1,848,912	122,730	412,851	[redacted]	5,082,791	*489,269*	394,435	122,730	18,416	[redacted]	$90.8
2023	[redacted]	1,797,326	122,730	414,721	[redacted]	5,004,173	*484,442*	395,097	122,730	19,624	[redacted]	$85.1
2024	[redacted]	1,745,492	122,730	416,639	[redacted]	4,936,778	*479,918*	395,775	122,730	20,864	[redacted]	$79.8
2025	[redacted]	1,717,223	122,730	419,924	[redacted]	4,905,115	*477,975*	397,178	122,730	22,746	[redacted]	$74.2
2026	[redacted]	1,688,706	122,730	423,258	[redacted]	4,894,453	*478,492*	398,572	122,730	24,686	[redacted]	$69.4
2027	[redacted]	1,699,629	122,730	428,838	[redacted]	4,903,732	*478,986*	401,108	122,730	27,730	[redacted]	$69.2
2028	[redacted]	1,710,303	122,730	434,467	[redacted]	4,915,737	*479,732*	403,616	122,730	30,851	[redacted]	$68.0
2029	[redacted]	1,720,729	122,730	440,144	[redacted]	4,936,488	*481,780*	406,114	122,730	34,030	[redacted]	$63.9
2030	[redacted]	1,730,907	122,730	445,868	[redacted]	4,946,154	*482,260*	408,618	122,730	37,250	[redacted]	$59.8
2031	[redacted]	1,740,837	122,730	451,641	[redacted]	4,955,673	*482,739*	411,089	122,730	40,552	[redacted]	$58.9
2032	[redacted]	1,750,519	96,575	483,616	[redacted]	4,967,715	*483,448*	413,529	96,575	70,087	[redacted]	$56.4
2033	[redacted]	1,759,952	0	586,060	[redacted]	4,977,327	*483,933*	415,939	0	170,120	[redacted]	$50.2
2034	[redacted]	1,769,137	0	591,976	[redacted]	4,993,878	*485,315*	418,330	0	173,646	[redacted]	$47.2
2035	[redacted]	1,778,074	0	597,940	[redacted]	5,005,809	*486,041*	420,650	0	177,290	[redacted]	$46.6
2036	[redacted]	1,786,762	0	603,953	[redacted]	5,019,772	*486,971*	422,918	0	181,035	[redacted]	$46.0
2037	[redacted]	1,795,203	0	610,013	[redacted]	5,032,998	*488,090*	425,147	0	184,865	[redacted]	$45.5
2038	[redacted]	1,803,395	0	616,121	[redacted]	5,041,649	*488,559*	427,337	0	188,783	[redacted]	$44.9
2039	[redacted]	1,811,339	0	622,277	[redacted]	5,050,160	*489,032*	429,515	0	192,761	[redacted]	$44.4
2040	[redacted]	1,819,034	0	628,481	[redacted]	5,058,533	*489,508*	431,657	0	196,823	[redacted]	$37.4
2041	[redacted]	1,826,482	0	634,732	[redacted]	5,067,684	*489,987*	433,749	0	200,983	[redacted]	$26.4
2042	[redacted]	1,833,681	0	641,032	[redacted]	5,078,247	*490,470*	435,814	0	205,218	[redacted]	$26.7
2043	[redacted]	1,840,632	0	647,380	[redacted]	5,092,940	*491,598*	437,861	0	209,519	[redacted]	$29.2
2044	[redacted]	1,847,334	0	653,775	[redacted]	5,103,016	*492,082*	439,890	0	213,885	[redacted]	$31.6
2045	[redacted]	1,853,789	0	660,219	[redacted]	5,112,861	*492,568*	441,916	0	218,303	[redacted]	$34.0
CAGR	[redacted]				[redacted]							
LCOE* (Real 2020$, 2020-2045)					$ [redacted]							$ [redacted]

** Assuming 4% nominal discount rate, 2% infation*

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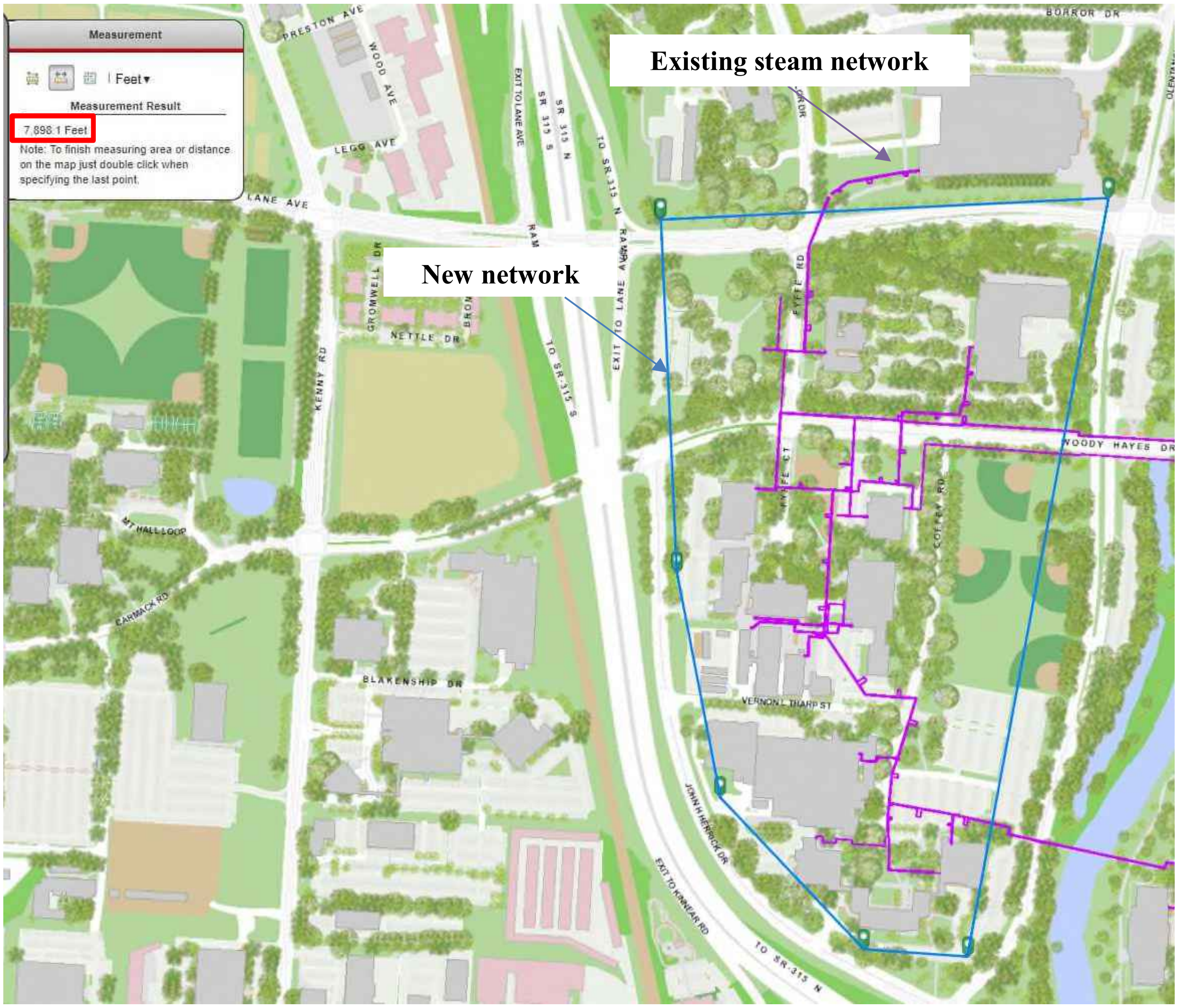
Appendix K – Case 1: Midwest Campus "DHC vs No DHC" calculations

Below is the preliminary layout of the new conceptual chilled water and hot water distribution network. The assumption is to bury all pipes in the same trench.



Length of distribution network for the new loop in MW campus	8,000 ft
Cost for 4 pipes	1,300 $/ft
Distribution network cost	$10,400,000

Below is a list of the existing buildings on Midwest campus connected to the existing steam network.

Existing Buildings on Midwest Campus		Gross Square Footage
Bldg #	**Name**	
3	Agricultural Administration Building	100,228
12	Ornamental Plant Germplasm Center	18,258
64	Parker Food Science and Technology Building	78,214
66	Plumb Hall	45,196
80	Sisson Hall	55,501
81	Schottenstein Center	604,784
136	Veterinary Medicine Academic	113,459
156	Animal Science Building	55,889
180	Goss Laboratory	67,943
282	Galbreath Equine Center	40,822
295	Howlett Hall	62,605
297	Howlett Greenhouses	41,484
298	Agricultural Engineering Building	120,345
299	Veterinary Medical Center	222,496
340	Kottman Hall	167,040
	Total	**1,794,264**

To transition from a steam to a hot water network, we would need to convert the equipment in the existing buildings. We will also need to create lateral piping from the distribution network to provide hot water to these buildings.

Conversion from steam to hot water (existing buildings)	
Hot water lateral piping	2,500 ft
Cost of piping	1,300 $/ft
Building Connections	15 bldg
Cost per building conversion	1,100,000 $/bldg
Total Cost	**$19,750,000**

We determined the average new construction building electrical, heating, and cooling loads using EIA guidelines and verified empirically comparing them to the historical data from representative buildings on campus. Below is the resulting table.

	Electrical	Heating	Cooling
	kwhr/sqft	**kBTU/sqft**	**Tonnes-hrs/sqft**
Research Lab with animals	24.62	204.26	8.04
Dry Lab (engineering)	14.71	122.21	7.20
Wet Lab (chemistry / bio)	28.71	111.42	7.56
Classroom	3.02	7.84	2.03
Residential	4.49	18.12	1.08
Athletics	7.35	29.66	1.77
Inpatient	18.07	51.66	4.44
Outpatient	4.25	17.12	1.02

As a result, the expected loads for the existing and planned buildings on Midwest campus are as followed:

Building	Area (gross square feet)	Avg Electrical Load (kW)	Avg Heating Load (kBTU/h)	Avg Cooling Load (RT)
Interdisciplinary Research Center	350,000	1,147	4,452	302
Midwest Phase I	830,000	1,503	5,650	455
Midwest Phase II	930,000	1,684	6,331	509
Existing buildings	1,794,264	2,694	14,397	849
Total	**3,904,264**	**7,029**	**30,829**	**2,115**

From the information above, the total investment for the DHC network on Midwest campus is:

CAPEX for DHC on Midwest	
Distribution Network for the new loop	$10,400,000
Chilled water plant centralized	$27,689,027
Conversion from steam to hot water (existing buildings)	$19,750,000
Mechanical Room provisions (existing buildings)	$1,055,000
Chiller Plant equipment replacement (Year 20)	$9,691,159
Contingency & Project execution	$11,585,928
DHC Midwest only Total	**$80,171,114**

As a comparison, the total investment for the "In-building" solution[1] for Midwest campus is:

CAPEX for "In Building Solution" on Midwest	
Mechanical Room	2,110,000
Hot water material + labor	2,169,006
Chilled water equipment + labor	22,000,000
Steam Header replacement	$25,000,000
Back up generation	$1,200,000
Existing chiller replacement (Year 8)	$7,700,000
Contingency & Project execution	$9,963,180
In Building Solution Midwest only	**$70,142,186**

[1] In-building cooling and heating equipment was sized for peak load – which was assumed to be twice of "average" heating loads, and three times of average cooling loads based on historic data from campus buildings -and redundancy.

Annual O&M costs build-up for the DHC solution:

DHC (Chilled water and Hot water)	Service contract	Cooling tower, pumps and controls	Chemical treatment	Management	Total
	$110,000	$125,000	$31,496	$156,000	$422,496

Annual O&M costs build-up for the "In-building" solution:

In-building Chilled water	Service contract full	Operation	Cooling tower	Chemical treatment	Pumps, controls, etc.	Management	Life cycle cost[2]	Total
	$198,000	$421,575	$58,500	$105,750	$99,000	$129,854	$560,000	$1,572,679

In-building Hot water	Service contract	Chemical treatment	Pumps, controls, etc.	Life cycle cost[3]	Management	Total
	$27,413	$24,676	$13,707	$111,943	$15,996	$193,735

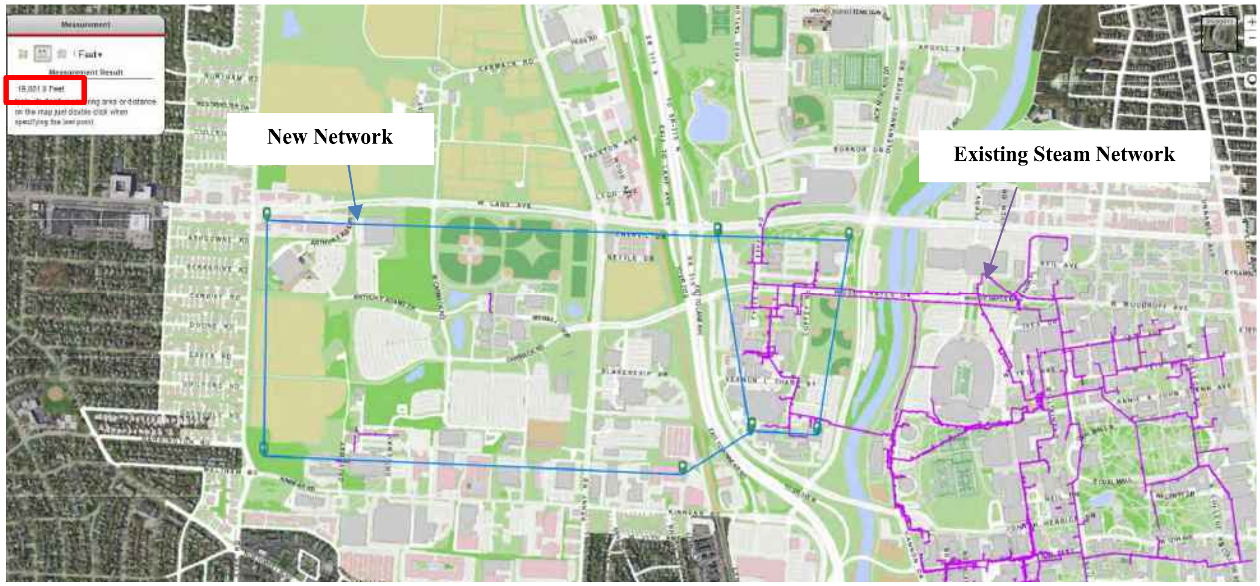
Annual O&M costs comparison:

OPEX for DHC Midwest only	$422,496
OPEX for "In Building Solution" Midwest only	$1,766,414

[2] In-building chiller end of life replacement costs are included in this line.
[3] In-building hot water heater end of life replacement costs are included in this line.

Case 2: Midwest and West Campus "DHC vs No DHC" calculations

Below is the preliminary layout of the new conceptual chilled water and hot water distribution network. The assumption is to bury all pipes in the same trench.



Length of distribution network for the new loop in MW and W campus	20,000 ft
Cost for 4 Pipes	1,300 $/ft
Distribution network cost	$26,000,000
Adder for special crossings (e.g. railroad)	$2,000,000
Total Distribution network	$28,000,000

The same methodology was applied regarding the load calculations.

As a result, the expected loads for the existing and planned buildings on Midwest campus and planned buildings on West campus are as followed:

Building	Area (gross square feet)	Avg Electrical Load (kW)	Avg Heating Load (kBTU/h)	Avg Cooling Load (RT)
Interdisciplinary Research Center	350,000	1,147	4,452	302
Midwest Phase I	830,000	1,503	5,650	455
Midwest Phase II	930,000	1,684	6,331	509
Ambulatory I	585,000	1,207	3,450	297
Ambulatory II	412,000	850	2,430	209
Innovation Expansion I	550,000	1,802	6,995	475

Innovation Expansion II	700,000	2,294	8,903	604
West Campus Research Village	500,000	1,639	6,359	432
West Campus Town Center - Residential	100,000	51	207	12
West Campus Town Center - Retail	50,000	17	45	12
West Campus Industry Partnership	300,000	983	3,816	259
West Campus New Center & Gateway	500,000	1,639	6,359	432
Existing buildings	1,794,264	2,694	14,397	849
Total	**7,601,264**	**17,510**	**69,393**	**4,847**

From the information above, the total investment for the DHC network on Midwest and West campus is:

CAPEX for DHC on Midwest and West campus	
Distribution Network for the new loop	$28,000,000
Chilled water plant centralized	$63,448,211
Conversion from steam to hot water (existing buildings)	$19,750,000
Mechanical Room provisions	$2,903,500
Chiller Plant equipment replacement (Year 20)	$22,206,874
Contingency & Project execution	$23,026,277
DHC Midwest and West	**$159,334,863**

As a comparison, the total investment for the "In-building" solution for on Midwest and West campus is:

CAPEX for "In Building Solution" Midwest and West campus	
Mechanical Room provisions (existing buildings)	5,807,000
Hot water equipment	7,259,514
Chilled water equipment	69,300,000
Steam Header replacement	$25,000,000
Existing chiller equipment replacement (Year 8)	$7,700,000
Back up generators	4,400,000
Contingency & Project execution	$19,437,906
In Building Solution Midwest and West campus	**$138,904,420**

Annual O&M costs build-up for the DHC solution:

DHC (Chilled water and Hot water)	Service contract	Cooling tower, pumps and controls	Chemical treatment	Management	Total
	$205,000	$231,250	$59,538	$156,000	$651,788

Annual O&M costs build-up for the "In-building" solution:

In-building Chilled water	Service contract	Operation	Cooling tower	Chemical treatment	Pumps, controls, etc.	Management	Life cycle cost	Total
	$391,500	$833,569	$132,167	$241,150	$195,750	$320,232	$1,764,000	$3,878,367

In-building Hot water	Service contract	Chemical treatment	Pumps, controls, etc.	Life cycle cost	Management	Total
	$120,080	$68,685	$60,040	$278,440	$47,452	$574,698

Annual O&M costs comparison:

OPEX for DHC Midwest and West campus	$651,788
OPEX for "In Building Solution" Midwest and West campus	$4,453,065

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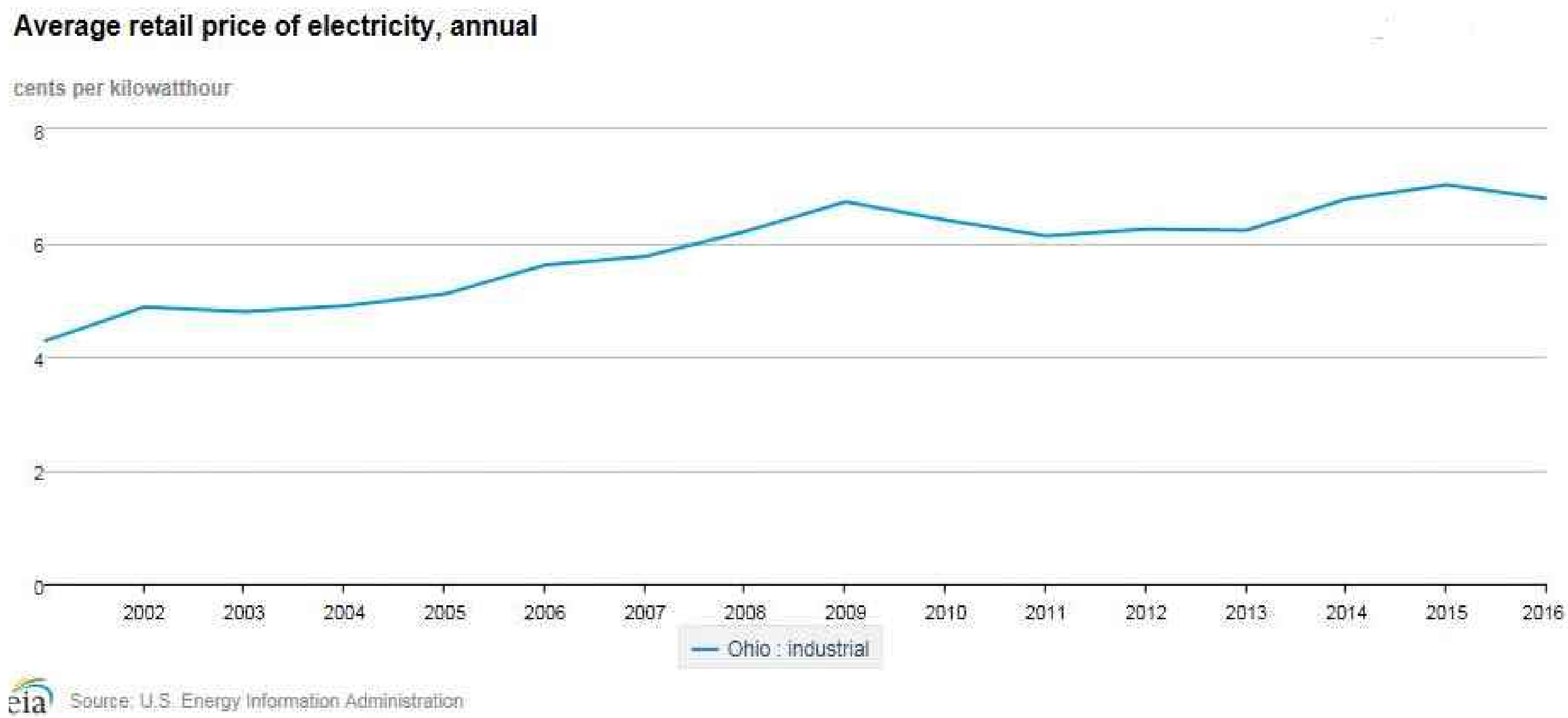
Appendix L - Historical Grid Price Chart



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Appendix M – CHP Facilities on Major College Campuses within the U.S.

Univeristy	Technology	Fuel Type	Capacity (kW)
Arizona State University	Boiler/Steam Turbine	NG - NG	9,000
Clemson University	Combustion Turbine	NG - NG	9,430
Harvard University	Boiler/Steam Turbine	NG - NG	13,053
	Reciprocating Engine	NG - NG	75
Iowa State University	Boiler/Steam Turbine	COAL - Coal	46,000
Kansas State University	Boiler/Steam Turbine	NG - NG	4,000
Louisiana State University	Combustion Turbine	NG - NG	23,700
Michigan State University	Boiler/Steam Turbine	COAL - Coal	71,450
Mississippi State University	Combustion Turbine	NG - NG	28,500
North Carolina State University	Reciprocating Engine	NG - Propane	5
Notre Dame	Microturbine	NG - NG	30
Oregon State University	Combustion Turbine	NG - NG	9,000
Pennsylvania State University	Boiler/Steam Turbine	COAL - Coal	8,000
		NG - NG	5,100
Purdue University	Boiler/Steam Turbine	COAL - Coal	43,200
Rutgers University	Combustion Turbine	NG - NG	1,210
Syracuse University	Combustion Turbine	NG - NG	96,000
Texas A&M University	Combustion Turbine	NG - NG	50,000
Texas Tech University	Boiler/Steam Turbine	NG - NG	935

Univeristy	Technology	Fuel Type	Capacity (kW)
University of Arizona	Combustion Turbine	NG - NG	12,000
University of Arkansas	Combustion Turbine	NG - NG	5,200
University of Illinois	Combustion Turbine	NG - NG	21,000
University Of Iowa	Boiler/Steam Turbine	COAL - Coal	24,900
	Reciprocating Engine	NG - NG	2,800
University of Maryland	Combustion Turbine	NG - NG	27,300
University Of Michigan	Combined Cycle	NG - NG	45,200
University of Minnesota	Boiler/Steam Turbine	NG - NG	16,200
University Of Missouri	Boiler/Steam Turbine	COAL - Coal	99,500
University Of Oklahoma	Boiler/Steam Turbine	NG - NG	31,800
University Of Oregon	Boiler/Steam Turbine	NG - NG	15,000
University of South Carolina	Backpressure Steam Turbine	WAST - Steam	1,354
University of Tennessee	Combustion Turbine	NG - NG	5,000
University Of Texas At Austin	Cackpressure NG Turbine	NG - NG	148,200
University of Utah	Combustion Turbine	NG - NG	6,500
University of Wisconsin	Boiler/Steam Turbine	BIOMASS - Biomass	370
Yale University	Combustion Turbine	NG - NG	53,300

https://doe.icfwebservices.com/chpdb/search/index

Appendix N – Hot Water vs Steam for Heating

Heating Hot Water vs Steam

The state of the market for district heating technologies has evolved over time, as displayed in Table 1. Early in the 20th century, district heating exclusively used steam. Multiple generations of district heating systems followed, all using heating hot water (HHW). A fifth generation serves to integrate both heating and cooling in a single water-based district system.

Table 1: Generations of District Heating

Year	Generation	Energy Carrier
1900	1st	Steam
1930	2nd	High Temperature Hot Water (> 212 °F)
1980	3rd	Medium Temperature Hot Water (<212 °F)
2020	4th	Low Temperature Hot Water 120 - 140 °F

Today, most first-generation systems outside the United States have been converted to hot water systems or have been closed, since steam is now considered an inefficient heat carrier due to heat losses and O&M costs. In the US, HHW is not the most common application (many first-generation systems remain in operation), but the clear majority of new district heating systems are HHW. Furthermore, an ever-increasing number of facilities have committed to investing in the conversion of steam to HHW.

Conversion from steam to hot water, once seemingly inconceivable among higher-education facilities in North America, is being recognized as an attainable and implementable solution based on the success of high-profile pioneers. Table 2 details some of the institutions that have decided to move away from first-generation steam district heating.

Table 2: Recent Conversions to HHW District Heating

Stanford University In 2015, Stanford University (15M sq ft) completed a conversion of its first-generation steam system to a third-generation hot water system, resulting in overall cost savings (20%), water savings (18%), and GHG reductions (50%).	**University of British Columbia** In 2015, UBC (15M sq ft) completed a conversion of its first-generation steam system to a third-generation hot water system, resulting in operational and energy cost savings ($5M/yr), thermal efficiency improvement (24%) and GHG reductions (22%).
University of California, Davis In 2017, UC Davis (11M sq ft) initiated a process to convert its first-generation steam system to a third-generation hot water system, hoping to save an	**Brown University** In 2017, Brown University (6M sq ft) initiated a project to convert its first and second-generation steam/high temperature water system into a

estimated 30%-50% in distribution losses, avoid spending $98M of planned maintenance costs on the aging steam system, reduce O&M costs by 42%, while cutting GHG emissions by 30% and getting closer to its 2025 net-zero commitment.	third-generation low temperature system, resulting in energy savings ($1M/yr or 11%), and contributing to its overall goal of reducing GHG emissions by 42%.

University of Rochester

In 2004, University of Rochester (14M sq ft) initiated a process to convert its first-generation steam system to a third-generation hot water system (70% completed as of today), resulting in thermal losses savings (24%).

Generally, the only disadvantage of a HHW system is the inability to perform sterilization or any other processes that directly require the use of steam. Otherwise, for new systems HHW is the clear choice, as shown in Table 3.

Table 3: Comparison of Steam and HHW

Pros and Cons	Steam	Hot Water
Usage		
Air and space heating	Yes	Yes
Low temperature process loads (domestic hot water, humidification)	Yes	Yes
High temperature process loads (sterilization)	Yes	No (needs stand-alone system)
Energy		
Generation efficiency (HHW: boilers and heat pumps, steam: boilers only)	Poor to Average (70-80%)	Good (85%) to Excellent (400%)
Distribution heat losses	High (30%-50% for old systems)	Low (5-10%)
Combined heat and power potential	Yes	Yes
Heat recovery potential	No	Yes
Energy storage potential (thermal, electric)	No	Yes
Operation & Maintenance		
Operation & maintenance cost	High (up to $12/ft for old systems)	Low (as low as $1/ft)
Hazard potential (due to high temperatures and pressures)	High	Low
Difficulty of hiring qualified personnel	High	Low
Sustainability		
Water usage	High	Low
Deep decarbonization potential	Unlikely	Favorable

Renewable energy potential (solar, wind, geo-exchange, air source, hydro)	No	Yes
Renewable energy potential (biomass, biofuels)	Yes	Yes

While hot water has many advantages over steam, its biggest weakness for implementation at Ohio State is evident: a steam system is currently utilized in the campus network hot water has very limited, localized applications. The coordination and planning of conversion to minimize the disruption to the campus itself as well as building heating services would be critical to the system's implementation.

The first step is the identification and prioritization of goals with respect to district energy: efficiency, sustainability, total cost of ownership, reliability, resiliency, ease of O&M, asset renewal needs, impact on occupants, and financial criteria.

The establishment of the University's goals can then be coupled with OSEP's knowledge of the existing Utility System infrastructure and current and projected energy profiles to identify and evaluate different district energy strategies (high vs low temperature, centralized vs distributed, timing with end-of-life of existing assets) and energy source/technology combinations (heat recovery with heat pump technology, renewables, energy storage, CHP, etc.).

Once the size and the location of the CHP is determined, or in combination with the determination of size and location of the CHP should the University directs OSEP to do so, the various steam to heating hot water conversion strategies can be evaluated and an optimum solution(s) can be provided to Ohio State.