**OHIO POWER SITING BOARD**

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| **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 MAJOR UNIT FACILITY IN FRANKLIN COUNTY, OHIO ON THE CAMPUS OF THE OHIO STATE UNIVERSITY** | ) ) ) ) ) ) ) ) | **CASE NO. 19-1641-EL-BGN** |

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# Direct Testimony of Ranajit (Ron) Sahu
# On Behalf of Sierra Club

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**July 9, 2020**

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## I. INTRODUCTION AND PURPOSE OF TESTIMONY

**Q. Please state your name and occupation.**

**A.** My name is Ranajit (Ron) Sahu. I am an engineering, environmental, and energy consultant.

**Q. Please summarize your work experience and educational background.**

**A.** I have Bachelor's degree in Mechanical Engineering from the Indian Institute of Technology (B.Tech), and Master's and Doctorate degrees from the California Institute of Technology.

I have thirty years of engineering and consulting experience working on environmental, engineering, and energy matters for a range of clients including federal agencies (the United States Environmental Protection Agency and the Department of Justice), various states and local agencies and municipalities, and industrial and non-profit clients. My resume is attached as Exhibit RS-A.

**Q. On whose behalf are you testifying in this case?**

**A.** Intervenor Sierra Club.

**Q. Have you previously testified before the Ohio Power Siting Board?**

**A.** No.

**Q. Please identify and briefly describe any other proceedings before state utility regulatory bodies in which you have provided testimony.**

**A.** I am currently working on a matter before the Oregon Public Utility Commission and expect to testify on that matter in the next few months. I have testified in a power plant siting matter before the Florida Department of Environmental Protection, Division of Administrative Hearings.

**Q. What is the purpose of your testimony in this proceeding?**

**A.** I reviewed and evaluated Ohio State University's ("OSU's") proposal for a combined heat and power plant on its Columbus, Ohio campus. I assessed the fundamental design of OSU's proposal and contrasted it with alternative and better approaches being taken by other institutions to meet their energy needs. Based on my review, I have concluded that the OSU proposal contains numerous deficiencies and lacks support for many of its assumptions. I have also assessed and comment on the environmental impact of this proposal, if it were built.

**Q. What documents do you rely on for your analysis, findings, and observations?**

**A.** I base my understanding of the proposed Combined Heat and Power ("CHP") facility at OSU's Columbus, Ohio campus on my review of the record in this proceeding, including the Application to the Ohio Power Siting Board for a Certificate of Environmental Compatibility and Public Need, The Ohio State University Combined Heat and Power Facility, submitted by the Ohio State University, November 4, 2019 (hereafter "Application"), the CHP Feasibility Study prepared by Ohio State Energy Partners (Public Version) February 20, 2018 (attached as Exhibit RS-B) and other documents produced in response to discovery requests by Intervenor Sierra Club. I rely to a limited extent on publicly available information. I provide citations to all documents that I have relied upon and documents not readily publicly available are attached as Exhibits RS-B through RS-P to this testimony.

## II. FINDINGS AND RECOMMENDATIONS

**Q. Please summarize your findings.**

**A.** I offer these findings for the Siting Board's consideration:

1. The proposed CHP facility is an inappropriate "solution" to OSU's current and future needs. As the most basic level, the design of the proposed system is flawed and did not consider alternatives that other institutions are using when faced with meeting their energy needs. I reach this overall conclusion based on several discrete findings.

2. The CHP design is based on work initiated in 2014 by Burns and McDonnell and the design incorporated into the Application has only minor differences from what was proposed in 2014. Many of the assumptions are therefore stale, especially given the rapid reductions in costs of renewable energy as well as thermal and electrical energy storage options available to OSU.[1]

3. The proposed CHP facility represents an older technology that has been rejected by other educational institutions. OSU's own CHP Feasibility Study (hereafter "Study") recognizes that hot water "is the clear choice" as compared to steam heat—as heated hot water provides greater generation efficiency, lower distribution heat losses, can incorporate energy storage potential, and can be powered by a wider variety of renewable

[1] Ohio State Energy Partners, CHP Feasibility Study, February 20, 2018 ("Study"), attached as Exhibit RS-B, at 2-17.

energy sources—yet inexplicably, rejects the possibility of conversion to hot water heating out of hand.[2]

4. OSU did not consider either geothermal or heat exchange technologies as a means of providing its heating needs which, in conjunction with off-site renewable electricity generation, could have replaced the proposed CHP facility with none of the emissions and associated adverse environmental effects of a gas-fired facility. OSU's analysis of even the few alternatives (such as off-site solar for electricity generation) it did purport to "consider" are not supported by data and therefore were inappropriately rejected.

5. OSU has not conducted an hourly-level data analysis of its thermal energy needs or loads. As other universities have demonstrated, analysis at this level of granularity generally supports the use of heating and cooling systems that do not rely on gas-fired generation and its environmental impacts. A proper data analysis would lead to the rejection of CHP in favor of these alternate solutions with smaller environmental impact.

6. OSU can and should make use of a superior alternate system to meet its stated electrical energy and heating needs. Such alternative systems include: (i) low-exergy[3] and more efficient district heating provided by heated water (hot water) only rather than steam for all of OSU's heating needs; (ii) maximizing hot water generation by first using reject heat from the cooling system (i.e., chillers); (iii) using ground-based resources (i.e., geothermal and heat pumps, etc.) for the rest of its heating needs; (iv) using renewable resources for off-site electricity generation (i.e., solar or additional wind); and (v) incorporation of battery energy storage systems. None of these are new options. In fact other universities in the United States located in similar or more extreme climates have implemented or are in the process of implementing many of these options.

7. Construction of the CHP will have avoidable adverse impacts on the immediate, regional, and broader environment.

8. OSU's analysis of the carbon emissions did not consider or include any of the life-cycle impacts of producing and delivering natural gas. OSU's proposed supplier, Columbia Gas of Ohio (a subsidiary of NiSource[4]), like most gas utilities in the Midwest,

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[2] Ohio State Energy Partners, CHP Feasibility Study, February 20, 2018, Appendix N.

[3] Exergy is a term in thermodynamics and, in simple terms, represents the available energy capable of doing work (and being degraded in the process).

[4] *See* https://investors.nisource.com/company-information/default.aspx

obtains some of its gas from shale deposits through fracking.[5] While any extraction process of natural gas causes environmental impacts, fracking of shale deposits causes severe environmental impacts associated with: (i) methane (a potent greenhouse gas) leakage during production and transmission; (ii) depletion of scare groundwater resources; and (iii) impacts due to mining for fracking sand; and many others. These impacts were not included in OSU's analysis and were not accounted for in OSU's claims regarding the relative carbon emission reductions attributable to construction of the proposed plant. OSU's environmental impact analysis, based solely on purported combustion-related "benefits" relative to the emissions associated with generation on the PJM grid is therefore incorrect and distorting. The analysis is even more misleading because OSU has not compared the purported combustion benefits of the proposed natural gas based electrical power generation with renewable alternatives for electrical power generation.

9. The proposed facility will have significant and detrimental effects on ambient air quality for the surrounding area which are not adequately accounted for in OSU's proposal. These effects are inadequately addressed in OSU's Application and supporting documents. Significant $PM_{2.5}$ emissions will be emitted (almost 40 tons per year, per OSU itself), affecting everyone at OSU and in particular patients at the many OSU medical facilities. $PM_{2.5}$ is a dangerous pollutant, for both respiratory and cardiac systems at any level of incremental exposure. Although OSU provides some analysis of the effects of these emissions on ambient air quality around the proposed facility, this analysis cannot be relied upon because it relies on unsupported meteorological assumptions and failed to consider the effects on ambient air quality at times when emissions are likely to be greatest.

10. OSU's "analysis" of critical future costs, such as the price of natural gas[6] are not realistic and not supportable given recent developments.

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[5] *See also* Study at 1-7 ("At the national level, the seven major shale plays have and will continue to account for nearly all the incremental U.S. production [of natural gas] over the long-term.")

[6] Study, Figure 1-5 (prices of natural gas at the Henry Hub are anticipated to remain roughly between $2.5 and $2.9 through 2047). Also, as stated in Study at 1-7, OSU's analysis assumes that US shale will continue to dominate natural gas production into the future. The Study states "…the seven major shale plays have and will continue to account for nearly all the incremental US production over the long term." Developments since the summer of 2019 and more recently show the error of such assumptions. Shale (or "tight" formation gas) development requires enormous quantities of capital and is accompanied by significant resources such as scarce water and sand, among others. That capital is simply unlikely to be deployed by investors anymore given its lack of returns since the beginning of shale "plays" in the US.

11. In sum, OSU failed to consider reasonable alternatives to meeting its energy needs with lower environmental impacts.

**Q. Please summarize your recommendations.**

**A.** I offer these recommendations for the Siting Board's consideration:

1. I recommend that the Siting Board reject OSU's request for a certificate for construction of the proposed facility.

2. All of the goals of the CHP facility, including affordability, reliability/resiliency, sustainability, and predictability can be met by alternate means, at lower environmental impact. Therefore, the Siting Board should not issue a certificate for construction of the proposed facility because it does not represent "minimum adverse environmental impact, considering the state of available technology and the nature of economics of the various alternatives[.]"

3. This proposed project should not be approved at this time. At a minimum, OSU should properly analyze alternative electrical generation resources along with a conversion from steam to hot water to meet heating needs.

## III. <u>THE ANALYSIS PROVIDED BY OSU DOES NOT SUPPORT THE NEED FOR THE PROPOSED CHP SYSTEM</u>

**Q. Please describe the proposed Combined Heat and Power system.**

**A.** The Ohio State University is proposing to install a Combined Heat and Power major utility facility on the Ohio State campus in Columbus, Ohio. Pursuant to the terms of an existing concession agreement between Ohio State and Ohio State Energy Partners ("OSEP"), the CHP real estate and the CHP facility will be leased to OSEP. The purpose of the CHP is to be the primary source of electricity and heating for the Columbus campus. If approved, heating will be provided in the form of steam, either through integration with the existing steam network for buildings east of the river or for heating hot water for newer buildings west of the Olentangy River.

In addition the Application states that "[T]he CHP facility will produce thermal energy powered by natural gas while introducing electricity generation on campus and will serve as a primary source of heating and electricity to the Columbus campus... The heating capacity of the CHP facility will be 285 klbs/hour of superheated steam. The CHP facility will have a nameplate maximum output capacity of 105.5 MW and will include the installation of two natural gas combustion turbine generators and one steam turbine generator….Using the exhaust energy of the combustion turbines, high pressure superheated steam will be generated in the heat recovery steam generators (HRSGs), which then will be used to:

i. Produce power in the steam turbine, or,
ii. Supplement the main campus steam network, or,
iii. Produce HHW through a heat exchanger and feed a new district heating and cooling (DHC) network to be built west of the Olentangy River, or
iv. Achieve any combination of the above."[7]

**Q. What has OSU identified as the reason(s) for constructing the system?**

**A.** OSU does not identify a specific insufficiency or gap in current utility services the proposed CHP facility will address. However, the Application does identify reliability and resiliency of electrical power to "critical buildings on campus, including the University's Wexner Medical Center," as contrasted with reliance on the grid, as a primary reason for the CHP's proposed construction.[8] OSU also claims the proposed facility will reduce its "Levelized Cost of Energy (LCOE) 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."[9] As I discuss later, the Application's reference to the Medical Center is misleading, as the CHP system cannot provide the reliability required by state regulations and the medical center will be required to continue to maintain diesel-powered generators as backup. I address OSU's claims about the environmental and cost benefits of the proposed CHP facility, particularly in relation to off-site renewable alternatives, in greater detail below.

**Q. In your view, is OSU's analysis of its load, reliability, and resiliency adequate?**

**A.** No.

**Q. Why is OSU's load analysis inadequate?**

**A.** OSU's analysis of its utility system is discussed in the Study (Exhibit RS-B) at Figures 2-1 through 2-3. Electrical and thermal loads are shown on a monthly basis. Thermal loads are not divided into separate heating and cooling loads. And, importantly, the analysis is not conducted on an hourly basis. I provide more discussion on this later in connection with how others (specifically Stanford University and Ball State University) have

[7] Application, p. 2.

[8] Application, p. 1-2.

[9] Study at i.

conducted required granular analysis. Essentially, OSU's load analysis was too simplistic to support the construction of such a large project because OSU failed to appropriately describe in detail, with temporal granularity, its actual heating and cooling energy needs and loads. By failing to conduct this analysis, OSU missed the possibility of taking advantage of obtaining a significant portion of its heating needs from the waste heat of its cooling system and then supplementing the rest of its heating needs via other sources such as geothermal or ground-based sources.

**Q. Why is important to analyze both heating and cooling loads?**

**A.** The OSU campus has both types of loads, at all times in the year, with variability. It is important to track both of these types of loads because much of the campus's heating loads can likely be met by using the reject heat from its cooling system. As discussed below, other similar institutions have concluded, after conducting an analysis that parses out heating and cooling as separate loads, that a significant portion of their heating needs can be met in this way. And, that means any additional heating loads that need to be met can be satisfied by a smaller and low-exergy (i.e., hot water, not steam) system, with significant environmental advantages as compared to a steam system. Therefore, options for a proper design of the overall system cannot be analyzed without conducting a detailed, granular, analysis of both loads.

Simply put, careful analysis of heating and cooling loads is necessary because the lowest cost, least-environmental impact option for meeting both of those loads might not be, and in fact likely will not be, the traditional CHP design as has been assumed by OSU.

**Q. Why is important to conduct load analysis on an hourly basis?**

**A.** The ability to determine the overlap between the rejected heat from the cooling system and the heating loads (and their temperatures) requires that the analysis be conducted on an hourly or even more granular basis.

**Q. Does OSU accurately support its characterization of the proposed CHP's contribution to overall resiliency on its campus?**

**A.** The Study simply assumes, without any support or data, that generating its own power using the CHP system will make OSU's electrical energy supply more resilient.[10] OSU does not discuss why its CHP system will be more reliable for electricity generation

[10] Study, Section 3.2, beginning at 3-7.

compared to electrical power obtained from the PJM grid, which includes significant generation diversity and extensive spatial redundancies among its generating resources.[11]

OSU admits that its CHP system cannot provide all of the campus's emergency needs.[12] A significant portion of medical and non-medical emergency needs would continue to need diesel backup as shown in Table 1 of the Study. In addition, the Study admits that since the CHP is "unable to meet the NFPA 110 level 1 requirements" all future medical facilities will need their own diesel emergency backup equipment. OSU does not adequately explain what advantages on-campus large-scale electrical generation will offer over the PJM grid in ensuring uninterrupted electricity on campus given that OSU will continue to rely both on the grid for a significant portion of its energy needs *and* less efficient diesel emergency backup equipment to ensure electrical supply to critical infrastructure is not disrupted.

In connection with its resiliency discussion, the Study pays lip-service to vague future incorporation of alternative technologies such as renewables and storage.[13] And it asserts that alternative technologies to meet the University's energy needs are not available, an assertion that (as I show below) is not true.[14] It does not discuss why these alternative technologies cannot be incorporated into the system design now or why these technologies should be "alternatives" and not the primary focus of the design.

[11] Reliability and resiliency are improved with increased diversity of resources. Thus, OSU's claim that relying on a single fuel, as the CHP would, would provide more reliability and resiliency for power generation, is simply not true. I note that PJM conducts extensive reliability and resiliency studies to ensure that its overall system remains reliable considering a wide-range of potential stressors. See, for example, "PJM's Evolving Resource Mix and System Reliability, March 30, 2017, *available at* https://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx.

[12] Study, Table 1.

[13] Study at 3-13. "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…Any future on site renewable generation, or smart demand response load reduction scheme can be added into the framework of this microgrid."

[14] Study at 3-19. "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." Other universities have implemented storage solutions and utility scale energy storage systems (i.e., battery) are now available.

## IV. THE PROPOSED CHP FACILITY WILL HAVE SIGNIFICANT ADVERSE ENVIRONMENTAL EFFECTS, BOTH LOCALLY AND AT FUEL EXTRACTION SITES

**Q. What adverse environmental effects of the operation of the proposed facility has OSU identified?**

**A.** OSU has identified emissions of various air pollutants as well as noise impacts.

In the Application, it states that "[T]he type and quantities of air pollutant emissions associated with the proposed CHP facility during operations are summarized in Table 4, Table 5, and Table 6."[15] Table 4 states that $PM_{2.5}$ emissions will be 40.32 tons/year from the "steady state" operations of the two CHP units. Startup and shutdown will add another 0.45 tons/year (Table 5) and the cooling towers will add a further 1.02 tons/year (Table 6). Even considering the removal of a boiler at the McCracken plant, net emissions for $PM_{2.5}$ will increase by close to 39 tons/year.

Tables 4 and 5 in the Application also show significant emissions of $NO_x$, another criteria pollutant under the Clean Air Act, which is not only a pollutant in its own right but is also a precursor for other pollutants such as ozone and additional fine particulate matter, $PM_{2.5}$. Table 4 shows $NO_x$ emissions at 39 tons/year for steady state operations and Table 5 shows an additional 3.89 tons/year of $NO_x$ from startup and shutdown.

**Q. Based on the location of the proposed facility, do you have any concerns about the effects of these air pollutant emissions on vulnerable populations?**

**A.** Yes. First, I note that the proposed CHP system will emit additional pollutants. These pollutants include $PM_{2.5}$ and $NO_x$, both criteria pollutants, will be produced along with additional criteria pollutants such as carbon monoxide, sulfur dioxide, also with adverse health impacts. I also note that the proposed CHP facility will be located in a central campus area and in close proximity to numerous medical facilities, where patients, health-care workers, and the campus community at large will experience incremental increases in concentrations of pollutants.

Second, there is no safe threshold for $PM_{2.5}$ and that any increase in exposure to fine particles increases the adverse health risk.[16] $PM_{2.5}$ emissions have been regulated by the

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[15] Application, p. 11.

[16] *See*, e.g., the California Air Resources Board's summary of $PM_{2.5}$ health impacts, *available at* https://ww2.arb.ca.gov/resources/inhalable-particulate-matter-and-health#:~:text=For%20PM2.,symptoms%2C%20and%20restricted%20activity%20days.

EPA for more than two decades. More recent research has established that even so-called "safe" levels such as the National Ambient Air Quality Standards (NAAQS) may still be harmful.[17]

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> "For $PM_{2.5}$, short-term exposures (up to 24-hours duration) have been associated with premature mortality, increased hospital admissions for heart or lung causes, acute and chronic bronchitis, asthma attacks, emergency room visits, respiratory symptoms, and restricted activity days. These adverse health effects have been reported primarily in infants, children, and older adults with preexisting heart or lung diseases. In addition, of all of the common air pollutants, $PM_{2.5}$ is associated with the greatest proportion of adverse health effects related to air pollution, both in the United States and world-wide.…Long-term (months to years) exposure to $PM_{2.5}$ has been linked to premature death, particularly in people who have chronic heart or lung diseases, and reduced lung function growth in children."

For a general discussion on the harmful effects of PM (including smaller sizes such as $PM_{2.5}$) see the U.S. EPA fact sheet, "Health and Environmental Effects of Particulate Matter (PM), at https://www.epa.gov/pm-pollution/health-and-environmental-effects-particulate-matter-pm

The nexus between COVID-19 and $PM_{2.5}$ is also coming into focus. *See*, e.g., Wu et al., "Exposure to air pollution and COVID-19 mortality in the United States: a nationwide cross-sectional study," *available at* https://projects.iq.harvard.edu/covid-pm/home. Harvard researchers found that

> "…an increase of only 1 $\mu g/m^3$ in $PM_{2.5}$ is associated with an 8% increase in the COVID-19 death rate (95% confidence interval [CI]).…[T]he results were statistically significant and robust to secondary and sensitivity analyses."

[17] *See*, e.g., 70 Fed. Reg. 65,983, 65,988 (Nov. 1, 2005) ("emissions reductions resulting in reduced concentrations below the level of the standards may continue to provide additional health benefits to the local population."); 71 Fed. Reg. 2620, 2635 (Jan. 17, 2006) (U.S. EPA unable to find evidence supporting the selection of a threshold level of $PM_{2.5}$ under which the death and disease associated with $PM_{2.5}$ would not occur at the population level); Letter from Gina McCarthy, EPA, to Hon. Fred Upton, U.S. House of Representatives (Feb. 3, 2012), *available at* https://www.nrdc.org/sites/default/files/epa-letter-upton-pm-benefits-20120203.pdf ("Studies demonstrate an association between premature mortality and fine particle pollution at the lowest levels measured in the relevant studies, levels that are significantly below the NAAQS for fine particles. These studies have not observed a level at which premature mortality effects do not occur. The best scientific evidence, confirmed by independent, Congressionally-mandated expert panels, is that there is no threshold level of fine particle pollution below which health risk reductions are not achieved by reduced exposure. Thus, based on specific advice from scientific peer-review, we project benefits from reducing fine particle pollution below the level of the NAAQS and below the lowest levels measured in the studies.").

Significantly, studies have found that attaining the air quality standards does not necessarily mean that health-protectiveness is assured. Even at the lowest observed concentrations, $PM_{2.5}$ is

Third, other pollutants that will be emitted by the CHP facility, such as oxides of nitrogen ($NO_x$), also have direct adverse health impacts.[18] $NO_x$ is also a precursor pollutant for other pollutants such as ozone and $PM_{2.5}$ in the atmosphere, which are also harmful.

**Q. Has OSU adequately and accurately accounted for the air pollution effects of the proposed facility?**

**A.** No. At the time it filed its Application, OSU had not conducted a Prevention of Significant Deterioration ("PSD") analysis as would otherwise be required as part of its Permit-to-Install based on the quantity of anticipated emissions for some of the pollutants that will be emitted, instead relying on an exemption under state law for non-profit educational institutions. In part to address this deficiency, OSU has recently submitted an updated modeling analysis[19] focusing on impacts of $PM_{2.5}$, $NO_x$, and ozone (which is created in the atmosphere in part by $NO_x$), which included an assessment of impacts at nearby medical facilities and other sensitive receptors. For the reasons discussed below, both OSU's initial analysis and its updated modeling are premised on unsupported and faulty assumptions about the meteorological data and background concentrations used in the modeling and therefore the results presented are not reliable.

**Q. What is a PSD analysis and why is it important?**

**A.** PSD permitting is required for major (or higher emitting) sources under the Clean Air Act and its implementing regulations located in areas that currently meet NAAQS. It is

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responsible for increased number of deaths or lowered life expectancy. *See generally* Bennett et al., Particulate Matter Air Pollution and National and County Life Expectancy Loss in the USA: A Spatiotemporal Analysis (2019), *available at* https://doi.org/10.1371/journal.pmed.1002856.

[18] As the U.S. EPA has stated:

> "Breathing air with a high concentration of $NO_2$ can irritate airways in the human respiratory system. Such exposures over short periods can aggravate respiratory diseases, particularly asthma, leading to respiratory symptoms (such as coughing, wheezing or difficulty breathing), hospital admissions and visits to emergency rooms. Longer exposures to elevated concentrations of $NO_2$ may contribute to the development of asthma and potentially increase susceptibility to respiratory infections. People with asthma, as well as children and the elderly are generally at greater risk for the health effects of $NO_2$.
>
> $NO_2$ along with other nitrogen oxides ($NO_x$) reacts with other chemicals in the air to form both particulate matter and ozone. Both of these are also harmful when inhaled due to effects on the respiratory system."

[19] July 6 Model, attached as Exhibit RS-D.

perhaps the most important permitting program, along with its counterpart Non-Attainment New Source Review for sources located in areas that do not meet NAAQS. The goal of the PSD program is to ensure that areas that meet NAAQS continue to do so without degrading the ambient air. PSD permitting achieves this by requiring: characterization of the existing or baseline air quality before construction; the application of Best Available Control Technology (BACT) for emissions sources thereby minimizing emissions to the maximum extent possible; detailed air dispersion modeling for all PSD pollutants to demonstrate that the NAAQS and other applicable regulatory thresholds such as increments will not be violated; analysis of impacts from the PSD source on nearby pristine areas (including Federal Class I areas such as National Parks and Wilderness Areas), including on visibility, acid deposition, and other impacts.

**Q. Did OSU conduct a PSD analysis?**

**A.** Relying on an exemption in the Ohio EPA regulations, OSU avoided conducting a proper Prevention of Significant deterioration (PSD) analysis for the project. As the Application confirms:

> "The project was exempt from review under PSD, including the requirement to complete a comprehensive air quality impact analysis pursuant to OAC rule 3745-31-16. Area-wide figures showing isopleths for impact concentrations above pollutant-specific NAAQS are not applicable and were not prepared."[20]

While I cannot comment on the legality of not doing this analysis, I note that, as a result, none of the air quality impacts of the project such as those noted in the previous response, except for PM modeling, have been analyzed or quantified. Thus, the impacts are simply not flagged at all. It is therefore premature to assume that there will be no adverse impacts.

**Q. Did OSU model the effects of $PM_{2.5}$ emissions from the proposed facility on surrounding areas?**

It did. It first did so in its Application and more recently as a separate modeling analysis.

In both instances it used EPA's AERMOD dispersion modeling program to conduct its analysis.

Table 18 in the Application (shown below) provides the results of the first or initial modeling for $PM_{10}$ and $PM_{2.5}$. Two sets of results are shown in the table – for 24-hour average and annual average impacts. As the results show, the acceptable value of $PM_{2.5}$ 24-hour average is shows as less than 4.5 micrograms per cubic meter. While this

[20] Application, p. 61.

acceptable value is itself questionable given the kinds of exposures that might occur in the vicinity of the proposed CHP plant (e.g., medical facilities, with sick patients, etc.), even so, the results show that modeled impacts are not significantly below the 4.5 micrograms per cubic meter level; for example the results show concentrations of 3.9 micrograms per cubic meter based on 2014 meteorological and background data using 75% load and 3.5 micrograms per cubic meter at 100% load. As the Table confirms, predicted impacts are higher as the load factor decreases, likely as a result of less flow velocity out of the stack and resulting poor dispersion. The modeling did not attempt to understand the effects of increased emissions on ambient concentrations if and when the load at the proposed facility is lower than 75% and whether that would exceed the acceptable value. The modeling does not address this question, even though there is no prohibition in the final air permit number P0126155 issued on October 25, 2019 for the project[21] that restricts the units to run at or above 75% load at all times. OSU's modeling of $PM_{2.5}$ impacts is therefore incomplete and misleading.

**Table 18. Air Quality Modeling Results ($\mu g/m^3$)**

| Model Year | Description | H2H 24-hr $PM_{10}$/ $PM_{2.5}$ | Highest Annual $PM_{10}$/PM2.5 |
|---|---|---|---|
| **2017** | 100% Load | 3.0 | 0.15 |
| **2016** | 100% Load | 2.2 | 0.16 |
| **2015** | 100% Load | 2.2 | 0.13 |
| **2014** | 100% Load | 3.5 | 0.15 |
| **2013** | 100% Load | 2.2 | 0.15 |
| **2017** | 75% Load | 3.4 | 0.17 |
| **2016** | 75% Load | 2.5 | 0.18 |
| **2015** | 75% Load | 2.6 | 0.15 |
| **2014** | 75% Load | 3.9 | 0.17 |
| **2013** | 75% Load | 2.5 | 0.18 |
| | **Acceptable Value** | **< 4.5 ($PM_{2.5}$)**<br>**< 15 ($PM_{10}$)** | **< 2 ($PM_{2.5}$)**<br>**< 8.5 ($PM_{10}$)** |

Note: H2H = highest 2nd high 24-hr concentration for that year. [22]

Only July 6, 2020, OSU also produced an updated modeling analysis for $PM_{2.5}$, $NO_x$, and ozone ("July 6 Model," attached as Exhibit RS-D), including impacts at sensitive

[21] Final Air Pollution Permit-to-Install (October 25, 2019), produced at OSU 000096 and attached as Exhibit RS-N.
[22] Application, p. 66.

receptors such as the nearby medical facilities. This report claims that the increased pollutant concentrations of $PM_{2.5}$, $NO_x$, and ozone are minor compared to the applicable NAAQS and therefore do not pose any adverse health risks. In other words, the report assumes that levels at or below NAAQS are safe. I disagree. The report fails to recognize that NAAQS, while supposedly set at levels protective of human health, are a result of complex technical, health, political, and other considerations. They do not reflect only toxicological or health considerations. As previously noted, for $PM_{2.5}$, for example, there is overwhelming scientific evidence that there is no safe level of ambient concentration. Thus, as a threshold matter, any increase in pollutant concentrations, which OSU's analysis clearly admits will occur, represents increases in health risks.

**Q. What other errors and omissions have you identified in this modeling?**

**A.** There are at least two major potential problems with the modeling that was conducted and which is described in the Application and the recent report.

First, like any dispersion modeling, the modeling conducted by OSU has to rely on meteorological data. This is an important input to any air dispersion model, such as EPA's AERMOD model (which was used by OSU). However, no meteorological data was collected at the site. OSU's modeling simply assumes that the meteorological that is used (which is collected not at OSU's campus but at a weather station several miles away from the proposed location of the CHP plant), is representative of the CHP location. There is no support for such a critical assumption. Features at the site and in its vicinity include the Olentangy River as well as the complex topography of the OSU campus itself (i.e., the many buildings of different heights) which will affect the meteorology (i.e., wind speeds and direction, etc.), as is true for any built environment. Therefore the results of the modeling, such as that shown in Table 18 of the Application, as well as the tables shown in the updated July 6 Model, which depend on the assumed meteorological data, are unreliable. One cannot use non-representative meteorological data and expect the model to accurately predict impacts. The July 6 Model compounds its error when it misrepresents its results as being "conservative" meaning that actual impacts would be lower. That claim is without support because the modeling does not consider emissions during so-called upset or malfunction events, for example, when pollutant emissions can be significant. The modeling results cannot therefore be relied upon.

Second, the modeling results presented by OSU are also unreliable because they include "background" concentrations for each pollutant (and averaging period) collected by the Ohio EPA at monitors approximately two miles from the proposed CHP site.[23] However,

[23] July 6 Model at p. 6 notes that four $PM_{2.5}$ monitors are located in Franklin County: at Korbel Avenue; at 7560 Smoky Road; at 58 Woodrow; and at 5750 Maple Canyon.

none of these monitors, including the closest monitor at the Fairground (Korbel Avenue), are located in the area where the CHP will be located. The proposed CHP will be located next to a freeway (Hwy 315), with expected higher levels of $PM_{2.5}$ due to traffic, including toxic diesel particulate emissions. This localized impact could not have been captured by any of the Ohio EPA background monitors, including the closest Korbel Avenue monitoring site, which is located further east of campus. Therefore the background concentrations used in OSU's modeling understates the current and therefore post-project impacts.

**Q. What is the significance of these errors and omissions for understanding the effects of the proposed facility on air quality and health in the surrounding area?**

**A.** As discussed above, the results of the modeling conducted by OSU cannot be relied upon. It is entirely plausible and likely that OSU's modeling understates the impacts of the proposed facility on ambient concentrations of air pollutants including $PM_{2.5}$ for reasons noted above. Therefore, OSU's conclusions that adverse health impacts particularly for portions of the population in the vicinity who might be patients at the OSU medical facilities nearby, is of no significance, is unfounded.

**Q. What technology does OSU propose to use to limit or control these emissions?**

**A.** OSU acknowledges the need for the project to meet best available technology requirements. In its request for a discretionary exception to PSD requirements, OSU stated that it would "submit a complete permit application, which will address the two primary requirements under PSD for $PM_{10}/PM_{2.5}$, best available control technology (BACT) and an air quality analysis and BACT for GHG. The requirement under OAC 3745-31-05 to employ best available technology (BAT) will satisfy the general PSD requirement to employ best available control technology (BACT)."[24]

What OSU characterizes as the $NO_x$ BAT is described as follows in the Application:

"BAT for $NO_x$ emissions from CHP Units #1 and 2 is the following:

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A review of OhioEPA's Ambient Monitoring site maps (https://epa.ohio.gov/Portals/27/ams/sites/D1-2020AMNP_NetworkMaps_Draft.pdf) shows that Site 81, the Fairgrounds site at Korbel Avenue) is the closest to OSU. And based on monitoring site descriptions (*available at* https://epa.ohio.gov/Portals/27/ams/sites/E1-2020AMNP-OhioSiteTemplates-Draft.pdf) the Korbel Avenue site is described as being located "5 miles north of downtown Columbus and just to the east of the Ohio State University."

[24] Correspondence from ENGIE NA to Ohio EPA Re: Request for Director's Discretionary Exemption, dated December 20, 2018, produced at OSU_000192 and attached as Exhibit RS-O.

• Turbine design with dry low-$NO_x$ combustion technology resulting in a design $NO_x$ emission rate of 15 ppmv dry, corrected to 15 percent O2 and 0.054 lb/MMBtu heat input.

• Duct burner design with low-$NO_x$ combustion technology resulting in a design NOx emission rate of 0.10 lb/MMBtu heat input.

• Installation and operation of an SCR system to reduce combustion $NO_x$ emissions from the combustion turbines and duct burners by a minimum of 85 percent. Post-SCR $NO_x$ emissions at the stack(s) will be less than 3 ppmvd at 15 percent O2. BAT for $NO_x$"[25]

**Q. Do these proposed technologies in fact represent the best available technology for controlling $NO_x$ emissions?**

**A.** No. BACT is an emissions level. While the types of technologies (i.e., dry low $NO_x$ combustion technology and SCR) can be used as BACT, the levels OSU has determined to be BACT for $NO_x$ (i.e., less than 3 ppmvd at 15 percent oxygen) are not, since other agencies have determined that dry low $NO_x$ combustors along with SCR can achieve levels as low as 2 ppm $NO_x$ corrected to 15% oxygen.[26] Had OSU committed to installing and operating an SCR system capable of meeting these levels (i.e., with efficiencies greater than 85%, which SCR systems can routinely achieve), OSU could have cut the allowable levels of $NO_x$ emissions from the CHP by one-third. OSU's claim to employ $NO_x$ BAT is therefore incorrect.

**Q. Please describe OSU's fuel supply for the proposed facility.**

**A.** The Study states that natural gas will be provided by Columbia Gas of Ohio, a subsidiary of NiSource.

**Q. What is the source of the natural gas the proposed facility will use?**

**A.** While it is not clear where Columbia Gas of Ohio procures its natural gas, given its location and the other sister subsidiaries of NiSource, it is reasonable to conclude that some or a substantial portion of this gas originates from fracked shale gas. While OSU mentions that the turbines at the CHP would, someday, be able to combust natural gas

[25] Application, p. 52.

[26] See Title V permit ID 3-3356-00136/00001 issued August 1, 2013 by the New York State Department of Environmental Conservation (NYSDEC) for the CPV Valley Energy Center in Middletown, NY, attached as Exhibit RS-E. Although this limit was issued as a LAER limit, it was deemed to be technically feasible and should have been evaluated as part of the BAT analysis.

derived from biomass or green hydrogen,[27] it is unclear where such fuels would be procured from and why they would be deemed to be environmentally superior to truly renewable fuels such as solar and wind. Thus, any claims by OSU as to environmental advantages of the proposed facility based on the use of these fuels are simply speculative.

**Q. Did OSU include the adverse environmental consequences associated with the extraction and transportation of natural gas as part of its analysis of the adverse environmental impacts of the proposed facility?**

**A.** No. Neither the Application nor the Study mentions any environmental impacts associated with the extraction and transportation of natural gas, whether such gas is extracted from conventional (*i.e.*, non-shale) or unconventional (*i.e.*, shale) formations. As a result, it simply does not consider the life-cycle environmental impacts of using natural gas at the CHP and thereby understates the benefits of using natural gas as compared to any other options. As far as it could be determined, only the carbon emissions associated with the combustion of natural gas at the CHP have been accounted for.

**Q. What adverse environmental consequences are associated with natural gas extraction?**

**A.** There are many adverse environmental consequences associated with natural gas extraction. These include water quantity and quality issues, air quality issues, waste management issues, and other general environmental issues. Included in the air quality issues are the emissions of methane at the point of extraction and initial separation at/near the well head. Fugitive methane emissions which are not captured, even under current best management practices associated with natural gas extraction, from both conventional and non-conventional formations, end up in the atmosphere and are detrimental because methane is a significant greenhouse gas. Studies have concluded that the largest portion of carbon emissions associated with shale gas are emitted at extraction, rather than combustion,[28] and that "shale-gas production in North America over the past decade may

[27] *See* Path to Carbon Neutrality: Ohio State Climate Action Plan (April 2020), attached as Exhibit RS-B, at p. 24.

[28] Howarth, R.W., Santoro, R. & Ingraffea, A. Methane and the greenhouse-gas footprint of natural gas from shale formations. *Climatic Change* 106, 679 (2011). https://doi.org/10.1007/s10584-011-0061-5.

have contributed more than half of all the increased emissions from fossil fuels globally."[29]

**Q. How feasible is OSU's plan to replace natural gas extracted through fracking with green hydrocarbons at some point in the future?**

**A.** The Study mentions in passing that certain campus loads "can be filled with the procurement of green energy and/or the procurement of Green E-RECs…"[30] There is no analysis of where such "green" hydrocarbons would be sourced or procured or why they would be green. Therefore, it is fair to conclude that the use of "green" hydrocarbons is not feasible and OSU has no plans to switch from fracked gas in the foreseeable future.

## V. <u>OSU'S CLAIMS ABOUT REDUCED CARBON EMISSIONS AS A RESULT OF THE CONSTRUCTION OF THE PROPOSED FACILITY ARE MISLEADING</u>

**Q. What claims do OSU and/or OSEP make regarding reductions in carbon emissions attributable to the operation of the CHP facility?**

**A.** OSU's analysis on this point is shown in Figure 3-18 from the Study, shown below.

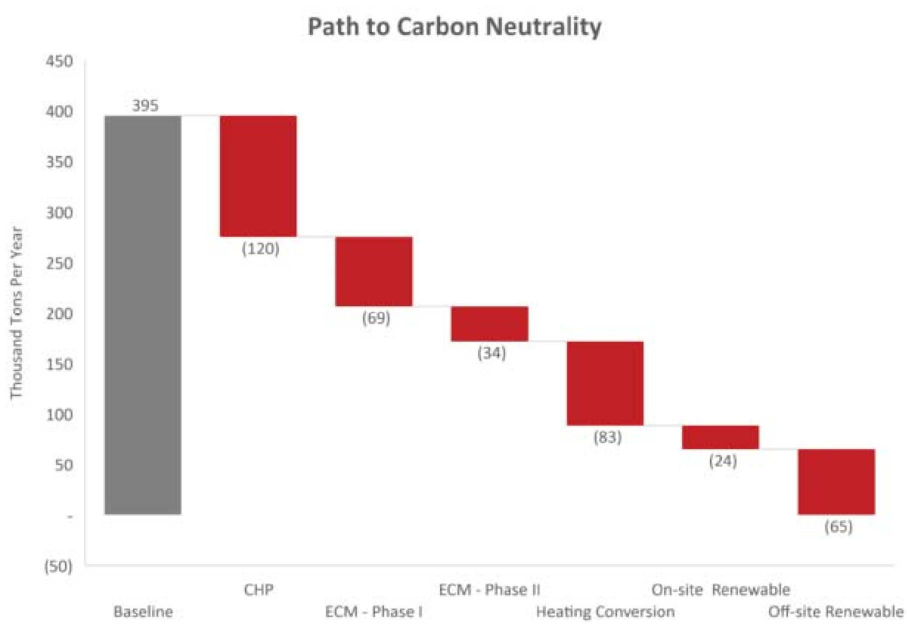


**Figure 3-18:** CHP and ECM Phase I implementation allow the University to reach nearly 50% of their goal

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[29] Howarth, R. W., "Ideas and perspectives: is shale gas a major driver of recent increase in global atmospheric methane?", *Biogeosciences*, 16, 3033–3046, *available at* https://doi.org/10.5194/bg-16-3033-2019, 2019.

[30] Study at 3-18.

Without any support for the numbers shown on the slide, OSU claims that 120,000 tons per year of carbon emissions would be reduced by the CHP facility. I reiterate, however, that OSU did not include life-cycle carbon emissions associated with natural gas that will be used by the CHP facility. Therefore, this benefit is overstated.

**Q. On what basis do OSU and/or OSEP make these claims?**

**A.** It is not clear. However, OSU and OSEP do not discuss life-cycle carbon emissions associated with natural gas at all. So, it is presumed that the claimed benefit from the use of natural gas at the CHP is due to combustion benefits.

**Q. Do you find this explanation adequate?**

**A.** No.

**Q. Do you find OSU and/or OSEP's claims about the reduction in carbon emissions as a result of the construction of the proposed facility plausible?**

**A.** I have excerpted Figure 3-18 in a prior response where the Study shows the baseline carbon emissions of 395,000 tons/year and the reduction of 120,000 tons/year due to the CHP. However, the Study (or the record) provides no details of how either of these numbers was calculated. So, these data are unsupported.

Further, there is inadequate support in the record as to the assumed carbon levels associated with continuing to obtain electricity from the PJM grid – which would be the rationale for claiming that the proposed CHP is less carbon intensive than the grid. Although OSU assumes a "grid carbon footprint of 1510 lb/MWh" as the basis for its claims regarding reduction in carbon emissions attributable to the proposed facility, OSU does not provide citation or support for its use of that figure.[31] Current electrical generation on the PJM grid is approximately 50% from natural gas, roughly 25% from coal, and the rest from nuclear and renewables. These estimated percentages are based on PJM's website, which provides a real-time update of the generation fuel mix based on successful bids into the generation market. The fuel distribution reported by PJM as of 4:00 p.m. on July 7 is reproduced below as an example.[32] This snapshot is consistent with the Independent Market Monitor's State of the Market Report, which reported that in the first three months of 2020, coal units provided 18.0% of electric generation,

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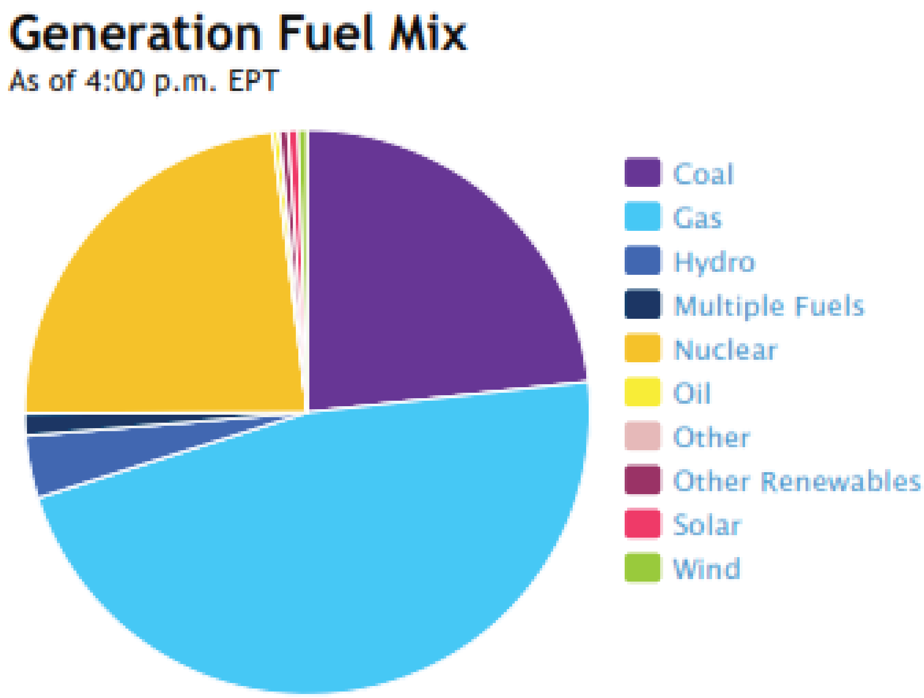
[31] *See* "Summary" Tab of Carbon Footprint worksheet, produced at OSU 003930, attached as Exhibit RS-P.

[32] *Downloaded on July 7 from* https://www.pjm.com/markets-and-operations.aspx.

nuclear units 34.5%, and natural gas 39.7%.[33] This mix is expected to include even less coal (which is more carbon intensive than any of the fuels) and more renewables in the future, including by the time the CHP begins operations.




OSU attributes the carbon emissions savings associated with the CHP to efficiencies associated with combined heating and electricity generation and the relative carbon intensity of coal versus natural gas.[34] These savings must be attributed to, in turn, any retirement of current heating resources (i.e., McCracken) and the relative carbon footprint of electricity generated on the PJM grid versus the proposed facility. The retirement of McCracken Boiler #5 (the only planned retirement prior to 2035 of current heating facilities) accounts for approximately 50,000 tons per year.[35] It is unclear as a matter of basic mathematics how the gas-fired CHP will produce carbon savings relative to the PJM grid to account for the remaining putative carbon savings when the share of coal in the grid is at 25% now and likely to decrease in the future, and the remaining generation

[33] Monitoring Analytics, LLC, *State of the Market Report for PJM* (May 14, 2020), p. 21, *available at* https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020/2020q1-som-pjm.pdf and excerpted at Exhibit RS-F.

[34] Study at 3-16.

[35] Application, p. 21.

mix has either no carbon emissions (in the case of nuclear, which makes up nearly a third of the grid, and renewables, which are a growing percentage) or emissions approximately equal (in the case of natural gas) to the proposed CHP facility.

For these reasons, I find OSU's analysis of carbon benefits to be unsupported and suspect.

## VI. <u>OSU'S REJECTION OF RENEWABLE ALTERNATIVES WITHOUT THESE ADVERSE EFFECTS IS NOT SUPPORTED</u>

**Q. Are there currently available technologies that do not have the above-described adverse environmental impacts?**

**A.** Yes. Simply, OSU could meet all of its heating needs by converting the entire campus to a hot water heating system and by continuing to rely either on the grid or off-site renewable (e.g., solar) for its electricity needs. All of the hot water heating needs can be met by: (i) extracting as much waste heat from the cooling system (i.e., the chillers); and (ii) supplementing this by geothermal or ground-based heating, as needed. Other universities, as I discuss later, have met their campus heating needs in this manner. And, there is simply no need for OSU to enter the electricity generating market, locked into using a single fuel whose environmental impacts are far worse than alternative, renewable, technologies such as solar in combination with storage. Indeed, OSU's Study acknowledges that this type of mix is preferable and could be relied on at some indefinite point in the future but does not account for why the campus cannot convert to this superior mix now instead of proceeding with the proposed CHP system.

Q. **Based on the documents available to you, what renewable strategies did OSU consider in lieu of the proposed CHP facility?**

**A.** OSU considered offsite solar for electricity.

**Q. On what basis did OSU reject an offsite renewable procurement strategy?**

**A.** On the basis of cost.

**Q. Did you identify any errors or inaccuracies in OSU's analysis of renewable alternatives?**

**A.** Yes. Errors and inaccuracies include the following:

(i) The Study states that “an offsite renewable procurements strategy by itself provides less carbon offset that a strategy combined with a CHP solution...”[36] The basis for this is shown in Table 5 of the Study, shown below.

**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

However, in making this assertion, OSU does not take into account the carbon emissions associated with the life-cycle impacts of natural gas procurement beginning with extraction and continuing all the way through final combustion. Thus, impacts such as methane leakage during extraction, collection, and distribution of shale gas are not included in the analysis. Therefore claim that renewables provide “less carbon offset” is not correct.

Nor are adverse impacts such as depletion of groundwater resources (due to the need for vast quantities of injection water needed to extract shale gas by fracking) or the tremendous, adverse impacts due to mining for sand (used as a “proppant” for shale gas fracking), included in the Study. While these may not have direct adverse carbon emissions impacts, there are significant, adverse, environmental impacts, nonetheless.

Moreover, the comparison is not “apples-to-apples,” as it compares 50 MW in offsite procurement to 100 MW of on-site generation.

(ii) The Study concludes that offsite renewables are not economically attractive, relying on data shown in Table 6 of the Study. That table shows four line items comprising the “all-in delivered cost” of solar at $64/MWh. However, the Study provides no backup or support for any of the four line items, and especially for: “PPA Capacity Tag,” which is assumed to be $5.2/MWh; “Ancillary, RPS, Shape costs, others,” which is assumed to be $10.1MWh; and “Utility Delivery Costs,” which is assumed to be $13.7/MWh. Therefore the total $64/MWh estimated cost for offsite solar cannot be relied upon. This cost estimate is also inconsistent with, and considerably higher than, well-regarded market analyses and bids by solar generators to utility companies. Lazard’s Levelized

[36] Study at 3-18.

Cost of Energy Analysis 2019, shows solar costs at utility scale between $32 and $43 per MWh (and wind at $28 to $54 per MWh).[37] The Annual Technology Baseline, compiled by analysts at the National Renewable Energy Laboratory, puts the levelized cost of energy for utility-scale solar at approximately $40/MWh and anticipates that cost decreasing over time.[38] NIPSCO, a utility in Indiana, solicited bids for solar purchase power agreements in 2018 and received 26 bids averaging $35.67/MWh.[39]

(iii) The Study provides no support for statements regarding the lack of reliability or resiliency due to the "intermittent nature of renewable generation." However, other district energy systems have successfully integrated renewable generation without undermining reliability or resiliency. Developments in storage technologies complement the intermittency of renewable energy resources such as solar. And, as I have indicated earlier, the PJM grid, with its mix of fuels and spatial locations of many generators offers a far more resilient system than the proposed CHP, which is solely reliant on a single fuel for all of its generation.

Moreover, as OSU itself acknowledges, the putative reliability and resiliency gains associated with the construction of on-campus generation will not and are not intended to facilitate complete campus independence. Critical facilities such as the hospital will continue to rely on diesel generators for backup power.[40] Thus, by requiring renewables such as offsite solar provide total independence for the campus's electrical needs, OSU is not engaging in an "apples-to-apples" comparison with the proposed CHP facility.

(iv) The Study notes that renewables "do not provide for thermal generation" without considering the overall thermal needs (*i.e.*, for district heating, which can be met using hot water) of the campus. The Study simply assumes, without explanation, that thermal-based electric generation must be a core mission of its energy supply.

In summary, the Study rejects offsite renewables such as wind and solar without proper or supported analysis. OSU overstates the cost of off-site solar generation, ignores better alternatives to steam heating systems (per its own admission, as I will explain), and fails to account for currently available technological options (including storage) that, in

[37] *Available at* https://www.lazard.com/perspective/lcoe2019 and attached as Exhibit RS-H

[38] *See* NREL, "Utility-Scale PV," *2019 ATB*, *available at* https://atb.nrel.gov/electricity/2019/index.html?t=su.

[39] NIPSCO Integrated Resource Plan 2018 Update (July 24, 2018), attached as Exhibit RS-G.

[40] Study at 3-10 ("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.")

conjunction with solar and/or wind generation, can ensure electrical generation reliability comparable to that of gas-generation.

**Q. What else did you find in your review of OSU's analysis of renewable alternatives?**

**A.** OSU failed to consider on-site geothermal at all, in conjunction with waste heat from its cooling system to meet the campus's heating needs. Other universities, as I discuss later, have adopted such systems to meet their campus heating needs.

## VII. <u>THE CONSTRUCTION OF A GAS-FIRED FACILITY IS NOT NECESSARY TO OBTAIN THE CLAIMED BENEFITS ASSOCIATED WITH CO-GENERATION</u>

**Q. Have other universities met heating needs similar to what OSU seeks to meet through construction of the proposed facility without reliance on fossil fuels?**

A. Yes. I am aware of at least seven colleges or universities (Stanford University; University of British Columbia; University of California, Davis; Brown University; Ball State University; University of Rochester; and Carleton College) that have achieved campus heating and energy goals without relying on the construction of gas-fired facilities. At least one of these universities utilized off-site solar generation to meet its electrical energy needs, thereby reducing its carbon footprint. In all cases, these campuses discarded steam-based heating systems in favor of hot water systems, generating substantial portions of their hot water needs from chiller waste heat, and used geothermal heat storage and recovery along with storage to meet their remaining needs. I discuss four examples below.

*Ball State University*[41]

Ball State University is approximately 150 miles due west of OSU's Columbus campus. Before beginning its conversion to a geothermal energy system (which began operations in 2012),[42] Ball State first conducted a thorough assessment of its heating and cooling loads year round and found considerable overlap as shown in the figure below.

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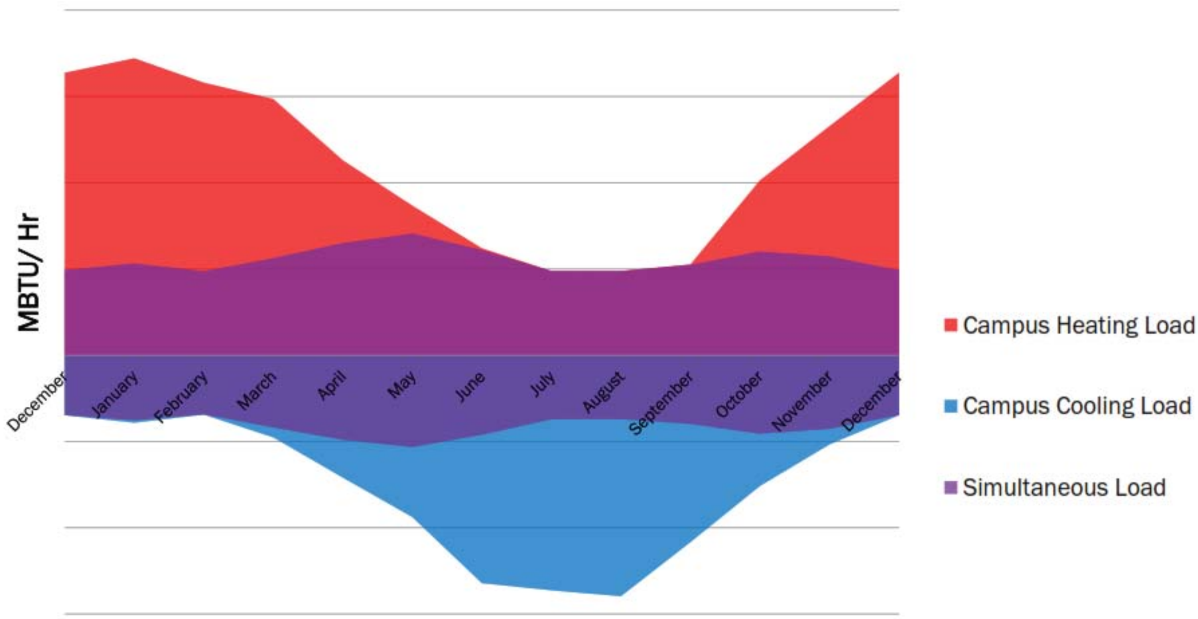
[41] Discussions and figures taken from Luster, M., Ball State University Campus Conversion to Geothermal, available at https://www.districtenergy.org/HigherLogic/System/DownloadDocumentFile.ashx?DocumentFileKey=b0f3ed01-7c78-e7bd-df18-f5a9213efec9&forceDialog=0, attached as Exhibit RS-I.

[42] *See* Ball State, "Geothermal Energy System," available at https://www.bsu.edu/About/Geothermal.




After conducting the load analysis, Ball State chose a heating system that utilizes as much heat exchange with the chiller exhaust, supplemented by a geothermal system to meet all of its heating needs. This system was installed in the beginning of 2009 and is now substantially complete, with continued replacement of building HVAC systems with more efficient units over time.

Notably, the climate at Ball State is similar to that of OSU. Despite relatively extreme winter and summer temperatures, Ball State still concluded that simultaneous heating and cooling load was significant throughout the calendar year. A schematic of Ball State's system is shown below.

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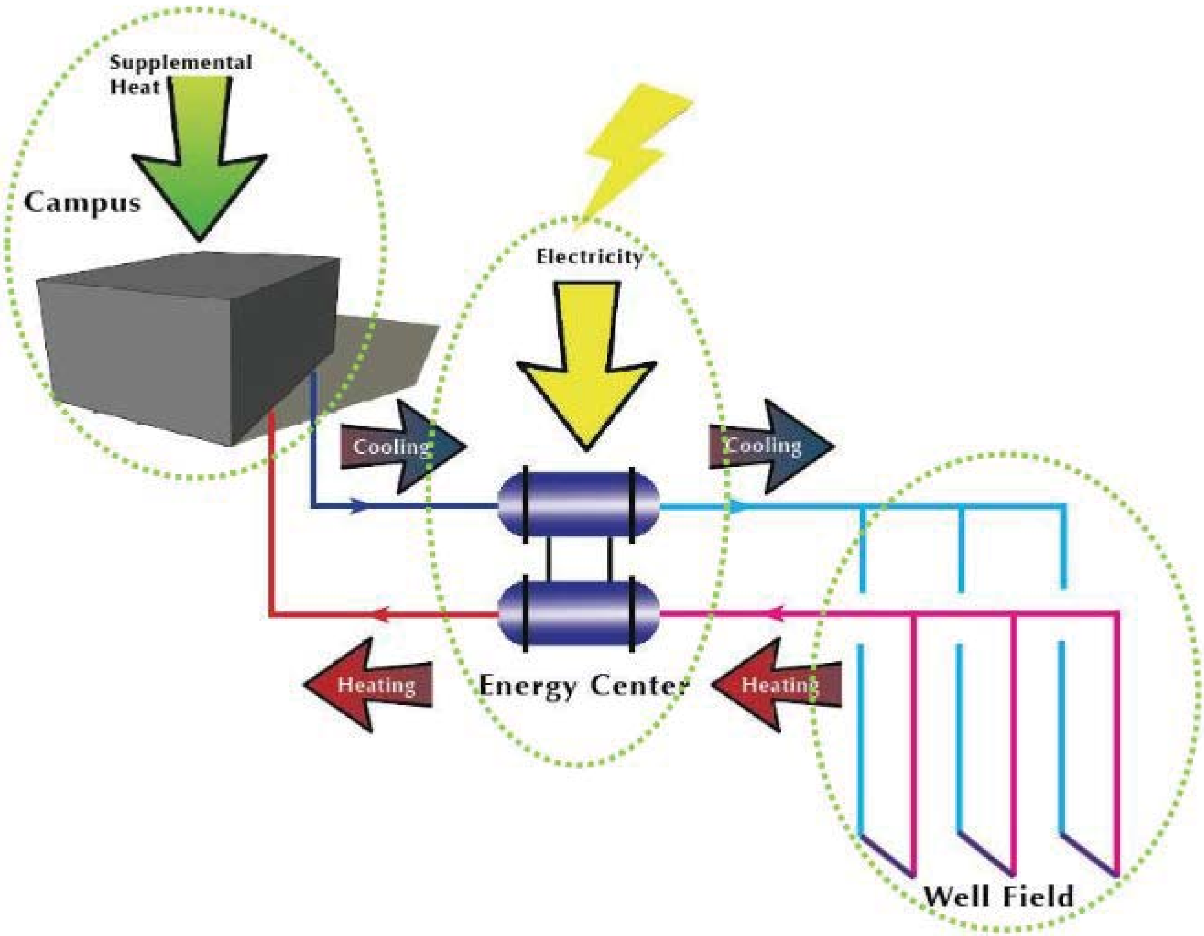


*Stanford University*[43]

Stanford constructed a facility similar to OSU's proposed CHP plant back in 1987 (i.e., over 30 years ago), installing a 50 MW natural gas-fired cogeneration plant to provide electricity, steam and chilled water for its campus. However, Stanford recently decided to replace this aging cogeneration facility with a new Stanford Energy System Innovations (SESI) project, an even more efficient system that immediately reduced its campus greenhouse gas emissions by 68 percent, decreased total campus water use by 18 percent, and is, based on the University's own analysis, anticipated to save the university hundreds of millions of dollars over the next three decades compared to other options. Stanford notes and I agree that "shifting from gas cogeneration to grid electricity may be

[43] This discussion is drawn substantially from Stagner, J.C., "Stanford University's "fourth-generation" district energy system," in *District Energy* (2016), available at https://sustainable.stanford.edu/sites/default/files/IDEA_Stagner_Stanford_fourth_Gen_DistrictEnergy.pdf and attached as Exhibit RS-J.

contrary to current trends, but heat recovery and renewable power are the keys to economic and sustainable energy for Stanford University."

Executive Director of Sustainability and Energy Management at Stanford, Joseph C. Stagner, refers to Stanford's new heat recovery system, which began operation in March 2015, as "CHC" (combined heating and cooling) in contrast to the more widely known SHP (separate heat and power, e.g., gas boilers, electric chillers and grid electricity) and CHP (combined heat and power, e.g., gas-fired cogeneration) district energy options. He noted in describing the project that "[K]ey features of the CHC system include replacing steam production and distribution with hot water; large heat recovery chillers (heat pumps); both hot and cold water thermal energy storage; and advanced "model predictive control" energy management software."

Stanford has reported that the CHC system "improves the reliability of the campus district energy system through simplification by eliminating gas and steam turbines…" Notably, this observation contrasts with OSEP's claims that moving to the CHP system—which depends on gas and steam turbines subject to malfunction—will increase resiliency.

*Carleton College*[44]

Carleton College in Minnesota has an even more demanding heating load than does OSU during the winter months due to Carleton's location. Despite these relatively extreme heating needs, Carleton has elected to shift to geothermal cooling and heating, moving from a steam-based system dating back to over 100 years. Crucial to this shift will be an "overhaul and transformation of the existing steam distribution system to a 120-degree Fahrenheit hot water system. This includes three geothermal bore fields and a heat pump to take advantage of simultaneous heating and cooling loads in addition to building upgrades."

Carleton has already turned off steam to portions of its campus in 2019 and expects to need no steam at all by 2021.

[44] *See* "Carleton shifts to geothermal cooling, heating for east side of campus, in *Carleton Now* (May 24, 2019), available at https://apps.carleton.edu/now/stories/?story_id=1835223; *see also* Carleton College Utility Master Plan, *available at* https://apps.carleton.edu/geothermal/, and attached as Exhibit RS-K.

*Brown University*[45]

As one more example, I discuss the changes at Brown University, in Providence, Rhode Island. Brown explicitly states greenhouse gas reduction as a goal to "increase energy efficiency across campus by replacing its central heating system with one that will generate heat using hot water instead of steam." Brown notes that its "50-year-old steam heating system was due for replacement already" and that "conversion to a medium-temperature hot water system will markedly increase the thermal efficiency of campus while creating the building blocks for future heat recovery and the use of low-carbon energy sources." Brown goes on to note that "[N]ot only will the conversion to hot water further decrease Brown's energy consumption by approximately 11 percent, it will enable the future implementation of other efficiency measures such as recovery systems in which emitted heat is captured and reused, Powell said. In addition, a hot water system, unlike a steam-based one, could potentially be supplied by high-tech heating and cooling technology, which in turn could be powered by non-fossil fuel energy sources such as solar, wind or geothermal."

**Q. Did OSU consider any of the above-described technologies or a CHC system prior to selecting gas-fired cogeneration for its heating needs?**

**A.** Based on the materials available to me, no. Crucially, and as discussed above, OSU did not conduct an hourly analysis of its heating and cooling needs, and thus could not have accurately evaluated whether a CHC system could meet its stated heating needs.

In the Stanford CHC system described above, for example, "the cornerstone of [the system] is the recovery of waste heat from the campus district chilled-water system to meet building heating and hot water needs…. With cooling occurring mostly in summer and heating in winter, the opportunity for heat recovery <u>was assumed to be modest until Stanford engineers compared the simultaneous delivery of heating and cooling from the cogeneration plant over all hours of the year</u>." Stanford's analysis of its hourly loads is shown in the Figure below excerpted from Stagner.

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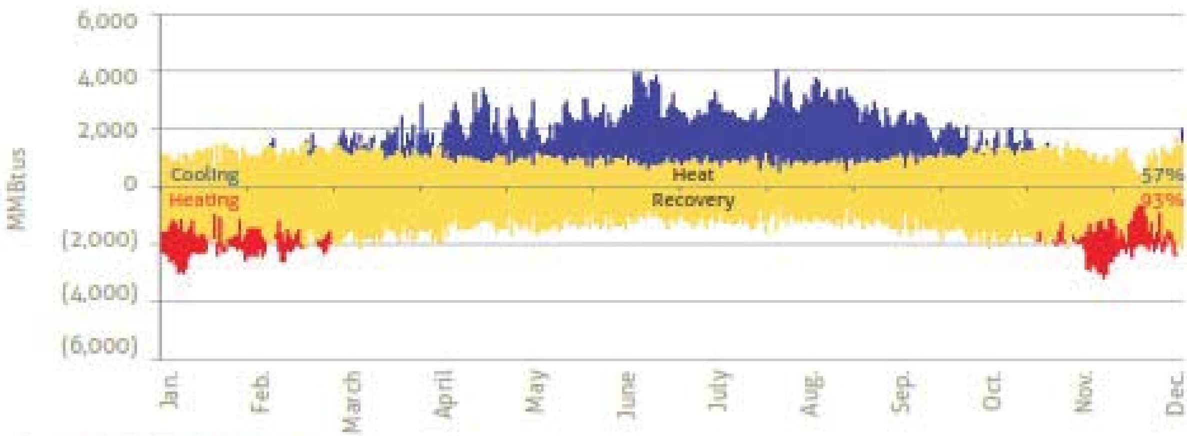
[45] "Brown launches three-year, $24 million project to boost thermal energy" (November 28, 2017), available at https://www.brown.edu/news/2017-11-28/thermal, and attached as Exhibit RS-L.

**Figure 2.** Annual heat recovery potential: heating and cooling overlap, Stanford University, 2016.




**Source: Stanford University.**

Stagner notes that "[T]he large thermal overlap [shown in the yellow band in the figure] that was revealed opened up a major new opportunity for improvement in the efficiency, economics and sustainability of the university's energy system – namely, a heat recovery-based heating and cooling system that could be powered by renewable electricity instead of natural gas."

A similar analysis was also conducted by Ball State University as I described earlier, showing the overlap of its heating and cooling demands.

That is exactly the type of analysis that OSU should have done and did not do at all. Instead, the Study simply presents the overall monthly thermal load in Figure 2-3, without even breaking it down into cooling and heating loads.

**Q. Is a similar CHC system feasible at OSU?**

**A.** In my opinion, yes. I see no OSU-specific factors that would prevent such as system, including geothermal and storage features from being implementable at OSU. Indeed, Appendix N to OSEP's feasibility study concludes that a 4th Generation heating system similar to those described above will eventually be needed to replace the current steam system and associated CHP facility. Implementing such a system now would also allow OSU to avoid the costs and downtime associated with maintaining the legacy steam heating system at McCracken.

Other universities that have conducted more thorough load studies than OSU have concluded that CHC is sufficient to meet at least half of a typical campus's heating and cooling needs over the course of a year without additional steam generation. The remainder of heating needs can be met using a combination of geothermal or ground-based features and thermal storage.

Stagner, for example, states that "Stanford conducted a review of thermal load studies done by campus utilities engineers at several major universities including in the Midwest and Northeast – very different climates than that of the university in California. All indicated a 50 percent or more annual overlap in heating and cooling and a greater-than-expected opportunity for a renewable electricity-based heat recovery system, ratifying the findings of Stanford….At first this seems counterintuitive given the extremely cold winters in the Midwest and Northeast; however, the studies reveal that much of the opportunity for heat recovery occurs in the summer and shoulder seasons, which makes sense given that the lower 48 states have a net environmental heat surplus for half the year….During that time there is no need to generate additional heat, and heat recovery can typically meet 100 percent of heating and hot water needs in most locations. The magnitude of heat recovery potential in the colder half of the year varies by location, but it is present everywhere year-round and not to an insignificant degree. In colder climates, large-scale ground source heat exchange, such as is implemented at Ball State University, offers a great complement to heat recovery by utilizing the same equipment that is used for heat recovery from campus buildings. Ground source heat exchange can boost annual sustainable heat supply from 50 percent up to almost 100 percent via building heat recovery alone." (emphasis added)

Thus, a combination from using reject heat from the cooling system, supplemented by geothermal or ground-based heat pumps, can meet 100% of the campus's heating needs using a hot water heating system,[46] with the small exception of certain targeted steam loads such as sterilizers, etc. whose needs can be met by local, small boiler(s).

**Q. Is a CHC system consistent with OSU's current steam heating system?**

**A.** No. However, the use of steam is not necessary and outdated. Indeed, the feasibility study prepared by OSEP describing the proposed facility reaches the same conclusion.

[46] It is important to point out that while OSU notes that newer buildings on campus will use hot water heating, this hot water will be created not from using waste heat from the chillers or from ground-based systems. Rather steam from the CHP will be used to generate the hot water, with associated heat transfer inefficiencies. This is not the type of systems that I have described above at Ball State or Carleton College, which don't use any steam in their hot water systems.

**Q. What conclusions did OSU and OSEP reach regarding replacing its current steam system with a heating hot water system?**

**A.** Table 1 in Appendix N, shown below, correctly notes that current $4^{th}$ Generation District heating systems rely on low temperature hot water at 120 – 140 F, while steam-based systems (i.e., $1^{st}$ Generation) date back to 1900. Yet, in spite of this, the Study proposes to perpetuate the same 100+ year technology for the next many decades. The feasibility study provides no basis or reasoning for this conclusion.

**Table 1:** Generations of District Heating

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

The Study correctly recognizes that "[T]oday, 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."[47] The

[47] For more discussion on why steam-based district heating systems are inferior from a thermodynamic and heat transfer standpoint given the low temperature loads at issue, please see Mikler, V., District Energy 101, Integral, Vancouver BC. Available at https://www.integralgroup.com/wp-content/uploads/2017/06/IntegralGroup_District-Energy-101.pdf, and attached as Exhibit RS-M. Mikler discusses the role of exergy, which is the quality or usability of energy and how, in the context of District energy systems, the "High Ex" form includes "high-grade forms of energy, such as steam, high-temperature hot water, or electricity" in which the heating portion of the system operates with temperatures higher than 140 F, which limits the consideration of "integrating recovery of various forms of low-grade (Low-Ex) "free waste" thermal energy or low-grade renewable energy."

In contrast, the Low-Ex District energy category "includes all versions of district energy systems that distribute low temperature heating water (< 140 F) as the heating medium. Using low-temperature water opens the possibilities for integrating recovery of various forms of free low-grade waste energy or low-grade renewable energy." Mikler then makes the crucial point, that many large-scale systems, such as the energy system at OSU, "…have a significant amount of heating and cooling demand simultaneously" and that "Low-Ex systems are ideally suited for these applications as they effectively provide both services with a single technology: heat-recovery chillers or heat pumps capable of utilizing available low-grade thermal energy sources or sinks (i.e. recovered waste heat from cooling, or from the surrounding environment; ambient air, geoexchange, sewer, or solar thermal). In the Centralized Low-Ex district energy system, the

Study goes on to note that in the U.S., while heating hot water may not be the most common system, “the clear majority of new district heating systems are [heating hot water] HHW’ and that “an ever-increasing number of facilities have committed to investing in the conversion of steam to HHW.” In fact, in Table 2 in its own Appendix N, the Study provides the following examples of universities where conversions to heating hot water have taken place: Stanford (2015); University of British Columbia (2015); University of California, Davis (initiated in 2017); Brown University (initiated in 2017); and University Rochester (initiated in 2004).

In fact, Table 3 in Appendix N provides a useful side-by-side comparison of heated hot water versus steam systems for District heating, concluding, as others have done, that there is simply no contest and that hot water systems are vastly superior for such District heating. I reproduce Table 3 below.

[*remainder of this page intentionally left blank*]

heat recovery chillers or heat pumps are the core of the central plant, and are the common technology serving two parallel distribution networks — a low-temp heating network and a chilled water network.” (emphasis added)

**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 |

Although there may be specific and targeted needs at a university that require steam (such as for sterilization at certain medical facilities, etc.), these targeted direct steam loads can be met using small package boilers just for that application.

Based on all of this, Appendix N in the Study properly concludes that “HHW is the clear choice.”

**Q. Given the recognized benefits of converting steam heating systems to HHW, why did OSEP not recommend doing so?**

**A.** The feasibility study provided by OSEP recommending the construction of the proposed facility does not offer any explanation for its rejection of hot water heat. Appendix N states "[W]hile hot water has many advantages over steam, its biggest weakness at Ohio State is evident: a steam system is currently utilized in the campus network hot water has very limited, localized application. The coordination and planning of conversion to minimize disruption to the campus itself as well as building heating services would be critical to the system's implementation." Setting aside the grammatical errors, this statement makes no sense. Of course, moving to the 4$^{th}$ Generation system would require conversion from the current 1$^{st}$ Generation steam system to hot water system. That is what others, including the examples provided in the Study's Appendix N itself have recognized and done. Therefore stating that because "a steam system is currently utilized" a much better hot water system cannot be implemented, is plainly illogical, and is inconsistent with what elsewhere OSU has characterized as an ambitious transformation of its campus electrical and heating systems. OSEP's dismissal of HHW conversion is like stating that while an electric car may have clear advantages over a horse-and-buggy, it cannot be implemented because the horse-and-buggy is still in use. In fact, stretching the analogy a bit, the current CHP system would perpetuate the horse-and-buggy for many more years at OSU by sinking close to $200 million into the construction of a facility whose only efficiency benefit is steam cogeneration—effectively investing in a horse farm.

Simply put, the Study does not provide a coherent or even semi-logical rationale for why the current 1$^{st}$ Generation system should be perpetuated at OSU, as would be the case by implementing the CHP system. OSU should recognize, as its own Study does, and as others have/are doing, that moving to a hot water system is far superior and that the university does not need to enter the electric generation business when far superior alternatives such as offsite solar, coupled with geothermal, storage, and similar technologies can meet all of its current and future heating and electricity needs, with far less environmental impacts, among other advantages.

Moreover, over a reasonable lifetime of an energy system, replacement of steam with hot water and a CHC system is likely to cost less than the construction and operation of the proposed facility – and especially so if any reasonable carbon price is included in the cost calculations.

Stagner notes that Stanford did not just assume the superiority of the CHC system. Rather, it was based on careful, life-cycle analysis. Stagner states "[P]rior to proceeding with CHC, Stanford also developed SHP and CHP system options and compared all using a total lifecycle present value cost analysis including fuel, O&M and capital costs. Long-term gas and electricity prices, inflation and discount rates have a large impact on the comparisons; so to assure objectivity, multiple sources for these were utilized, including consultants, the U.S. Energy Information Administration and Stanford faculty. Assumptions for these and other key factors were then developed for the analysis, including sensitivity bands. Multiple internal and external peer reviews of the models were also performed…The best gas-based option was a hybrid internal combustion engine and heat recovery scheme that presented long-term costs similar to that of CHC. Given the better sustainability performance of the CHC option and the long-term flexibility it provides in energy sourcing by using electricity instead of gas, Stanford selected the combined heating and cooling option" (*emphasis added*).

**Q. What would be the environmental benefits of adopting a combined heating and cooling system similar to those installed or planned to be installed at Ball State, Stanford, Carleton, and Brown?**

**A.** Adoption of combined heating and cooling, including geothermal heat storage and heat exchanges, will avoid the need to generate steam for either power generation or for campus heating needs. Electricity from renewable sources off-campus can be procured today to meet campus electricity needs, with no loss of reliability. Doing so would avoid the adverse environmental impacts associated with both extracting and burning natural gas, including hundreds of thousands of tons of carbon dioxide and methane emissions and significant $PM_{2.5}$ and $NO_x$ emissions in an urban location adjacent to multiple medical facilities. Finally, as discussed below, adoption of a CHC heating system will allow retirement of McCracken far sooner than 2035 and will allow OSU to meet its stated goal carbon neutrality much sooner than 2050.

## VIII. MCCRACKEN'S RETIREMENT COULD BE ACCELERATED WITH ALTERNATIVE GENERATION AND HEATING CHOICES

**Q. Please describe the McCracken Plant and its current role within OSU's energy and heat systems.**

**A.** McCracken Power Plant is currently part of the utility facility at OSU and includes boilers, chillers, air compressors, as well as office space and staff. It provides both steam heating and cooling to various campus loads.

**Q. What do the relevant documents conclude about the retirement of the McCracken facility?**

**A.** The Study concludes that McCracken can be retired as early as 2021 based on its meeting chilled water/cooling needs of the campus[48] but that although the proposed CHP facility will allow the retirement of two McCracken boilers, the facility as a whole cannot be retired consistent with the campus's heating needs under 2035 even on an accelerated schedule with the CHP.[49].

Indeed, the Study anticipates that retirement of McCracken will be contingent on constructing technologies "including hot water heaters, geothermal wells, heat pump chillers, and hot water storage"—i.e., those technologies Ball State, Stanford, Carleton, and Brown have already implemented or are implementing now.

**Q. Could McCracken be retired sooner consistent with OSU's heating needs?**

**A.** Yes. If the campus converted to a hot-water based heating system along with geothermal wells similar to those adopted by other universities, there would be no need for a central steam plant and McCracken could retire much sooner than 2035 as currently proposed. The actual retirement date would depend on when such an alternate design is implemented.

**Q. Does this conclude your testimony?**

**A.** Yes.

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[48] Study at 6-3.

[49] Study at 6-5.

**Exhibits for Ranajit (Ron) Sahu's Direct Testimony**

| | Title | Format |
|---|---|---|
| A | Ranajit (Ron) Sahu's Resume | PDF |
| B | CHP Feasibility Study (Feb. 20, 2018) | PDF |
| C | OSU Climate Action Plan (April 2020) | PDF |
| D | 2020 TRC Summary Report ("July 6 Model") | PDF |
| E | CPV Valley Energy Center NYSDEC Air State Facility Permit | PDF |
| F | PJM Market Report for 2020 Q1 (excerpt) | PDF |
| G | NIPSCO IRP Public Advisory (July 24, 2018) | PDF |
| H | Lazard Levelized Cost of Energy and Levelized Cost of Storage 2019 | PDF |
| I | Ball State University's Campus Conversion to a Campus Geothermal System | PDF |
| J | Stagner, "Stanford University's 'Fourth-Generation' District Energy System" in *International District Energy Association* (2016) | PDF |
| K | Carleton College Utility Master Plan | PDF |
| L | "Brown launches three-year, $24 million project to boost thermal energy" | PDF |
| M | Mikler and Integral Group Vancouver, *District Energy 101* | PDF |
| N | Final Air Pollution Permit-to-Install (October 25, 2019) | PDF |
| O | Correspondence from ENGIE NA to Ohio EPA Re: Request for Director's Discretionary Exemption, dated December 20, 2018 | PDF |
| P | OSU CHP Carbon Footprint Workpaper, "Summary" | PDF |

# Exhibit RS-A

**RANAJIT (RON) SAHU, Ph.D, QEP, CEM (Nevada)**

**CONSULTANT, ENVIRONMENTAL AND ENERGY ISSUES**

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## EXPERIENCE SUMMARY

Dr. Sahu has over thirty years of experience in the fields of environmental, mechanical, and chemical engineering including: program and project management services; design and specification of pollution control equipment for a wide range of emissions sources including stationary and mobile sources; soils and groundwater remediation including landfills as remedy; combustion engineering evaluations; energy studies; multimedia environmental regulatory compliance (involving statutes and regulations such as the Federal CAA and its Amendments, Clean Water Act, TSCA, RCRA, CERCLA, SARA, OSHA, NEPA as well as various related state statutes); transportation air quality impact analysis; multimedia compliance audits; multimedia permitting (including air quality NSR/PSD permitting, Title V permitting, NPDES permitting for industrial and storm water discharges, RCRA permitting, etc.), multimedia/multi-pathway human health risk assessments for toxics; air dispersion modeling; and regulatory strategy development and support including negotiation of consent agreements and orders.

He has over twenty seven years of project management experience and has successfully managed and executed numerous projects in this time period. This includes basic and applied research projects, design projects, regulatory compliance projects, permitting projects, energy studies, risk assessment projects, and projects involving the communication of environmental data and information to the public.

He has provided consulting services to numerous private sector, public sector and public interest group clients. His major clients over the past twenty five years include various trade associations as well as individual companies such as steel mills, petroleum refineries, cement manufacturers, aerospace companies, power generation facilities, lawn and garden equipment manufacturers, spa manufacturers, chemical distribution facilities, and various entities in the public sector including EPA, the US Dept. of Justice, several states, various agencies such as the California DTSC, various municipalities, etc.). Dr. Sahu has performed projects in all 50 states, numerous local jurisdictions and internationally.

In addition to consulting, for approximately twenty years, Dr. Sahu taught numerous courses in several Southern California universities including UCLA (air pollution), UC Riverside (air pollution, process hazard analysis), and Loyola Marymount University (air pollution, risk assessment, hazardous waste management). He also taught at Caltech, his alma mater (various engineering courses), at the University of Southern California (air pollution controls) and at California State University, Fullerton (transportation and air quality).

Dr. Sahu has and continues to provide expert witness services in a number of environmental areas discussed above in both state and Federal courts as well as before administrative bodies (please see Annex A).

## EXPERIENCE RECORD

2000-present **Independent Consultant.** Providing a variety of private sector (industrial companies, land development companies, law firms, etc.), public sector (such as the US Department of Justice), and public interest group clients with project management, environmental consulting, project management, as well as regulatory and engineering support consulting services.

1995-2000 Parsons ES, **Associate, Senior Project Manager and Department Manager for** Air Quality/Geosciences/Hazardous Waste Groups, Pasadena. Responsible for the management of a group of approximately 24 air quality and environmental professionals, 15 geoscience, and 10 hazardous waste professionals providing full-service consulting, project management, regulatory compliance and A/E design assistance in all areas.

Parsons ES, **Manager for Air Source Testing Services**. Responsible for the management of 8 individuals in the area of air source testing and air regulatory permitting projects located in Bakersfield, California.

1992-1995 Engineering-Science, Inc. **Principal Engineer and Senior Project Manager** in the air quality department. Responsibilities included multimedia regulatory compliance and permitting (including hazardous and nuclear materials), air pollution engineering (emissions from stationary and mobile sources, control of criteria and air toxics, dispersion modeling, risk assessment, visibility analysis, odor analysis), supervisory functions and project management.

1990-1992 Engineering-Science, Inc. **Principal Engineer and Project Manager** in the air quality department. Responsibilities included permitting, tracking regulatory issues, technical analysis, and supervisory functions on numerous air, water, and hazardous waste projects. Responsibilities also include client and agency interfacing, project cost and schedule control, and reporting to internal and external upper management regarding project status.

1989-1990 Kinetics Technology International, Corp. **Development Engineer.** Involved in thermal engineering R&D and project work related to low-NOx ceramic radiant burners, fired heater NOx reduction, SCR design, and fired heater retrofitting.

1988-1989 Heat Transfer Research, Inc. **Research Engineer**. Involved in the design of fired heaters, heat exchangers, air coolers, and other non-fired equipment. Also did research in the area of heat exchanger tube vibrations.

## EDUCATION

1984-1988 Ph.D., Mechanical Engineering, California Institute of Technology (Caltech), Pasadena, CA.

1984 M. S., Mechanical Engineering, California Institute of Technology (Caltech), Pasadena, CA.

1978-1983 B. Tech (Honors), Mechanical Engineering, Indian Institute of Technology (IIT) Kharagpur, India

## TEACHING EXPERIENCE

Caltech

"Thermodynamics," Teaching Assistant, California Institute of Technology, 1983, 1987.

"Air Pollution Control," Teaching Assistant, California Institute of Technology, 1985.

"Caltech Secondary and High School Saturday Program," - taught various mathematics (algebra through calculus) and science (physics and chemistry) courses to high school students, 1983-1989.

"Heat Transfer," - taught this course in the Fall and Winter terms of 1994-1995 in the Division of Engineering and Applied Science.

“Thermodynamics and Heat Transfer,” Fall and Winter Terms of 1996-1997.

U.C. Riverside, Extension

"Toxic and Hazardous Air Contaminants," University of California Extension Program, Riverside, California. Various years since 1992.

"Prevention and Management of Accidental Air Emissions," University of California Extension Program, Riverside, California. Various years since 1992.

"Air Pollution Control Systems and Strategies," University of California Extension Program, Riverside, California, Summer 1992-93, Summer 1993-1994.

"Air Pollution Calculations," University of California Extension Program, Riverside, California, Fall 1993-94, Winter 1993-94, Fall 1994-95.

"Process Safety Management," University of California Extension Program, Riverside, California. Various years since 1992-2010.

"Process Safety Management," University of California Extension Program, Riverside, California, at SCAQMD, Spring 1993-94.

"Advanced Hazard Analysis - A Special Course for LEPCs," University of California Extension Program, Riverside, California, taught at San Diego, California, Spring 1993-1994.

"Advanced Hazardous Waste Management" University of California Extension Program, Riverside, California. 2005.

Loyola Marymount University

"Fundamentals of Air Pollution - Regulations, Controls and Engineering," Loyola Marymount University, Dept. of Civil Engineering. Various years since 1993.

"Air Pollution Control," Loyola Marymount University, Dept. of Civil Engineering, Fall 1994.

"Environmental Risk Assessment," Loyola Marymount University, Dept. of Civil Engineering. Various years since 1998.

"Hazardous Waste Remediation" Loyola Marymount University, Dept. of Civil Engineering. Various years since 2006.

University of Southern California

"Air Pollution Controls," University of Southern California, Dept. of Civil Engineering, Fall 1993, Fall 1994.

"Air Pollution Fundamentals," University of Southern California, Dept. of Civil Engineering, Winter 1994.

University of California, Los Angeles

"Air Pollution Fundamentals," University of California, Los Angeles, Dept. of Civil and Environmental Engineering, Spring 1994, Spring 1999, Spring 2000, Spring 2003, Spring 2006, Spring 2007, Spring 2008, Spring 2009.

International Programs

"Environmental Planning and Management," 5 week program for visiting Chinese delegation, 1994.

"Environmental Planning and Management," 1 day program for visiting Russian delegation, 1995.

"Air Pollution Planning and Management," IEP, UCR, Spring 1996.

"Environmental Issues and Air Pollution," IEP, UCR, October 1996.

## PROFESSIONAL AFFILIATIONS AND HONORS

President of India Gold Medal, IIT Kharagpur, India, 1983.

Member of the Alternatives Assessment Committee of the Grand Canyon Visibility Transport Commission, established by the Clean Air Act Amendments of 1990, 1992.

American Society of Mechanical Engineers: Los Angeles Section Executive Committee, Heat Transfer Division, and Fuels and Combustion Technology Division, 1987-mid-1990s.

Air and Waste Management Association, West Coast Section, 1989-mid-2000s.

## PROFESSIONAL CERTIFICATIONS

EIT, California (#XE088305), 1993.

REA I, California (#07438), 2000.

Certified Permitting Professional, South Coast AQMD (#C8320), since 1993.

QEP, Institute of Professional Environmental Practice, since 2000.

CEM, State of Nevada (#EM-1699). Expiration 10/07/2021.

## PUBLICATIONS (PARTIAL LIST)

"Physical Properties and Oxidation Rates of Chars from Bituminous Coals," with Y.A. Levendis, R.C. Flagan and G.R. Gavalas, *Fuel*, **67**, 275-283 (1988).

"Char Combustion: Measurement and Analysis of Particle Temperature Histories," with R.C. Flagan, G.R. Gavalas and P.S. Northrop, *Comb. Sci. Tech.* **60**, 215-230 (1988).

"On the Combustion of Bituminous Coal Chars," PhD Thesis, California Institute of Technology (1988).

"Optical Pyrometry: A Powerful Tool for Coal Combustion Diagnostics," *J. Coal Quality*, **8**, 17-22 (1989).

"Post-Ignition Transients in the Combustion of Single Char Particles," with Y.A. Levendis, R.C. Flagan and G.R. Gavalas, *Fuel*, **68**, 849-855 (1989).

"A Model for Single Particle Combustion of Bituminous Coal Char." Proc. ASME National Heat Transfer Conference, Philadelphia, **HTD-Vol. 106**, 505-513 (1989).

"Discrete Simulation of Cenospheric Coal-Char Combustion," with R.C. Flagan and G.R. Gavalas, *Combust. Flame*, **77**, 337-346 (1989).

"Particle Measurements in Coal Combustion," with R.C. Flagan, in "**Combustion Measurements**" (ed. N. Chigier), Hemisphere Publishing Corp. (1991).

"Cross Linking in Pore Structures and Its Effect on Reactivity," with G.R. Gavalas in preparation.

"Natural Frequencies and Mode Shapes of Straight Tubes," Proprietary Report for Heat Transfer Research Institute, Alhambra, CA (1990).

"Optimal Tube Layouts for Kamui SL-Series Exchangers," with K. Ishihara, Proprietary Report for Kamui Company Limited, Tokyo, Japan (1990).

"HTRI Process Heater Conceptual Design," Proprietary Report for Heat Transfer Research Institute, Alhambra, CA (1990).

"Asymptotic Theory of Transonic Wind Tunnel Wall Interference," with N.D. Malmuth and others, Arnold Engineering Development Center, Air Force Systems Command, USAF (1990).

"Gas Radiation in a Fired Heater Convection Section," Proprietary Report for Heat Transfer Research Institute, College Station, TX (1990).

"Heat Transfer and Pressure Drop in NTIW Heat Exchangers," Proprietary Report for Heat Transfer Research Institute, College Station, TX (1991).

"NOx Control and Thermal Design," Thermal Engineering Tech Briefs, (1994).

“From Purchase of Landmark Environmental Insurance to Remediation: Case Study in Henderson, Nevada,” with Robin E. Bain and Jill Quillin, presented at the AQMA Annual Meeting, Florida, 2001.

“The Jones Act Contribution to Global Warming, Acid Rain and Toxic Air Contaminants,” with Charles W. Botsford, presented at the AQMA Annual Meeting, Florida, 2001.

## PRESENTATIONS (PARTIAL LIST)

"Pore Structure and Combustion Kinetics - Interpretation of Single Particle Temperature-Time Histories," with P.S. Northrop, R.C. Flagan and G.R. Gavalas, presented at the AIChE Annual Meeting, New York (1987).

"Measurement of Temperature-Time Histories of Burning Single Coal Char Particles," with R.C. Flagan, presented at the American Flame Research Committee Fall International Symposium, Pittsburgh, (1988).

"Physical Characterization of a Cenospheric Coal Char Burned at High Temperatures," with R.C. Flagan and G.R. Gavalas, presented at the Fall Meeting of the Western States Section of the Combustion Institute, Laguna Beach, California (1988).

"Control of Nitrogen Oxide Emissions in Gas Fired Heaters - The Retrofit Experience," with G. P. Croce and R. Patel, presented at the International Conference on Environmental Control of Combustion Processes (Jointly sponsored by the American Flame Research Committee and the Japan Flame Research Committee), Honolulu, Hawaii (1991).

"Air Toxics - Past, Present and the Future," presented at the Joint AIChE/AAEE Breakfast Meeting at the AIChE 1991 Annual Meeting, Los Angeles, California, November 17-22 (1991).

"Air Toxics Emissions and Risk Impacts from Automobiles Using Reformulated Gasolines," presented at the Third Annual Current Issues in Air Toxics Conference, Sacramento, California, November 9-10 (1992).

"Air Toxics from Mobile Sources," presented at the Environmental Health Sciences (ESE) Seminar Series, UCLA, Los Angeles, California, November 12, (1992).

"Kilns, Ovens, and Dryers - Present and Future," presented at the Gas Company Air Quality Permit Assistance Seminar, Industry Hills Sheraton, California, November 20, (1992).

"The Design and Implementation of Vehicle Scrapping Programs," presented at the 86th Annual Meeting of the Air and Waste Management Association, Denver, Colorado, June 12, 1993.

"Air Quality Planning and Control in Beijing, China," presented at the 87th Annual Meeting of the Air and Waste Management Association, Cincinnati, Ohio, June 19-24, 1994.

## Annex A

Expert Litigation Support

A. Occasions where Dr. Sahu has provided Written or Oral testimony before Congress:

1. In July 2012, provided expert written and oral testimony to the House Subcommittee on Energy and the Environment, Committee on Science, Space, and Technology at a Hearing entitled "Hitting the Ethanol Blend Wall – Examining the Science on E15."

B. Matters for which Dr. Sahu has provided affidavits and expert reports include:

2. Affidavit for Rocky Mountain Steel Mills, Inc. located in Pueblo Colorado – dealing with the technical uncertainties associated with night-time opacity measurements in general and at this steel mini-mill.

3. Expert reports and depositions (2/28/2002 and 3/1/2002; 12/2/2003 and 12/3/2003; 5/24/2004) on behalf of the United States in connection with the Ohio Edison NSR Cases. *United States, et al. v. Ohio Edison Co., et al.*, C2-99-1181 (Southern District of Ohio).

4. Expert reports and depositions (5/23/2002 and 5/24/2002) on behalf of the United States in connection with the Illinois Power NSR Case. *United States v. Illinois Power Co., et al.*, 99-833-MJR (Southern District of Illinois).

5. Expert reports and depositions (11/25/2002 and 11/26/2002) on behalf of the United States in connection with the Duke Power NSR Case. *United States, et al. v. Duke Energy Corp.*, 1:00-CV-1262 (Middle District of North Carolina).

6. Expert reports and depositions (10/6/2004 and 10/7/2004; 7/10/2006) on behalf of the United States in connection with the American Electric Power NSR Cases. *United States, et al. v. American Electric Power Service Corp., et al.*, C2-99-1182, C2-99-1250 (Southern District of Ohio).

7. Affidavit (March 2005) on behalf of the Minnesota Center for Environmental Advocacy and others in the matter of the Application of Heron Lake BioEnergy LLC to construct and operate an ethanol production facility – submitted to the Minnesota Pollution Control Agency.

8. Expert Report and Deposition (10/31/2005 and 11/1/2005) on behalf of the United States in connection with the East Kentucky Power Cooperative NSR Case. *United States v. East Kentucky Power Cooperative, Inc.*, 5:04-cv-00034-KSF (Eastern District of Kentucky).

9. Affidavits and deposition on behalf of Basic Management Inc. (BMI) Companies in connection with the BMI vs. USA remediation cost recovery Case.

10. Expert Report on behalf of Penn Future and others in the Cambria Coke plant permit challenge in Pennsylvania.

11. Expert Report on behalf of the Appalachian Center for the Economy and the Environment and others in the Western Greenbrier permit challenge in West Virginia.

12. Expert Report, deposition (via telephone on January 26, 2007) on behalf of various Montana petitioners (Citizens Awareness Network (CAN), Women's Voices for the Earth (WVE) and the Clark Fork Coalition (CFC)) in the Thompson River Cogeneration LLC Permit No. 3175-04 challenge.

13. Expert Report and deposition (2/2/07) on behalf of the Texas Clean Air Cities Coalition at the Texas State Office of Administrative Hearings (SOAH) in the matter of the permit challenges to TXU Project Apollo's eight new proposed PRB-fired PC boilers located at seven TX sites.

14. Expert Testimony (July 2007) on behalf of the Izaak Walton League of America and others in connection with the acquisition of power by Xcel Energy from the proposed Gascoyne Power Plant – at the State of Minnesota, Office of Administrative Hearings for the Minnesota PUC (MPUC No. E002/CN-06-1518; OAH No. 12-2500-17857-2).

15. Affidavit (July 2007) Comments on the Big Cajun I Draft Permit on behalf of the Sierra Club – submitted to the Louisiana DEQ.

16. Expert Report and Deposition (12/13/2007) on behalf of Commonwealth of Pennsylvania – Dept. of Environmental Protection, State of Connecticut, State of New York, and State of New Jersey (Plaintiffs) in connection with the Allegheny Energy NSR Case. *Plaintiffs v. Allegheny Energy Inc., et al.,* 2:05cv0885 (Western District of Pennsylvania).

17. Expert Reports and Pre-filed Testimony before the Utah Air Quality Board on behalf of Sierra Club in the Sevier Power Plant permit challenge.

18. Expert Report and Deposition (October 2007) on behalf of MTD Products Inc., in connection with *General Power Products, LLC v MTD Products Inc.*, 1:06 CVA 0143 (Southern District of Ohio, Western Division) .

19. Expert Report and Deposition (June 2008) on behalf of Sierra Club and others in the matter of permit challenges (Title V: 28.0801-29 and PSD: 28.0803-PSD) for the Big Stone II unit, proposed to be located near Milbank, South Dakota.

20. Expert Reports, Affidavit, and Deposition (August 15, 2008) on behalf of Earthjustice in the matter of air permit challenge (CT-4631) for the Basin Electric Dry Fork station, under construction near Gillette, Wyoming before the Environmental Quality Council of the State of Wyoming.

21. Affidavits (May 2010/June 2010 in the Office of Administrative Hearings))/Declaration and Expert Report (November 2009 in the Office of Administrative Hearings) on behalf of NRDC and the Southern Environmental Law Center in the matter of the air permit challenge for Duke Cliffside Unit 6. Office of Administrative Hearing Matters 08 EHR 0771, 0835 and 0836 and 09 HER 3102, 3174, and 3176 (consolidated).

22. Declaration (August 2008), Expert Report (January 2009), and Declaration (May 2009) on behalf of Southern Alliance for Clean Energy in the matter of the air permit challenge for Duke Cliffside Unit 6. *Southern Alliance for Clean Energy et al., v. Duke Energy Carolinas, LLC*, Case No. 1:08-cv-00318-LHT-DLH (Western District of North Carolina, Asheville Division).

23. Declaration (August 2008) on behalf of the Sierra Club in the matter of Dominion Wise County plant MACT.us

24. Expert Report (June 2008) on behalf of Sierra Club for the Green Energy Resource Recovery Project, MACT Analysis.

25. Expert Report (February 2009) on behalf of Sierra Club and the Environmental Integrity Project in the matter of the air permit challenge for NRG Limestone's proposed Unit 3 in Texas.

26. Expert Report (June 2009) on behalf of MTD Products, Inc., in the matter of *Alice Holmes and Vernon Holmes v. Home Depot USA, Inc., et al.*

27. Expert Report (August 2009) on behalf of Sierra Club and the Southern Environmental Law Center in the matter of the air permit challenge for Santee Cooper's proposed Pee Dee plant in South Carolina).

28. Statements (May 2008 and September 2009) on behalf of the Minnesota Center for Environmental Advocacy to the Minnesota Pollution Control Agency in the matter of the Minnesota Haze State Implementation Plans.

29. Expert Report (August 2009) on behalf of Environmental Defense, in the matter of permit challenges to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

30. Expert Report and Rebuttal Report (September 2009) on behalf of the Sierra Club, in the matter of challenges to the proposed Medicine Bow Fuel and Power IGL plant in Cheyenne, Wyoming.

31. Expert Report (December 2009) and Rebuttal reports (May 2010 and June 2010) on behalf of the United States in connection with the Alabama Power Company NSR Case. *United States v. Alabama Power Company*, CV-01-HS-152-S (Northern District of Alabama, Southern Division).

32. Pre-filed Testimony (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed White Stallion Energy Center coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

33. Pre-filed Testimony (July 2010) and Written Rebuttal Testimony (August 2010) on behalf of the State of New Mexico Environment Department in the matter of Proposed Regulation 20.2.350 NMAC – *Greenhouse Gas Cap and Trade Provisions*, No. EIB 10-04 (R), to the State of New Mexico, Environmental Improvement Board.

34. Expert Report (August 2010) and Rebuttal Expert Report (October 2010) on behalf of the United States in connection with the Louisiana Generating NSR

Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana) – Liability Phase.

35. Declaration (August 2010), Reply Declaration (November 2010), Expert Report (April 2011), Supplemental and Rebuttal Expert Report (July 2011) on behalf of the United States in the matter of DTE Energy Company and Detroit Edison Company (Monroe Unit 2). *United States of America v. DTE Energy Company and Detroit Edison Company*, Civil Action No. 2:10-cv-13101-BAF-RSW (Eastern District of Michigan).

36. Expert Report and Deposition (August 2010) as well as Affidavit (September 2010) on behalf of Kentucky Waterways Alliance, Sierra Club, and Valley Watch in the matter of challenges to the NPDES permit issued for the Trimble County power plant by the Kentucky Energy and Environment Cabinet to Louisville Gas and Electric, File No. DOW-41106-047.

37. Expert Report (August 2010), Rebuttal Expert Report (September 2010), Supplemental Expert Report (September 2011), and Declaration (November 2011) on behalf of Wild Earth Guardians in the matter of opacity exceedances and monitor downtime at the Public Service Company of Colorado (Xcel)'s Cherokee power plant. No. 09-cv-1862 (District of Colorado).

38. Written Direct Expert Testimony (August 2010) and Affidavit (February 2012) on behalf of Fall-Line Alliance for a Clean Environment and others in the matter of the PSD Air Permit for Plant Washington issued by Georgia DNR at the Office of State Administrative Hearing, State of Georgia (OSAH-BNR-AQ-1031707-98-WALKER).

39. Deposition (August 2010) on behalf of Environmental Defense, in the matter of the remanded permit challenge to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

40. Expert Report, Supplemental/Rebuttal Expert Report, and Declarations (October 2010, November 2010, September 2012) on behalf of New Mexico Environment Department (Plaintiff-Intervenor), Grand Canyon Trust and Sierra Club (Plaintiffs) in the matter of *Plaintiffs v. Public Service Company of New Mexico* (PNM), Civil No. 1:02-CV-0552 BB/ATC (ACE) (District of New Mexico).

41. Expert Report (October 2010) and Rebuttal Expert Report (November 2010) (BART Determinations for PSCo Hayden and CSU Martin Drake units) to the Colorado Air Quality Commission on behalf of Coalition of Environmental Organizations.

42. Expert Report (November 2010) (BART Determinations for TriState Craig Units, CSU Nixon Unit, and PRPA Rawhide Unit) to the Colorado Air Quality Commission on behalf of Coalition of Environmental Organizations.

43. Declaration (November 2010) on behalf of the Sierra Club in connection with the Martin Lake Station Units 1, 2, and 3. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Case No. 5:10-cv-00156-DF-CMC (Eastern District of Texas, Texarkana Division).

44. Pre-Filed Testimony (January 2011) and Declaration (February 2011) to the Georgia Office of State Administrative Hearings (OSAH) in the matter of Minor Source HAPs status for the proposed Longleaf Energy Associates power plant (OSAH-BNR-AQ-1115157-60-HOWELLS) on behalf of the Friends of the Chattahoochee and the Sierra Club).

45. Declaration (February 2011) in the matter of the Draft Title V Permit for RRI Energy MidAtlantic Power Holdings LLC Shawville Generating Station (Pennsylvania), ID No. 17-00001 on behalf of the Sierra Club.

46. Expert Report (March 2011), Rebuttal Expert Report (June 2011) on behalf of the United States in *United States of America v. Cemex, Inc.*, Civil Action No. 09-cv-00019-MSK-MEH (District of Colorado).

47. Declaration (April 2011) and Expert Report (July 16, 2012) in the matter of the Lower Colorado River Authority (LCRA)'s Fayette (Sam Seymour) Power Plant on behalf of the Texas Campaign for the Environment. *Texas Campaign for the Environment v. Lower Colorado River Authority,* Civil Action No. 4:11-cv-00791 (Southern District of Texas, Houston Division).

48. Declaration (June 2011) on behalf of the Plaintiffs MYTAPN in the matter of Microsoft-Yes, Toxic Air Pollution-No (MYTAPN) v. State of Washington, Department of Ecology and Microsoft Corporation Columbia Data Center to the Pollution Control Hearings Board, State of Washington, Matter No. PCHB No. 10-162.

49. Expert Report (June 2011) on behalf of the New Hampshire Sierra Club at the State of New Hampshire Public Utilities Commission, Docket No. 10-261 – the 2010 Least Cost Integrated Resource Plan (LCIRP) submitted by the Public Service Company of New Hampshire (re. Merrimack Station Units 1 and 2).

50. Declaration (August 2011) in the matter of the Sandy Creek Energy Associates L.P. Sandy Creek Power Plant on behalf of Sierra Club and Public Citizen. *Sierra Club, Inc. and Public Citizen, Inc. v. Sandy Creek Energy Associates, L.P.*, Civil Action No. A-08-CA-648-LY (Western District of Texas, Austin Division).

51. Expert Report (October 2011) on behalf of the Defendants in the matter of *John Quiles and Jeanette Quiles et al. v. Bradford-White Corporation, MTD Products, Inc., Kohler Co., et al.,* Case No. 3:10-cv-747 (TJM/DEP) (Northern District of New York).

52. Declaration (October 2011) on behalf of the Plaintiffs in the matter of *American Nurses Association et. al. (Plaintiffs), v. US EPA (Defendant)*, Case No. 1:08-cv-02198-RMC (US District Court for the District of Columbia).

53. Declaration (February 2012) and Second Declaration (February 2012) in the matter of *Washington Environmental Council and Sierra Club Washington State Chapter v. Washington State Department of Ecology and Western States Petroleum Association,* Case No. 11-417-MJP (Western District of Washington).

54. Expert Report (March 2012) and Supplemental Expert Report (November 2013) in the matter of *Environment Texas Citizen Lobby, Inc and Sierra Club v.*

*ExxonMobil Corporation et al.,* Civil Action No. 4:10-cv-4969 (Southern District of Texas, Houston Division).

55. Declaration (March 2012) in the matter of *Center for Biological Diversity, et al. v. United States Environmental Protection Agency,* Case No. 11-1101 (consolidated with 11-1285, 11-1328 and 11-1336) (US Court of Appeals for the District of Columbia Circuit).

56. Declaration (March 2012) in the matter of *Sierra Club v. The Kansas Department of Health and Environment*, Case No. 11-105,493-AS (Holcomb power plant) (Supreme Court of the State of Kansas).

57. Declaration (March 2012) in the matter of the Las Brisas Energy Center *Environmental Defense Fund et al., v. Texas Commission on Environmental Quality,* Cause No. D-1-GN-11-001364 (District Court of Travis County, Texas, 261st Judicial District).

58. Expert Report (April 2012), Supplemental and Rebuttal Expert Report (July 2012), and Supplemental Rebuttal Expert Report (August 2012) on behalf of the states of New Jersey and Connecticut in the matter of the Portland Power plant *State of New Jersey and State of Connecticut (Intervenor-Plaintiff) v. RRI Energy Mid-Atlantic Power Holdings et al.,* Civil Action No. 07-CV-5298 (JKG) (Eastern District of Pennsylvania).

59. Declaration (April 2012) in the matter of the EPA's EGU MATS Rule, on behalf of the Environmental Integrity Project.

60. Expert Report (August 2012) on behalf of the United States in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC,* 09-CV100-RET-CN (Middle District of Louisiana) – Harm Phase.

61. Declaration (September 2012) in the Matter of the Application of *Energy Answers Incinerator, Inc.* for a Certificate of Public Convenience and Necessity to Construct a 120 MW Generating Facility in Baltimore City, Maryland, before the Public Service Commission of Maryland, Case No. 9199.

62. Expert Report (October 2012) on behalf of the Appellants (Robert Concilus and Leah Humes) in the matter of Robert Concilus and Leah Humes v. Commonwealth of Pennsylvania Department of Environmental Protection and Crawford Renewable Energy, before the Commonwealth of Pennsylvania Environmental Hearing Board, Docket No. 2011-167-R.

63. Expert Report (October 2012), Supplemental Expert Report (January 2013), and Affidavit (June 2013) in the matter of various Environmental Petitioners v. North Carolina DENR/DAQ and Carolinas Cement Company, before the Office of Administrative Hearings, State of North Carolina.

64. Pre-filed Testimony (October 2012) on behalf of No-Sag in the matter of the North Springfield Sustainable Energy Project before the State of Vermont, Public Service Board.

65. Pre-filed Testimony (November 2012) on behalf of Clean Wisconsin in the matter of Application of Wisconsin Public Service Corporation for Authority to

Construct and Place in Operation a New Multi-Pollutant Control Technology System (ReACT) for Unit 3 of the Weston Generating Station, before the Public Service Commission of Wisconsin, Docket No. 6690-CE-197.

66. Expert Report (February 2013) on behalf of Petitioners in the matter of Credence Crematory, Cause No. 12-A-J-4538 before the Indiana Office of Environmental Adjudication.

67. Expert Report (April 2013), Rebuttal report (July 2013), and Declarations (October 2013, November 2013) on behalf of the Sierra Club in connection with the Luminant Big Brown Case. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Civil Action No. 6:12-cv-00108-WSS (Western District of Texas, Waco Division).

68. Declaration (April 2013) on behalf of Petitioners in the matter of *Sierra Club, et al., (Petitioners) v Environmental Protection Agency et al. (Resppondents),* Case No., 13-1112, (Court of Appeals, District of Columbia Circuit).

69. Expert Report (May 2013) and Rebuttal Expert Report (July 2013) on behalf of the Sierra Club in connection with the Luminant Martin Lake Case. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Civil Action No. 5:10-cv-0156-MHS-CMC (Eastern District of Texas, Texarkana Division).

70. Declaration (August 2013) on behalf of A. J. Acosta Company, Inc., in the matter of *A. J. Acosta Company, Inc., v. County of San Bernardino*, Case No. CIVSS803651.

71. Comments (October 2013) on behalf of the Washington Environmental Council and the Sierra Club in the matter of the Washington State Oil Refinery RACT (for Greenhouse Gases), submitted to the Washington State Department of Ecology, the Northwest Clean Air Agency, and the Puget Sound Clean Air Agency.

72. Statement (November 2013) on behalf of various Environmental Organizations in the matter of the Boswell Energy Center (BEC) Unit 4 Environmental Retrofit Project, to the Minnesota Public Utilities Commission, Docket No. E-015/M-12-920.

73. Expert Report (December 2013) on behalf of the United States in *United States of America v. Ameren Missouri*, Civil Action No. 4:11-cv-00077-RWS (Eastern District of Missouri, Eastern Division).

74. Expert Testimony (December 2013) on behalf of the Sierra Club in the matter of Public Service Company of New Hampshire Merrimack Station Scrubber Project and Cost Recovery, Docket No. DE 11-250, to the State of New Hampshire Public Utilities Commission.

75. Expert Report (January 2014) on behalf of Baja, Inc., in *Baja, Inc., v. Automotive Testing and Development Services, Inc. et. al*, Civil Action No. 8:13-CV-02057-GRA (District of South Carolina, Anderson/Greenwood Division).

76. Declaration (March 2014) on behalf of the Center for International Environmental Law, Chesapeake Climate Action Network, Friends of the Earth, Pacific

Environment, and the Sierra Club (Plaintiffs) in the matter of *Plaintiffs v. the Export-Import Bank (Ex-Im Bank) of the United States*, Civil Action No. 13-1820 RC (District Court for the District of Columbia).

77. Declaration (April 2014) on behalf of Respondent-Intervenors in the matter of *Mexichem Specialty Resins Inc., et al., (Petitioners) v Environmental Protection Agency et al.,* Case No., 12-1260 (and Consolidated Case Nos. 12-1263, 12-1265, 12-1266, and 12-1267), (Court of Appeals, District of Columbia Circuit).

78. Direct Prefiled Testimony (June 2014) on behalf of the Michigan Environmental Council and the Sierra Club in the matter of the Application of DTE Electric Company for Authority to Implement a Power Supply Cost Recovery (PSCR) Plan in its Rate Schedules for 2014 Metered Jurisdictional Sales of Electricity, Case No. U-17319 (Michigan Public Service Commission).

79. Expert Report (June 2014) on behalf of ECM Biofilms in the matter of the US Federal Trade Commission (FTC) v. ECM Biofilms (FTC Docket #9358).

80. Direct Prefiled Testimony (August 2014) on behalf of the Michigan Environmental Council and the Sierra Club in the matter of the Application of Consumers Energy Company for Authority to Implement a Power Supply Cost Recovery (PSCR) Plan in its Rate Schedules for 2014 Metered Jurisdictional Sales of Electricity, Case No. U-17317 (Michigan Public Service Commission).

81. Declaration (July 2014) on behalf of Public Health Intervenors in the matter of *EME Homer City Generation v. US EPA* (Case No. 11-1302 and consolidated cases) relating to the lifting of the stay entered by the Court on December 30, 2011 (US Court of Appeals for the District of Columbia).

82. Expert Report (September 2014), Rebuttal Expert Report (December 2014) and Supplemental Expert Report (March 2015) on behalf of Plaintiffs in the matter of *Sierra Club and Montana Environmental Information Center (Plaintiffs) v. PPL Montana LLC, Avista Corporation, Puget Sound Energy, Portland General Electric Company, Northwestern Corporation, and Pacificorp (Defendants)*, Civil Action No. CV 13-32-BLG-DLC-JCL (US District Court for the District of Montana, Billings Division).

83. Expert Report (November 2014) on behalf of Niagara County, the Town of Lewiston, and the Villages of Lewiston and Youngstown in the matter of CWM Chemical Services, LLC New York State Department of Environmental Conservation (NYSDEC) Permit Application Nos.: 9-2934-00022/00225, 9-2934-00022/00231, 9-2934-00022/00232, and 9-2934-00022/00249 (pending).

84. *Declaration (January 2015) relating to Startup/Shutdown in the MATS Rule (EPA Docket ID No. EPA-HQ-OAR-2009-0234) on behalf of the Environmental Integrity Project.*

85. Pre-filed Direct Testimony (March 2015), Supplemental Testimony (May 2015), and Surrebuttal Testimony (December 2015) on behalf of Friends of the Columbia Gorge in the matter of the Application for a Site Certificate for the Troutdale Energy Center before the Oregon Energy Facility Siting Council.

86. Brief of Amici Curiae Experts in Air Pollution Control and Air Quality Regulation in Support of the Respondents, On Writs of Certiorari to the US Court of Appeals for the District of Columbia, No. 14-46, 47, 48. *Michigan et. al., (Petitioners) v. EPA et. al., Utility Air Regulatory Group (Petitioners) v. EPA et. al., National Mining Association et. al., (Petitioner) v. EPA et. al.,* (Supreme Court of the United States).

87. Expert Report (March 2015) and Rebuttal Expert Report (January 2016) on behalf of Plaintiffs in the matter of *Conservation Law Foundation v. Broadrock Gas Services LLC, Rhode Island LFG GENCO LLC, and Rhode Island Resource Recovery Corporation (Defendants)*, Civil Action No. 1:13-cv-00777-M-PAS (US District Court for the District of Rhode Island).

88. Declaration (April 2015) relating to various Technical Corrections for the MATS Rule (EPA Docket ID No. EPA-HQ-OAR-2009-0234) on behalf of the Environmental Integrity Project.

89. Direct Prefiled Testimony (May 2015) on behalf of the Michigan Environmental Council, the Natural Resources Defense Council, and the Sierra Club in the matter of the Application of DTE Electric Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy and for Miscellaneous Accounting Authority, Case No. U-17767 (Michigan Public Service Commission).

90. Expert Report (July 2015) and Rebuttal Expert Report (July 2015) on behalf of Plaintiffs in the matter of *Northwest Environmental Defense Center et. al., v. Cascade Kelly Holdings LLC, d/b/a Columbia Pacific Bio-Refinery, and Global Partners LP (Defendants),* Civil Action No. 3:14-cv-01059-SI (US District Court for the District of Oregon, Portland Division).

91. Declaration (August 2015, Docket No. 1570376) in support of "Opposition of Respondent-Intervenors American Lung Association, et. al., to Tri-State Generation's Emergency Motion;" Declaration (September 2015, Docket No. 1574820) in support of "Joint Motion of the State, Local Government, and Public Health Respondent-Intervenors for Remand Without Vacatur;" Declaration (October 2015) in support of "Joint Motion of the State, Local Government, and Public Health Respondent-Intervenors to State and Certain Industry Petitioners' Motion to Govern, *White Stallion Energy Center, LLC v. US EPA*, Case No. 12-1100 (US Court of Appeals for the District of Columbia).

92. Declaration (September 2015) in support of the Draft Title V Permit for Dickerson Generating Station (Proposed Permit No 24-031-0019) on behalf of the Environmental Integrity Project.

93. Expert Report (Liability Phase) (December 2015) and Rebuttal Expert Report (February 2016) on behalf of Plaintiffs in the matter of *Natural Resources Defense Council, Inc., Sierra Club, Inc., Environmental Law and Policy Center, and Respiratory Health Association v. Illinois Power Resources LLC, and Illinois Power Resources Generating LLC (Defendants),* Civil Action No. 1:13-cv-01181 (US District Court for the Central District of Illinois, Peoria Division).

94. Declaration (December 2015) in support of the Petition to Object to the Title V Permit for Morgantown Generating Station (Proposed Permit No 24-017-0014) on behalf of the Environmental Integrity Project.

95. Expert Report (November 2015) on behalf of Appellants in the matter of *Sierra Club, et al. v. Craig W. Butler, Director of Ohio Environmental Protection Agency et al.*, ERAC Case No. 14-256814.

96. Affidavit (January 2016) on behalf of Bridgewatch Detroit in the matter of *Bridgewatch Detroit v. Waterfront Petroleum Terminal Co., and Waterfront Terminal Holdings, LLC.*, in the Circuit Court for the County of Wayne, State of Michigan.

97. Expert Report (February 2016) and Rebuttal Expert Report (July 2016) on behalf of the challengers in the matter of the Delaware Riverkeeper Network, Clean Air Council, et. al., vs. Commonwealth of Pennsylvania Department of Environmental Protection and R. E. Gas Development LLC regarding the Geyer well site before the Pennsylvania Environmental Hearing Board.

98. Direct Testimony (May 2016) in the matter of Tesoro Savage LLC Vancouver Energy Distribution Terminal, Case No. 15-001 before the State of Washington Energy Facility Site Evaluation Council.

99. Declaration (June 2016) relating to deficiencies in air quality analysis for the proposed Millenium Bulk Terminal, Port of Longview, Washington.

100. Declaration (December 2016) relating to EPA's refusal to set limits on PM emissions from coal-fired power plants that reflect pollution reductions achievable with fabric filters on behalf of Environmental Integrity Project, Clean Air Council, Chesapeake Climate Action Network, Downwinders at Risk represented by Earthjustice in the matter of *ARIPPA v EPA, Case No. 15-1180.* (D.C. Circuit Court of Appeals).

101. Expert Report (January 2017) on the Environmental Impacts Analysis associated with the Huntley and Huntley Poseidon Well Pad on behalf citizens in the matter of the special exception use Zoning Hearing Board of Penn Township, Westmoreland County, Pennsylvania.

102. Expert Report (January 2017) on the Environmental Impacts Analysis associated with the Apex Energy Backus Well Pad on behalf citizens in the matter of the special exception use Zoning Hearing Board of Penn Township, Westmoreland County, Pennsylvania.

103. Expert Report (January 2017) on the Environmental Impacts Analysis associated with the Apex Energy Drakulic Well Pad on behalf citizens in the matter of the special exception use Zoning Hearing Board of Penn Township, Westmoreland County, Pennsylvania.

104. Expert Report (January 2017) on the Environmental Impacts Analysis associated with the Apex Energy Deutsch Well Pad on behalf citizens in the matter of the special exception use Zoning Hearing Board of Penn Township, Westmoreland County, Pennsylvania.

105. Affidavit (February 2017) pertaining to deficiencies water discharge compliance issues at the Wood River Refinery in the matter of *People of the State of Illinois (Plaintiff) v. Phillips 66 Company, ConocoPhillips Company, WRB Refining LP (Defendants),* Case No. 16-CH-656, (Circuit Court for the Third Judicial Circuit, Madison County, Illinois).

106. Expert Report (March 2017) on behalf of the Plaintiff pertaining to non-degradation analysis for waste water discharges from a power plant in the matter of *Sierra Club (Plaintiff) v. Pennsylvania Department of Environmental Protection (PADEP) and Lackawanna Energy Center,* Docket No. 2016-047-L (consolidated), (Pennsylvania Environmental Hearing Board).

107. Expert Report (March 2017) on behalf of the Plaintiff pertaining to air emissions from the Heritage incinerator in East Liverpool, Ohio in the matter of *Save our County (Plaintiff) v. Heritage Thermal Services, Inc. (Defendant), Case No. 4:16-CV-1544-BYP*, (US District Court for the Northern District of Ohio, Eastern Division).

108. Rebuttal Expert Report (June 2017) on behalf of Plaintiffs in the matter of *Casey Voight and Julie Voight (Plaintiffs) v Coyote Creek Mining Company LLC (Defendant),* Civil Action No. 1:15-CV-00109 (US District Court for the District of North Dakota, Western Division).

109. Expert Affidavit (August 2017) and Penalty/Remedy Expert Affidavit (October 2017) on behalf of Plaintiff in the matter of *Wildearth Guardians (Plaintiff) v Colorado Springs Utility Board (Defendant,)* Civil Action No. 1:15-cv-00357-CMA-CBS (US District Court for the District of Colorado).

110. Expert Report (August 2017) on behalf of Appellant in the matter of *Patricia Ann Troiano (Appellant) v. Upper Burrell Township Zoning Hearing Board (Appellee),* Court of Common Pleas of Westmoreland County, Pennsylvania, Civil Division.

111. Expert Report (October 2017), Supplemental Expert Report (October 2017), and Rebuttal Expert Report (November 2017) on behalf of Defendant in the matter of *Oakland Bulk and Oversized Terminal (Plaintiff) v City of Oakland (Defendant,)* Civil Action No. 3:16-cv-07014-VC (US District Court for the Northern District of California, San Francisco Division).

112. Declaration (December 2017) on behalf of the Environmental Integrity Project in the matter of permit issuance for ATI Flat Rolled Products Holdings, Breckenridge, PA to the Allegheny County Health Department.

113. Expert Report (Harm Phase) (January 2018), Rebuttal Expert Report (Harm Phase) (May 2018) and Supplemental Expert Report (Harm Phase) (April 2019) on behalf of Plaintiffs in the matter of *Natural Resources Defense Council, Inc., Sierra Club, Inc., and Respiratory Health Association v. Illinois Power Resources LLC, and Illinois Power Resources Generating LLC (Defendants),* Civil Action No. 1:13-cv-01181 (US District Court for the Central District of Illinois, Peoria Division).

114. Declaration (February 2018) on behalf of the Chesapeake Bay Foundation, et. al., in the matter of the Section 126 Petition filed by the state of Maryland in *State of*

*Maryland v. Pruitt (Defendant)*, Civil Action No. JKB-17-2939 (Consolidated with No. JKB-17-2873) (US District Court for the District of Maryland).

115. Direct Pre-filed Testimony (March 2018) on behalf of the National Parks Conservation Association (NPCA) in the matter of *NPCA v State of Washington, Department of Ecology and BP West Coast Products, LLC*, PCHB No. 17-055 (Pollution Control Hearings Board for the State of Washington.

116. Expert Affidavit (April 2018) and Second Expert Affidavit (May 2018) on behalf of Petitioners in the matter of *Coosa River Basin Initiative and Sierra Club (Petitioners) v State of Georgia Environmental Protection Division, Georgia Department of Natural Resources (Respondent) and Georgia Power Company (Intervenor/Respondent)*, Docket Nos: 1825406-BNR-WW-57-Howells and 1826761-BNR-WW-57-Howells, Office of State Administrative Hearings, State of Georgia.

117. Direct Pre-filed Testimony and Affidavit (December 2018) on behalf of Sierra Club and Texas Campaign for the Environment (Appellants) in the contested case hearing before the Texas State Office of Administrative Hearings in Docket Nos. 582-18-4846, 582-18-4847 (Application of GCGV Asset Holding, LLC for Air Quality Permit Nos. 146425/PSDTX1518 and 146459/PSDTX1520 in San Patricio County, Texas).

118. Expert Report (February 2019) on behalf of Sierra Club in the State of Florida, Division of Administrative Hearings, Case No. 18-2124EPP, Tampa Electric Company Big Bend Unit 1 Modernization Project Power Plant Siting Application No. PA79-12-A2.

119. Declaration (March 2019) on behalf of Earthjustice in the matter of comments on the renewal of the Title V Federal Operating Permit for Valero Houston refinery.

120. Expert Report (March 2019) on behalf of Plaintiffs for Class Certification in the matter of *Resendez et al v Precision Castparts Corporation* in the Circuit Court for the State of Oregon, County of Multnomah, Case No. 16cv16164.

121. Expert Report (June 2019), Affidavit (July 2019) and Rebuttal Expert Report (September 2019) on behalf of Appellants relating to the NPDES permit for the Cheswick power plant in the matter of *Three Rivers Waterkeeper and Sierra Club (Appellees) v. State of Pennsylvania Department of Environmental Protection (Appellee) and NRG Power Midwest (Permittee)*, before the Commonwealth of Pennsylvania Environmental Hearing Board, EHB Docket No. 2018-088-R.

122. Affidavit/Expert Report (August 2019) relating to the appeal of air permits issued to PTTGCA on behalf of Appellants in the matter of *Sierra Club (Appellants) v. Craig Butler, Director, et. al., Ohio EPA (Appellees)* before the State of Ohio Environmental Review Appeals Commission (ERAC), Case Nos. ERAC-19-6988 through -6991.

123. Expert Report (October 2019) relating to the appeal of air permit (Plan Approval) on behalf of Appellants in the matter of *Clean Air Council and Environmental Integrity Project (Appellants) v. Commonwealth of Pennsylvania Department of Environmental Protection and Sunoco Partners Marketing and Terminals L.P.*,

before the Commonwealth of Pennsylvania Environmental Hearing Board, EHB Docket No. 2018-057-L.

124. Expert Report (December 2019) on behalf of Earthjustice in the matter of *Objection to the Issuance of PSD/NSR and Title V permits for Riverview Energy Corporation*, Dale, Indiana, before the Indiana Office of Environmental Adjudication, Cause No. 19-A-J-5073.

125. Affidavit (December 2019) on behalf of Plaintiff-Intervenor (Surfrider Foundation) in the matter of *United States and the State of Indiana (Plaintiffs), Surfrider Foundation (Plaintiff-Intervenor), and City of Chicago (Plaintiff-Intervenor) v. United States Steel Corporation (Defendant),* Civil Action No. 2:18-cv-00127 (US District Court for the Northern District of Indiana, Hammond Division).

126. Declaration (February 2020) in support of Petitioner's Motion for Stay of PSCAA NOC Order of Approval No. 11386 in the matter of the *Puyallup Tribe of Indians v. Puget Sound Clean Air Agency (PSCAA) and Puget Sound Energy (PSE), before the State of Washington Pollution Control Hearings Board*, PCHB No. P19-088.

C. Occasions where Dr. Sahu has provided oral testimony <u>in depositions, at trial or in similar proceedings</u> include the following:

127. Deposition on behalf of Rocky Mountain Steel Mills, Inc. located in Pueblo, Colorado – dealing with the manufacture of steel in mini-mills including methods of air pollution control and BACT in steel mini-mills and opacity issues at this steel mini-mill.

128. Trial Testimony (February 2002) on behalf of Rocky Mountain Steel Mills, Inc. in Denver District Court.

129. Trial Testimony (February 2003) on behalf of the United States in the Ohio Edison NSR Cases, *United States, et al. v. Ohio Edison Co., et al.*, C2-99-1181 (Southern District of Ohio).

130. Trial Testimony (June 2003) on behalf of the United States in the Illinois Power NSR Case, *United States v. Illinois Power Co., et al.*, 99-833-MJR (Southern District of Illinois).

131. Deposition (10/20/2005) on behalf of the United States in connection with the Cinergy NSR Case. *United States, et* al. *v. Cinergy Corp., et al.*, IP 99-1693-C-M/S (Southern District of Indiana).

132. Oral Testimony (August 2006) on behalf of the Appalachian Center for the Economy and the Environment re. the Western Greenbrier plant, WV before the West Virginia DEP.

133. Oral Testimony (May 2007) on behalf of various Montana petitioners (Citizens Awareness Network (CAN), Women's Voices for the Earth (WVE) and the Clark

Fork Coalition (CFC)) re. the Thompson River Cogeneration plant before the Montana Board of Environmental Review.

134. Oral Testimony (October 2007) on behalf of the Sierra Club re. the Sevier Power Plant before the Utah Air Quality Board.

135. Oral Testimony (August 2008) on behalf of the Sierra Club and Clean Water re. Big Stone Unit II before the South Dakota Board of Minerals and the Environment.

136. Oral Testimony (February 2009) on behalf of the Sierra Club and the Southern Environmental Law Center re. Santee Cooper Pee Dee units before the South Carolina Board of Health and Environmental Control.

137. Oral Testimony (February 2009) on behalf of the Sierra Club and the Environmental Integrity Project re. NRG Limestone Unit 3 before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

138. Deposition (July 2009) on behalf of MTD Products, Inc., in the matter of *Alice Holmes and Vernon Holmes v. Home Depot USA, Inc., et al*.

139. Deposition (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed Coleto Creek coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

140. Deposition (October 2009) on behalf of Environmental Defense, in the matter of permit challenges to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

141. Deposition (October 2009) on behalf of the Sierra Club, in the matter of challenges to the proposed Medicine Bow Fuel and Power IGL plant in Cheyenne, Wyoming.

142. Deposition (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed Tenaska coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH). (April 2010).

143. Oral Testimony (November 2009) on behalf of the Environmental Defense Fund re. the Las Brisas Energy Center before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

144. Deposition (December 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed White Stallion Energy Center coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

145. Oral Testimony (February 2010) on behalf of the Environmental Defense Fund re. the White Stallion Energy Center before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

146. Deposition (June 2010) on behalf of the United States in connection with the Alabama Power Company NSR Case. *United States v. Alabama Power Company*, CV-01-HS-152-S (Northern District of Alabama, Southern Division).

147. Trial Testimony (September 2010) on behalf of Commonwealth of Pennsylvania – Dept. of Environmental Protection, State of Connecticut, State of New York, State of Maryland, and State of New Jersey (Plaintiffs) in connection with the Allegheny Energy NSR Case in US District Court in the Western District of Pennsylvania. *Plaintiffs v. Allegheny Energy Inc., et al.*, 2:05cv0885 (Western District of Pennsylvania).

148. Oral Direct and Rebuttal Testimony (September 2010) on behalf of Fall-Line Alliance for a Clean Environment and others in the matter of the PSD Air Permit for Plant Washington issued by Georgia DNR at the Office of State Administrative Hearing, State of Georgia (OSAH-BNR-AQ-1031707-98-WALKER).

149. Oral Testimony (September 2010) on behalf of the State of New Mexico Environment Department in the matter of Proposed Regulation 20.2.350 NMAC – *Greenhouse Gas Cap and Trade Provisions*, No. EIB 10-04 (R), to the State of New Mexico, Environmental Improvement Board.

150. Oral Testimony (October 2010) on behalf of the Environmental Defense Fund re. the Las Brisas Energy Center before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

151. Oral Testimony (November 2010) regarding BART for PSCo Hayden, CSU Martin Drake units before the Colorado Air Quality Commission on behalf of the Coalition of Environmental Organizations.

152. Oral Testimony (December 2010) regarding BART for TriState Craig Units, CSU Nixon Unit, and PRPA Rawhide Unit) before the Colorado Air Quality Commission on behalf of the Coalition of Environmental Organizations.

153. Deposition (December 2010) on behalf of the United States in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana).

154. Deposition (February 2011 and January 2012) on behalf of Wild Earth Guardians in the matter of opacity exceedances and monitor downtime at the Public Service Company of Colorado (Xcel)'s Cherokee power plant. No. 09-cv-1862 (D. Colo.).

155. Oral Testimony (February 2011) to the Georgia Office of State Administrative Hearings (OSAH) in the matter of Minor Source HAPs status for the proposed Longleaf Energy Associates power plant (OSAH-BNR-AQ-1115157-60-HOWELLS) on behalf of the Friends of the Chattahoochee and the Sierra Club).

156. Deposition (August 2011) on behalf of the United States in *United States of America v. Cemex, Inc.*, Civil Action No. 09-cv-00019-MSK-MEH (District of Colorado).

157. Deposition (July 2011) and Oral Testimony at Hearing (February 2012) on behalf of the Plaintiffs MYTAPN in the matter of Microsoft-Yes, Toxic Air Pollution-No (MYTAPN) v. State of Washington, Department of Ecology and Microsoft Corporation Columbia Data Center to the Pollution Control Hearings Board, State of Washington, Matter No. PCHB No. 10-162.

158. Oral Testimony at Hearing (March 2012) on behalf of the United States in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana).

159. Oral Testimony at Hearing (April 2012) on behalf of the New Hampshire Sierra Club at the State of New Hampshire Public Utilities Commission, Docket No. 10-261 – the 2010 Least Cost Integrated Resource Plan (LCIRP) submitted by the Public Service Company of New Hampshire (re. Merrimack Station Units 1 and 2).

160. Oral Testimony at Hearing (November 2012) on behalf of Clean Wisconsin in the matter of Application of Wisconsin Public Service Corporation for Authority to Construct and Place in Operation a New Multi-Pollutant Control Technology System (ReACT) for Unit 3 of the Weston Generating Station, before the Public Service Commission of Wisconsin, Docket No. 6690-CE-197.

161. Deposition (March 2013) in the matter of various Environmental Petitioners v. North Carolina DENR/DAQ and Carolinas Cement Company, before the Office of Administrative Hearings, State of North Carolina.

162. Deposition (August 2013) on behalf of the Sierra Club in connection with the Luminant Big Brown Case. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Civil Action No. 6:12-cv-00108-WSS (Western District of Texas, Waco Division).

163. Deposition (August 2013) on behalf of the Sierra Club in connection with the Luminant Martin Lake Case. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Civil Action No. 5:10-cv-0156-MHS-CMC (Eastern District of Texas, Texarkana Division).

164. Deposition (February 2014) on behalf of the United States in *United States of America v. Ameren Missouri*, Civil Action No. 4:11-cv-00077-RWS (Eastern District of Missouri, Eastern Division).

165. Trial Testimony (February 2014) in the matter of *Environment Texas Citizen Lobby, Inc and Sierra Club v. ExxonMobil Corporation et al.*, Civil Action No. 4:10-cv-4969 (Southern District of Texas, Houston Division).

166. Trial Testimony (February 2014) on behalf of the Sierra Club in connection with the Luminant Big Brown Case. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Civil Action No. 6:12-cv-00108-WSS (Western District of Texas, Waco Division).

167. Deposition (June 2014) and Trial (August 2014) on behalf of ECM Biofilms in the matter of the *US Federal Trade Commission (FTC) v. ECM Biofilms* (FTC Docket #9358).

168. Deposition (February 2015) on behalf of Plaintiffs in the matter of *Sierra Club and Montana Environmental Information Center (Plaintiffs) v. PPL Montana LLC, Avista Corporation, Puget Sound Energy, Portland General Electric Company, Northwestern Corporation, and Pacificorp (Defendants)*, Civil Action No. CV

13-32-BLG-DLC-JCL (US District Court for the District of Montana, Billings Division).

169. Oral Testimony at Hearing (April 2015) on behalf of Niagara County, the Town of Lewiston, and the Villages of Lewiston and Youngstown in the matter of CWM Chemical Services, LLC New York State Department of Environmental Conservation (NYSDEC) Permit Application Nos.: 9-2934-00022/00225, 9-2934-00022/00231, 9-2934-00022/00232, and 9-2934-00022/00249 (pending).

170. Deposition (August 2015) on behalf of Plaintiff in the matter of *Conservation Law Foundation (Plaintiff) v. Broadrock Gas Services LLC, Rhode Island LFG GENCO LLC, and Rhode Island Resource Recovery Corporation (Defendants)*, Civil Action No. 1:13-cv-00777-M-PAS (US District Court for the District of Rhode Island).

171. Testimony at Hearing (August 2015) on behalf of the Sierra Club in the matter of *Amendments to 35 Illinois Administrative Code Parts 214, 217, and 225* before the Illinois Pollution Control Board, R15-21.

172. Deposition (May 2015) on behalf of Plaintiffs in the matter of *Northwest Environmental Defense Center et. al., (Plaintiffs) v. Cascade Kelly Holdings LLC, d/b/a Columbia Pacific Bio-Refinery, and Global Partners LP (Defendants)*, Civil Action No. 3:14-cv-01059-SI (US District Court for the District of Oregon, Portland Division).

173. Trial Testimony (October 2015) on behalf of Plaintiffs in the matter of *Northwest Environmental Defense Center et. al., (Plaintiffs) v. Cascade Kelly Holdings LLC, d/b/a Columbia Pacific Bio-Refinery, and Global Partners LP (Defendants)*, Civil Action No. 3:14-cv-01059-SI (US District Court for the District of Oregon, Portland Division).

174. Deposition (April 2016) on behalf of the Plaintiffs in *UNatural Resources Defense Council, Respiratory Health Association, and Sierra Club (Plaintiffs) v. Illinois Power Resources LLC and Illinois Power Resources Generation LLC (Defendants)*, Civil Action No. 1:13-cv-01181 (Central District of Illinois, Peoria Division).

175. Trial Testimony at Hearing (July 2016) in the matter of Tesoro Savage LLC Vancouver Energy Distribution Terminal, Case No. 15-001 before the State of Washington Energy Facility Site Evaluation Council.

176. Trial Testimony (December 2016) on behalf of the challengers in the matter of the Delaware Riverkeeper Network, Clean Air Council, et. al., vs. Commonwealth of Pennsylvania Department of Environmental Protection and R. E. Gas Development LLC regarding the Geyer well site before the Pennsylvania Environmental Hearing Board.

177. Trial Testimony (July-August 2016) on behalf of the United States in *United States of America v. Ameren Missouri*, Civil Action No. 4:11-cv-00077-RWS (Eastern District of Missouri, Eastern Division).

178. Trial Testimony (January 2017) on the Environmental Impacts Analysis associated with the Huntley and Huntley Poseidon Well Pad Hearing on behalf citizens in the matter of the special exception use Zoning Hearing Board of Penn Township, Westmoreland County, Pennsylvania.

179. Trial Testimony (January 2017) on the Environmental Impacts Analysis associated with the Apex energy Backus Well Pad Hearing on behalf citizens in the matter of the special exception use Zoning Hearing Board of Penn Township, Westmoreland County, Pennsylvania.

180. Trial Testimony (January 2017) on the Environmental Impacts Analysis associated with the Apex energy Drakulic Well Pad Hearing on behalf citizens in the matter of the special exception use Zoning Hearing Board of Penn Township, Westmoreland County, Pennsylvania.

181. Trial Testimony (January 2017) on the Environmental Impacts Analysis associated with the Apex energy Deutsch Well Pad Hearing on behalf citizens in the matter of the special exception use Zoning Hearing Board of Penn Township, Westmoreland County, Pennsylvania.

182. Deposition Testimony (July 2017) on behalf of Plaintiffs in the matter of *Casey Voight and Julie Voight v Coyote Creek Mining Company LLC (Defendant)* Civil Action No. 1:15-CV-00109 (US District Court for the District of North Dakota, Western Division).

183. Deposition Testimony (November 2017) on behalf of Defendant in the matter of *Oakland Bulk and Oversized Terminal (Plaintiff) v City of Oakland (Defendant,)* Civil Action No. 3:16-cv-07014-VC (US District Court for the Northern District of California, San Francisco Division).

184. Deposition Testimony (December 2017) on behalf of Plaintiff in the matter of *Wildearth Guardians (Plaintiff) v Colorado Springs Utility Board (Defendant)* Civil Action No. 1:15-cv-00357-CMA-CBS (US District Court for the District of Colorado).

185. Deposition Testimony (January 2018) in the matter of National Parks Conservation Association (NPCA) v. State of Washington Department of Ecology and British Petroleum (BP) before the Washington Pollution Control Hearing Board, Case No. 17-055.

186. Trial Testimony (January 2018) on behalf of Defendant in the matter of *Oakland Bulk and Oversized Terminal (Plaintiff) v City of Oakland (Defendant,)* Civil Action No. 3:16-cv-07014-VC (US District Court for the Northern District of California, San Francisco Division).

187. Trial Testimony (April 2018) on behalf of the National Parks Conservation Association (NPCA) in the matter of NPCA v State of Washington, Department of Ecology and BP West Coast Products, LLC, PCHB No. 17-055 (Pollution Control Hearings Board for the State of Washington.

188. Deposition (June 2018) (harm Phase) on behalf of Plaintiffs in the matter of *Natural Resources Defense Council, Inc., Sierra Club, Inc., and Respiratory*

*Health Association v. Illinois Power Resources LLC, and Illinois Power Resources Generating LLC (Defendants)*, Civil Action No. 1:13-cv-01181 (US District Court for the Central District of Illinois, Peoria Division).

189. Trial Testimony (July 2018) on behalf of Petitioners in the matter of *Coosa River Basin Initiative and Sierra Club (Petitioners) v State of Georgia Environmental Protection Division, Georgia Department of Natural Resources (Respondent) and Georgia Power Company (Intervenor/Respondent)*, Docket Nos: 1825406-BNR-WW-57-Howells and 1826761-BNR-WW-57-Howells, Office of State Administrative Hearings, State of Georgia.

190. Deposition (January 2019) and Trial Testimony (January 2019) on behalf of Sierra Club and Texas Campaign for the Environment (Appellants) in the contested case hearing before the Texas State Office of Administrative Hearings in Docket Nos. 582-18-4846, 582-18-4847 (Application of GCGV Asset Holding, LLC for Air Quality Permit Nos. 146425/PSDTX1518 and 146459/PSDTX1520 in San Patricio County, Texas).

191. Deposition (February 2019) and Trial Testimony (March 2019) on behalf of Sierra Club in the State of Florida, Division of Administrative Hearings, Case No. 18-2124EPP, Tampa Electric Company Big Bend Unit 1 Modernization Project Power Plant Siting Application No. PA79-12-A2.

192. Deposition (June 2019) relating to the appeal of air permits issued to PTTGCA on behalf of Appellants in the matter of *Sierra Club (Appellants) v. Craig Butler, Director, et. al., Ohio EPA (Appellees)* before the State of Ohio Environmental Review Appeals Commission (ERAC), Case Nos. ERAC-19-6988 through -6991.

193. Deposition (September 2019) on behalf of Appellants relating to the NPDES permit for the Cheswick power plant in the matter of *Three Rivers Waterkeeper and Sierra Club (Appellees) v. State of Pennsylvania Department of Environmental Protection (Appellee) and NRG Power Midwest (Permittee)*, before the Commonwealth of Pennsylvania Environmental Hearing Board, EHB Docket No. 2018-088-R.

194. Deposition (December 2019) on behalf of the Plaintiffs in the matter of David Kovac, individually and on behalf of wrongful death class of Irene Kovac v. Bp Corporation North America Inc., Circuit Court of Jackson County, Missouri (Independence), Case No. 1816-CV12417.

195. Deposition (February 2020) on behalf of Earthjustice in the matter of *Objection to the Issuance of PSD/NSR and Title V permits for Riverview Energy Corporation*, Dale, Indiana, before the Indiana Office of Environmental Adjudication, Cause No. 19-A-J-5073.

# Exhibit RS-B

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

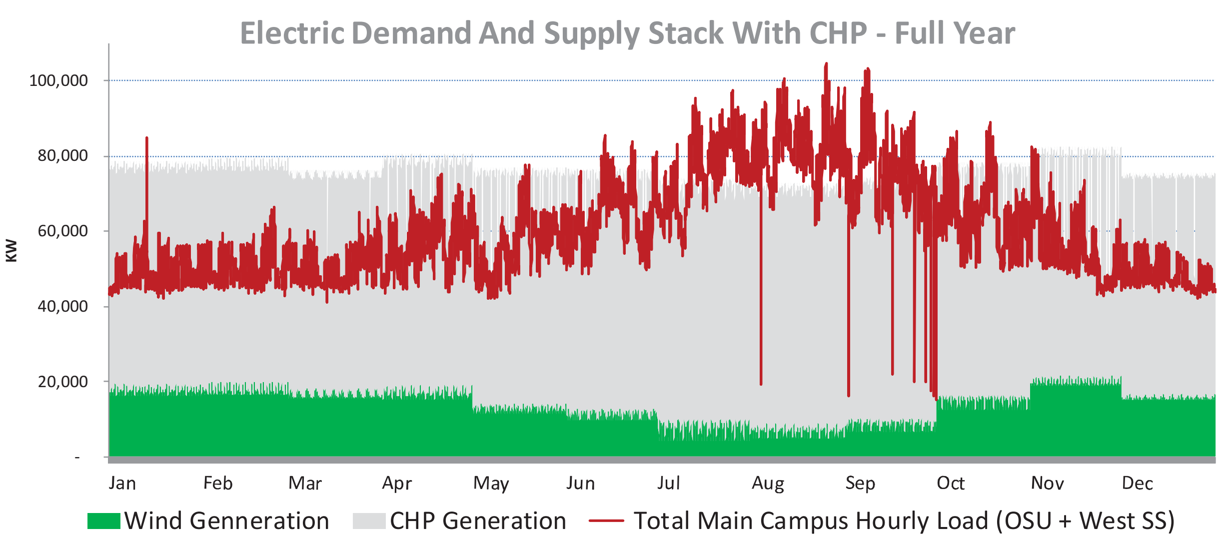


**Figure i-1:** Ohio State University's demand and supply stack with CHP and wind for the full calendar year

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<br>• Condensing steam turbine with an extraction for process steam.<br>• Supplemental duct burners for increased steam production.<br>• 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<br>or<br>2x1 SGT 600 | • Two heat recovery steam generators<br>• Condensing steam turbine with an extraction for process steam.<br>• Supplemental duct burners for increased steam production. |
| Case 3 | Midwest Campus | 2x1 Titan 250<br>or<br>2x1 SGT 600 | • Two heat recovery steam generators<br>• Condensing steam turbine with an extraction for process steam.<br>• 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<br>• Condensing steam turbine with an extraction for process steam.<br>• Supplemental duct burners for increased steam production.<br>• 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.

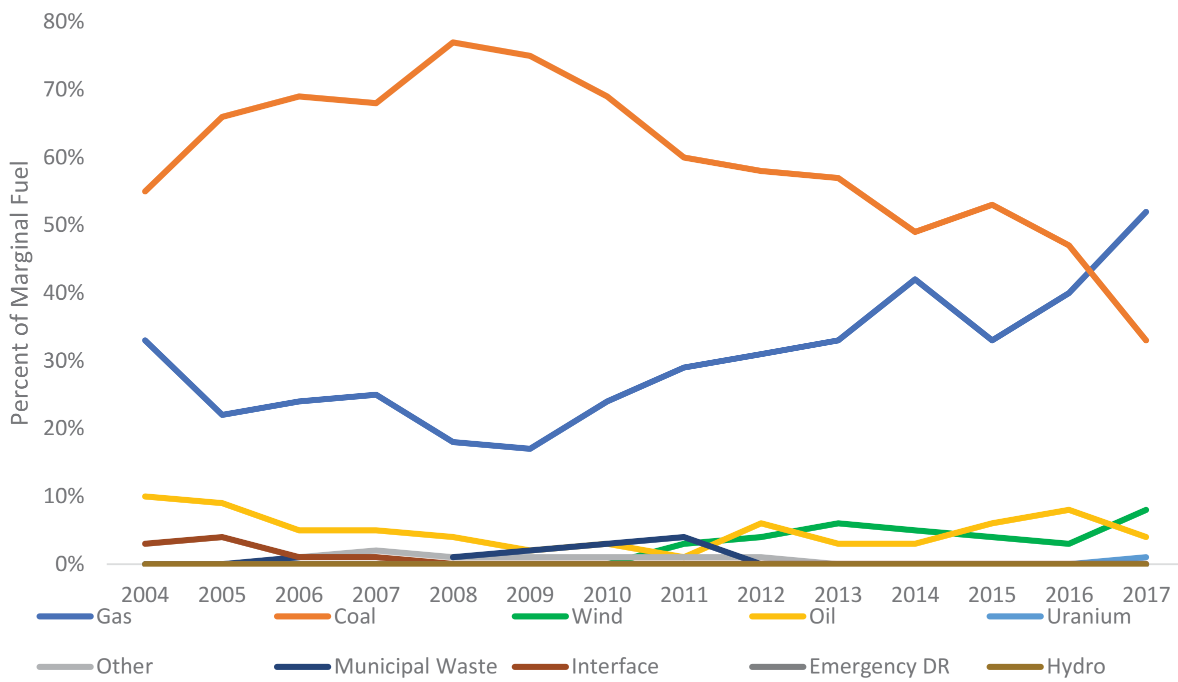


**Figure 1-3:** Type of fuel used in PJM market from 2004 to 2017

## 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.

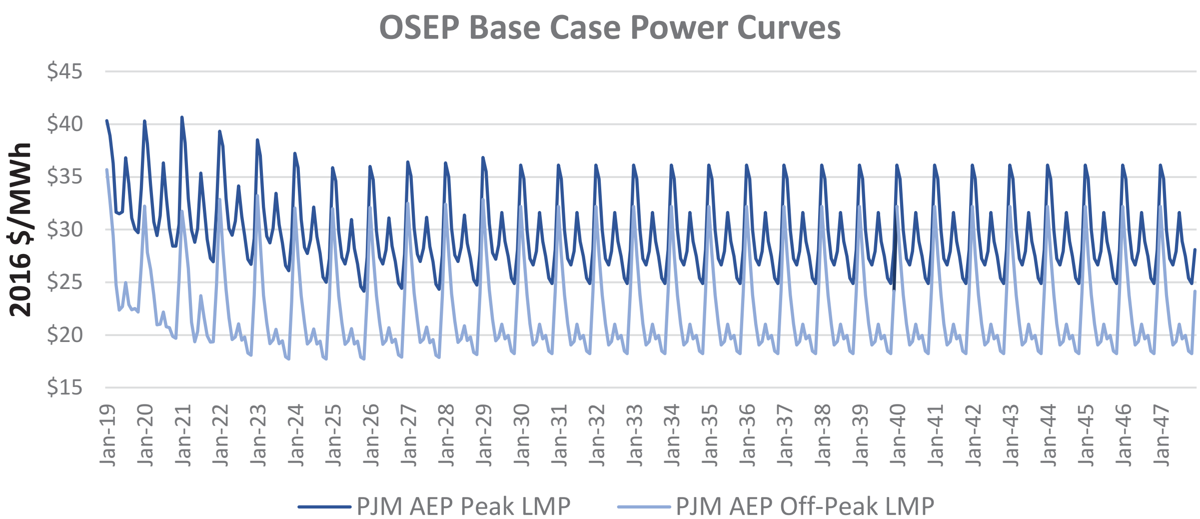


**Figure 1-4:** LMP forward price projection

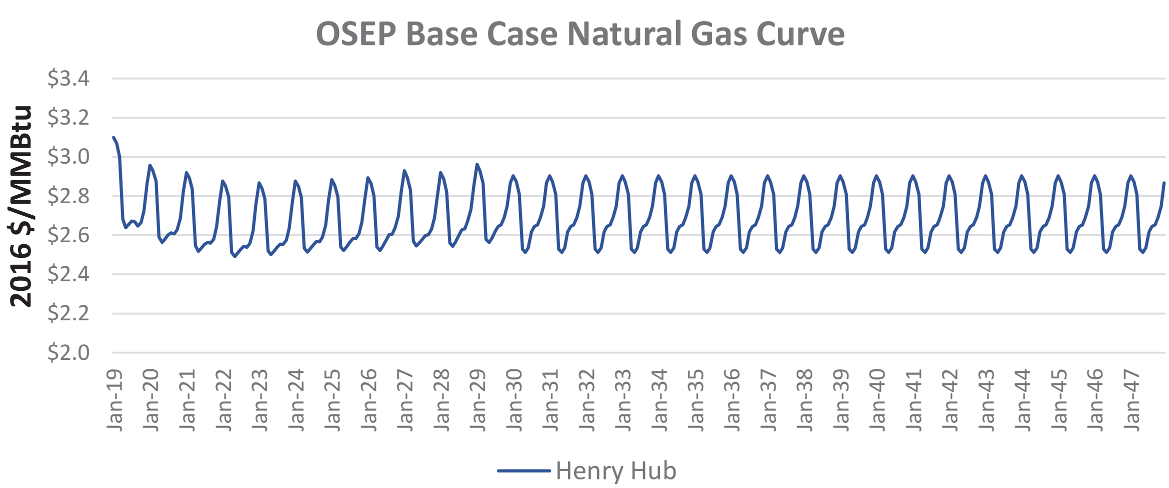


**Figure 1-5**: Henry Hub forward price projection

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.

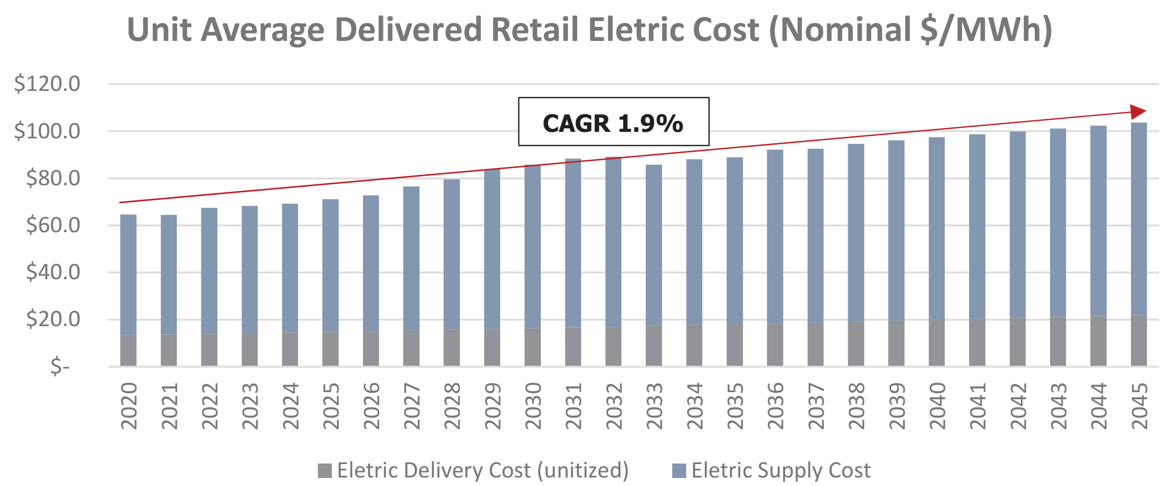


**Figure 1-6:** CAGR for delivered retail electric cost is less than inflation of 2% and historical growth of 2.4%

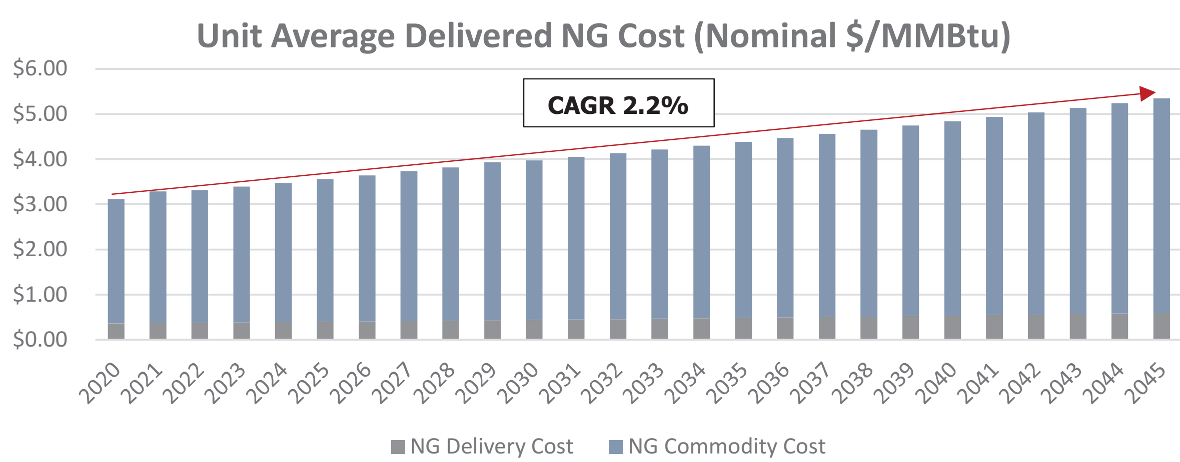


**Figure 1-7:** CAGR for natural gas is 2.2%; prices have come with vast natural gas reserve and Shale play in the U.S.

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:

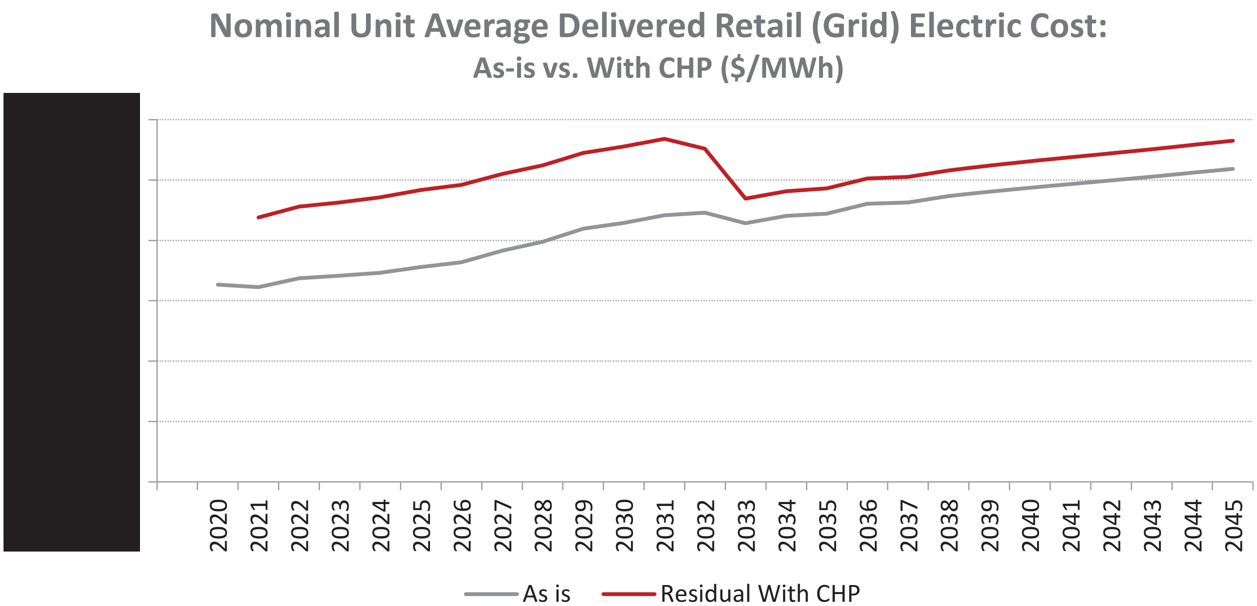


**Figure 1-8:** Residual grid supply costs expected to increase after implementation of CHP

## 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.

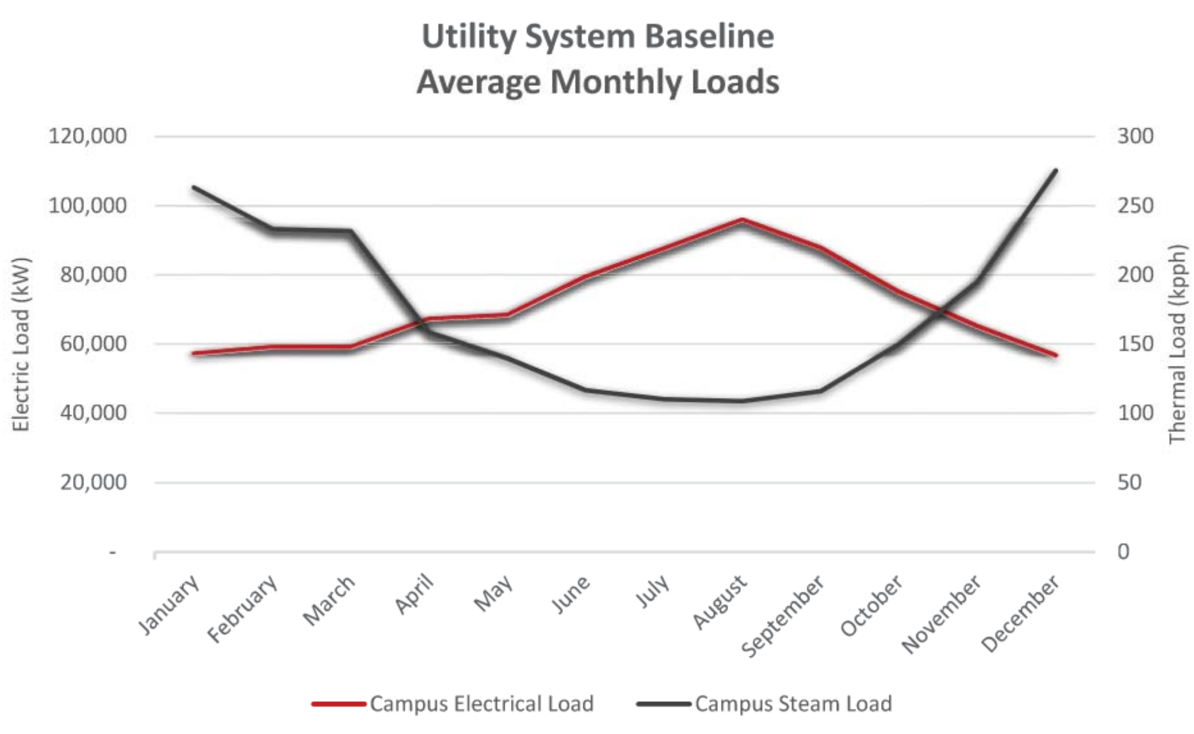


**Figure 2-1:** Historical electrical and steam loads

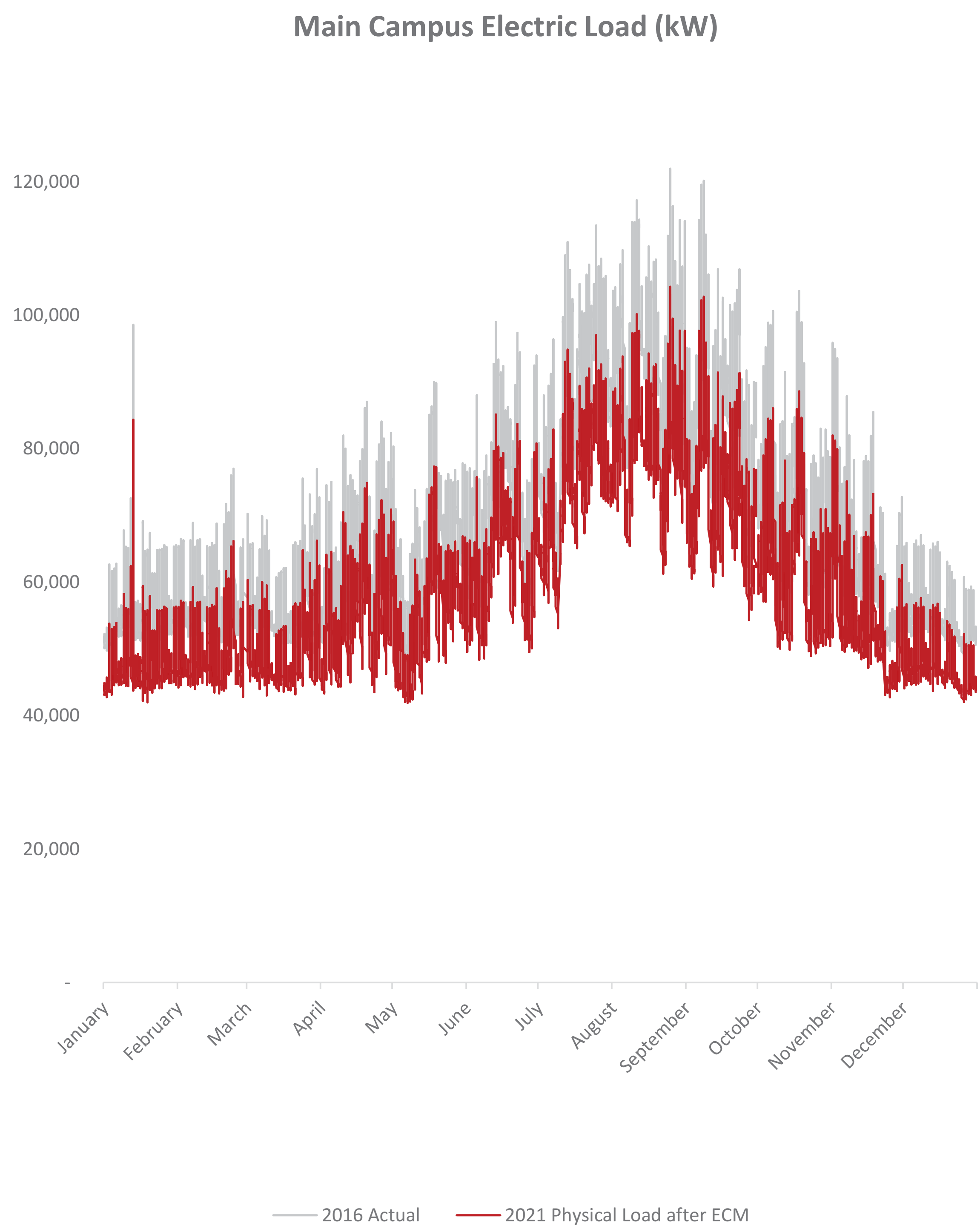


**Figure 2-2:** Historical electric profile Main Campus (OSU + West SS) and available physical load after ECM

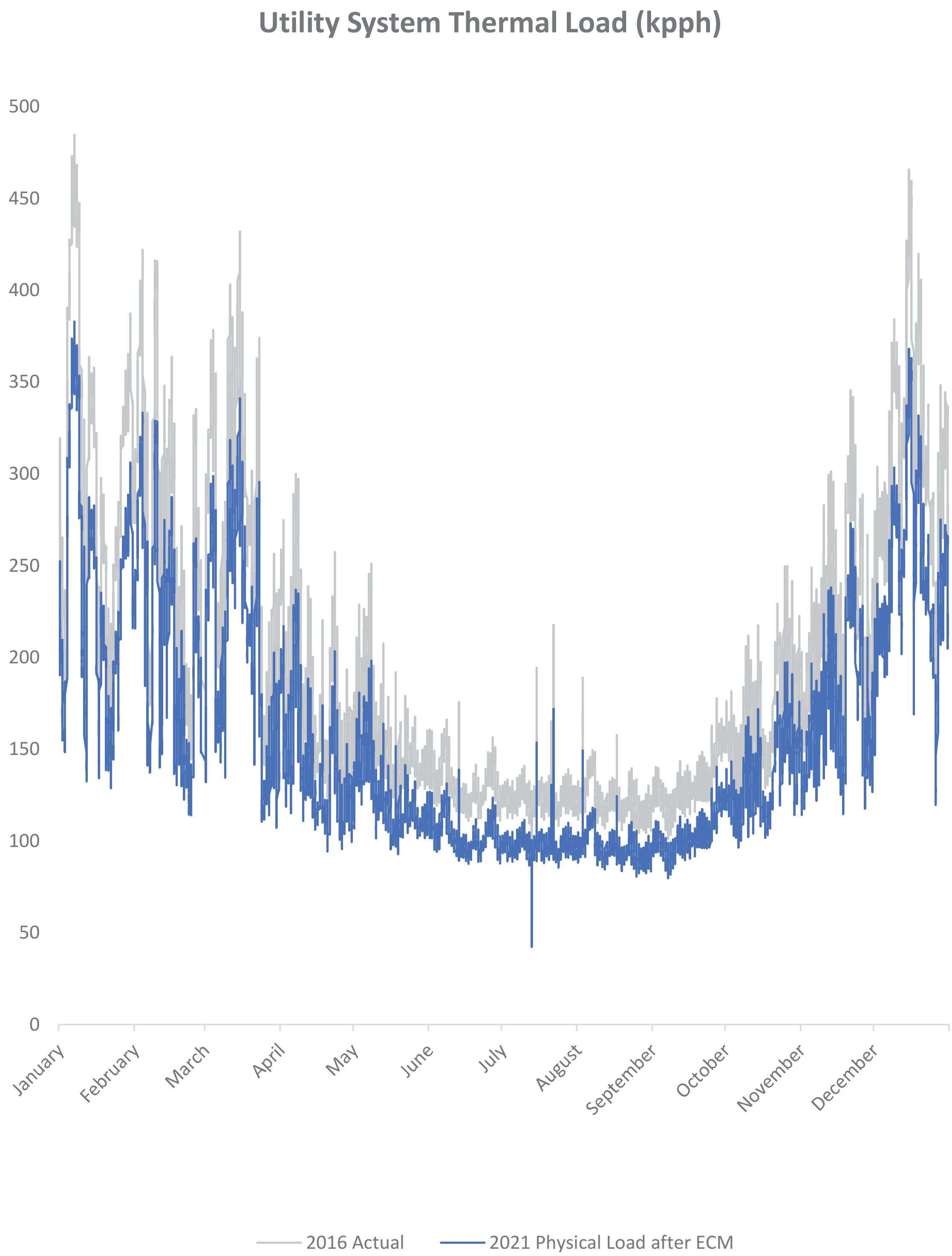


**Figure 2-3:** Historical steam profile and available physical load after ECM

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).

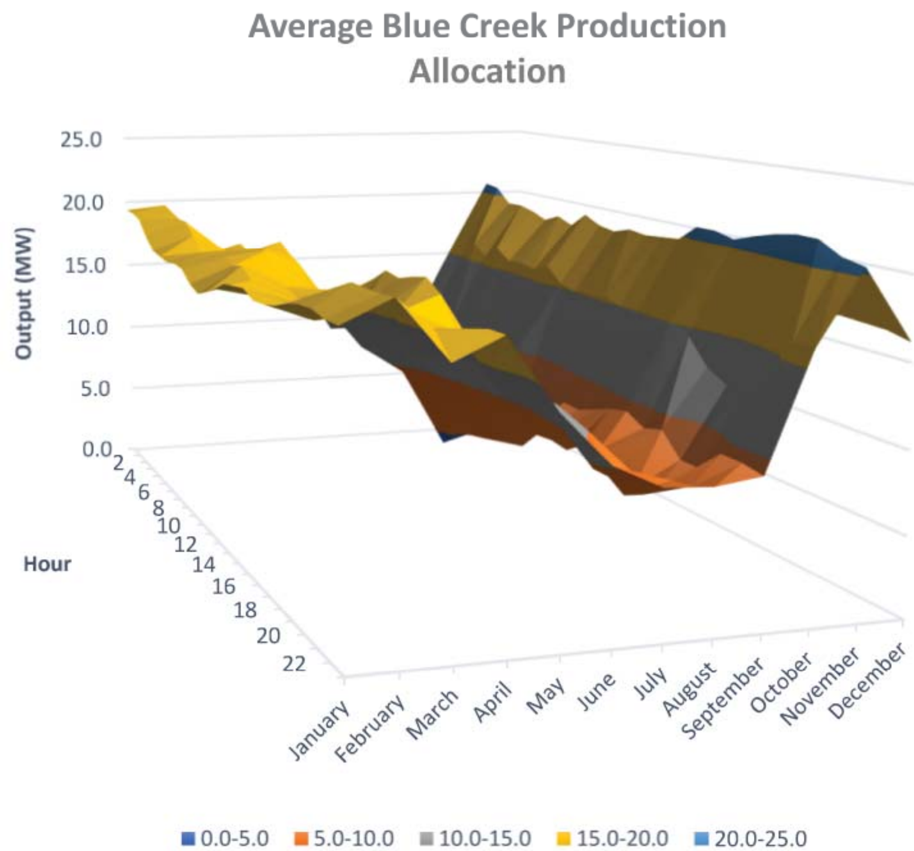


**Figure 2-4:** Average instantaneous Blue Creek wind production

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.

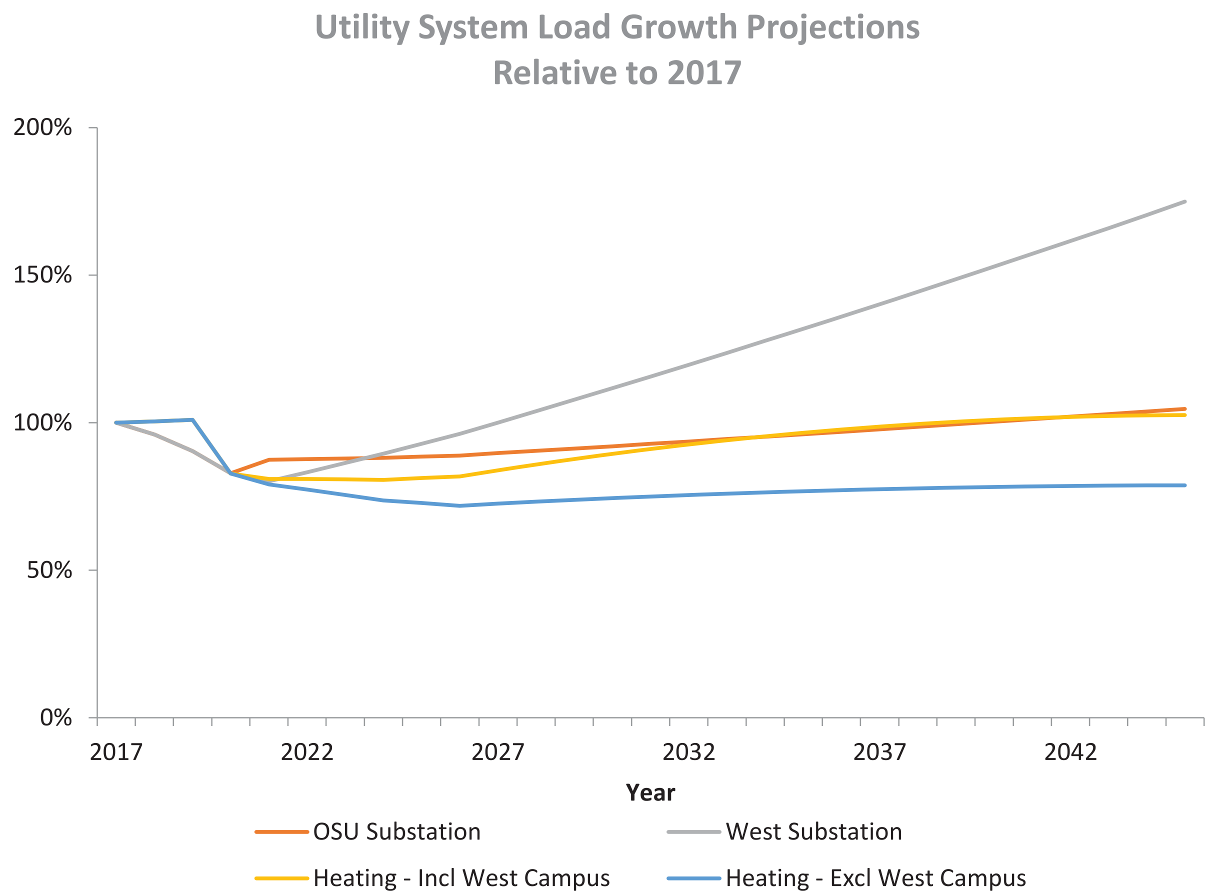


**Figure 2-5:** Load growth projections for the campus

## 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.

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[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 2$^{nd}$ 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.

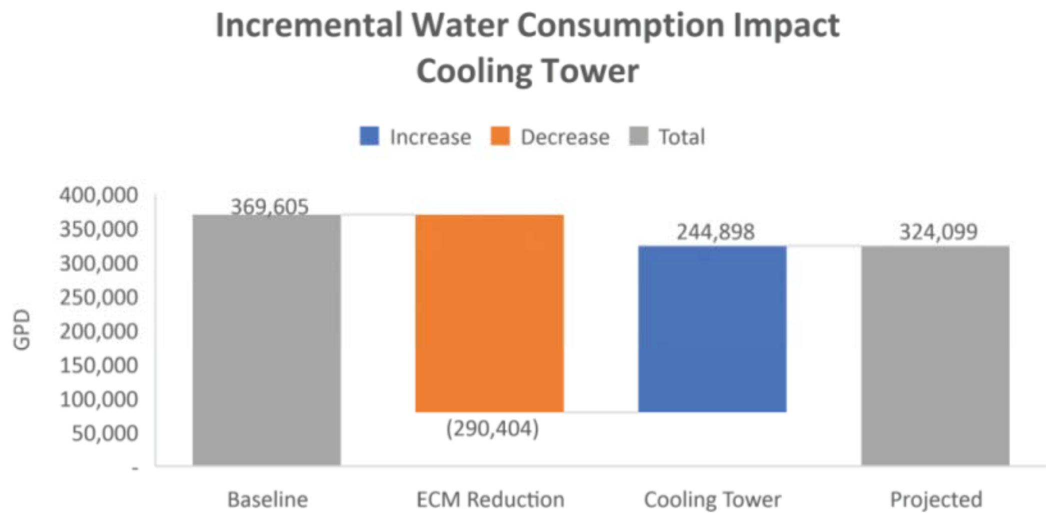


**Figure 2-6:** Water losses are minimum within the CHP steam cycle. "Baseline" illustrates current average water consumption at McCracken and the steam/condensate network.

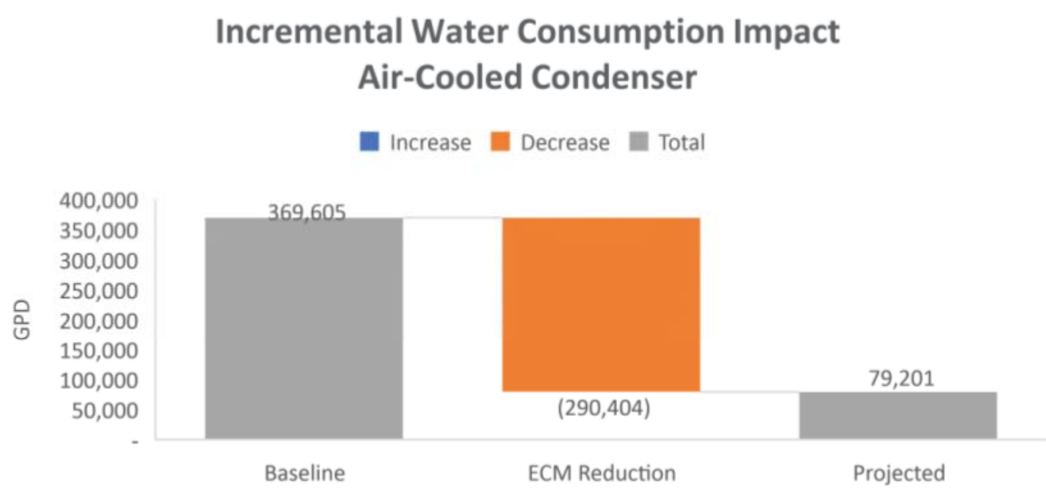


**Figure 2-7:** CHP water losses are minimal when utilizing an ACC, compared to the baseline water consumption of McCracken

## 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

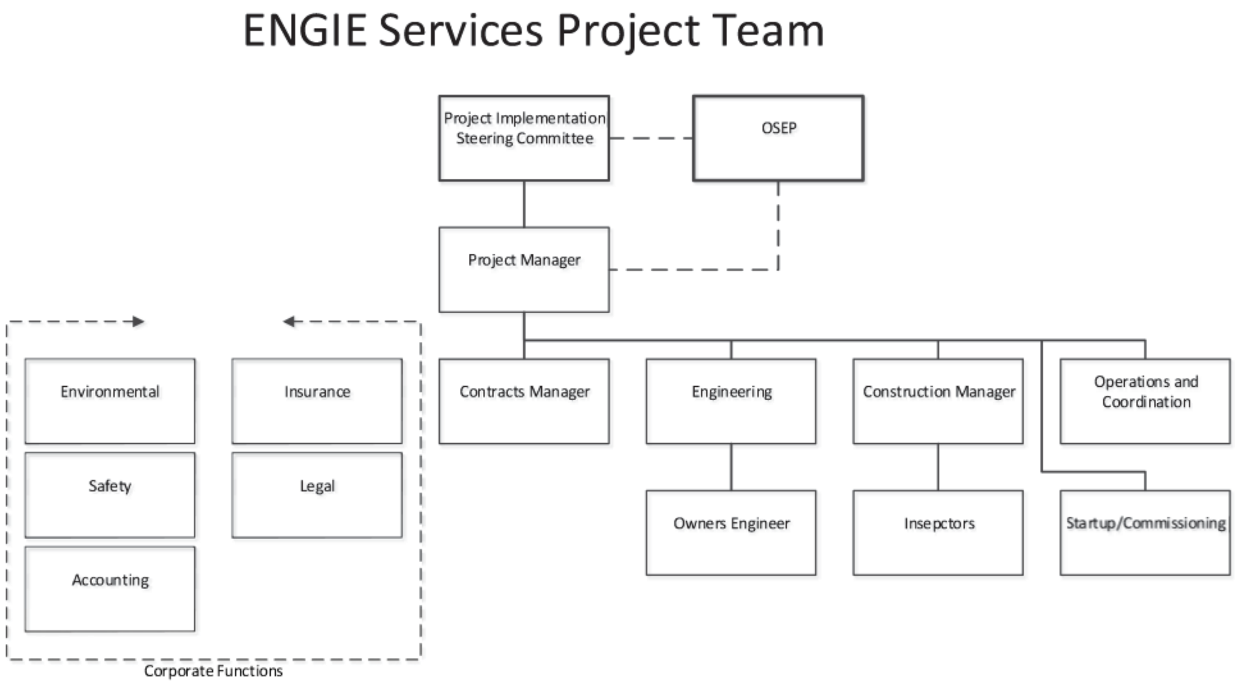


**Figure 2-9:** ENGIE Services CHP implementation team organization chart

## 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.

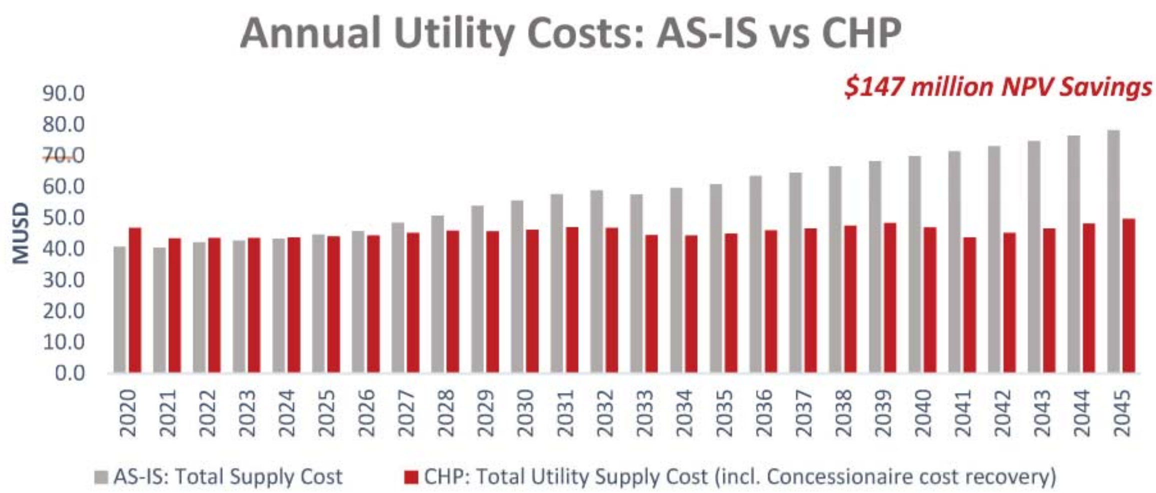


**Figure 3-2:** North of Smith substation (Case 2) provides $147M of NPV supply cost savings for the University

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.

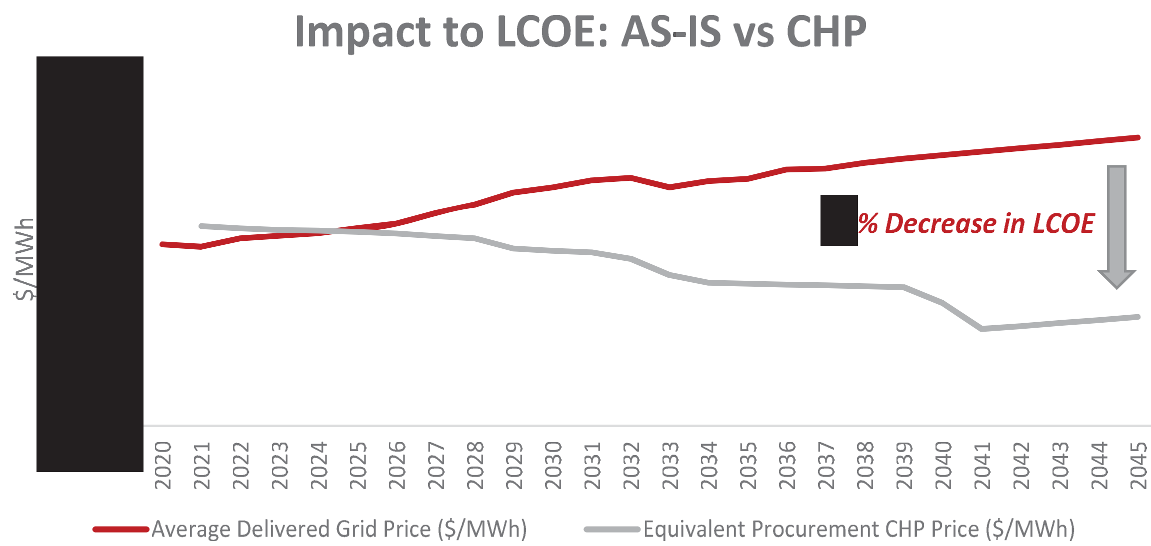


**Figure 3-3:** Both Case 2 and Case 4 provide the University with a [redacted]% reduction in LCOE compared to baseline

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.

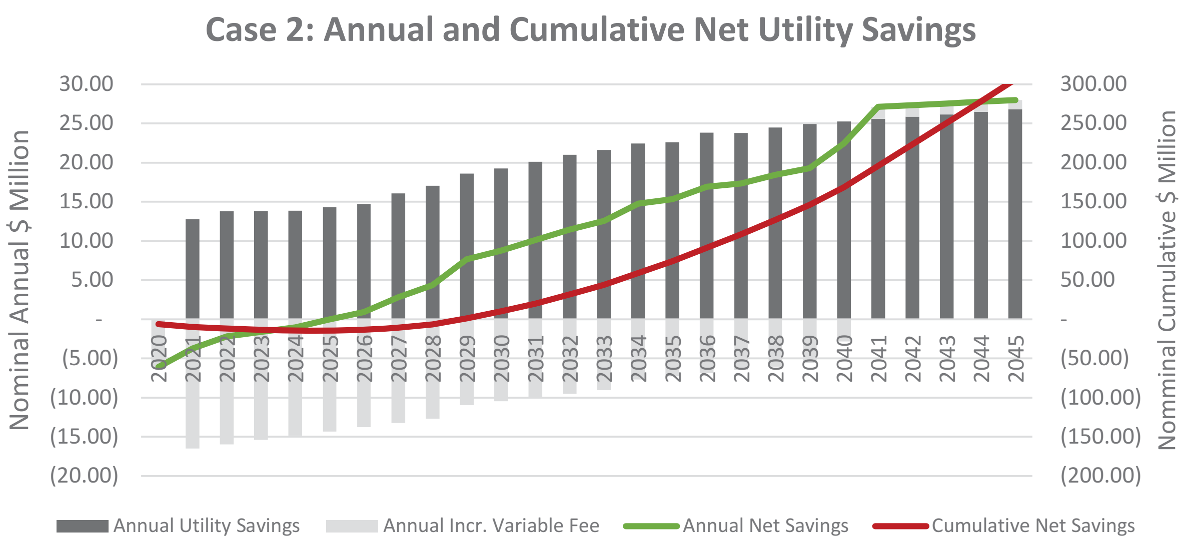


**Figure 3-4:** Payback Period for Case 2 is realized in approximately 9 years using 20-yr Recovery Period for the Variable Fee.

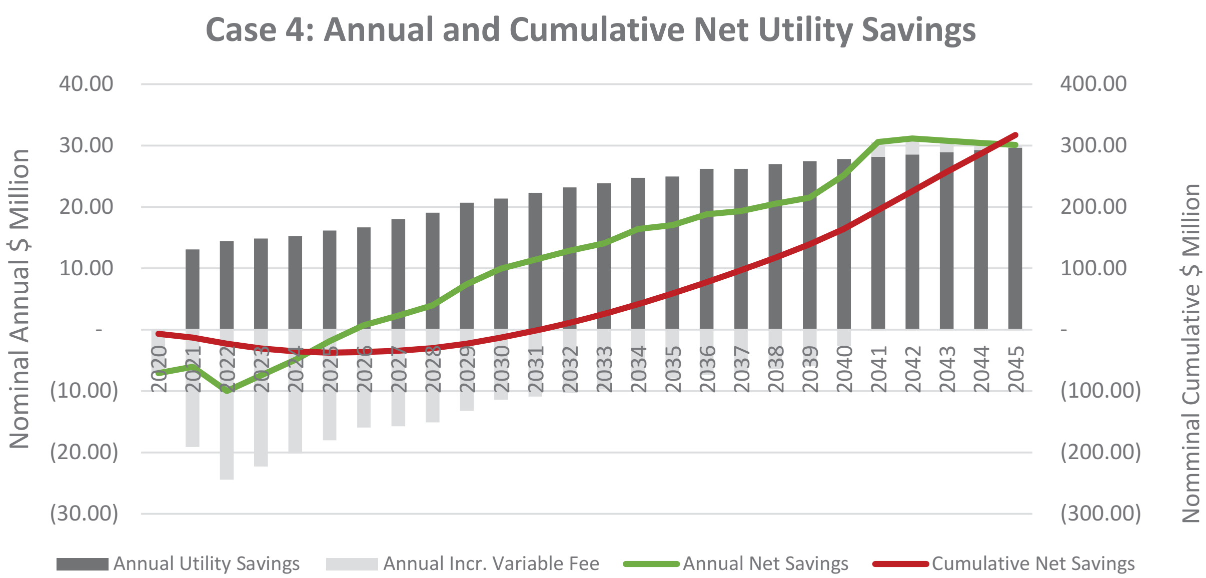


**Figure 3-5:** Payback Period for Case 4 is realized in approximately 11 years using 20-yr Recovery Period for the Variable Fee.

## 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.

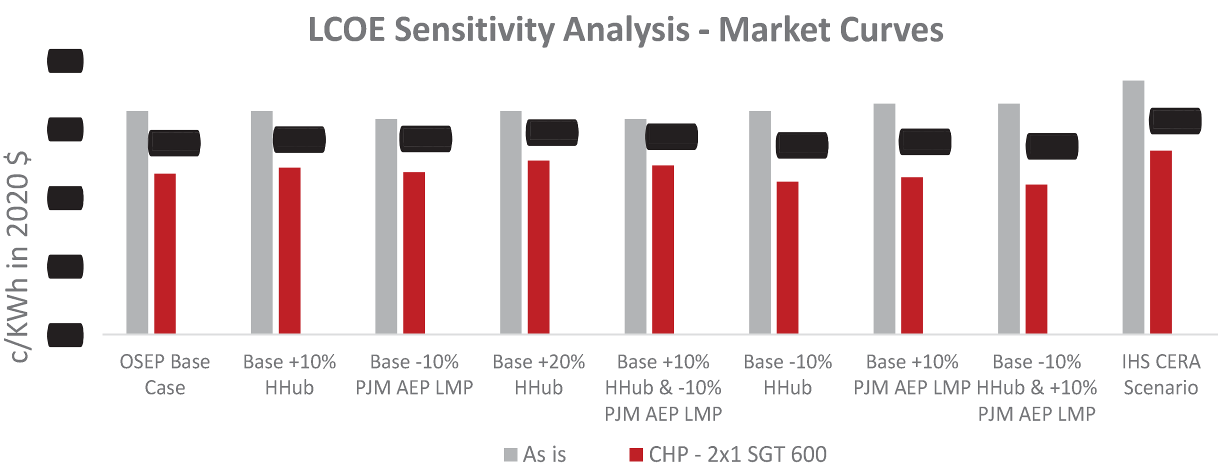


**Figure 3-6 (a):** Market sensitivities: shows a minimum reduction of [redacted] in real LOCE

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>.

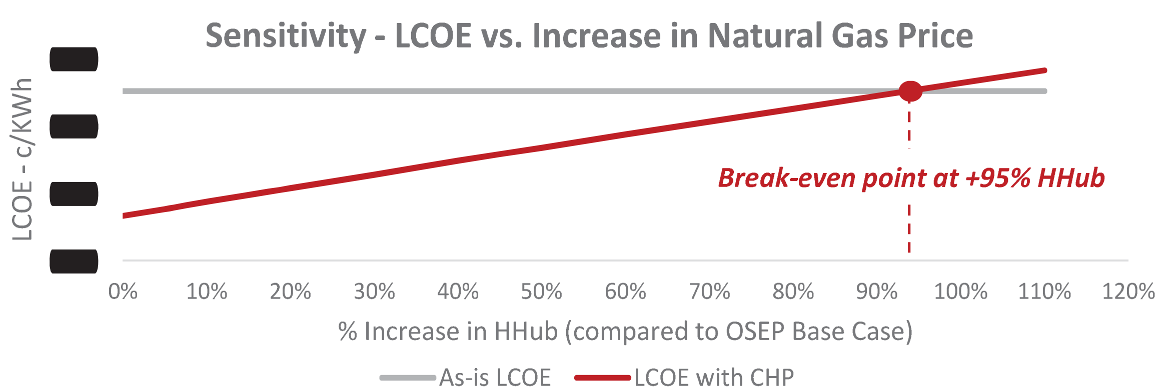


**Figure 3-6 (b):** A 95% increase in Natural Gas Price (compared to the Base Case) would result in a break-even scenario

## 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 <u>extreme pessimistic scenario</u> 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].

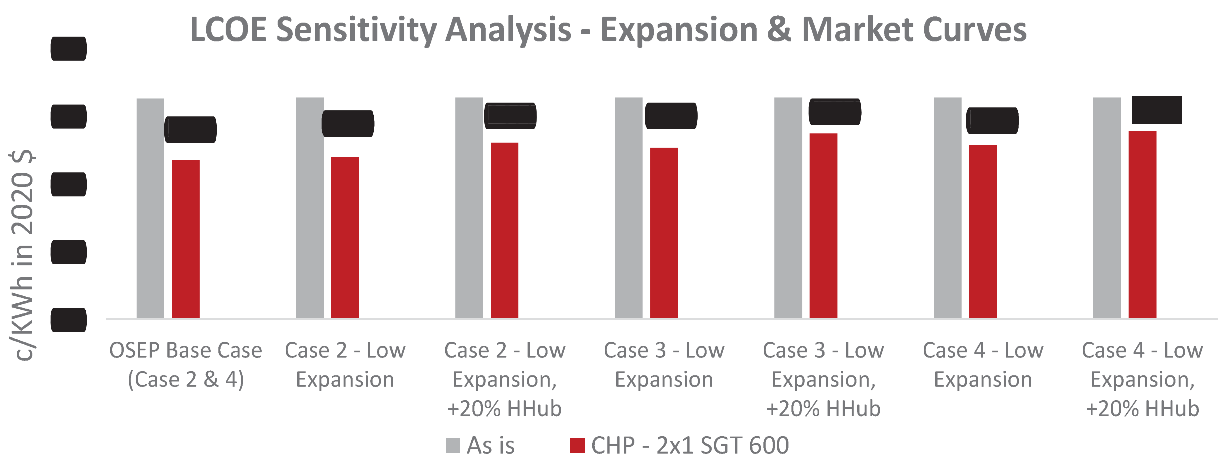


**Figure 3-7**: Minimal Campus Expansion coupled with very high Natural Gas price yields a minimum reduction in LCOE of [redacted]

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.

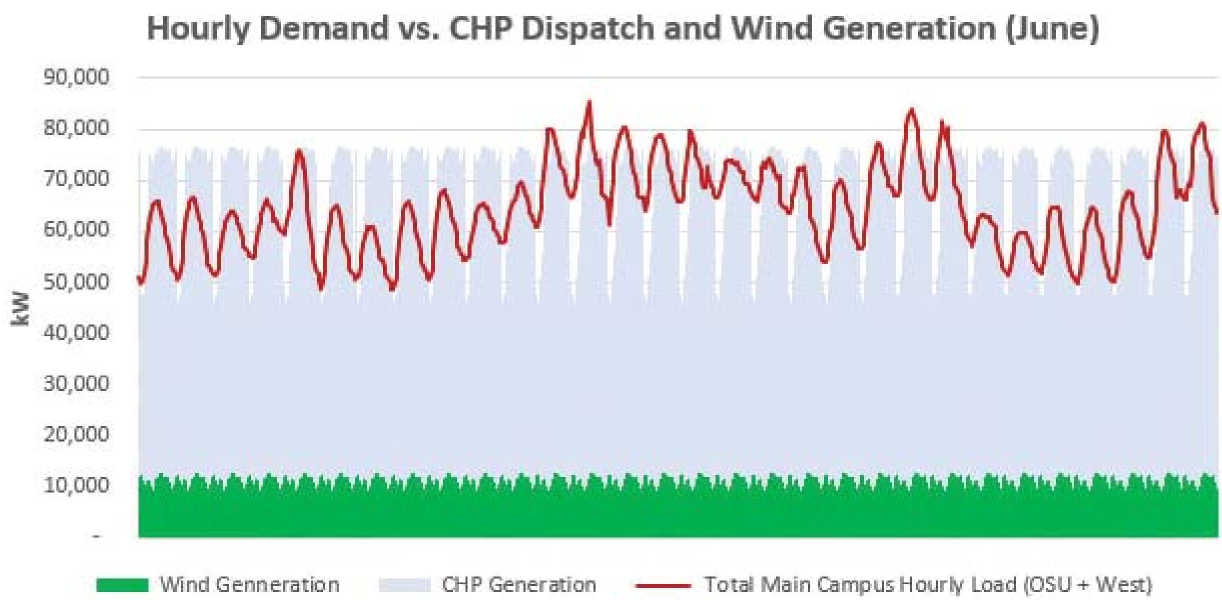


**Figure 3-9**: Wind generation for the month of June

## 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.

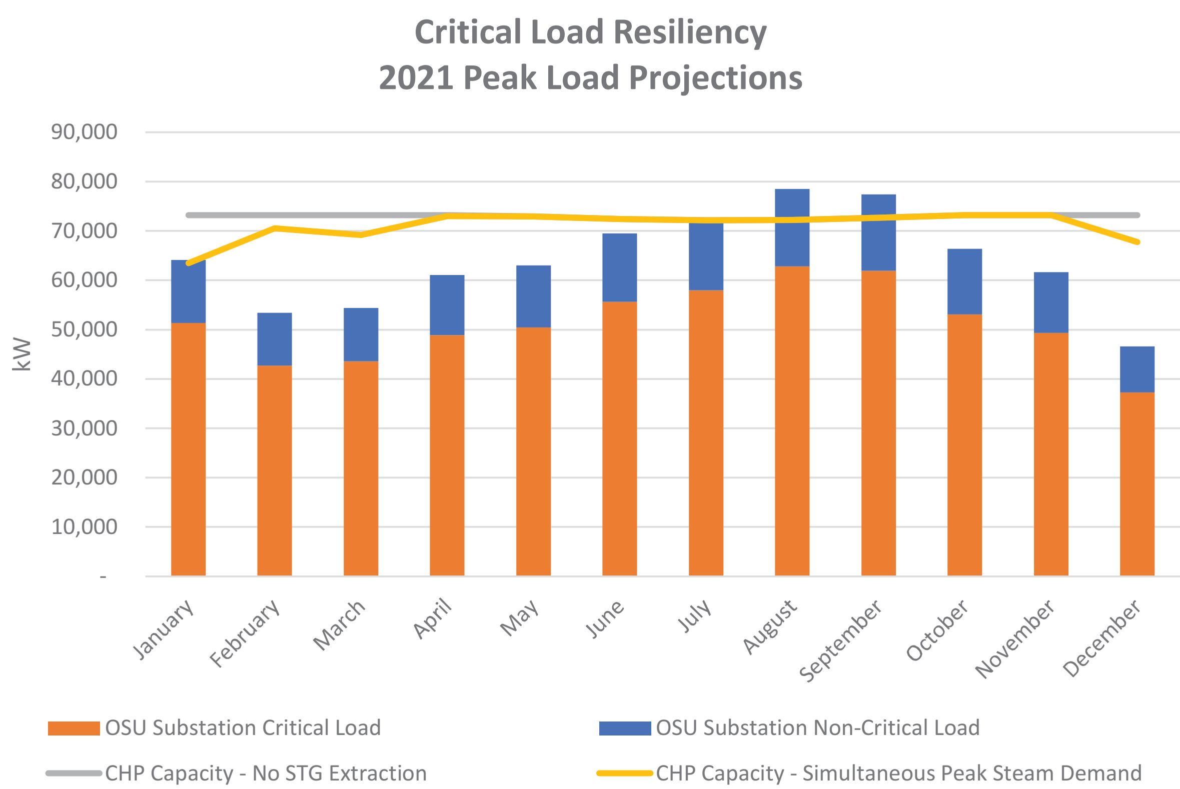


**Figure 3-10**: Critical loads are met using optimized CHP solution

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.

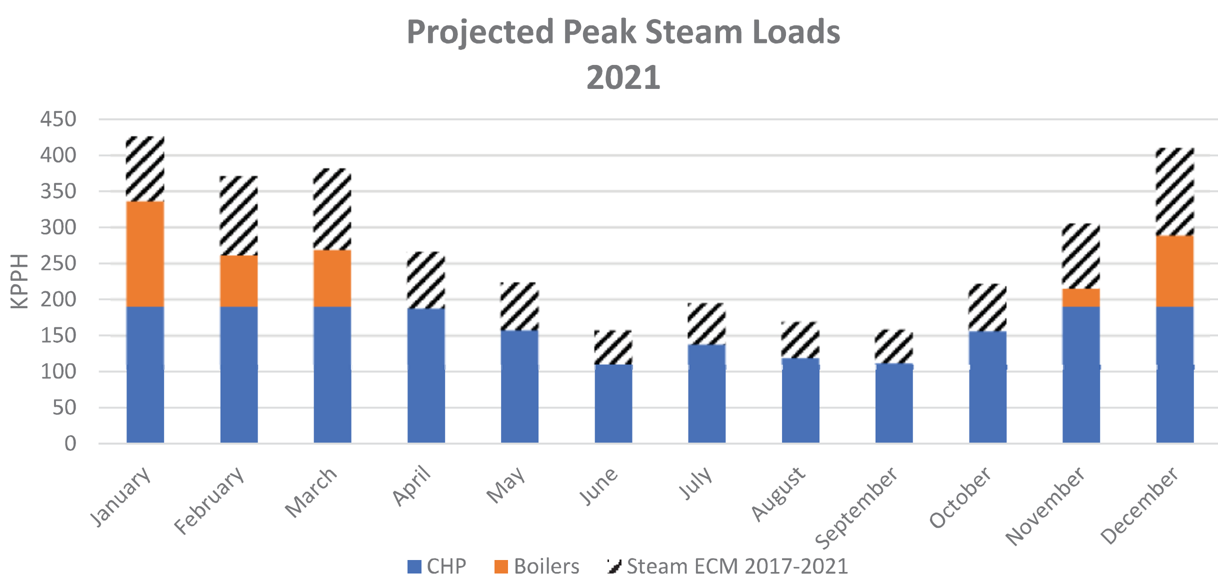


**Figure 3-11:** CHP and existing boilers provide steam to operate at N+2 levels

## 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 | | $ 1KUSD |
| Annual Major maintenance | | $ 47 KUSD |
| Natural gas during test | | $ 26 KUSD |
| Natural gas during back up operations | | $ 0 KUSD (Note 1) |
| Natural gas during back up operations | | $ 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.

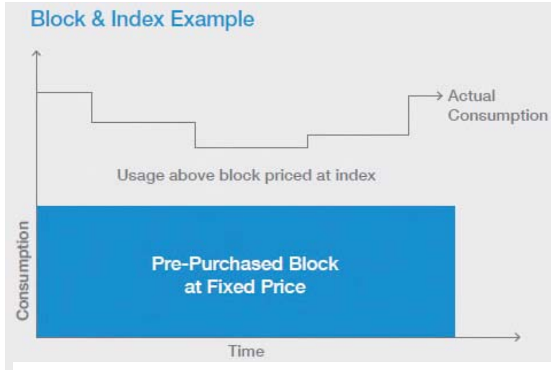


**Figure 3-13:** Hedge solution to reduce the University's exposure to commodity pricing

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.

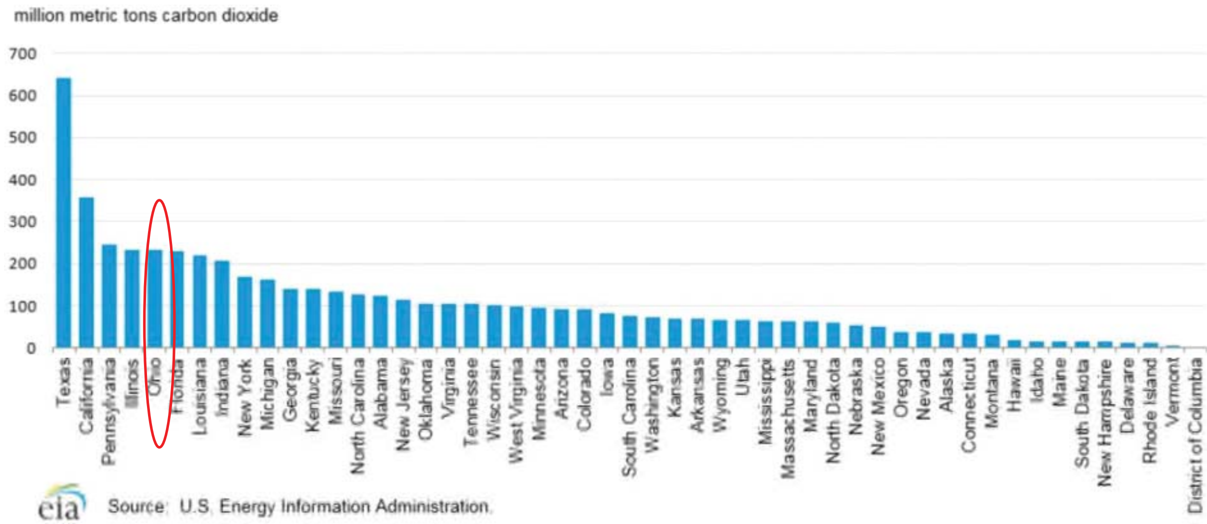


**Figure 3-14**: State of Ohio is 5th largest producer of $CO_2$ emissions

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.

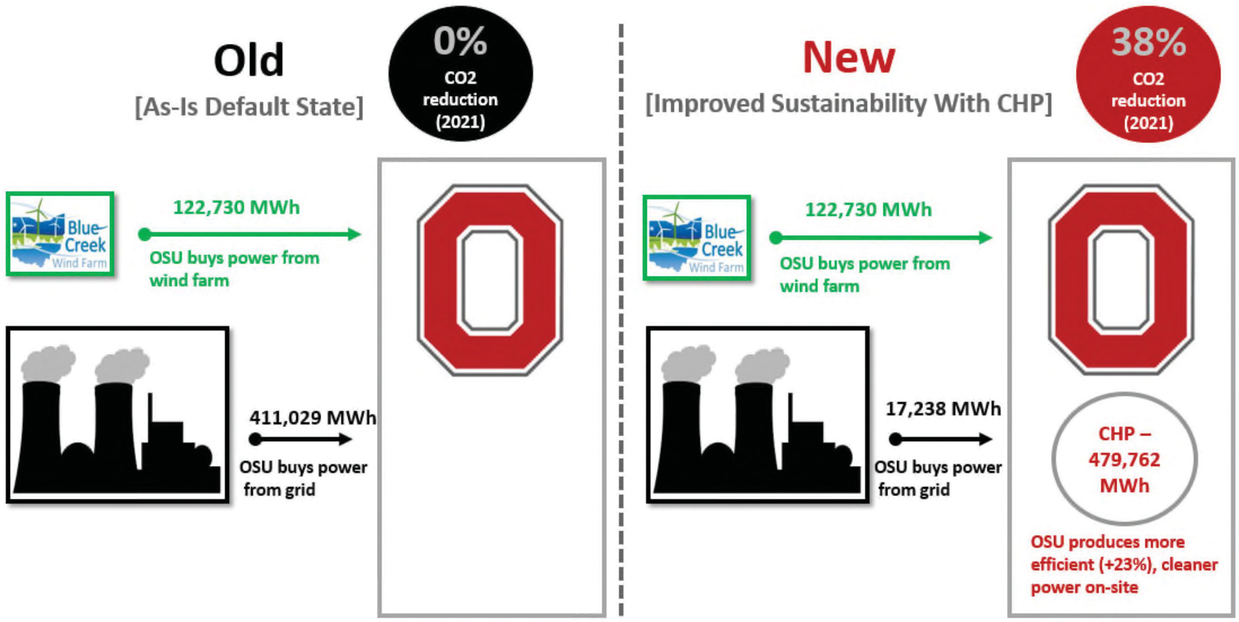


**Figure 3-15**: 38% $CO_2$ reduction by 2021 with CHP

## Campus Energy Consumption

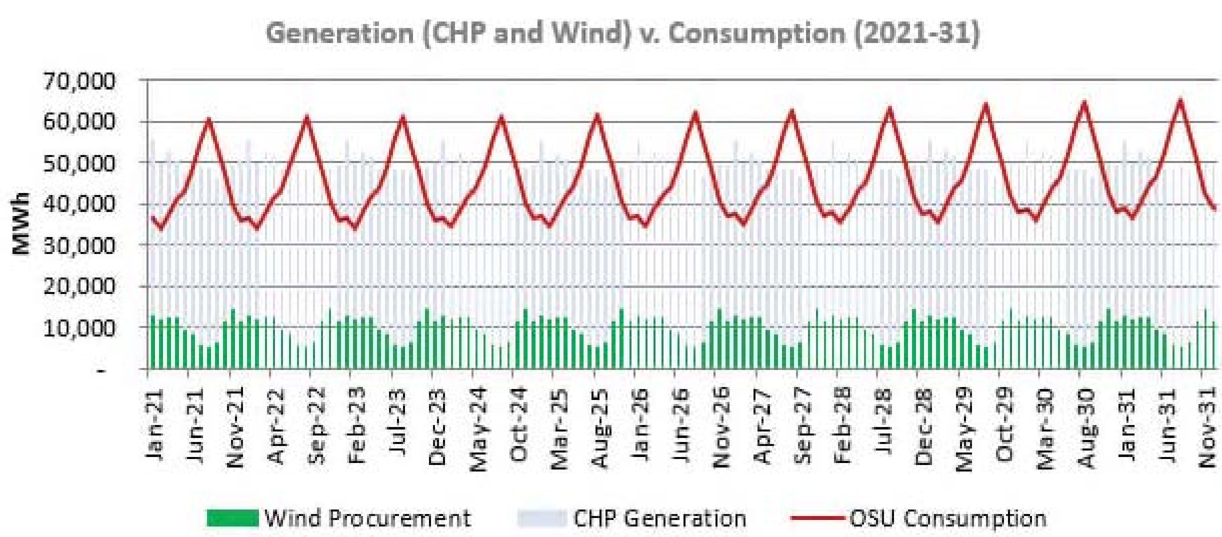


**Figure 3-16:** Wind procurement is not sufficient to offset campus load

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:

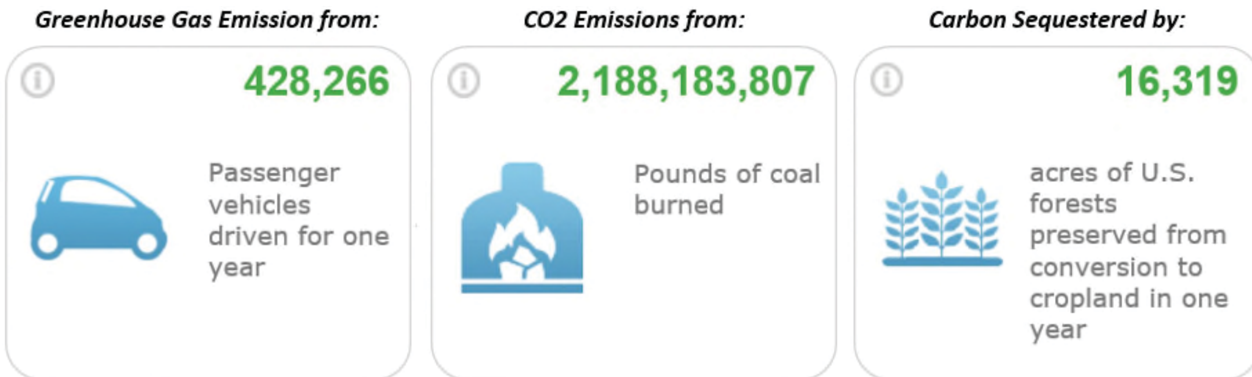


**Figure 3-17:** EPA greenhouse equivalencies (https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator)

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.

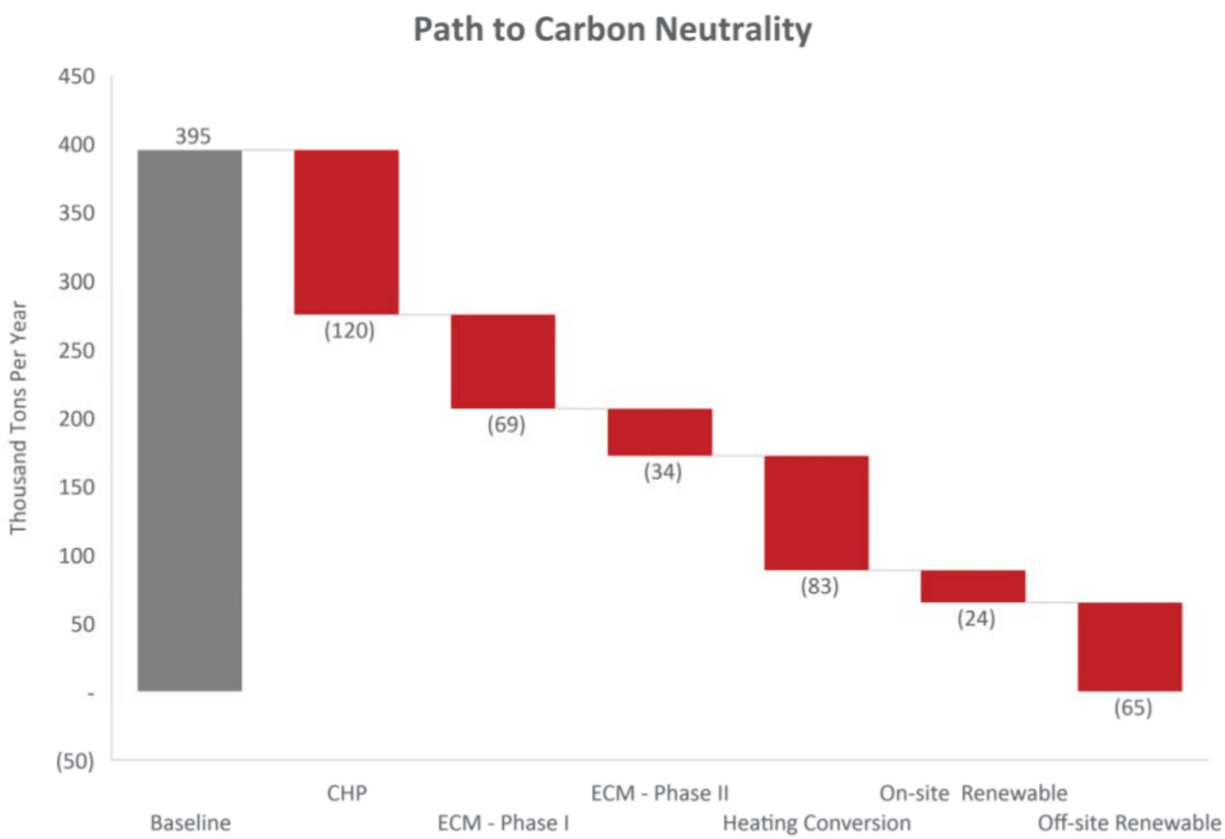


**Figure 3-18:** CHP and ECM Phase I implementation allow the University to reach nearly 50% of their goal

# 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

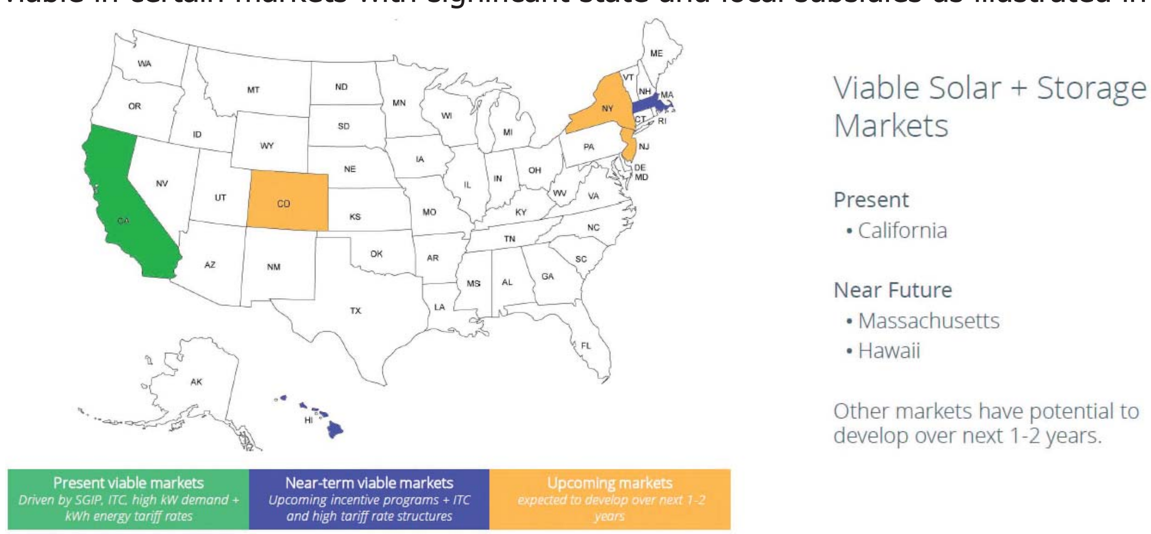


**Figure 4-1:** Combination of storage and solar are viable in certain markets

# 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.

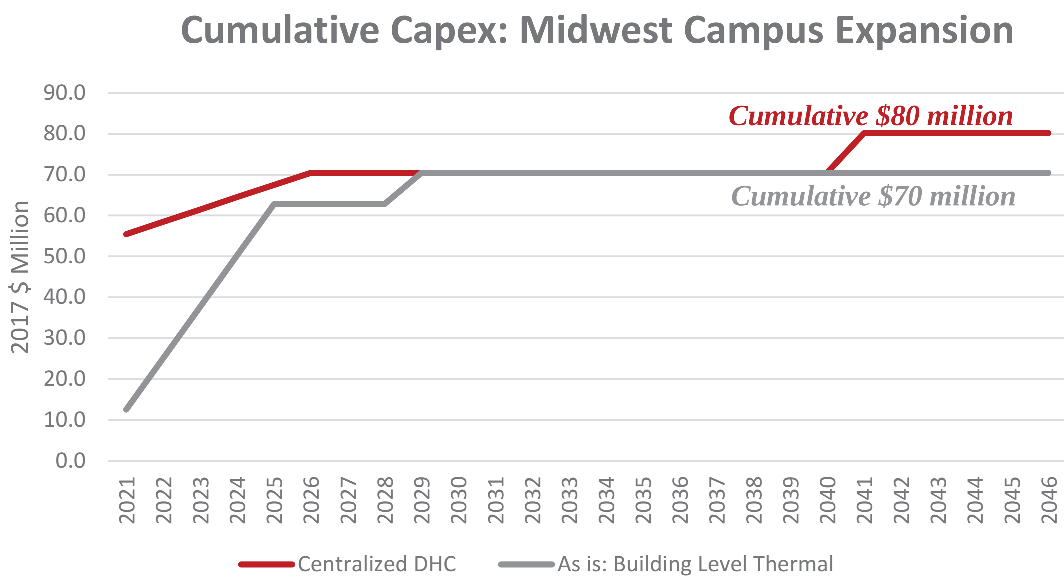


**Figure 5-1**: Cumulative CAPEX over time: Centralized DHC system vs. Building Level Thermal (Case 3 & 4)

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.

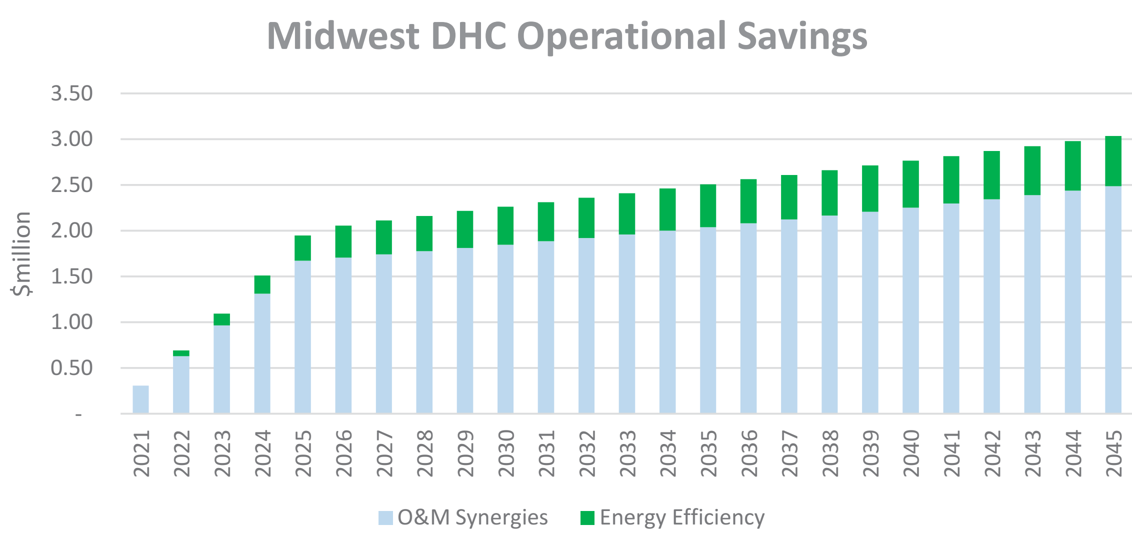


**Figure 5-2**: Annual O&M Savings & Synergies: Centralized DHC system vs. Building Level Thermal (Case 3 & 4)

# 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.

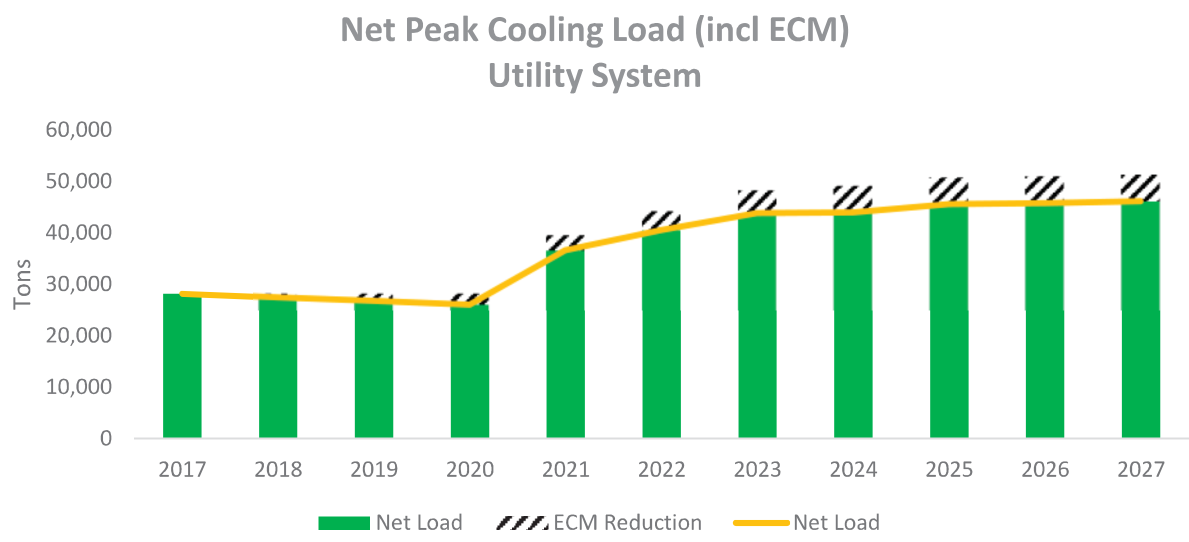


**Figure 6-1:** Net Peak Cooling Load

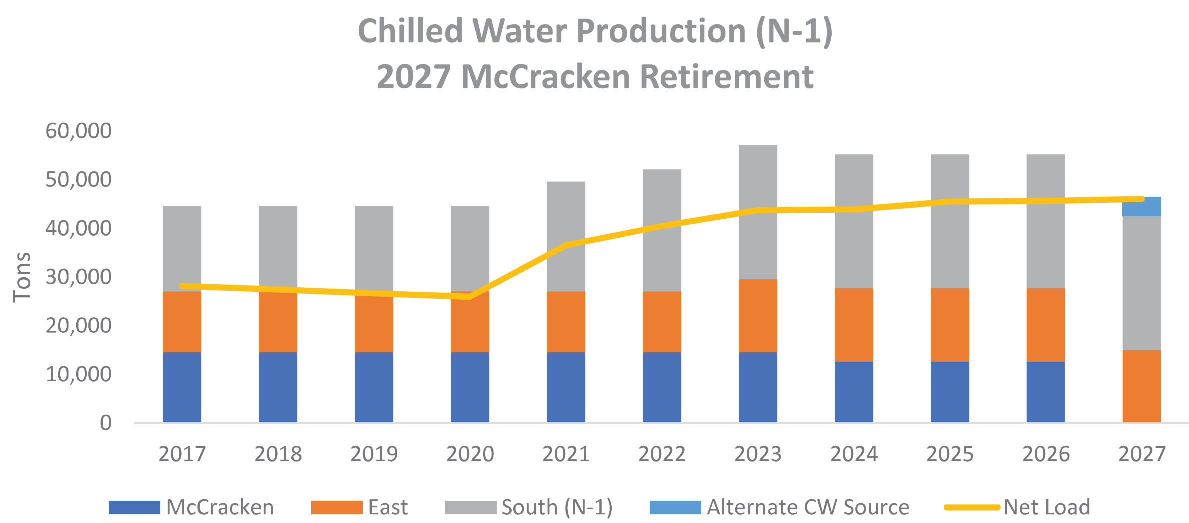


**Figure 6-2:** Chilled Water Production (2027 Retirement Strategy). N-1 denotes total chilled water capacity when one of the largest chillers is out of service.

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.

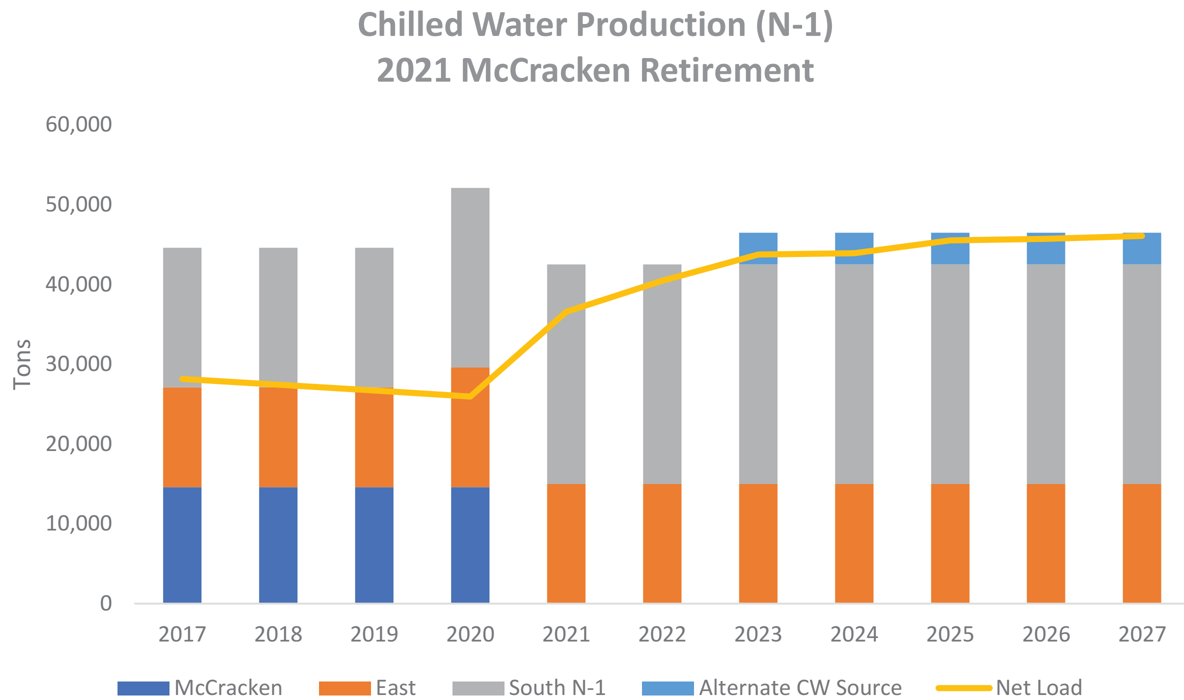


**Figure 6-3:** Chilled Water Production (2021 Retirement Strategy)

## 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.

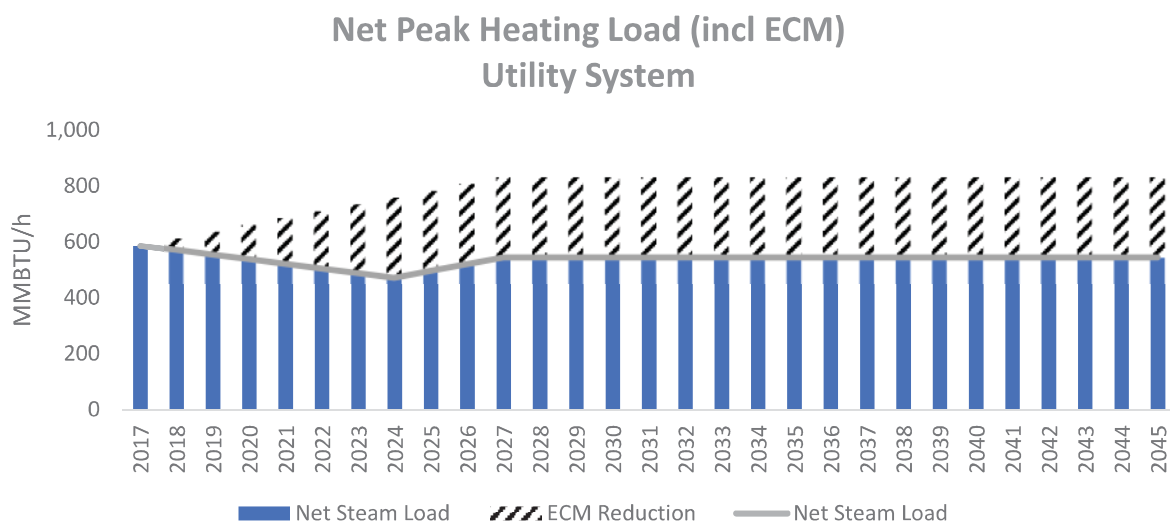


**Figure 6-4**: Net Peak Heating Load

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.

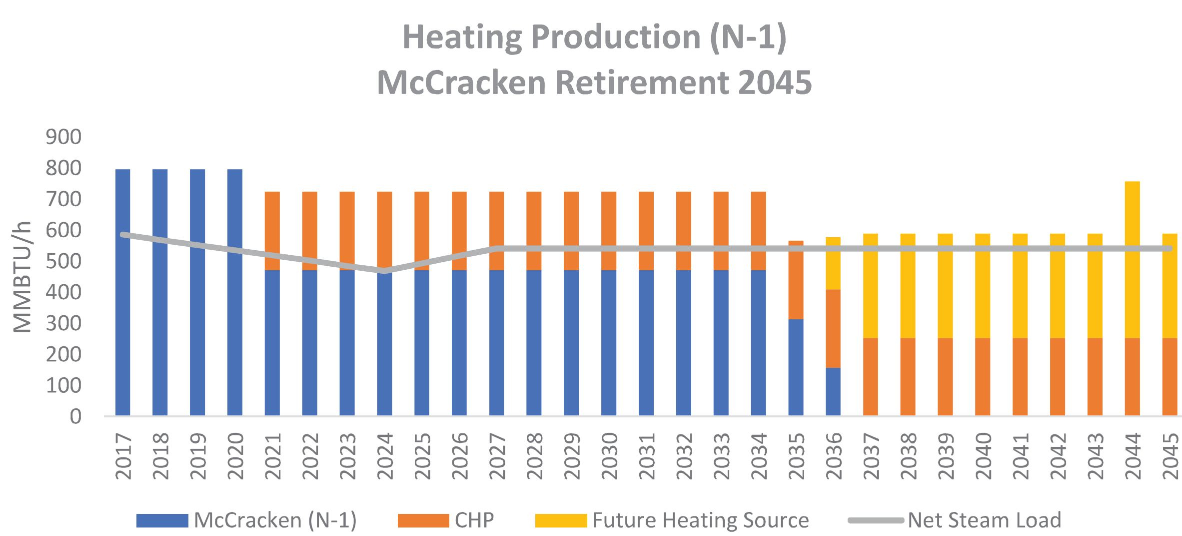


**Figure 6-5:** Heating Production (2045 Retirement Strategy)

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.

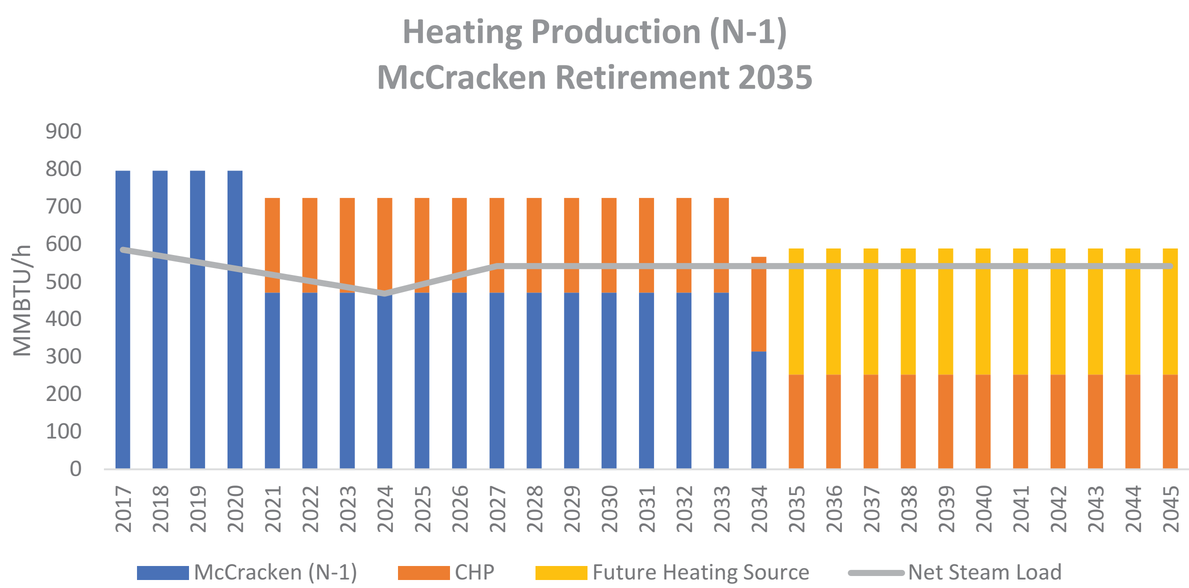


**Figure 6-6:** Heating Production (2035 Retirement Strategy)

## 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.

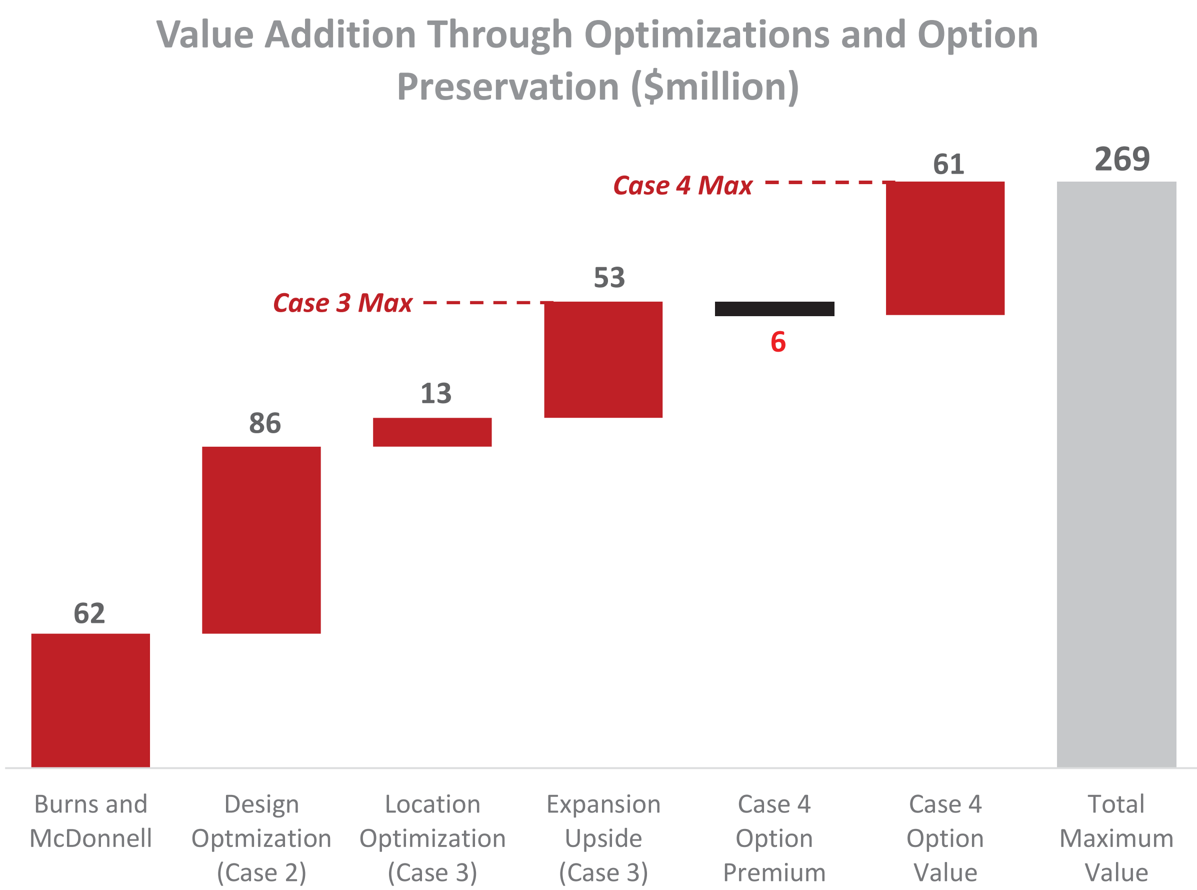


**Figure 7-1:** Full Expansion with addition of a 3rd turbine could create value up to $269 million in NPV savings

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.

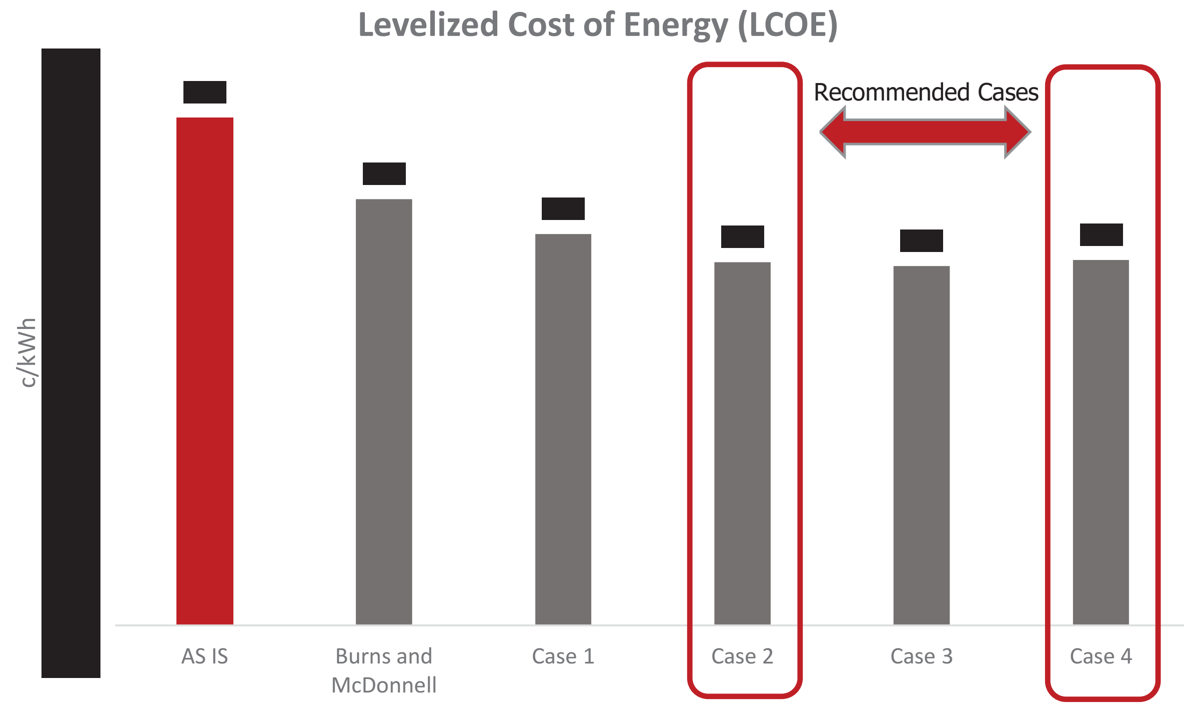


**Figure 7-3**: Recommended cases provide for best LCOE

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.

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Combined Heat and Power Project

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# APPENDIX

FEBRUARY 20, 2018

OHIO STATE ENERGY PARTNERS

# 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% |

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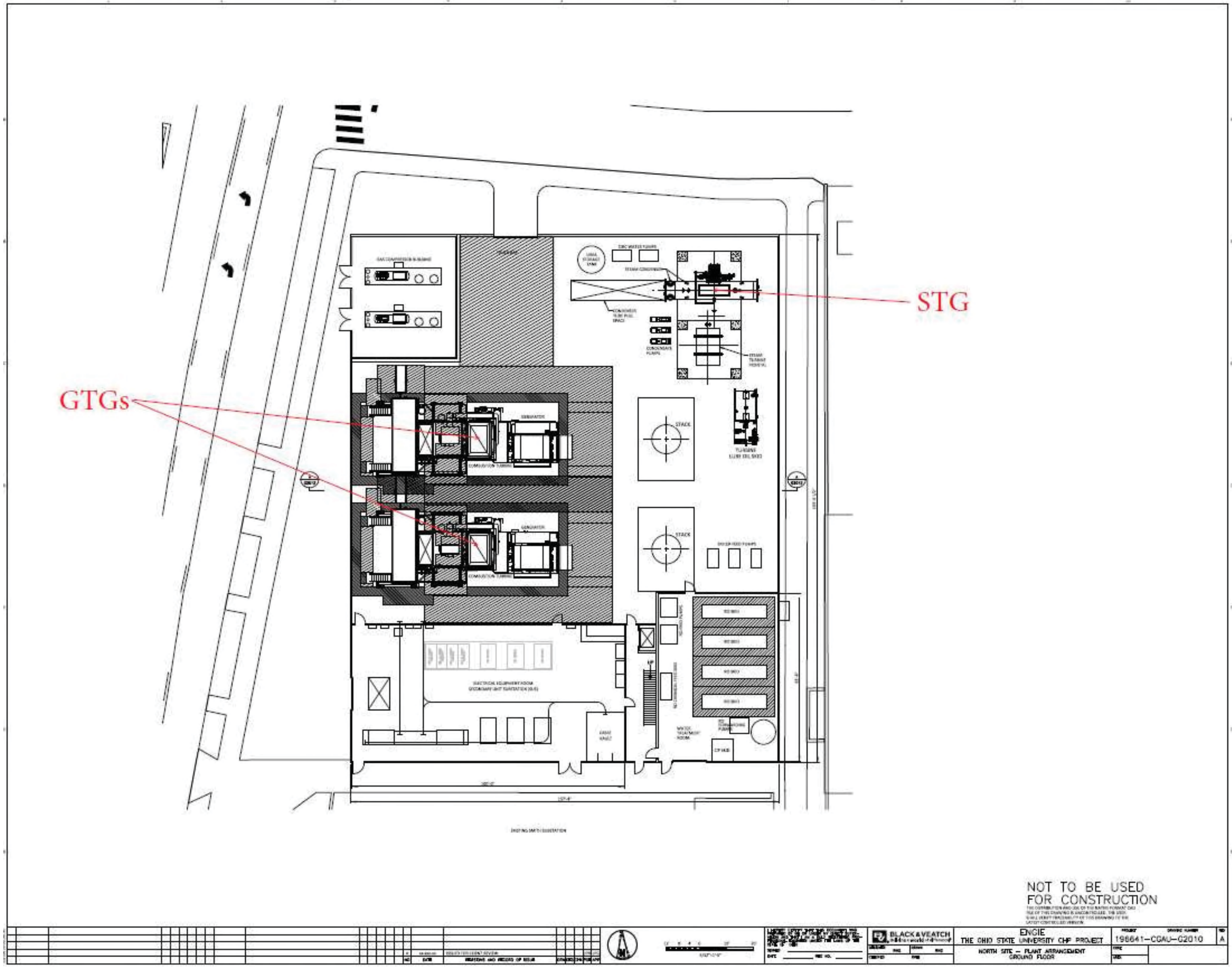
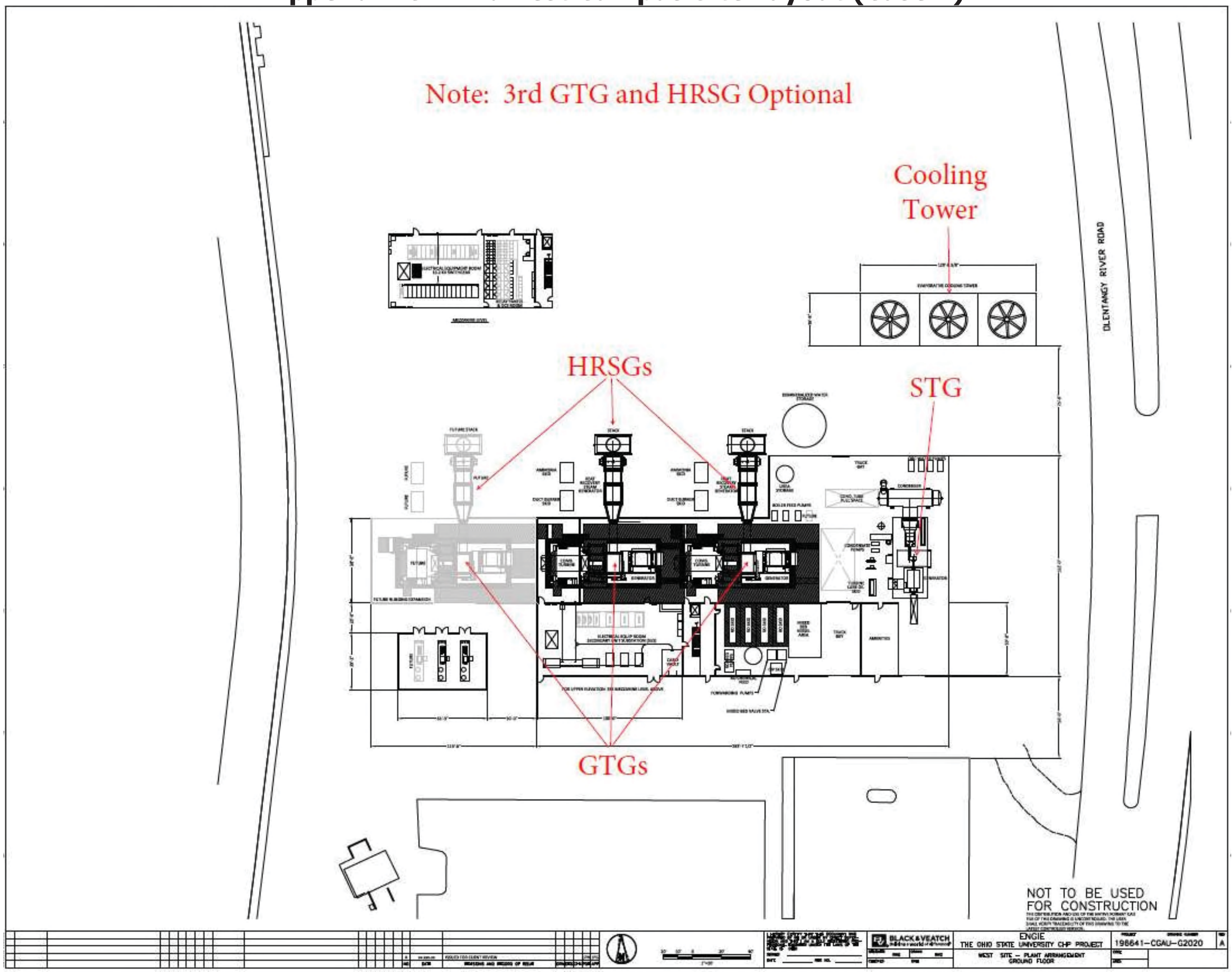
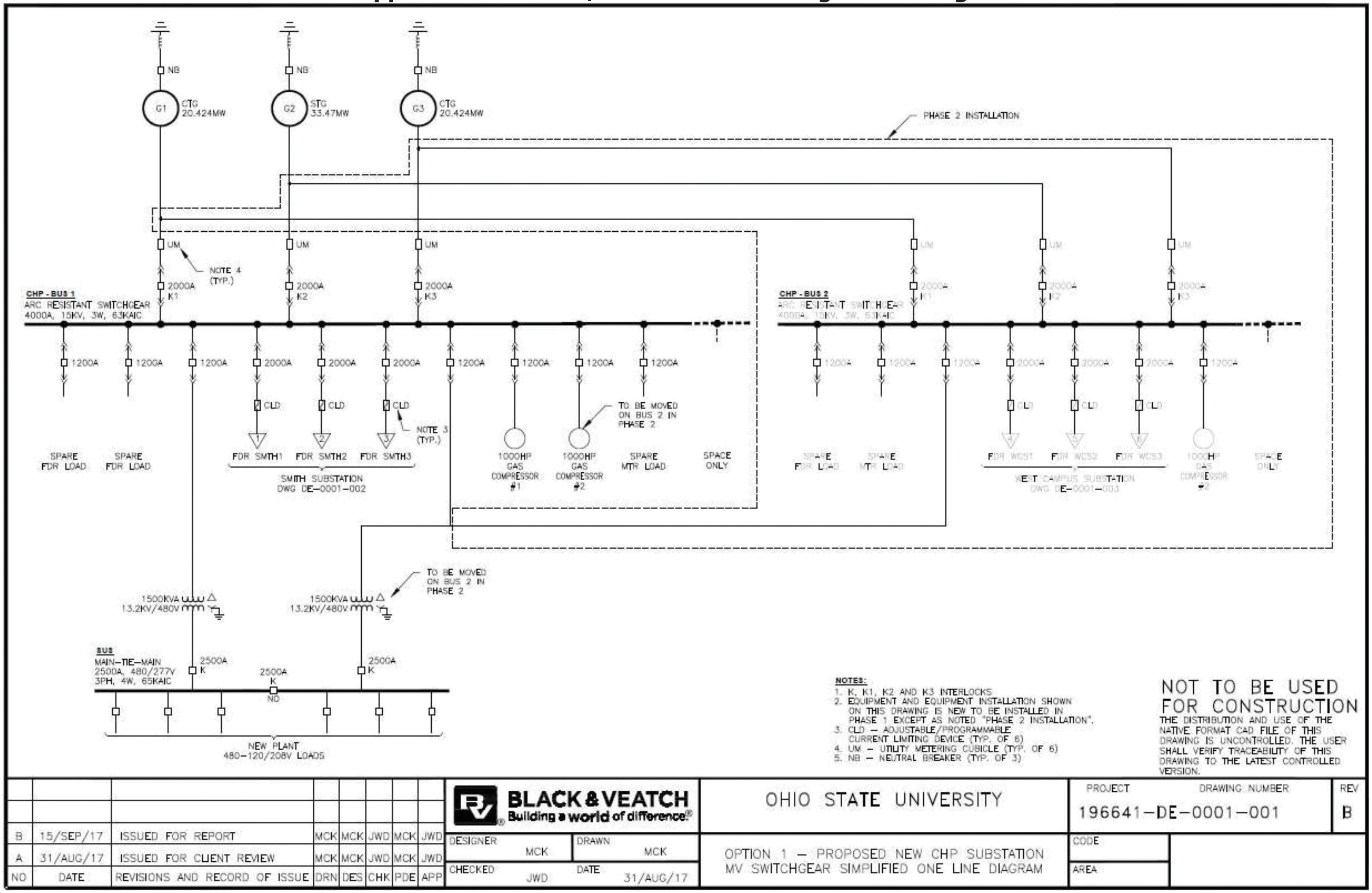
## Appendix B – North of Smith Substation Layout



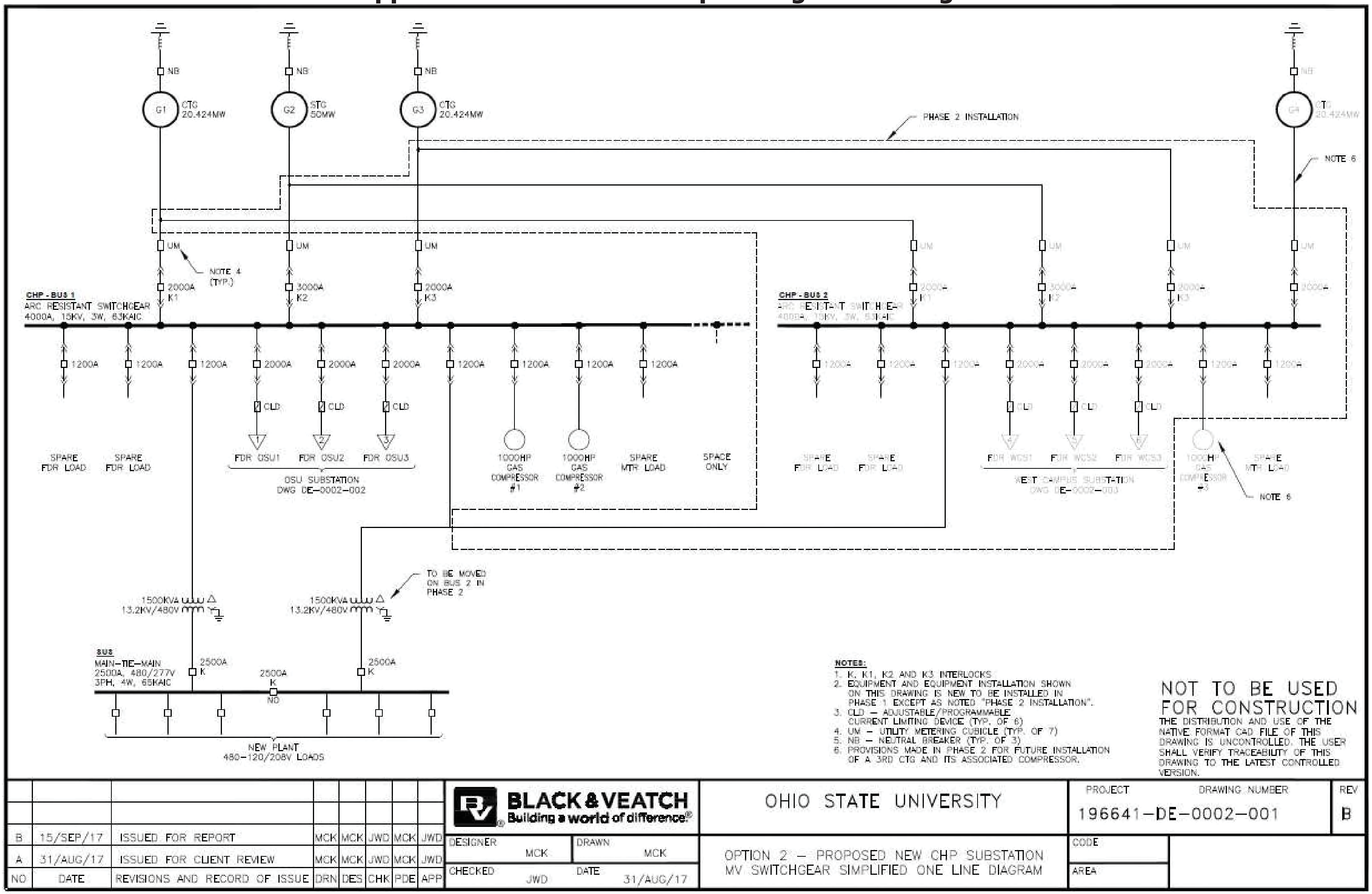
## Appendix C – Midwest Campus Site Layout (Case 4)



## Appendix D – North/South Location Single Line Diagram



## Appendix E – Midwest Campus Single Line Diagram



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

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



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# 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): 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 | Annual Utility Cost With CHP ($ million): 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 | Annual Net Utility Savings |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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** |

# Appendix J – NPV Savings Model (Midwest Campus)

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

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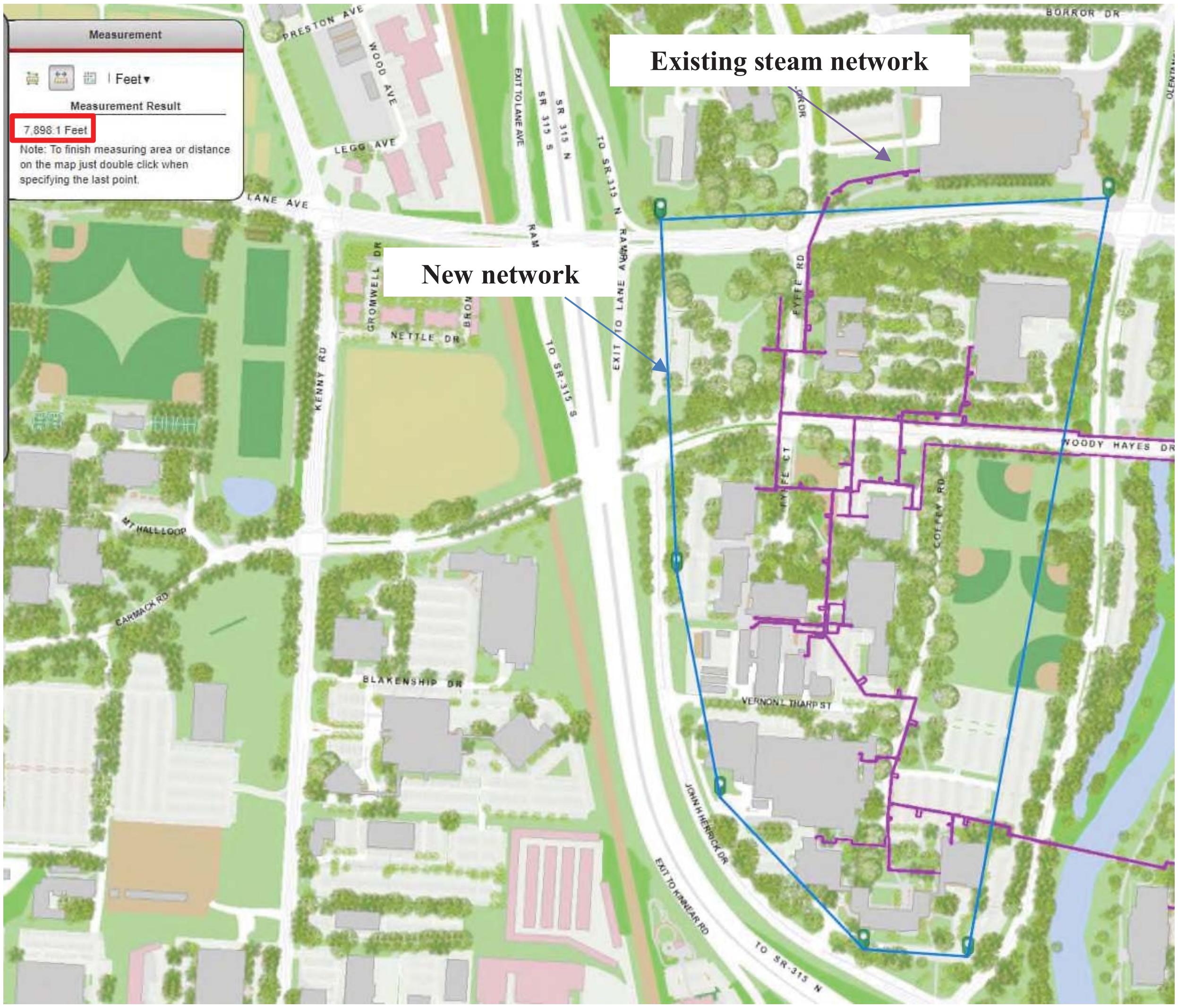
## Appendix K – Case 1: Midwest Campus "DHC vs No DHC" calculations

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 |

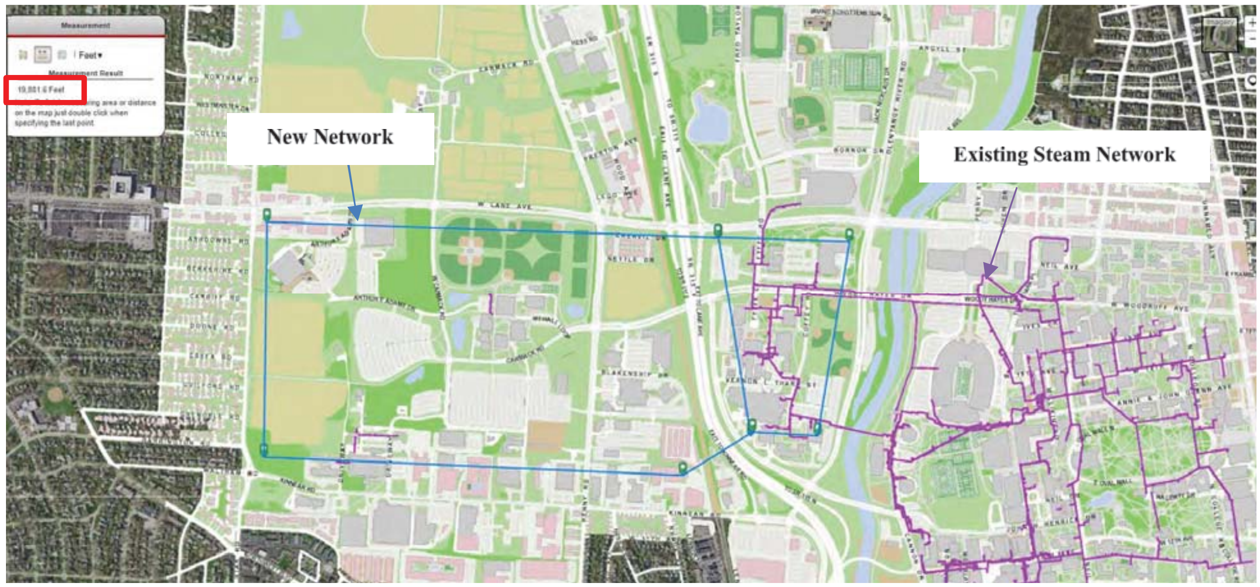
Annual O&M costs comparison:

| | |
|---|---|
| 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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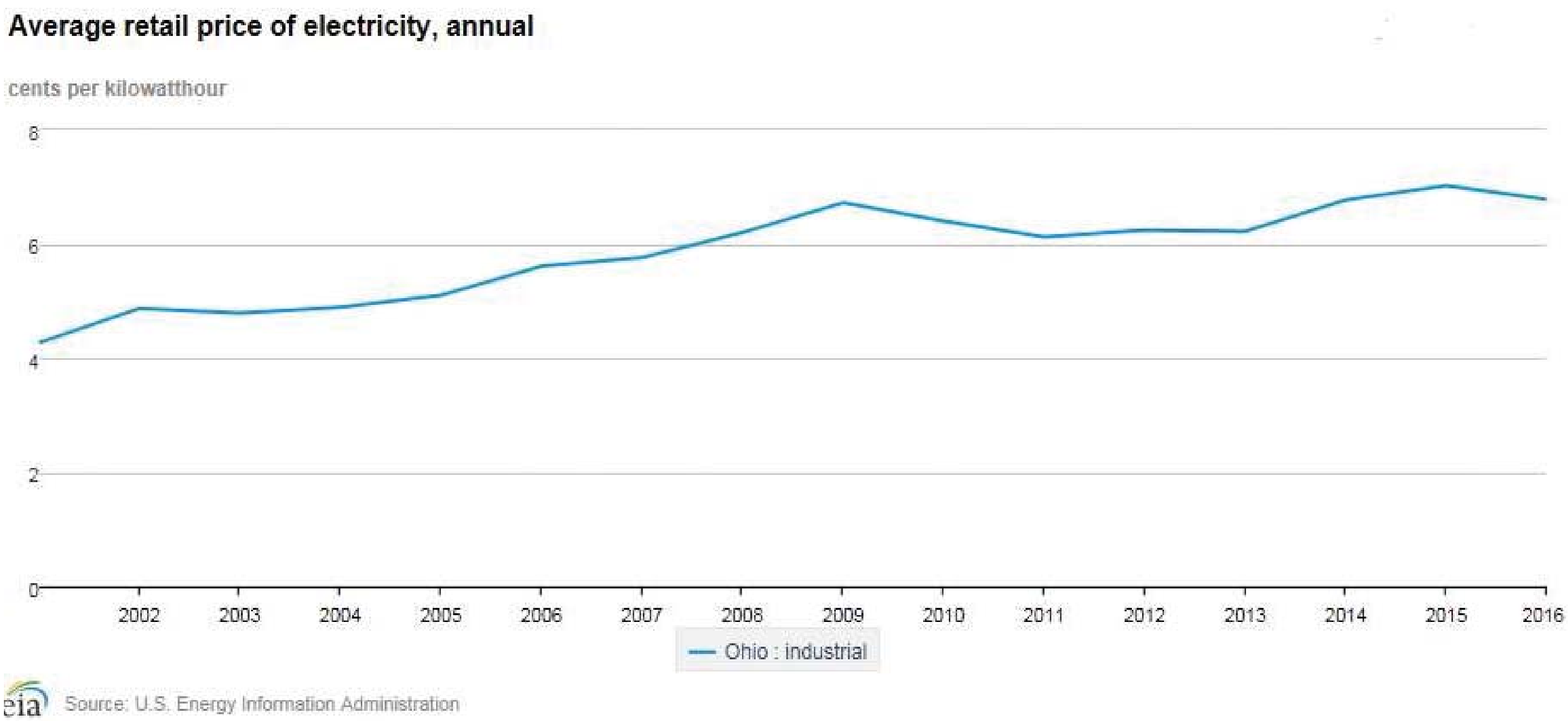
# Appendix L - Historical Grid Price Chart



## 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

**The Ohio State University**

Combined Heat and Power Project

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**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**<br>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**<br>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**<br>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**<br>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.

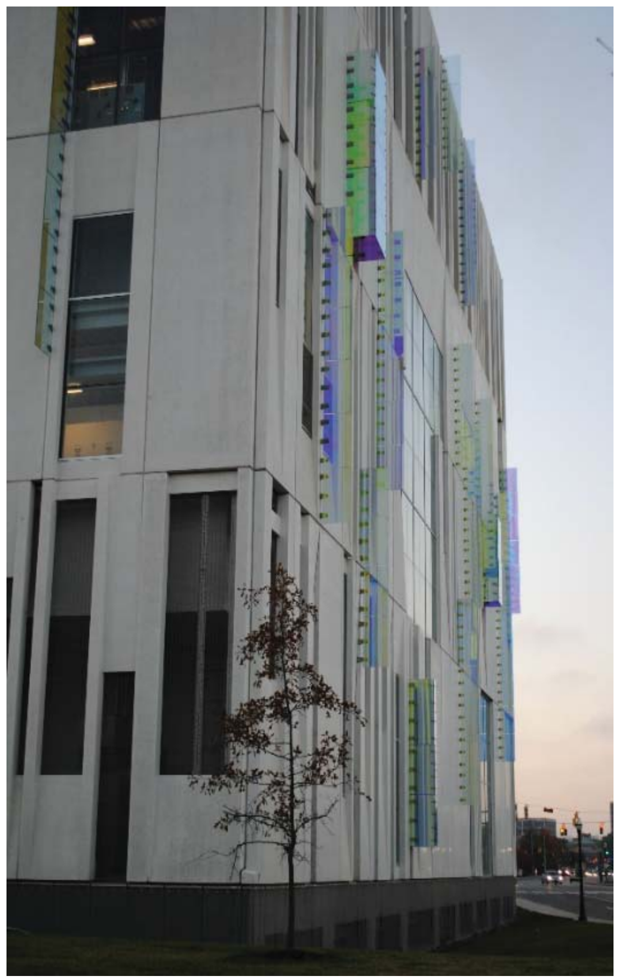
The first step is the identification and prioritization of goals with respect to district energy: efficiency, sustainability, total cost of ownership, reliability, resiliency, ease of O&M, asset renewal needs, impact on occupants, and financial criteria.

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.

# Exhibit RS-C

# Path to Carbon Neutrality:
# Ohio State Climate Action Plan

April 2020

THE OHIO STATE UNIVERSITY

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*President Michael V. Drake*

## Dear Ohio State Community and Partners:

The Ohio State University is deeply committed to solving sustainability challenges in our communities and beyond. To be successful, we know we need to address these challenges from multiple angles – from our curriculum and research to community engagement and innovative operations.

The students at Ohio State motivate our actions, and they give me hope on so many fronts. We are educating the leaders of the future. They want to be engaged in addressing the most pressing issues of our time, and climate change is certainly one of the most pressing issues facing us all.

Climate change is most certainly that. Since Ohio State's 2008 commitment to achieve climate neutrality by 2050, and the release of our first Climate Action Plan in 2011, global climate conditions have rapidly escalated into a pending crisis for many communities.

Ohio State continues to take actions to advance scientific knowledge, social understanding, and model operational techniques that will propel new solutions to climate change.

In 2019, Ohio State approved the most significant overhaul of our undergraduate general education requirements in the past 30 years. Our new approach will include a focus on citizenship, with sustainability as a primary theme. This will bring future thought leaders of all backgrounds into a wider discussion on how we can better balance our social, economic, and environmental resources.

We also need to continue to attract the very best scientists and empower their discoveries. I'm proud that Ohio State's oldest research center is the Byrd Polar Climate and Research Center. Since 1960, our scientists have been collecting and preserving

glacial ice cores, some from glaciers that no longer exist. This work continues to help form the bedrock understanding of how humans are changing our climate.

As institutions dedicated to providing affordable and excellent education, we must operate as good stewards, fiscally and environmentally. Our recent public-private partnership in energy management is one way that Ohio State is bringing new expertise and financial resources to meet our energy demand and reduce our carbon footprint.

As one of the largest research universities in North America, Ohio State is committed to creating a deeper understanding of climate change and working with our communities to implement solutions.

This updated Climate Action Plan will help guide our work in the coming years to achieve our carbon neutrality goal, while helping others achieve theirs as well.

Sincerely,

Michael V. Drake

President

*President Drake visited with the Ohio State Venturi Buckeye Bullet student team as it attempted to set a new world land speed record at the Bonneville Salt Flats in Utah.*

# I. Executive Summary

## Introduction

For decades, researchers at The Ohio State University and other leading institutions around the world have studied how global climatic conditions are changing as a result of human activity. While the dramatic increase in global energy consumption since the Industrial Revolution has powered incredible advancements for humanity, the associated releases of greenhouse gasses into our atmosphere is threatening our current living conditions.

In fact, the number and severity of changes we are witnessing across the world are outpacing even moderate projected impacts. Forests in the American West are becoming dryer landscapes, feeding increasingly deadly fires, while heavier rain events in the American Midwest and East are driving more nutrient runoff into increasingly warmer freshwater bodies causing more widespread harmful algal blooms.

In an alarming clarion call, the International Panel on Climate Change (IPCC) reported in October 2018 that in order to contain global warming to just 1.5 degrees Celsius, global carbon dioxide emissions would need to be reduced by 45% by 2030 (from 2010 levels), and "net zero" by 2050. Just seven months after that report, in May 2019, atmospheric carbon dioxide exceeded 415 parts per million. That is an unprecedented threshold in modern human history.

It is against this larger social backdrop that Ohio State's commitment to carbon neutrality rises in importance. No single institution, or even country, can solve climate change on its own. Society will have to work collectively, across all sectors and disciplines, to avoid the worst impacts of climate change.

In that context, an institution such as Ohio State can serve as an example and living laboratory of how to achieve mission-oriented growth and success while shrinking its carbon emission footprint. Further, as a land-grant institution, Ohio State is charged with the responsibility to educate the state's citizens and help them implement strategies for wider social success. Addressing climate change through its teaching, research, outreach, and demonstrative actions will help achieve the university's land-grant mission by providing students of all ages and backgrounds with a breadth of awareness, knowledge and skills across disciplinary boundaries to prepare them to be global citizens.

## Goal Statement

Over a decade ago, in 2008, Ohio State committed to **achieving carbon neutrality by 2050**.

This public commitment was made by then-Ohio State President E. Gordon Gee through signature onto the American College & University Presidents Climate Commitment, now referred to as the [Presidents' Climate Leadership Commitment]. Shortly into his new tenure as Ohio State President, Michael V. Drake reaffirmed the university's carbon neutrality commitment in 2015. Later in 2015, Ohio State issued a broader suite of [university-wide sustainability goals], with the carbon neutrality goal forming the cornerstone of its operational resource stewardship goals:

> Goal 7a. Achieve carbon neutrality by 2050 per Presidents' Climate Leadership Commitment

The Presidents' Climate Leadership Commitment brings visibility to the issue of climate change and the role of higher education institutions. Currently, over 400 signatories have now committed to a carbon neutrality goal through the Commitment.

## Objectives

The Climate Action Plan is an active document, meaning it will be reviewed and updated regularly, that outlines Ohio State's progress and strategy moving forward to meet the carbon neutrality goal.

Within the Presidents' Climate Leadership Commitment, carbon neutrality is defined as "having no net greenhouse gas emissions, to be achieved by either: a) eliminating net greenhouse gas emissions, or, b) by minimizing greenhouse gas emissions as much as possible, and using carbon offsets or other measures to mitigate the remaining emissions."[1]

While the Climate Action Plan details the university's emission sources, trends, accomplishments, challenges, and opportunities for improvement, there are two primary objectives to achieve the carbon neutrality goal:

- **Address University Building Energy Use.** Ohio State's use of electricity, natural gas, and fuel oil for heating, cooling, lighting, and powering its campus buildings accounts for roughly 73% of the university's carbon footprint. Given the different energy sources and ways in which energy is used throughout the campus setting, there is no single action that can be deployed to reduce the university's carbon footprint to neutral. Therefore, a number of strategies and tactics need to be implemented together into a coherent strategy that incorporates financial and social impacts.
- **Address Transportation Related Emissions.** Transportation (all modes, including air travel) accounts for nearly all the university's remaining carbon emissions. However, the majority of those transportation related emissions are generated by faculty, students, and staff driving to the university's various

campuses. This activity is outside of the university's direct control, and, again, no singular tactic will reduce all transportation related emissions. As a result, the university will need to implement numerous tactics to address these emissions.

## Recommendations

To achieve the university's carbon neutrality goal, several strategies and tactics will need to be employed in the short and long term. Some will require infrastructure changes, some will involve policy changes, and others still need technological innovation. Collectively, the following recommended tactics form an overall strategy that is intended to be updated and revised as conditions and opportunities change. They identify specific actions to address the two primary objectives and create a new path to offset any remaining carbon emissions that cannot be directly eliminated or mitigated in another manner.

Building Energy Use Tactics

- Execute the energy conservation measures (ECM) program as developed through the Comprehensive Energy Management Program with Ohio State Energy Partners. Consider initiating a new ECM program upon successful completion of current one.
- Comprehensively revise the university Green Build and Energy Policy to more effectively control energy use as the university continues to grow and update its built spaces.
- Implement a new combined heat and power plant (CHP) on the Columbus campus.
- Extend on-campus solar photovoltaics, and any future feasible technology, for increased renewable power generation capacity.
- Complete campus steam network conversion to heating hot water.
- Optimize geothermal sources for heating hot water and chilled water networks and explore new geothermal sources.
- Extend the university's existing level of renewable energy power purchase (preferably solar) and integrate large-scale battery storage for renewable energy generation to meet campus demand.
- Include renewable natural gas ("biogas") within the university's renewable energy purchasing mix to replace conventional natural gas as a fuel source.
- Advance CHP fuel source from natural gas to green hydrogen and/or renewable natural gas.

Transportation Emissions Tactics

- Complete existing university Green Fleet Action Plan and consider further future fuel switch from compressed natural gas to green hydrogen or renewable natural gas.
- Develop a new university financed air travel emissions offset policy.

- Create new incentives to reduce impact of driving to and from campus, including expanding campus user access to electric vehicle fueling stations.

On-Site Carbon Sequestration Mitigation

- Expand campus land management techniques to maximize, and account for, carbon sequestration and additional ecosystem services.

## Conclusion

The recommendations detailed in this updated Climate Action Plan position the university to continue to demonstrate leadership in addressing climate change in meaningful ways that provide financial benefits back to the university community and help deliver the promise of an affordable education.

In fact, it may be possible that if the recommendations are fully implemented in the order and timeline described in this Plan, **Ohio State might achieve its carbon neutrality goal as early as 2030 – a full 20 years ahead of goal**, while leveraging 100% renewable energy to power its built infrastructure. This will require institutional dedication and focus, as well as new innovations from internal experts and external partners, and wider market and regulatory changes over the course of the next decade.

However, under a more likely scenario, based on existing technology and financial cost-benefits, Ohio State could still address 55% of its carbon emissions by 2030.

Regardless of when neutrality is achieved, given the broad consequences of climate change, the university should accelerate its pace of activity to demonstrate how action, research, and teaching can ensure a bright future for generations of students to come.

## II. Introduction

Over a decade ago, in 2008, Ohio State committed to **achieving carbon neutrality by 2050**.

This public commitment was made by then-Ohio State President E. Gordon Gee through signature onto the American College & University Presidents Climate Commitment, now referred to as the Presidents' Climate Leadership Commitment. Shortly into his new tenure as Ohio State President, Michael V. Drake reaffirmed the university's carbon neutrality commitment in 2015. Later in 2015, Ohio State issued a broader suite of university-wide sustainability goals, with the carbon neutrality goal forming the cornerstone of its operational resource stewardship goals:

Goal 7a. Achieve carbon neutrality by 2050 per American College and University Presidents Climate Commitment

The Presidents' Climate Leadership Commitment brings visibility to the issue of climate change and the role of higher education institutions. Currently, over 400 signatories have now committed to a carbon neutrality goal through the Commitment.

### Ohio State Climate Action Plan

The university's Climate Action Plan (CAP) is an active document that outlines Ohio State's progress and strategy to meet the carbon neutrality goal.

The CAP details the university's emission sources, trends, accomplishments, challenges, and opportunities. Considered an active document, the CAP is intended to be reviewed and updated regularly to reflect dynamic changes in university operations, regulatory policy, and technological advancements.

> **Defining Carbon Neutrality**
>
> Within the Presidents' Climate Leadership Commitment, carbon neutrality is defined as "having no net greenhouse gas emissions, to be achieved by either: a) eliminating net greenhouse gas emissions, or, b) by minimizing greenhouse gas emissions as much as possible, and using carbon offsets or other measures to mitigate the remaining emissions."
>
> *Second Nature. Presidents' Climate Commitment (2015)*

*Figure 1: Carbon Neutrality Definition, per Presidents' Climate Commitment*

Ohio State's initial CAP was formally endorsed in April 2011. While that original Plan provided a high-level overview of the university's Columbus campus carbon emissions and outlined a set of mitigation strategies to address some of those emissions, it did not fully map a path to carbon neutrality. Instead, it focused on where Ohio State should start its efforts towards carbon neutrality and continue to study how the university could achieve its goal.

During the intervening years, the university did adopt several of the initial CAP proposals:

- **Regional Chiller Plants.** In order to deliver chilled water across the Columbus campus in an energy efficient manner, the 2011 CAP recommended establishing two additional regional chiller plants to potentially generate energy savings for chilled water production. The 2011 CAP contemplated moving forward with one of the two in the near term and adding a second plant sometime after 2020. By early 2015, the university had established both, one to serve the Wexner Medical Center and one to serve the Academic Core campus.
- **Geothermal Heating and Cooling.** By 2011, Ohio State already had its first building utilizing geothermal energy, the Nationwide and Ohio Farm Bureau 4-H Center. The initial CAP recommended expanding that effort, specifically to reduce energy use in student residence halls. In 2013, the university completed a project that now supplies five south campus high-rise halls with 100% of their annual cooling and 90% of their annual heating consumption through a 411 geothermal well field network located beneath the South Oval and Hale Green on the Columbus campus.
- **Energy Conservation Measures.** A bedrock action to reducing energy waste and associated financial costs and unnecessary carbon emissions, implementing energy conservation measures and improved energy use metering has continuously occurred throughout Ohio State buildings since the initial CAP was adopted.
- **Transportation Strategies.** The 2011 CAP contemplated ten different transportation related actions to address carbon emissions from the university's vehicle fleet as well as commuters to campus. The university has acted on, and continues to implement, a number of these, including: a Transportation Master Plan, employee incentives for mass transit use, adoption of electric vehicles into the university fleet and related charging stations, and employee incentives for living near campus.

Other actions mentioned within the initial CAP have not been adopted to date by the university, most notably the establishment of a combined heat and power plant at the Columbus campus. However, this will figure prominently in the university's carbon neutrality strategy moving forward.

In addition, the initial CAP did not anticipate a number of significant actions the university took in subsequent years that have helped reduce the university's carbon emissions:

- Established one of the largest individual green power purchase agreements among higher education institutions, for up to 50 megawatts of wind energy capacity to help power the Columbus campus.
- Installed a compressed natural gas fueling station on the Columbus campus to transition the university's bus and vehicle fleet to cleaner burning natural gas fuel.
- Converted some of the university's fleet to electric vehicles and installed a network of electric vehicle charging stations for university fleet and campus community use.

- Implemented bike and scooter sharing agreements to expand access to alternative transportation options to, from, and across the Columbus campus.
- Launched a long-term comprehensive energy management public-private partnership that embeds energy conservation as a contractual goal, provides new funding to implement energy conservation measures, and creates a new center to propel energy research findings into commercialization, among other benefits.

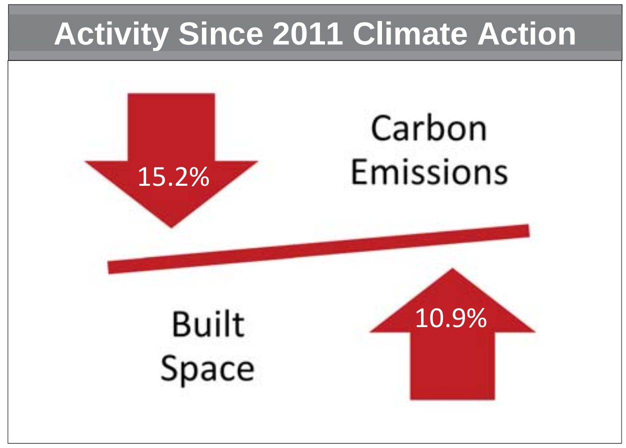

*Figure 2: Carbon Emission and Built Space Activity since 2011 Climate Action Plan Adoption.*

Altogether, with the implemented recommendations and additional actions, Ohio State reduced its Columbus campus carbon emissions by 15.2% since the initial CAP was adopted in 2011. This reduction occurred over the same time period as the university added over 2.4 million square feet of built space (a 10.9% increase) and improved carbon emission data capture methodologies that generally increased the number of reported emissions in different categories.

## Carbon Footprint Boundary Scope

The university's carbon neutrality commitment through the Presidents' Climate Leadership Commitment focused its scope upon Ohio State's Columbus campus. This scope is reflected within the annual carbon emission data reporting the university submits to Second Nature, the third party organization that manages and publishes the Presidents' Climate Leadership Commitments and related data.

**Ohio State Properties Not Included in Scope**

The following properties are not included within Ohio State's FY19 carbon emission calculations:

- Molly Caren Agricultural Center
- Ohio State East Hospital
- Ohio State Extension offices
- Ohio State University Golf Club
- Stone Laboratory

*Figure 3: Ohio State University Properties Excluded from Climate Action Plan Scope and Related Emissions Reporting.*

However, in 2015, the university adopted a broader suite of university-wide sustainability goals, and expanded the university's carbon neutrality goal scope to include all of the university's academic campuses: Columbus, Lima, Mansfield, Marion, Newark, and Wooster. The Wexner Medical Center is considered a part of the Columbus campus, and was therefore included in the original 2008 Presidents' Climate Leadership Commitment.

The university does own or operate many properties outside of these academic campuses. For several reasons, these properties are generally not currently included within the scope of the university's carbon neutrality goal. Among others, these reasons include:

- These properties generate de minimis annual carbon emissions.
- Ohio State does not maintain ownership control of the facilities located at these properties.
- Ohio State does not have access to relevant data pertaining to these properties.

## III. Greenhouse Gas Emissions Inventory: Emission Sources

In order to establish a long-term strategy towards achieving carbon neutrality, any institution must understand the various individual sources that generate its greenhouse gas emissions. Those individual sources are then grouped by type into widely accepted categories, or scopes. This not only allows the institution to develop specific tactics to reduce emissions by source, it also allows for data comparability across institutions to provide learning opportunities amongst peers for best practices within each emission source scope.

### Methodology

To calculate the university's greenhouse gas emissions, Ohio State utilizes the Sustainability Indicator Management & Analysis Platform (SIMAP™). SIMAP is an online tool created specifically for use by higher education institutions to calculate and report their emissions through a common framework. Second Nature, the third party that administers the President's Climate Leadership Commitment, partnered with the University of New Hampshire (UNH) to develop and support SIMAP out of previous emission calculator tools that UNH helped to co-develop. SIMAP is now the most trusted and most used emissions calculator among higher education institutions.

| Carbon Dioxide Equivalent Definition |
|---|
| Carbon dioxide equivalent, or CO2e, means the number of metric tons of carbon dioxide emissions with the same global warming potential as one metric ton of another greenhouse gas, and is calculated using a federally defined equation (Equation A-1 in 40 CFR Part 98). |

*Figure 4: U.S. EPA Definition of Carbon Dioxide Equivalent.* *https://www3.epa.gov/carbon-footprint-calculator/tool/definitions/co2e.html*

SIMAP uses data from many different aspects of campus: campus enrollment, building area, campus-owned fleet data, purchased electricity, electric grid source composition, student and faculty transportation data, fertilizer usage, and waste management, to name a few. The input data is collected through various methods by the university: direct meters, billing data, university-wide surveys, etc.

Once the university's raw data is input to SIMAP, the program runs a series of calculations to convert each greenhouse gas emission source and amount into units of carbon dioxide equivalents ($CO_2e$), for a common measurement across emission sources. Each source, and its related $CO_2e$ is then categorized into a wider, commonly accepted, scope:

| Scope | Definition | Source |
|---|---|---|
| Scope 1 | Direct Emissions | From sources directly owned or controlled by the university. Examples include on-site fuel combustion and fleet vehicle fuel consumption. |
| Scope 2 | Indirect Emissions | From sources indirectly owned or controlled by the university. Examples include the generation of purchased electricity, heat, or steam. |
| Scope 3 | Emissions Related to University Activities | From sources not owned or directly controlled by the university. Examples include student and employee travel and commuting, and waste disposal and treatment. |

*Figure 5: Greenhouse Gas Emissions Scope Definitions, Adapted from U.S. EPA*
*https://www.epa.gov/greeningepa/greenhouse-gases-epa*

The definitions of these scopes imply the following:

- If the university's campus community and business partners are committed to their own sustainability actions, the university's Scope 2 and 3 emissions will reduce with their improvements.
- As the scope increases from 1 to 3, data collection becomes increasingly difficult and the accuracy of the calculation decreases.
- It is extremely difficult to collect every piece of data needed for a complete Scope 3 assessment. Thus, there is a need to continuously review and evaluate data gaps and their potential impacts.

## Results

In Fiscal Year 2019, Ohio State's total greenhouse gas emissions equaled 619,944 tonnes CO2e within the annual greenhouse gas emissions inventory. Not surprisingly, of the university's six academic campuses, the Columbus campus generated the most emissions, accounting for 568,985 tonnes CO2e, or 91.8% of the university's total emissions (Figure 6).

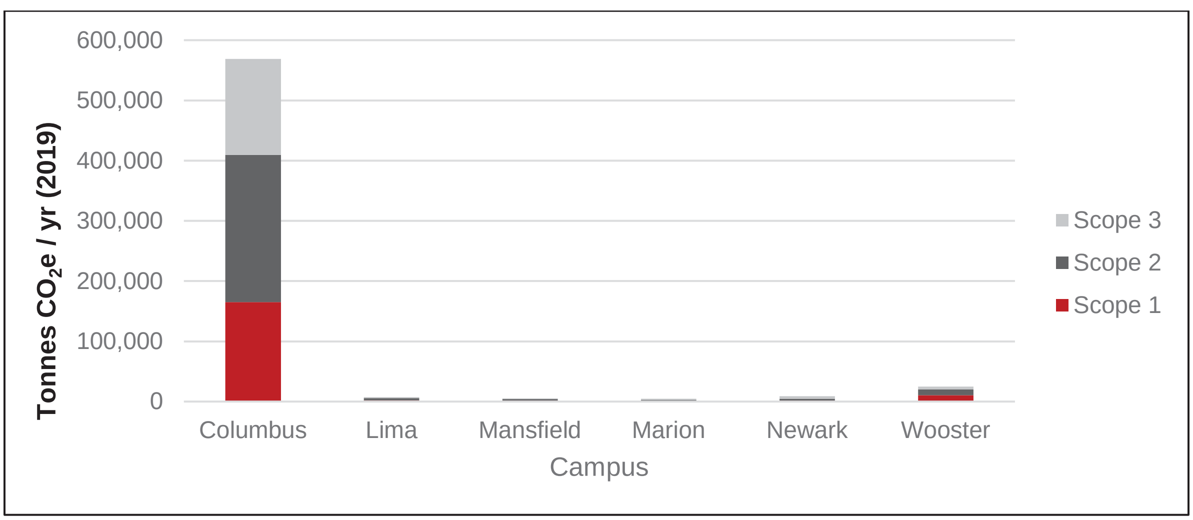


*Figure 6: Carbon Footprint Results for Each Campus in Fiscal Year 2019.*

Due to the scale of operations for the Columbus campus, and resulting percentage share of greenhouse gas emissions, this CAP will largely focus on information and solutions most applicable to the Columbus campus, although much could apply to all the campuses on different scales.

That said, more than 40% of the university's overall total greenhouse gas emissions (264,718 tonnes CO2e) in Fiscal Year 2019 were generated from the university's purchased electricity, heat and steam within Scope 2. The remaining emissions were nearly evenly split between Scope 1 and Scope 3 emissions, at 29.4% and 27.9% respectively, of the university's total emissions.

| Scope | CO2e Metric Tonnes | Percentage of Total Emissions |
|---|---|---|
| Scope 1 | 182,044 | 29.4% |
| Scope 2 | 264,718 | 42.7% |
| Scope 3 | 173,182 | 27.9% |
| Total | 619,944 | 100% |

*Figure 7: Fiscal Year 2019 Greenhouse Gas Emissions by Scope.*

**Recent Emissions Trend**

Since the university established its suite of sustainability goals in 2015, the university has increased its reported annual carbon emissions by 4,892.77 tonnes CO2e, or 0.8% (Figure 8).

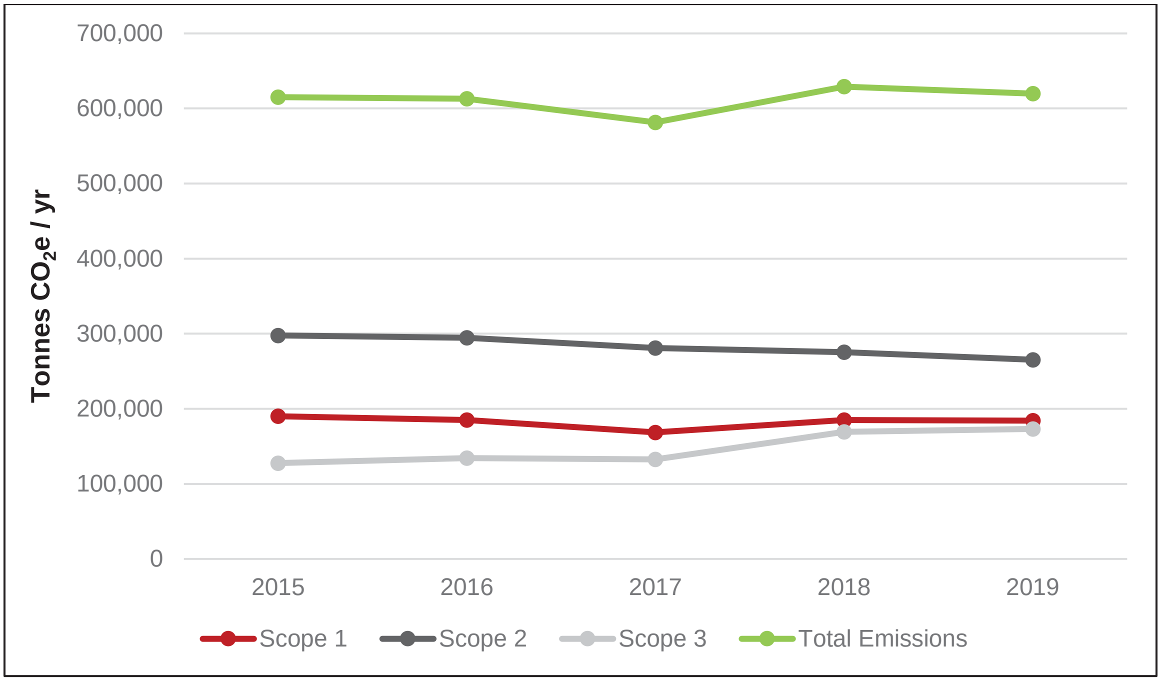


*Figure 8: Total University Carbon Footprint Results from 2015-2019.*

The overall increase in reported emissions during this time frame is largely the result of improved data collection and monitoring efforts, particularly as the university was able to capture additional emissions records, beginning in Fiscal Year 2018, that were not previously available. Namely, directly financed university air travel emissions are now more holistically included in the university's annual carbon emissions record keeping and reporting than they were in previous years.

In addition, the 10.9% decline in Scope 2 emissions from Fiscal Year 2015 through Fiscal Year 2019 reflect a number of factors, including the implementation of energy conservation measures particularly through the Comprehensive Energy Management Project with Ohio State Energy Partners, the improved fuel mix associated with the electrical grid ("grid greening"), and the university's significant, long-term investment in renewable energy supply to the Columbus campus from the Blue Creek Wind Farm, which has helped maintain a lower plateau of Scope 2 emissions since 2013.

### University Emissions by Source

Understanding what sources contribute to the university's greenhouse gas inventory, at what levels, is critical to developing a successful strategy to achieve carbon neutrality. Mapping the source breakdown of emissions helps the university identify the highest priority sources to address and provides a starting point for considering what tactics would be most effective to employ against each source.

As noted above, emissions generated from the purchase of electricity represent the single largest source of emissions for the university. That is followed by on-campus stationary sources (e.g. combustion of natural gas at McCracken Power Plant to supply heating and process steam), then a series of transportation related emission sources (Figure 9).

Although energy and transportation emissions make up the majority of the university's carbon footprint, it is important to see how many different sources contribute greenhouse gas emissions. For this reason, commitments and actions from across all areas of the university will be necessary to achieve carbon neutrality.

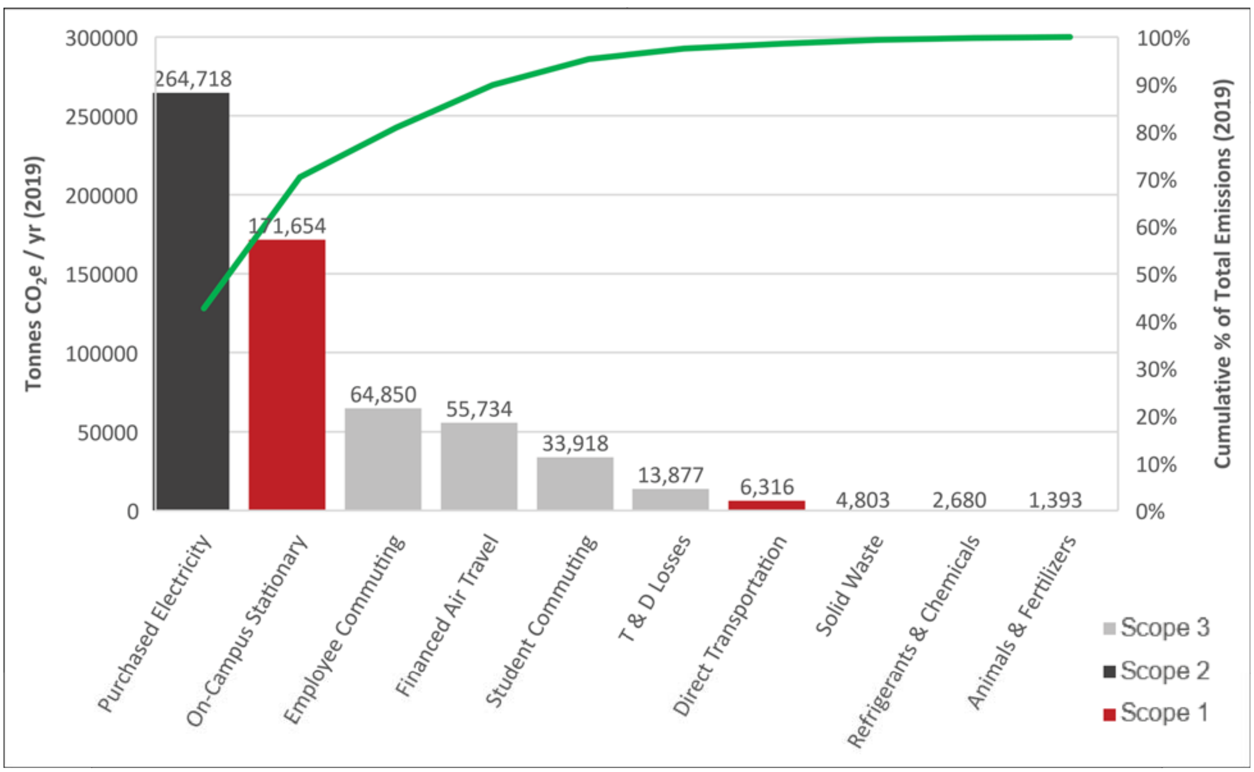


*Figure 9: Distribution of University Carbon Emissions by Source in Fiscal Year 2019.*

## University Emissions Trends by Source

Just as it is important to understand the university's emissions by individual source, and the overall long-term trajectory of total emissions, it is important to understand the emissions trends within individual sources. This helps the university understand how operational changes or improved data collection efforts affect a targeted source's emissions. The figure below demonstrates the university's emissions by source for the five-year period beginning with 2015 and ending with 2019 (Figure 10).

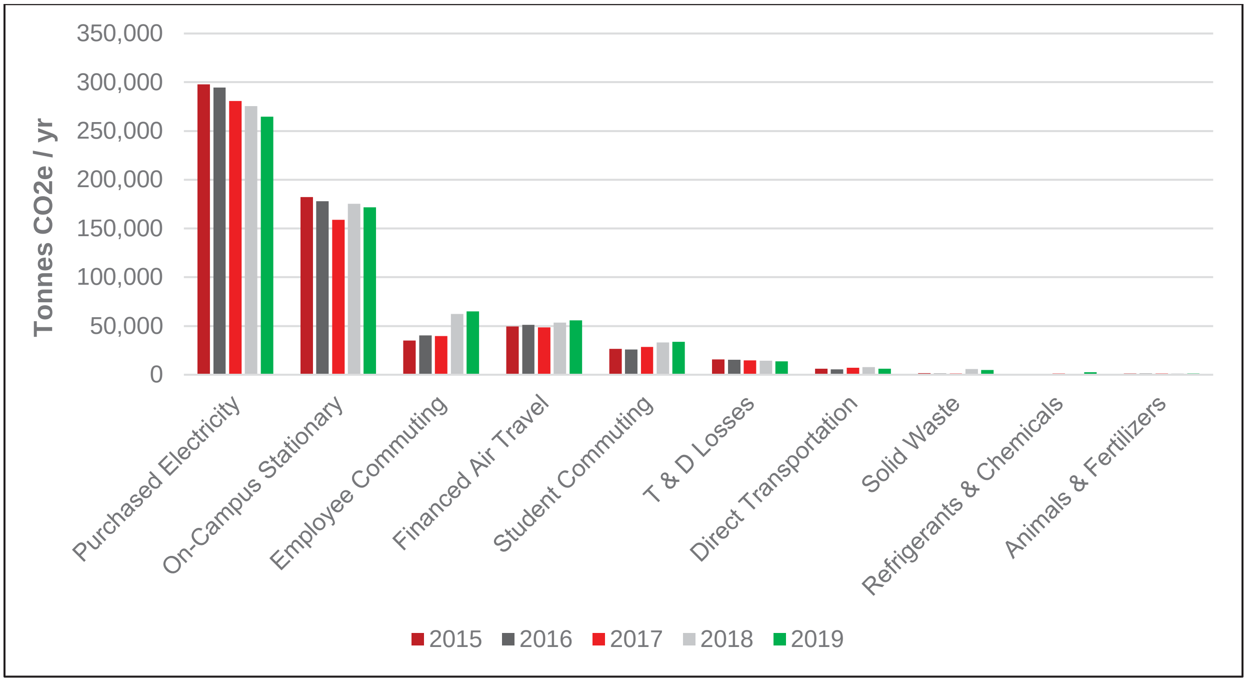


*Figure 10: Distribution of University Carbon Emissions by Source from 2015-2019.*

## IV. Operating Framework for Progress

As stated in the university's previous Climate Action Plan:

> *Achieving climate neutrality will require aggressive reductions, avoidance, and neutralization in existing and future greenhouse gas emissions. One thing is clear – there is no single solution. Many strategies will need to be implemented to meet the overall goal.*

While this is still true, it is clear that the university will need to emphasize strategies that address building energy use and transportation-related emissions, given the dominant roles those two sectors have in the university's total emissions footprint. In order to organize those tactics into an operating framework, Ohio State will follow the carbon management hierarchy, presented in the *Second Nature Carbon Markets and Offset Guide*.[2]

Further, while this Climate Action Plan identifies a set of recommendations for Ohio State to implement in the short and near term, the university will adaptively manage its resources and programming towards achieving carbon neutrality. In that sense, this is a "living" document, one that will change with societal, economic, technological, and public policy changes over time.

Finally, it is also important to note that electric utility driven "grid greening" is anticipated to continue, which will benefit Ohio State's carbon footprint regardless of actions the university takes. In fact, Ohio State's current primary electricity utility provider, American Electric Power (AEP), has publicly committed to accelerating its carbon emission reduction goals, in order to achieve an 80% emission reduction by 2050, measured from a 2000 baseline. While that activity is clearly outside of Ohio State's control, it could have a direct beneficial impact to the university's carbon neutrality efforts.

### Carbon Management Hierarchy

1) **AVOID** New Emissions
2) **REDUCE** Existing Emissions
3) **REPLACE** Sources of Emissions
4) **OFFSET** Remaining Emissions

This hierarchy is not meant to act as a list of competing or restricting strategies, but rather to consider the value of different actions to meet carbon neutrality. Essentially, this hierarchy promotes behavioral changes which avoid carbon emissions altogether over technological or market-based solutions. However, it is better to act urgently than it is to debate the ranking and implementation of the hierarchy. Any action to reduce emissions is better than none.

### Avoid – Minimize Consumption

The top priority towards becoming a carbon neutral university is to avoid emissions and carbon-intensive activities altogether. This means avoiding unnecessary use of electricity, process steam, heating and cooling, and transportation among other sources of emissions. This may also mean avoiding a new project if it does not align with the mission of the university or designing projects to avoid carbon emissions once they are completed. Most of the avoidance opportunities are subject to human behavior and show a need for a strong culture across Ohio State that is committed to its sustainability initiatives.

### Reduce – Improve Efficiency

Maximizing the efficiency of the university's current operations will help reduce emissions. This category of the hierarchy will include most of the recommended technological changes.

### Replace – Cleaner Energy Sources

Replacement involves substituting high-carbon energy sources with low-carbon or renewable energy sources. This can include both on-site and off-site energy generation. This can also include procurement of renewable power, such as solar or wind power, paired with battery storage to cover intermittency of renewable power generation. Also, the development or procurement of renewable natural gas can replace or offset conventional natural gas usage.

### Offset – Obtain Certified Credits

Within the hierarchy, offsetting greenhouse gas emissions is an effort of last resort towards carbon neutrality. Offsets can occur in distinctly different ways, but generally involve investing in projects that either directly sequester emissions or displace existing emissions. While either option results in a similar outcome (the generation of certified credits), these are considerably different routes to offset emissions.

- **Direct Sequestration.** Projects that sequester emissions require third party certification to verify the intended emissions are sequestered. Carbon

**Carbon Sequestration "Sinks"**

Just as human activities emit carbon, nature has many ways of sequestering carbon as part of the carbon cycle. For the Climate Action Plan, Ohio State will consider the land which sequesters carbon as "sinks," or negative emissions compared to carbon sources. The impacts of climate change are a result of releasing more carbon into the atmosphere than the natural world has capacity to sequester. Therefore, instead of solely focusing on reducing emissions, the university will seek to include natural sequestration in the assessment of the Plan. The two main sinks that will be considered in the university's carbon sequestration analysis are: **tree canopy** and **soil**. Carbon sequestration can occur above and below ground as part of ecosystem growth, such as through the process of photosynthesis. For tree canopy, the species, size and age of the tree(s) are most important for determining the rate of carbon sequestration. For soil, several different measurements are necessary, including soil organic carbon (SOC), the biomass above ground, climate, and others.

For more detail on the sequestration calculations, see Recommendations.

*Figure 11: Definition of Carbon Sequestration Sinks*

sequestration projects can be designed to improve local landscapes and cultivate long-term future value, creating “carbon sinks.”

- **Emission Displacement.** Projects that involve displacing existing emissions typically involve the purchase of renewable energy credits (RECs), which are available in a variety of forms in a variety of markets. However, REC purchases must be replenished on an annual basis to maintain equal displacement of continuously generated emissions.

## “Living” Document and Measuring Progress

To measure progress moving forward, the university will commit to updating the Climate Action Plan every five years. The Climate Action Plan will assess how far the university has come towards its commitment to climate neutrality and reevaluate its plan and recommended tactics to meet the goal by 2050, if not earlier.

The greenhouse gas inventory will be reassessed annually, publicly reported through the Presidents’ Climate Leadership Commitment reporting platform, and communicated through the variety of entities already in place at the university that focus on sustainability, including the President and Provost’s Council on Sustainability, Sustainability Institute, Energy Services and Sustainability, and Resource Stewardship Working Group.

## V. Recommendations

Using the carbon management hierarchy as an operating framework, the following action recommendations seek to address the university's currently feasible opportunities to achieve carbon neutrality across primary sector use, the three scopes of greenhouse gas emissions, and implementation timeline.

### Avoid – Minimize Consumption

- **Update University Green Build and Energy Policy.** Currently, the university policy requires building projects valued at $4 million or above to achieve LEED Silver certification. While this policy has advanced the university's overall sustainable building design criteria since its adoption, there may be more direct ways to achieve the university's sustainability goals, including carbon neutrality. The university should update the existing policy to ensure that building and construction projects are designed in a manner that utilizes energy as efficiently as possible for the intended purpose in the project's post-construction operation. This university-wide policy update should be informed by the work conducted in Fiscal Year 2019 to develop updated sustainable campus building standards specifically for the Time and Change: Building the Future construction projects, which included stronger energy efficiency recommendations than the existing university Green Build and Energy Policy.
  **When:** Short Term – 1-2 Years (FY20-21)
  **Sector:** Building Energy Use
  **GHG Scope:** 1 & 2
  **Emissions Reduction:** Will vary by building project
  **Financial Cost Impact:** No direct cost impact for policy revision, but updated policy will have varying upfront and lifecycle cost impacts, with a goal to lower overall cost of ownership.

- **Advance and Promote Teleconferencing and Remote Meetings.** The university is in the process of broadly adopting tools such as *Skype for Business* and *Microsoft Teams* that should enable increased distance-meeting capabilities. This opens new avenues to reduce travel related costs and greenhouse gas emissions. The university should provide appropriate user training for these tools and identify specific in-person meetings with internal or external partners to participate via teleconference, with an emphasis on those currently requiring university financed airline travel.
  **When:** Short Term – 1-2 Years (FY20-21)
  **Sector:** Transportation
  **GHG Scope:** 1 & 3
  **Emissions Reduction:** TBD
  **Financial Cost Impact:** Expected cost savings

- **Foster Energy Conscious Culture.** As the university has conducted a variety of educational campaigns on other sustainability topics, there are opportunities to demonstrate to the campus community how behavioral change can help reduce the university's emissions footprint. While these activities can be manifested in many different ways, new programming would benefit from engaging the university's behavioral change researchers to help design and implement effective, science-based behavioral interventions.
  **When:** Short Term – 1-5 Years (FY20-25)
  **Sector:** Building Energy Use, Transportation
  **GHG Scope:** 1, 2 & 3
  **Emissions Reduction:** TBD
  **Financial Cost Impact:** Expected cost savings

| "CAPEX" Definition |
|---|
| Capital expenditures are institutional investments into physical assets. These physical assets include, among other items: buildings, roadways, vehicles, land and related infrastructure.<br><br>"CAPEX" is a well-established abbreviation for capital expenditures and is used within this Plan to demonstrate the expected capital expenditure amount for executing some of the recommendations. |

*Figure 12: "CAPEX" Definition*

## Reduce – Improve Efficiency

- **Implement Energy Conservation Measures.** Under its partnership with Ohio State Energy Partners (OSEP), the university is positioned to significantly increase energy efficiency efforts across the Columbus campus. In coordination with university staff, OSEP develops and proposes energy conservation projects on an annual basis to the university Board of Trustees. The university must approve those projects. Under the terms of the partnership agreement, OSEP is obligated to improve the university's Columbus campus energy efficiency by a minimum of 25% by June 2028, and further support improvement in energy efficiency beyond that amount through the life of the partnership (June 2068). In addition, the partnership agreement envisions developing new energy efficiency targets and incentives every ten years following the first 25% efficiency target. Finally, the university will ensure the energy conservation projects operate as designed to retain long-term energy efficiency benefits through a focused preventative maintenance and retro-commissioning program.
  **When:** Short to Long Term: 1-8 years (FY20-FY28)
  **Sector:** Building Energy Use
  **GHG Scope:** 1 & 2
  **Emissions Reduction:** 75,000 tonnes $CO_2e$, 12% of total emissions
  **Financial Cost Impact:** $250 million capital investment through CAPEX, with each ECM project providing positive net present value to Ohio State

- **Construct Combined Heat and Power Plant.** Following a feasibility study conducted by OSEP, the university Board of Trustees has approved construction

for a combined heat and power (CHP) solution on the Columbus campus. The plant is sized to level the cost of energy for the university and designed for flexible operation to meet the university's dynamic energy needs and campus resiliency. Heat resulting from the power production is used to produce steam, which can either be fed to the existing campus district steam heating network, used in the new campus district hot water network, or directed to generate power in a steam turbine.
**When:** Short Term: 1-3 years (FY20-FY22)
**Sector:** Building Energy Use
**GHG Scope:** 1 & 2
**Emissions Reductions:** 148,000 tonnes $CO_2e$, 24% of total emissions
**Financial Cost Impact:** $290 million capital investment through CAPEX, expected lifecycle cost savings

## Replace – Cleaner Energy Sources

- **Continue to Implement University Green Fleet Action Plan.** Along with its carbon neutral goal, the university has established a goal to reduce the carbon footprint of its fleet by 25% by 2025. Led by the Office of Transportation and Traffic Management (TTM), this effort includes "right-sizing" the university fleet, converting the fleet to alternative fuel vehicles, and the incorporation of increasingly carbon friendly fuel sources. As TTM continues to execute the plan's fleet conversion to compressed natural gas and electric vehicles, the university should achieve a 15% reduction in fleet related emissions. Achieving the additional 10% reduction to reach the fleet goal will require additional planning and solutions, given the currently prohibitive pricing for less intensive fuel sources. Given this, for Climate Action Plan purposes, the latter is not currently included in the emissions reduction figure below.
  **When:** Short to Medium Term: 1-6 years (FY20-25)
  **Sector:** Transportation
  **GHG Scope:** 1
  **Emissions Reduction:** 1,160 tonnes $CO_2e$, 0.2% of total emissions
  **Financial Cost Impact:** TBD

- **Expand Campus User Access to Electric Vehicle Charging Stations.** In addition to the university owned fleet, TTM has been actively seeking to expand university user access to electric vehicle charging stations. This includes work to develop a user access policy (including fuel pricing), and strategic placement of charging stations to leverage maximum use. Depending on electric vehicle adoption rates within the university community, this effort will help reduce the university's greenhouse gas emissions related to employee and student commuting but may slightly increase purchased electricity related emissions. For the purposes of estimating emissions reductions within this plan, the Smart Columbus 1.8% adoption rate projection was applied to employee and student commuting generated emissions.
  **When:** Short to Medium Term: 1-6 years (FY20-25)

**Sector:** Transportation
**GHG Scope:** 3
**Emissions Reduction:** 1,700 tonnes $CO_2$e, 0.3% of total emissions
**Financial Cost Impact:** TBD

- **Explore Campus-Based Solar Energy Generation.** Currently, Ohio State has a few solar arrays across its campuses, most notably the “Block O” rooftop array on the RPAC and the more recent rooftop installation on the Marion campus Science and Engineering Building. Unfortunately, there are surprisingly few campus locations that could feasibly host an economically sound solar array. Ohio State’s existing building stock presents considerable challenges for rooftop solar mounting – ranging from appropriate roof strength, to historical architecture, to lack of south-facing roofs, among other considerations. As a result, ground mount systems are likely more physically feasible, but will be difficult to implement due to the constantly changing nature of the university’s land assets. The university should continue to monitor opportunities to install solar energy generation on campus, particularly as economic conditions change, and long-term sites are identified. By 2030, it might be possible to install a modest amount of solar energy generation the university’s campuses, on the order of 10 megawatts. Beyond any potential future energy cost savings and carbon emission reductions, on-site solar energy generation would provide increased educational and outreach opportunities.
  **When:** Short to Long Term: 1-11 years (FY20-30)
  **Sector:** Building Energy Use
  **GHG Scope:** 1
  **Emissions Reduction:** 6,100 tonnes CO2e, 1% of total emissions
  **Financial Cost Impact:** $24 million capital investment through CAPEX, expected energy cost savings

- **Advance Green Hydrogen and/or Green Biogas Fuel Replacement.** The proposed combined heat and power plant will achieve both energy efficiency and a carbon emission beneficial fuel switch from grid energy to natural gas for most of the university’s power generation. However, natural gas still generates carbon emissions. Among other private sector energy entities, OSEP’s operating entity on campus, ENGIE, is currently developing hydrogen and biogas fuel solutions as a replacement source for natural gas. This includes “green hydrogen,” which can be generated through the electrolysis of water using renewable electricity resources. Generally, this requires the consumption of water as the basic fuel feedstock. So, siting this type of energy operation would need to ensure the appropriate body of water could sustain the necessary level of consumption withdrawal. Ohio State’s energy research experts have already begun a dialog on how the university’s academic assets could help advance hydrogen technology for quicker, and more sustainable, adoption. Recognizing the significant market based and regulatory challenges that would enable green hydrogen to be a viable fuel source, the current pace of research progress is

encouraging. In fact, the university's planned Energy Advancement and Innovation Center, which will be established in partnership with ENGIE, could be a significant driver to advance green hydrogen adoption, and help make it a viable fuel replacement at some level for Ohio State's CHP in/around 2030. The university should continue to explore with OSEP how to advance this development and leverage the Energy Advancement and Innovation Center as a location to house this collaboration. "Green biogas" is produced by decomposition of waste feedstocks, including agricultural and post-consumer waste. Emerging opportunities to leverage ENGIE's experience with green biogas have been explored through a pilot project with the university and should be continued to advance development suited for the university's unique waste streams.
**When:** Long Term: 10 years (FY30)
**Sector:** Building Energy Use
**GHG Scope:** 1
**Emissions Reduction:** 340,000 tonnes CO2e, 55% of total emissions (full replacement of conventional natural gas fuel source)
**Financial Cost Impact:** Hydrogen costs are nearly 40 times the cost of natural gas in 2019 and are not feasible for consideration at this point. Technological advances are expected in the coming decade to reduce the cost of green hydrogen production. Green biogas processes are limited by the available waste streams. As the university continues to enhance its ability to separate post-consumer waste and manage agricultural and dining waste, onsite or near-site green biogas may become increasingly feasible.

- **Increase Renewable Energy Procurement.** As the university experiences electricity use efficiencies through energy conservation measures and the CHP, the university should explore additional renewable energy procurement in an amount that is compatible for optimal leverage of the CHP capacity. Based on CHP operations, the remainder of the imported grid electricity could be provided through renewable procurement. Given the university's energy use pattern, it would be preferable for the additional renewable energy to be solar generated. Solar energy generation matches the university's daytime energy use loads closer than wind energy generation, which generates more energy overnight that would require additional energy storage capacity for university use. Battery storage systems could be included to cover the variability in solar generation. Further, renewable natural gas ("biogas") to replace conventional natural gas burned in the CHP could also be a pathway to increase renewable energy supply for the university.
  **When:** Medium Term: 3-5 years (FY22-24)
  **Sector:** Building Energy Use
  **GHG Scope:** 2
  **Emissions Reduction:** 30,000 tonnes CO2e, 4.8% of total emissions (replacement of purchased electricity from the grid); 340,000 tonnes CO2e, 55% of total emissions (full replacement of natural gas fuel source for CHP)

**Financial Cost Impact:** Incremental energy costs for solar are 15-20% higher than current purchased electricity from the grid. The competitive renewable natural gas ("biogas") market has not been explored for this purpose as of the release of this document.

- **Extend Existing University Commitment to Renewable Energy.** In 2012, Ohio State became one of the largest purchasers of renewable energy among higher education institutions. Through this 20-year purchase agreement with the Blue Creek Wind Farm, that wind energy accounted for approximately 14% of the university's total energy purchase in Fiscal Year 2019. This agreement drove a reduction of approximately 85,000 tonnes $CO_2e$ in the university's Columbus campus annual emissions. The existing agreement will end in Fiscal Year 2033. Closer to the end of that agreement, the university should develop a plan to extend or replace that level of renewable energy purchase.
  **When:** Long Term: 13 years (FY33)
  **Sector:** Building Energy Use
  **GHG Scope:** 2
  **Emissions Reduction:** Not applicable
  **Financial Cost Impact:** TBD

## Offset – Obtain Certified Credits

- **Develop University Air Travel Policy.** Recognizing the greenhouse gas impact of university related air travel, some higher education institutions have begun implementing policies to offset these emissions, which are largely beyond the university's control. Ohio State's most significant air travel use categories include its academic research and learning efforts, which are integral to the university's reputation and student experience. As other institutions realize successes in their travel policies – ranging from requiring ground transportation within a certain distance to implementing flat fees per flight – Ohio State should develop a program to offset its annual air travel related emissions that fits the university's culture.
  **When:** Short Term: 1-2 years (FY20-21)
  **Sector:** Transportation
  **GHG Scope:** 3
  **Emissions Reduction:** 55,734 tonnes CO2e, 9% of total emissions
  **Financial Cost Impact:** $280,000 annually (based on $5.00 average carbon offset cost per metric tonne)

- **Enable Carbon Sequestration Through Campus Land Management.** As mentioned in the Carbon Management Hierarchy above, natural landscapes have the capacity to sequester carbon. In moving towards neutrality, it is important to consider efforts to increase the sequestration capacity of campus lands in parallel with mitigating emissions. Ohio State can increase its sequestration rates across all six university campuses through increasing tree canopy and land use management techniques focused on sequestration.

Current rough estimates of average reforestation projects have been found to cost 5-19 $/tonnes CO2e. Looking at the potential of carbon sequestration for Ohio State campuses, two cases were considered. The first case (Potential I), considers no change in land-use, but rather beneficial land management practices identified by research findings to which Dr. Rattan Lal has significantly contributed. These management practices affect the soils of grasslands, croplands, and forest, such as: fertility management through liming and mineral fertilizers, application of local manure, planting improved and native plant species, erosion reduction, longer crop rotations, and partial cutting versus clear-cuts, to name a few. The second case (Potential II) includes land-use change. To prevent competition between food production and carbon sequestration, the land-use change scenario does not consider a decrease in crop and agricultural land, especially since most of this land is used for the university's agriculture research. It also does not consider the change of all grasslands (lawns) to forest or tree cover. Changes in sunlight absorption due to different land cover or emissions by trees are not included in this analysis. Although it is an extreme scenario to consider a complete conversion of grassland to forest, it does best show the potential of land use change to meet the goals of carbon neutrality. The results of carbon sequestration associated with these scenarios are shown in Figure 14 and Figure 15. Figure 14 shows total sequestration as a rate in the same units as presented in the greenhouse gas emissions inventory. Figure 15 shows these results as a fraction compared to the Scope 1 emissions in Fiscal Year 2019 by campus location, as to compare the carbon directly emitted on each campus with that being sequestered by the surrounding land – Scope 1 positive and negative emissions.

**Calculating Sequestration**

To calculate the rate of tree canopy sequestration across Ohio State campuses, a data set of over 15,000 trees on the Columbus campus was used as a sample population. Using the Urban Forest Effects- Dry Deposition (UFORE-D) model[3] built into iTree Eco[4], the amount of carbon sequestered per unit of tree coverage area [tonnes CO2 / acre] was calculated. Then, using GIS data and campus maps, this value was scaled to the amount of tree covered land area across the different campuses.

To calculate soil sequestration, a collection of research from Ohio State's Dr. Rattan Lal and collaborators[5,6,7] provided estimates of U.S. soil sequestration for three different land uses: forest, cropland and grazing land. The literature provided current analysis of carbon sequestration of these land types across the U.S. along with future potential sequestration given a variety of different management strategies. The soil sequestration data from the given literature was normalized and scaled to reflect the land-use of each campus. The same GIS data used for tree area was used to determine crop and grassland area across the different campuses.

*Figure 13: Methodology for Calculating Carbon Sequestration*

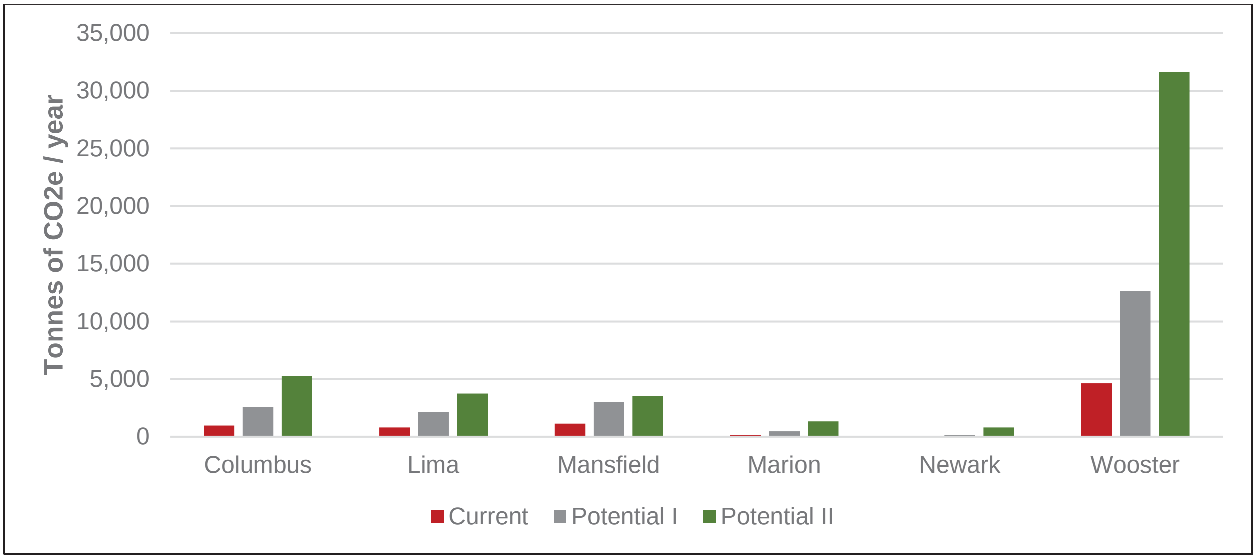


*Figure 14: Scenarios of Sequestration, Shown as Amount of $CO_{2e}$ Annually Sequestered.*

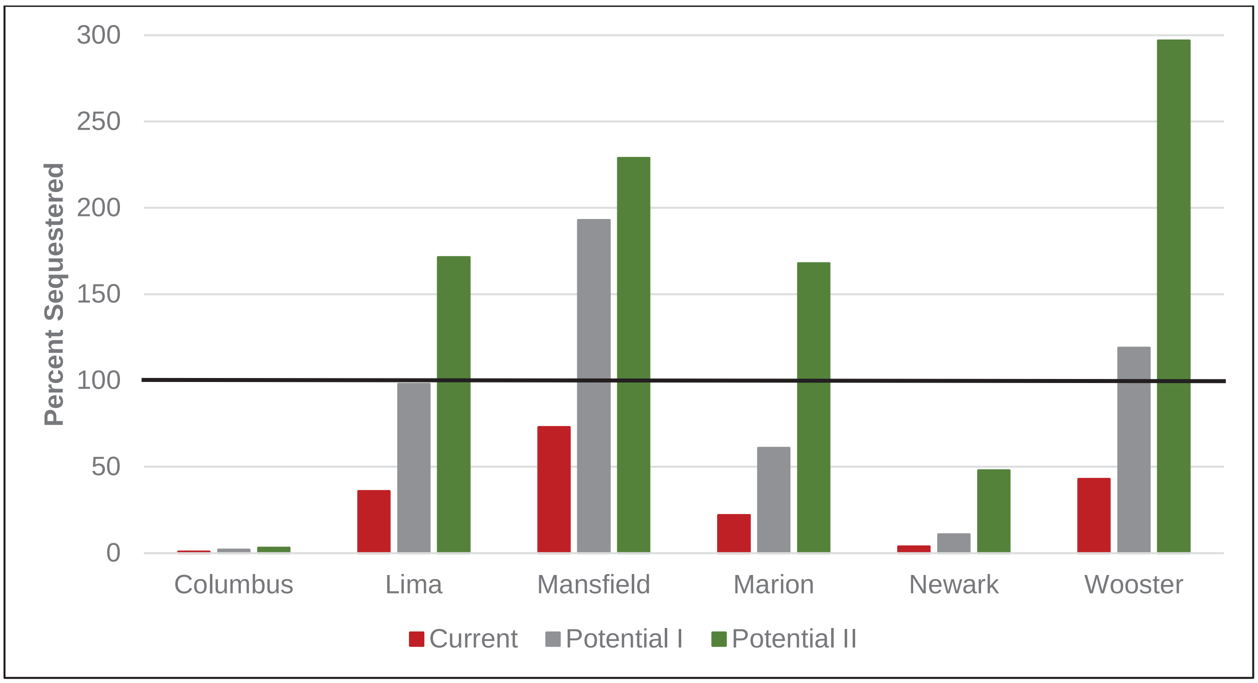


*Figure 15: Scenarios of Sequestration, Shown as Percent Sequestered of Scope I Emissions of Each Campus.*

Under these scenarios, the sum of the sequestration across all campuses is:

| Scenario | CO2e Metric Tonnes Sequestered | Percentage of Total Emissions |
|---|---|---|
| Current | 7,750 | 1.25% |
| Potential I | 21,000 | 3.4% |
| Potential II | 46,250 | 7.5% |

*Figure 16: Carbon Sequestration Potential Comparison*

Outside of just Potential I and Potential II, an unlimited number of scenarios exist and could include multi-purpose land use, such as green roofs or parking lots. Adding to the feasibility of investing in the natural land on Ohio State property, projects funded as offsets could occur either on or off campus, as long as they are in addition to "business as usual." Land use changes take time to grow and they produce more sequestration with time. Therefore, more immediate adoption would enable the possibility to reap the benefits sooner. Such changes in land use will also provide other ecosystem services such as air quality regulation, water provisioning, climate regulation, and recreation. Therefore, Ohio State should cultivate peer institutions in a broader effort to enable SIMAP to consider and allow appropriate carbon sink projects as a recognized greenhouse gas emission offset. Further, the university should pursue the available land use and land management techniques to maximize carbon sequestration opportunities as closely aligned to the Potential II scenario outcome as possible.

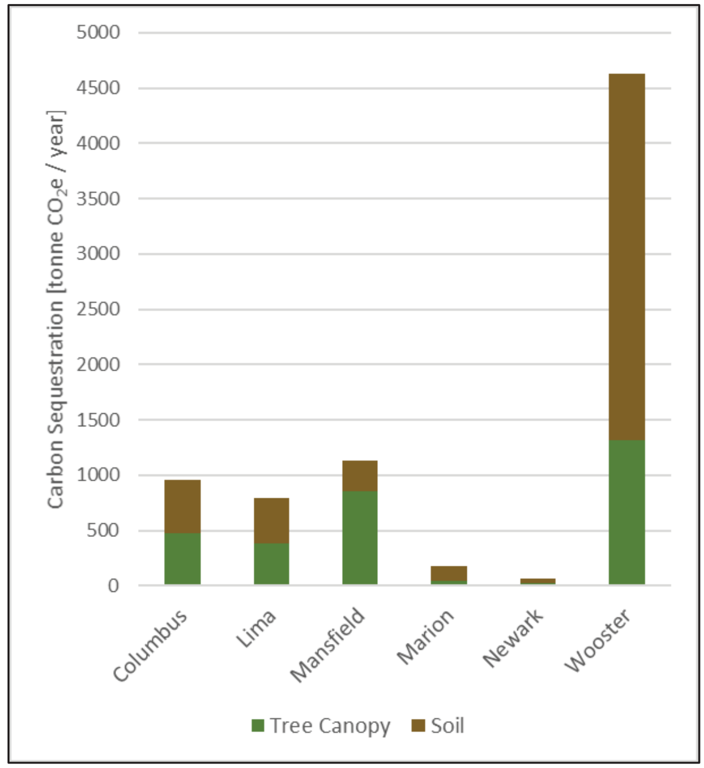


*Figure 17: Carbon Sequestration Results for Soil and Trees on Each Campus.*

**When:** Short to Mid Term: 1-6 years (FY20-25)
**Sector:** Carbon Sequestration
**GHG Scope:** 3
**Emissions Reduction:** 46,250 tonnes CO2e, 7.5% of total emissions
**Financial Cost Impact:** $231,250 - $878,750 annually (based on estimated per acre ecosystem restoration/carbon sequestration figures)

## VI. Integrated Plan

As stated above, there is no single solution for the university to achieve carbon neutrality. Many strategies will need to be implemented to meet the overall goal. This is especially important to keep in mind because Ohio State is one of the largest universities in the country. Each member of the Ohio State community can play a role in the goal of carbon neutrality, showing the value of a campus culture committed to sustainability. This campus culture may be as important as the operational decisions made by university leaders.

While there are many ways to achieve carbon neutrality, one item is clear: the university needs to continue to take meaningful actions now in order to achieve the goal. Also, it is equally important to continue discussion of bold actions and possibilities as it is to develop realistic and clear next steps. This keeps implementation activities moving forward while opening the door to new possible opportunities.

Figure 18 showcases the impact of pursuing some of the options presented in this Plan, including the impact of the Comprehensive Energy Management Partnership (CEMP) and the relative utility emissions footprint in various scenarios for the Columbus campus. The CEMP includes implementing the energy conservation measure program on the Columbus campus. Figure 18 also demonstrates the limitations of options for emissions mitigation. For example, if the university had chosen to procure renewable energy credit offsets for all its electricity demand in Fiscal Year 2019, the emissions footprint of the university's utility heating would remain a substantial source of overall emissions. Therefore, in order for the university to meet its carbon neutrality goal, a suite of actions is necessary, including pursuit of new power sources and renewable energy procurement in the near future (2-10 years) and a longer-term switch to alternative fuel sources (such as green hydrogen or renewable natural gas/biogas) when available in the mid- to longer-term future (15-30 years). Figure 18 shows one feasible future scenario of many the university could pursue to achieve carbon neutrality within its Columbus campus utility system.

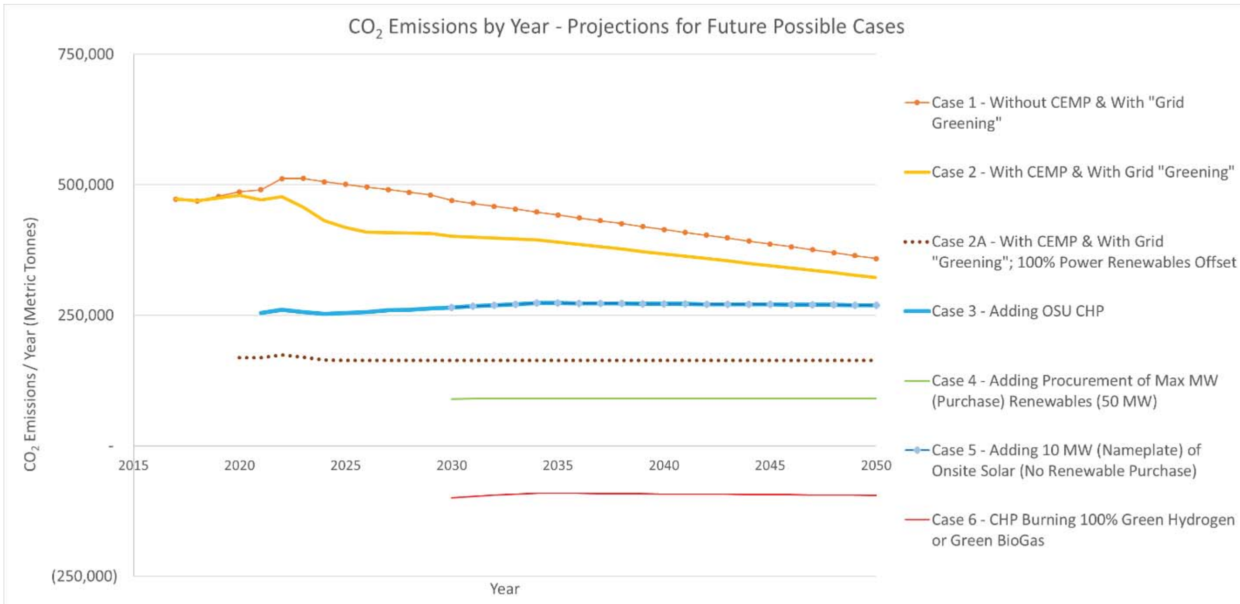


*Figure 18: Carbon footprint comparisons of current and future utility energy footprint for the Columbus campus.*

The recommendations within this Plan outline a scenario where the university could achieve its carbon neutrality goal, and potentially become *carbon positive*, by 2030. Added together, the recommendations would reduce, replace, or offset 703,944 tonnes $CO_2e$ on an annual basis, compared to the university's Fiscal Year 2019 emissions of 619,944 tonnes $CO_2e$.

Figure 19 demonstrates how the separate recommendations within this Plan add up to that conclusion, by emission source Scope. This includes moving to green hydrogen as a fuel source for the combined heat and power plant, which as a cleaner fuel source than the existing electric grid, could generate excess carbon credits for the university beyond what is necessary to power university operations. Similarly, as shown in Figures 18 and 19, the university's Scope 2 emissions might be more than fully reduced or offset by a combination of increased energy efficiency and further utilization of renewable energy (through purchase and on-site generation).

Figure 20 demonstrates an alternative scenario that does not include green hydrogen as a fuel source for the combined heat and power plant, but rather, moving from conventional natural gas to renewable natural gas. In this case, the university is unlikely to generate any excess carbon credits and would more likely simply reduce the related emissions on a one-to-one basis. In this scenario, the university could still achieve an 86.4% emission footprint reduction from Fiscal Year 2019 levels. The remaining gap, less than 85,000 tonnes $CO_2e$, could be addressed through the purchase of offsets to achieve climate neutrality.

Considering the available options, then, carbon neutrality is achievable for Ohio State, but will require substantial, continuous actions, including the development of new technology and infrastructure. These actions will also have a considerable up-front cost impact to the university, with the energy conservation measures and combined heat and power plant totaling $540 million in CAPEX by themselves. These, and the other noted recommendations above, should generate a combined net savings to the university over the course of their lifecycle, but the initial capital investment needs to be planned and budgeted before moving any individual project forward.

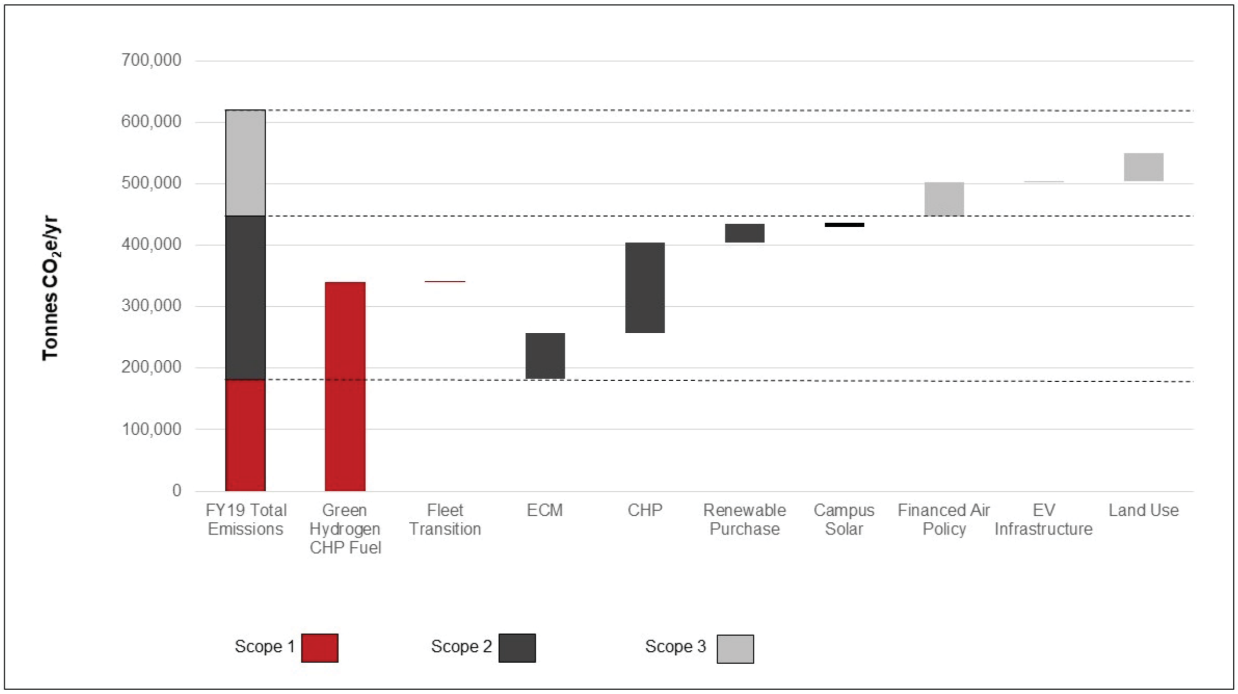


*Figure 19: Multi-Solution Approach to Carbon Neutrality, Scenario 1.*

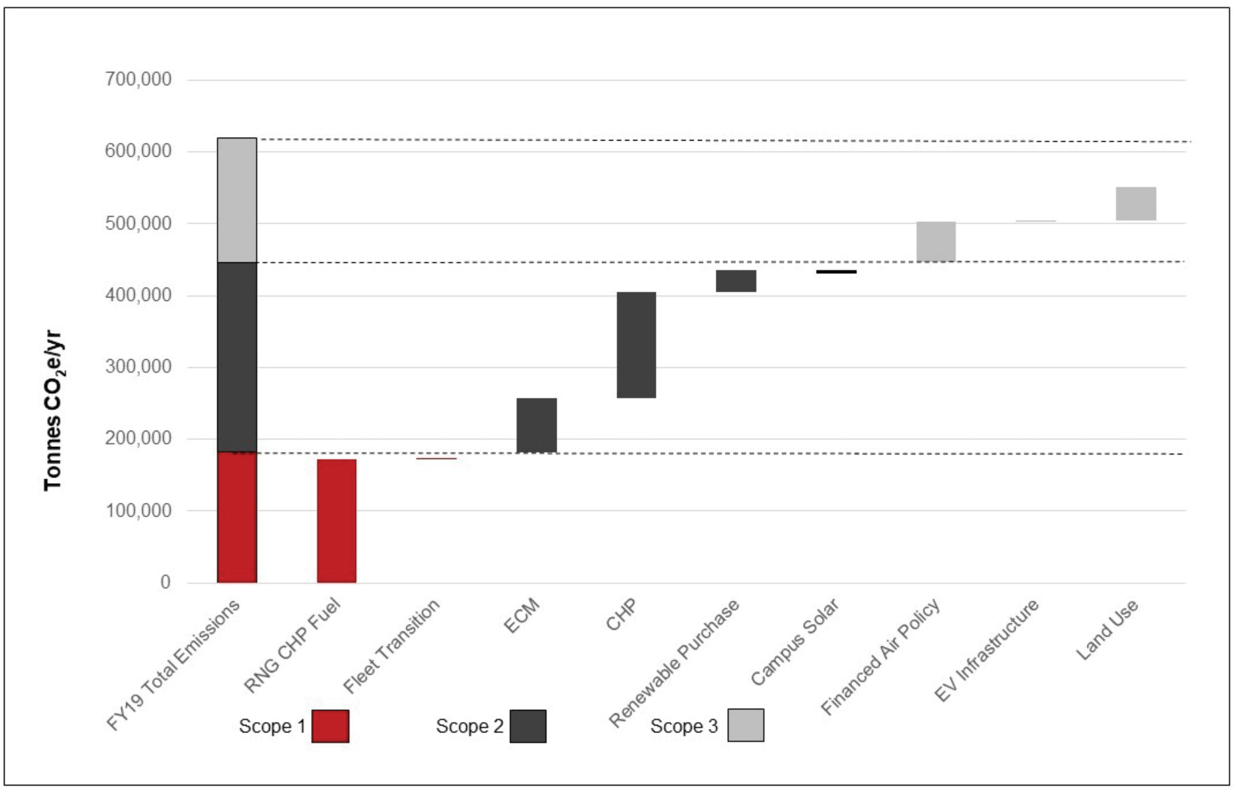


*Figure 20: Multi-Solution Approach to Carbon Neutrality, Scenario 2.*

## VII. Challenges

While the recommended actions within this Plan outline the possibility of achieving carbon neutrality, a number of challenges exist in front of the university.

### Future Growth

The university is a dynamic entity with continued growth in population and built environments expected for the forseeable future. Ohio State's Framework 2.0 plan is a considerable projection for the anticipated built environment growth at the Columbus campus. Similar planning is currently being initiated at the university's other campuses. These new building assets and academic and research offerings will attract an expanded population of students, staff, and faculty to the university over time.

As noted above, the university's greenhouse gas inventory is highly impacted by the buildings and operations of the university, as well as those who interact with the campus. If the university only focuses on reducing existing emissions through efficiencies, but continues to undertake activities that increase the total amount of carbon-emitting activities, the university will never achieve its carbon neutrality goal.

It is therefore critical that the university aggressively avoid creating new emissions whenever possible as it continues to grow. This includes designing new buildings to meet better energy use standards that will prevent the generation of unnecessary new emissions, as recommended above through a revised Green Build and Energy Policy.

While this Plan acknowledges the estimated increased energy use demand associated with the university's *Time and Change: Building the Future* projects, it does not account for additional anticipated growth within the Framework 2.0 plan and any related campus population growth over the next few decades. The integrated plan demonstrated in Figure 19 could accommodate an increase in emissions associated with new building and population growth, while still achieving the carbon neutrality goal. However, this will be an ongoing issue to monitor and incorporate into future planning.

### Technology and Infrastructure Leap

Clearly, the recommendation that would mitigate the largest single amount of greenhouse gas emissions – converting a combined heat and power plant to a green hydrogen fuel source – requires the advancement of technology and logistic infrastructure that does not currently exist at the necessary scale to make the switch.

While this opens the possibility for new innovation and research collaboration for the university and its key energy partners, there is risk in pinning the university's goal achievement to an unpredictable outcome. That said, this should provide the university and its energy partners additional drive to address this topic, which could have a multiplier benefit upon society beyond just Ohio State.

## Institutional Leadership

As Ohio State aspires to demonstrate sustainability leadership throughout Ohio, the Midwest, and the nation, achieving carbon neutrality by 2050 may become out-of-step with that aspiration as other higher education institutions push towards more aggressive achievement timelines.  In 2018, American University became the first publicly announced carbon neutral institution of higher education in the country, Duke University has targeted 2024 for its neutrality date, and other larger schools such as the University of California-Los Angeles and the University of Florida are striving to achieve neutrality by 2025.

While there are obvious differences between institutions relevant to size and geography, and even defined scope, that will impact any single institution's ability to achieve carbon neutrality, it is clear from published research that society must address its overall greenhouse gas emissions by 2030 to avoid drastic impacts to humanity and the planet.

Institutions that wait another twenty years beyond that date to achieve neutrality will be hard pressed to position themselves as leaders.  For an institution of the size and complexity of Ohio State, that may necessitate accelerated decision making or alternative options (such as purchased credit offsets) from the recommendations contained within this Plan.

## VIII. Aligning Ohio State's Academic Mission

The primary purpose of this Climate Action Plan is to address the university's physical greenhouse gas emission outputs. As a land-grant institution, however, the primary mission of Ohio State is to educate citizens and demonstrate new research innovations that address society's challenges.

Since the university's original Climate Action Plan, the university has embedded its efforts into the full range of university activities. Moving forward, the university aims to continue to increase the meaningful interaction between the university's operations and its academic and research community for value-added sustainability results and findings.

At a leadership level, the President and Provost's Council on Sustainability is an interdisciplinary body made up of faculty, staff and students that provides strategic review and advice on issues related to the integration of sustainable practices, programs and projects across the university's goals.

Further, the university's sustainability goals align with its core institutional pillars:

1. Teaching and Learning
2. Research and Innovation
3. Outreach and Engagement
4. Resource Stewardship

There are numerous operational and academic departments across the university that are working independently and in partnership to advance the established sustainability goals, including carbon neutrality. Through these actions, Ohio State hopes not only to achieve sustainable operational success, but to cultivate new sustainability leaders and innovations that drive society forward.

### Teaching and Learning: Student Opportunity

**Sustainability Goal 1:** Deliver a Curriculum that provides Ohio State students at all stages of instruction – from General Education to professional and technical programs – with opportunities to understand sustainability holistically, framed by the environment, science, technology, society, the economy, history, culture, and politics.

**Sustainability Goal 2:** Address the Complexities of Sustainability through a variety of learning formats, strategies, and occasions.

Students from across the globe have entrusted the Ohio State University to deliver the learning opportunities that will propel them into successful careers and leadership positions post-graduation. While the university helps students build the educational platform they will launch from into the world, the university is compelled to demonstrate a commitment to the health, well-being, and success of its students long after they leave campus.

This includes developing a context to understand and respond to local and global sustainability challenges, particularly the growing climate concerns they are entering into.

To meet these goals, the university has created the Environment, Economy, Development & Sustainability (EEDS) major for undergraduate studies. With over 200 graduates, this curriculum has been a successful partnership between the university's School of Environment and Natural Resources, AEDE and the Fisher College of Business. Based on student demand for this academic programming, an EEDS minor is also available for undergraduate studies.

Further, in the spring of 2019, the university's Board of Trustees endorsed an historic new approach to undergraduate education that will bolster a student's ability to become a citizen leader. Through this action, beginning with the 2020-2021 academic year, the university's General Education curriculum requirements will include a sustainability theme. This will help students of all backgrounds and academic disciplines gain direct knowledge of sustainability challenges while providing an opportunity for them to consider how to meet those challenges from their own experiences.

Ohio State already offers over 1,200 undergraduate and graduate level courses that include sustainability learning, a figure that is expected to increase through the adopted General Education curriculum changes.

In addition, project-based learning for students of all levels is currently occurring across the university on a variety of sustainability topics. By the end of 2020, the university's Sustainability Institute aims to formalize a campus as living lab program to catalog existing student learning projects, spur new interdisciplinary research partnerships, and advance student's understanding of how sustainability efforts are successfully implemented. One recent project example includes a collaboration between the university's Byrd Polar and Climate Research Center and Department of Geography, funded with a grant from the Sustainability Institute, to teach Geography students how to measure and study the university's own urban heat island effect. The results of the student's work will be incorporated into the univeristy's Ecosystem Services Index, which is a measurement tool the university's operating staff are using to document the environmental and social performance of the university's grounds and landscapes.

Beyond the classroom, Ohio State offers a rich environment for students to integrate themselves with sustainability learning initiatives. Some of these are more university-structured from the Environmental Professionals Network programming, to sustainability-oriented study abroad opportunities, to the SUSTAINS Learning Community. Additional opportunities are more student-driven, including the annual Time For Change Week programming and the 80+ active student organizations conducting different sustainability projects throughout the academic year.

Finally, aligned with the university's goal to ensure affordable access to a higher education degree, Ohio State has implemented a new full-tuition and board scholarship for undergraduate students whose studies focus on sustainability topics but face financial need. The university also now provides fellowships and one-time incentives for graduate students focusing on sustainability topics. Both offerings represent just one positive outcome from the university's academic collaboration within the larger Comprehensive Energy Management Project agreement with Ohio State Energy Partners.

## Research and Innovation: Faculty Opportunity

**Sustainability Goal 3:** Reward Sustainability Scholarship, including the scholarship of engagement, by providing incentives for students, faculty and staff to make discoveries and stimulate creative efforts that promote and achieve sustainability.

**Sustainability Goal 4:** Magnify Sustainability Scholarly Output and Impact to create new knowledge, solve real world problems, including for our own operations, and increase Ohio State's national/international reputation as a sustainability research leader.

A comprehensive approach to sustainability research is only possible at an institution with the size and diversity of Ohio State. The university brings scholars together – working on a wide range of research and technological innovations – to discover new approaches and solutions to persistent problems. Ohio State is a leader in key areas including climate change, behavioral science, environmental economics, resilient infrastructure design, materials and energy technology innovation, and environmental health sciences.

Today, major challenges facing society include sustainable food and water production, climate change, and accelerating urbanization. The land-grant mission of Ohio State drives discovery and knowledge enhancement in order to achieve significant advances for public well-being. The university houses over 500 faculty and researchers, representing 11 colleges and 64 academic departments, who study sustainability issues. Since 2014, the university has hired 60 faculty through the Discovery Themes Initiative, with the specific charge of contributing to sustainability and resilience research, teaching, and collaboration.

For many years, Ohio State researchers have led the world's understanding of and solutions for the changes we are experiencing across the globe. Take, for example, Byrd Polar and Climate Research Center's efforts to collect, analyze, and maintain ice cores from around the world, providing long-term understanding of earth's climate. Given that some of the locations Byrd has studied, and continues to maintain physical evidence from, no longer exist because they have melted away, this foundational work is nothing short of heroic.

In addition, Ohio State Professor Rattan Lal was recently awarded the prestigious Japan Prize for his groundbreaking research on how agricultural lands could sequester more carbon in the planet's soils, which would improve soil health and benefit agricultural productivity to feed a growing population.

In the coming months and years, the university's support for new climate related research and innovation will continue to grow, also thanks to the academic collaboration within the Comprehensive Energy Management Project agreement. While that agreement has already endowed five faculty chair positions primarily focused on energy use issues, perhaps more visionary will be the establishment of a new Energy Advancement and Innovation Center (EAIC). A cornerstone of new research development at the university's Columbus West Campus, the EAIC will bring Ohio State research work together with private sector partners to advance lab findings into new, socially beneficial energy efficiencies and climate related advancements.

### Outreach and Engagement: Community Opportunity

**Sustainability Goal 5:** Foster Campus-to-Community, Students-to-Alumni Culture of sustainability-oriented practices and educational and research experiences that students and alumni transfer into local and global communities.

**Sustainability Goal 6:** Catalyze Engagement, Ownership, and Buy-In to Sustainability via engaged and inclusive partnerships, on and off campus that support the long-term economic, social and environmental welfare of the campus, surrounding neighborhoods and the global community.

Durable solutions to sustainability challenges require community engagement and lasting partnerships with stakeholders. Ohio State has a long history of engaging urban and rural communities in ways that are highly responsive to their needs and interests. OSU Extension reaches all of Ohio's 88 counties, while the university's faculty have relationships throughout the Midwest, nation, and the world. Ohio State strives to develop solutions that promote social equity and ensure that enjoyment of the benefits from sustainability is widespread.

Leveraging the university's expertise and knowledge gained from on-campus operational experimentation, Ohio State has the capability to help others achieve their own greenhouse gas emission reduction goals. In doing so, the university could have a physical impact of much greater importance than achieving its own carbon neutrality goal.

There are numerous ways to demonstrate the university's climate-related community engagement and partnership building, but three recent efforts exemplify the diversity of engagement:

1. **Columbus Climate Adaptation Plan.** With the help of Byrd Polar and Climate Research Center experts, the City of Columbus issued its first climate adaptation plan in December 2018. Over the course of four years, city, regional, and Ohio State leaders assessed climate change impacts, risks, and vulnerabilities in Columbus. Engaging a wider community audience for feedback and input, the plan identifies 43 prioritized actions for the city to take to protect its citizens in the wake of expected climate changes.
2. **Smart Columbus.** In 2016, the City of Columbus was awarded $50 million in grant funding and the designation as America's Smart City as the winner of the U.S. Department of Transportation's (USDOT) first-ever Smart City Challenge. The goal of Smart Columbus is to embrace the reinvention of transportation in the city so as to improve the quality of life, drive economic growth, and foster

sustainability.  Ohio State was named the primary research partner to Smart Columbus, and has leveraged a $2 million cash commitment by the university to engage faculty, staff, and students in Smart Columbus deliverables.  Just one example of this significant partnership is the ongoing effort of Ohio State's Environment, Economy, Development and Sustainability (EEDS) capstone course students to provide private and public sector partners with research projects that advance the Smart Columbus objectives.  With projects including municipal and private sector electric vehicle fleet adoption strategies as well as increasing renewable energy sources to power electric vehicle recharging, Ohio State students and their faculty mentors are providing many necessary research needs to help the Central Ohio community reduce its overall transportation related greenhouse gas emissions.  In turn, the students gain valuable experience in team-oriented, project-based learning to advance sustainability outcomes in a dynamic urban setting.

3. **University Climate Change Coalition.** Launched in February 2018, the University Climate Change Coalition (UC3) seeks to accelerate local greenhouse gas reduction efforts through the collective research expertise of 20 leading climate research institutions across North America.  As one of the Coalition's founding institutions, throughout 2019, Ohio State has led the group's effort to develop a joint white paper on carbon pricing in order to share the value of such a tool with public policy leaders.

Ohio State students, faculty, and staff regularly interact with private, public, and non-profit sector partners to address many facets of climate mitigation and adaptation.  From campus and community based tree plantings, to integrating the electrification of the transportation sector, to helping the agricultural sector plan for changing growing zones while increasingly sequestering more carbon through management activities, Ohio State looks to partner in comprehensive ways to help bring more diverse climate solutions forward.

## Resource Stewardship: Campus Opportunity

**Sustainability Goal 7:** Implement specific, "world-leading" university-wide operational goals to reduce resource consumption, neutralize carbon emissions and minimize waste, including:

a. Achieve carbon neutrality by 2050 per American College and University Presidents Climate Commitment [Presidents' Climate Leadership Commitment]
b. Reduce total campus building energy consumption by 25% by 2025
c. Reduce potable water consumption by 5% per capita every five years, resetting baseline every five years
d. Increase campus ecosystem services by 60% by 2025
e. Reduce carbon footprint of university fleet by 25% by 2025
f. Achieve zero waste by 2025 by diverting 90% of waste away from landfills
g. Increase production and purchase of locally and sustainably sourced food to 40% by 2025

h. Develop university-wide standards for targeted environmentally preferred products and fully implement preferable products and services by 2025

Achieving many of these resource stewardship goals will help the university address its own greenhouse gas emissions. As importantly, they will help Ohio State develop its own solutions to the pressing challenges of sustainability and evolve a culture of sustainability within the university's diverse group of stakeholders. Collaborative teaching, pioneering research, comprehensive outreach, and innovative operations, practices, and policies will help Ohio State demonstrate to others how environmental, economic and social goals can be mutually achieved.

## IX. Future Considerations

Future Ohio State Climate Action Plans should consider accounting university emissions by sector or department so different aspects of campus can track their own progress, such as university operated hospitals, student residences and athletic facilities.

Increasing the quality of data collection across the university's campuses, particularly those outside of the flagship Columbus campus, needs to remain a priority to continually increase the accuracy of the greenhouse gas emissions inventory.

To increase the viability of carbon sequestration opportunities on university owned lands, the existing tree inventory conducted on the Columbus campus should be expanded to all campuses. In addition, soil data across all campuses should be assessed on the three identified land types referenced above: cropland, grassland and forest. These efforts would increase knowledge of both the existing amount of carbon sequestered on university properties and how to manage those properties to further increase sequestration levels.

Finally, as a research institution, it is important to explore future research needs for campus sustainability, such as the intersection of technology, ecology, behavior and economics to devise approaches for the future. Meeting the goal of carbon neutrality is no small task and will take the cooperation and ambition of the entire Ohio State community.

As noted in this Plan's Executive Summary, the Intergovernmental Panel on Climate Change's (IPCC) fifth assessment found that limiting global warming to 1.5 degrees Celsius requires "rapid and far-reaching" action. There will need to be drastic changes to the infrastructure and operation of our cities, buildings, transportation, energy, manufacturing and land use. This shows the need for Ohio State to take urgent action now, as well as the importance of the university fulfilling its commitment to carbon neutrality, in collaboration with people, organizations and universities across the world.

## X. Appendix

### Acknowledgements


This Climate Action Plan represents the collective thought and work from numerous Ohio State University staff, faculty, and partners. However, special thanks should be extended to:

**Dr. Bhavik Bakshi**, Professor, Chemical & Biomolecular Engineering, College of Engineering
**Michael Charles**, PhD. Student, Chemical & Biomolecular Engineering, College of Engineering
Dr. Bakshi and Mr. Charles developed the content of this Plan, including conducting informative interviews across the university, analyzing existing university documents and agreements to inform the available options to achieve carbon neutrality, modeling individual greenhouse gas mitigation recommendations, and building future carbon neutral scenarios.

**Serdar Tufekci**, Chief Executive Officer, Ohio State Energy Partners
**Caitlin Holley**, Program Manager, Capital Projects, ENGIE Campus
Mr. Tufekci and Ms. Holley performed critical analysis of the university's Columbus campus energy use, projections, and mitigation options, including project cost assessments.

**Brett Garrett**, P.E., Director, Facilities Operations and Development
**Tony Gillund**, Sustainability Manager, Facilities Operations and Development
Messrs. Garrett and Gillund provided whole document review and input. In addition, Mr. Gillund provided necessary greenhouse gas inventory data and related data review.

**Kate Bartter**, Executive Director, Sustainability Institute at Ohio State
**Mike Shelton**, Associate Director, Sustainability Institute at Ohio State
Ms. Bartter and Mr. Shelton provided context for the overall establishment and individual sections of this Plan. This included whole document review and input. In addition, the Sustainability Institute provided the funding to Dr. Bakshi to execute the authorship of this Plan.

## XI. Citations


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# Exhibit RS-D

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July 6, 2020

Mr. Bryceson Nunley
Project Manager
ENGIE Buckeye Operations LLC
1990 Post Oak Boulevard, Suite 1900
Houston, Texas 77056

Re: OSU/ENGIE CHP Project
REVISED Summary Report - Evaluation of Relative Air Quality Impacts

Dear Mr. Nunley:

TRC Environmental Corporation (TRC) is please to submit this revised final summary report describing our evaluation of air quality impacts from the combined heat and power (CHP) plant to be operated at the Ohio State University's Main Campus in Columbus, Ohio. This revised version corrects an inadvertent misstatement in the original version regarding the objective of this analysis. The analysis was completed to address concerns raised by the Sierra Club in their intervention in the OPSB regulatory process for the CHP, and not to address concerns raised by the OPSB.

Through a dispersion modeling analysis, TRC found:

- The CHP project will have 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
- The impacts due to the CHP project are predicted to be negligible at the OSU Wexner Medical Center.

David Fox, CCM, was the dispersion modeler and principal author of this analysis.

Jeff Slayback, P.E., was the project manager and senior reviewer.

Sincerely,

**TRC Environmental Corporation**

Jeff Slayback, P.E.
Project Manager

# OSU/ENGIE CHP PROJECT
# EVALUATION OF RELATIVE AIR QUALITY IMPACTS

## EXECUTIVE SUMMARY

Key points related to the operation of a CHP plant at the Ohio State University.

- Franklin County is in attainment for all National Ambient Air Quality Standards (NAAQS). The CHP project will have negligible impact on the existing air quality in Franklin County and will not affect its attainment status for any pollutant. For $PM_{2.5}$, the project impact is less than 0.44 percent above the 24-hour background concentration and less than 0.13 percent above the annual background concentration. For $NO_2$, the project impact is less than 0.66 percent above the 1-hour background concentration and less than 0.05 percent above the annual background concentration. For ozone, the project impact is less than 0.13 percent above the monitored background concentration on an 8-hour basis.
- 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 one percent of the corresponding Primary NAAQS established to protect human health and particularly vulnerable populations.
- The impacts due to the CHP project are predicted to be negligible at the OSU Wexner Medical Center. For $PM_{2.5}$, the project impact is 0.8 percent above the 24-hour background concentration and 0.2 percent above the annual background concentration. For $NO_2$, the project impact is one percent above the 1-hour background concentration and 0.08 percent above the annual background concentration. For ozone, the project impact is 0.13 percent above the monitored background concentration on an 8-hour basis.

## POTENTIAL EMISSION MAGNITUDE

**Potential Annual Emissions from Project – two CHP units (combustion turbines with duct burner/HRSG) and two multi-cell cooling towers**

| | |
|---|---|
| Nitrogen oxide ($NO_X$) | 42.9 tpy |
| VOC | 27.7 tpy |
| $PM_{2.5}$ | 41.9 tpy (filterable plus condensable, includes cooling towers) |
| Sulfur dioxide ($SO_2$) | 11.9 tpy |

These emission levels are relatively minor when compared to electric utility level emissions and similar to many common industrial sources as can be seen by the following emission numbers.

**Coal Fired Utilities in Ohio (2018)**

| | |
|---|---|
| Nitrogen oxides | 48,958 tpy |
| Sulfur dioxide | 86,534 tpy |
| $PM_{2.5}$ | 6,281 tpy |

**Mid-Size Printing Facility Authorized by an Ohio EPA Permit-by-Rule**

| | |
|---|---|
| VOC (allowable) | 25 tpy |

**Operation of a 50 MMBtu/hr gas boiler, plus space heating**

| | |
|---|---|
| Nitrogen oxides | 25-30 tpy |

## AIR QUALITY SETTING OF THE CHP PROJECT

Franklin County is in attainment with the National Ambient Air Quality Standards (NAAQS) for ozone, $NO_2$, and $PM_{2.5}$.

It is noted that the federal Clean Air Act requires the USEPA to establish and update NAAQS (at 40 CFR Part 50) for pollutants considered harmful to public health and the environment. The Act identifies two types of standards – Primary and Secondary standards. USEPA states that ***Primary standards*** provide public health protection, including protecting the health of "sensitive" populations such as asthmatics, children, and the elderly. ***Secondary standards*** are less stringent than ***Primary Standards*** but provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings.

In this analysis the ambient air quality impacts from the CHP project are compared directly to the Primary $PM_{2.5}$, $NO_2$, and ozone NAAQS. As a result, the analysis specifically addresses both the expected impact on the air quality of central Ohio (Franklin County) as well as sensitive receptors in close proximity to the project location.

## CONSERVATIVE AIR QUALITY ANALYSIS CONDUCTED

### Direct Modeling of $PM_{2.5}$ and $NO_2$

An air quality impact analysis for the CHP project was previously conducted as part of the Ohio EPA air permit-to-install (PTI) application process. That analysis was more of a prescribed screening level analysis which followed the Ohio Environmental Protection Agency (OEPA), Division of Air Pollution Control (DAPC), Engineering Guide No. 69) for assessing the air quality impact of a new project. These guidelines define air quality impact thresholds for several pollutants, including $PM_{2.5}$ and $NO_2$, in micrograms per cubic meter. For the air PTI application, the CHP project was only required to assess the impact of $PM_{2.5}$ (and the less restrictive threshold for $PM_{10}$). The results of that screening analysis clearly demonstrated acceptable impacts. The results of that screening analysis were also incorporated into the application for Ohio Power Siting Board certification.

In the previous screening analysis, the highest overall predicted impacts using 5 years of hourly meteorological data are compared to conservatively protective thresholds outlined in Engineering Guide No. 69 (https://epa.ohio.gov/Portals/27/engineer/eguides/2018_EG69_DRAFT.pdf). If the highest impacts exceed the corresponding thresholds, a more refined modeling analysis is required that takes into account background concentrations of the area. The refined modeling analysis considers model predicted impacts in a similar statistical fashion (analyzing frequency of occurrence over a given time period such as 3 or 5 years) to how compliance with NAAQSs are defined by the USEPA. While the CHP project did not have predicted impacts for $PM_{2.5}$ above Ohio EPA trigger thresholds, OSU and ENGIE have conservatively completed a refined analysis for $PM_{2.5}$, as well as for $NO_2$ and ozone, to address concerns raised by the Sierra Club in their intervention in the OPSB regulatory process for the CHP.

The refined air quality modeling analysis to assess the possible impact of the project described for remainder of this summary considered 12 possible operating conditions for the CHP units. This analysis was completed with the latest version of the AERMOD dispersion model. This model has been developed by the USEPA and is utilized by the Ohio EPA and environmental review agencies in every other State. Each of the 12 conditions was tested in the model with 43,824 hours (5 years) of meteorological observations from the Columbus National Weather Service site. For $PM_{2.5}$ the model also included all cooling tower units. Model predicted impacts were made at over 3,000 regularly spaced (70- meter) generic receptor locations surrounding the project site. Thirty (30) possible sensitive receptor locations were also considered (see Figure 1) and the eleven closest ones to the project (within 1.3 miles) were evaluated for impacts.

Based on these assumptions the highest predicted values from the analysis were compared to applicable NAAQS standards. The term "highest" results in this context were based upon:

- The highest predicted impact within the grid of 3,000 generic receptors.
- The highest predicted impact within the group of sensitive receptors.
- The highest annual predicted concentrations based on 5 separate years of meteorological data.
- The highest 24-hr calendar day concentrations based on 1,826 days of meteorological data
- The highest 1-hr concentrations based on 43,824 hours of meteorological observations.
- The CHP plant operating scenario (out of a group 12 CHP plant operating scenarios modeled) that produced the highest predicted impact(s).

The highest predicted impacts were compared to both the Primary NAAQS and the Columbus-area background concentrations monitored by Ohio EPA.

**Secondary Impact Assessment of Project Emissions**

In addition to modeling the direct emissions of $NO_2$ and $PM_{2.5}$, TRC utilized the USEPA's Modeled Emission Rate Precursors (MERPs) methodology to assess the impact of the project on secondary formation of $PM_{2.5}$ (from nitrogen oxide and sulfur dioxide emissions) and also the project contribution to area ozone concentrations due to VOC and NOx emissions. The results of this analysis showed that the project would have trivial secondary impacts on the formation of $PM_{2.5}$ and ozone.

**Modeling Results for the CHP Project**

The air quality model was used to predict the overall highest impacts and the highest impacted sensitive receptor (Martha Morehouse Outpatient Care - see locations in Figure 2). For comparison, results are also shown for the OSU Wexner Medical Center. A summary of those impacts is presented below. These results correspond to the CHP operating condition (out of 12 modeled) that had the highest predicted impact. Note that a background concentration represents the concentration of a given pollutant that may be present in the ambient air. The Ohio EPA operates monitors in Franklin County for $PM_{2.5}$, $NO_2$, and ozone. The background values listed below were derived from area-wide monitored values in the years 2017-2019.

**Overall Highest Predicted Impact Location**

| Pollutant | CHP Project Impact | Background | Total Impact | NAAQS (PRIMARY) | Project Impact above Background |
|---|---|---|---|---|---|
| $PM_{2.5}$ 24-hr | 1.51 | 26 | 27.51 | 35 | 5.8% |
| $PM_{2.5}$ Annual | 0.17 | 9.9 | 10.07 | 12 | 1.7% |
| $NO_2$ 1-hr | 5.0 | 86.2 | 91.2 | 188 | 5.8% |
| $NO_2$ Annual | 0.13 | 21.7 | 21.83 | 100 | 0.60% |
| Ozone 8-hr | 0.000084 | 0.065 | 0.065084 | 0.07 | 0.13% |

**Highest predicted impacts from 3,000 locations modeled**
**Units for $NO_2$ and $PM_{2.5}$ are µg/m$^3$, for ozone ppm**

**Impacts at Highest Impacted Sensitive Receptor (Martha Morehouse Outpatient Care)**

| Pollutant | CHP Project Impact | Background | Total Impact | NAAQS (PRIMARY) | Project Impact above Background |
|---|---|---|---|---|---|
| $PM_{2.5}$ 24-hr | 0.42 | 26 | 26.42 | 35 | 1.6% |
| $PM_{2.5}$ Annual | 0.048 | 9.9 | 9.948 | 12 | 0.5% |
| $NO_2$ 1-hr | 1.56 | 86.2 | 87.76 | 188 | 1.8% |
| $NO_2$ Annual | 0.031 | 21.7 | 21.731 | 100 | 0.14% |
| Ozone 8-hr | 0.000084 | 0.065 | 0.065084 | 0.07 | 0.13% |

**Units for $NO_2$ and $PM_{2.5}$ are µg/m$^3$, for ozone ppm**

**Predicted Impacts at the OSU Wexner Medical Center**

| Pollutant | CHP Project Impact | Background | Total Impact | NAAQS (PRIMARY) | Project Impact above Background |
|---|---|---|---|---|---|
| $PM_{2.5}$ 24-hr | 0.22 | 26 | 26.22 | 35 | 0.8% |
| $PM_{2.5}$ Annual | 0.023 | 9.9 | 9.923 | 12 | 0.2% |
| $NO_2$ 1-hr | 0.89 | 86.2 | 87.09 | 188 | 1.0% |
| $NO_2$ Annual | 0.017 | 21.7 | 21.717 | 100 | 0.08% |
| Ozone 8-hr | 0.000084 | 0.065 | 0.065084 | 0.07 | 0.13% |

**Note: Units for $NO_2$ and $PM_{2.5}$ are µg/m$^3$, for ozone ppm**

The highest predicted impacts were found less than one quarter mile from the project site (see Figure 2 for location relative to project site). The highest impacted sensitive receptor was the closest sensitive receptor to the project site (Figure 2). Due to the conservative assumptions used and the conservative nature of the air quality model itself, the actual effect of the CHP installation would be much less than indicated above.

**Model Results for Expected Average Operating Conditions.**

Engie has identified emission and stack conditions that would be expected to be representative or typical of average operating conditions. The model predicted impacts at the overall highest, highest sensitive receptor and the Wexner Medical Center locations for the expected typical operating conditions, are shown in the following tables.

**Overall Highest Predicted Impact Location**
**(average operating conditions)**

| Pollutant | CHP Project Impact | Background | Total Impact | NAAQS (PRIMARY) | Project Impact above Background |
|---|---|---|---|---|---|
| $PM_{2.5}$ 24-hr | 1.31 | 26 | 27.31 | 35 | 5.0% |
| $PM_{2.5}$ Annual | 0.16 | 9.9 | 10.06 | 12 | 1.6% |
| $NO_2$ 1-hr | 4.9 | 86.2 | 91.1 | 188 | 5.7% |
| $NO_2$ Annual | 0.12 | 21.7 | 21.82 | 100 | 0.60% |
| Ozone 8-hr | 0.000084 | 0.065 | 0.065084 | 0.07 | 0.13% |

**Highest predicted impacts from 3,000 locations modeled**
**Units for $NO_2$ and $PM_{2.5}$ are $\mu g/m^3$, for ozone ppm**

**Impacts at Highest Impacted Sensitive Receptor (Martha Morehouse Outpatient Care)**
**(average operating conditions)**

| Pollutant | CHP Project Impact | Background | Total Impact | NAAQS (PRIMARY) | Project Impact above Background |
|---|---|---|---|---|---|
| $PM_{2.5}$ 24-hr | 0.37 | 26 | 26.37 | 35 | 1.4% |
| $PM_{2.5}$ Annual | 0.042 | 9.9 | 9.942 | 12 | 0.4% |
| $NO_2$ 1-hr | 1.5 | 86.2 | 87.7 | 188 | 1.7% |
| $NO_2$ Annual | 0.031 | 21.7 | 21.731 | 100 | 0.14% |
| Ozone 8-hr | 0.000084 | 0.065 | 0.065084 | 0.07 | 0.13% |

**Units for $NO_2$ and $PM_{2.5}$ are $\mu g/m^3$, for ozone ppm**

**Predicted Impacts at the OSU Wexner Medical Center (average operating conditions)**

| Pollutant | CHP Project Impact | Background | Total Impact | NAAQS (PRIMARY) | Project Impact above Background |
|---|---|---|---|---|---|
| **$PM_{2.5}$ 24-hr** | 0.21 | 26 | 26.21 | 35 | 0.8% |
| **$PM_{2.5}$ Annual** | 0.022 | 9.9 | 9.922 | 12 | 0.2% |
| **$NO_2$ 1-hr** | 0.79 | 86.2 | 86.99 | 188 | 0.9% |
| **$NO_2$ Annual** | 0.015 | 21.7 | 21.715 | 100 | 0.07% |
| **Ozone 8-hr** | 0.000084 | 0.065 | 0.065084 | 0.07 | 0.13% |

**Note: Units for $NO_2$ and $PM_{2.5}$ are µg/m$^3$, for ozone ppm**

**Modeled Impacts at Ohio EPA Ambient Monitoring Locations**

The AERMOD model was also used to predict the air quality impact of the CHP project at Ohio EPA ambient air quality monitoring stations in Franklin County. The ambient air quality information gathered at these stations are what Ohio EPA and USEPA use to determine whether the area is meeting the pollutant-specific NAAQS. As such, by predicting the increase in pollutant concentrations at the monitoring stations through modeling, the impact to air quality in Franklin County can be addressed. A comparison of predicted impacts to measured values at the respective monitoring stations is shown in the tables below.

**$PM_{2.5}$**

| | Monitor-Measured Values | | Model Predicted Values at Monitor | | | |
|---|---|---|---|---|---|---|
| **Monitor Location** | **2017-2019 24-hr value** | **2017-2019 Annual maximum** | **Project Impact 24-hr** | **Project Impact Annual** | **Project Impact over Monitored Value 24-hr** | **Project Impact over Monitored Value Annual** |
| **Korbel Ave** | 25 | 9.9 | 0.11 | 0.013 | 0.44% | 0.13% |
| **7560 Smoky Road** | 26 | 9.9 | 0.035 | 0.006 | 0.13% | 0.06% |
| **580 Woodrow** | 22 | 8.7 | 0.039 | 0.005 | 0.18% | 0.06% |
| **5750 Maple Canyon** | 22 | 8.7 | 0.035 | 0.006 | 0.16% | 0.07% |
| ***NAAQS*** | ***35*** | ***12*** | | | | |

**All values in ug/m$^3$**

**$NO_2$**

| | Monitor-Measured Values | | Model Predicted Values at Monitor | | | |
|---|---|---|---|---|---|---|
| **Monitor Location** | **2017-2019 1-hr value** | **2017-2019 Annual maximum** | **Project Impact 1-hr** | **Project Impact Annual** | **Project Impact over Monitored Value 1-hr** | **Project Impact over Monitored Value Annual** |
| **Korbel Ave** | 86.2 | 19.1 | 0.57 | 0.01 | 0.66% | 0.05% |
| **7560 Smoky Road** | 74.5 | 21.7 | 0.30 | 0.006 | 0.40% | 0.03% |
| ***NAAQS*** | ***196*** | ***100*** | | | | |

**All values in $ug/m^3$**

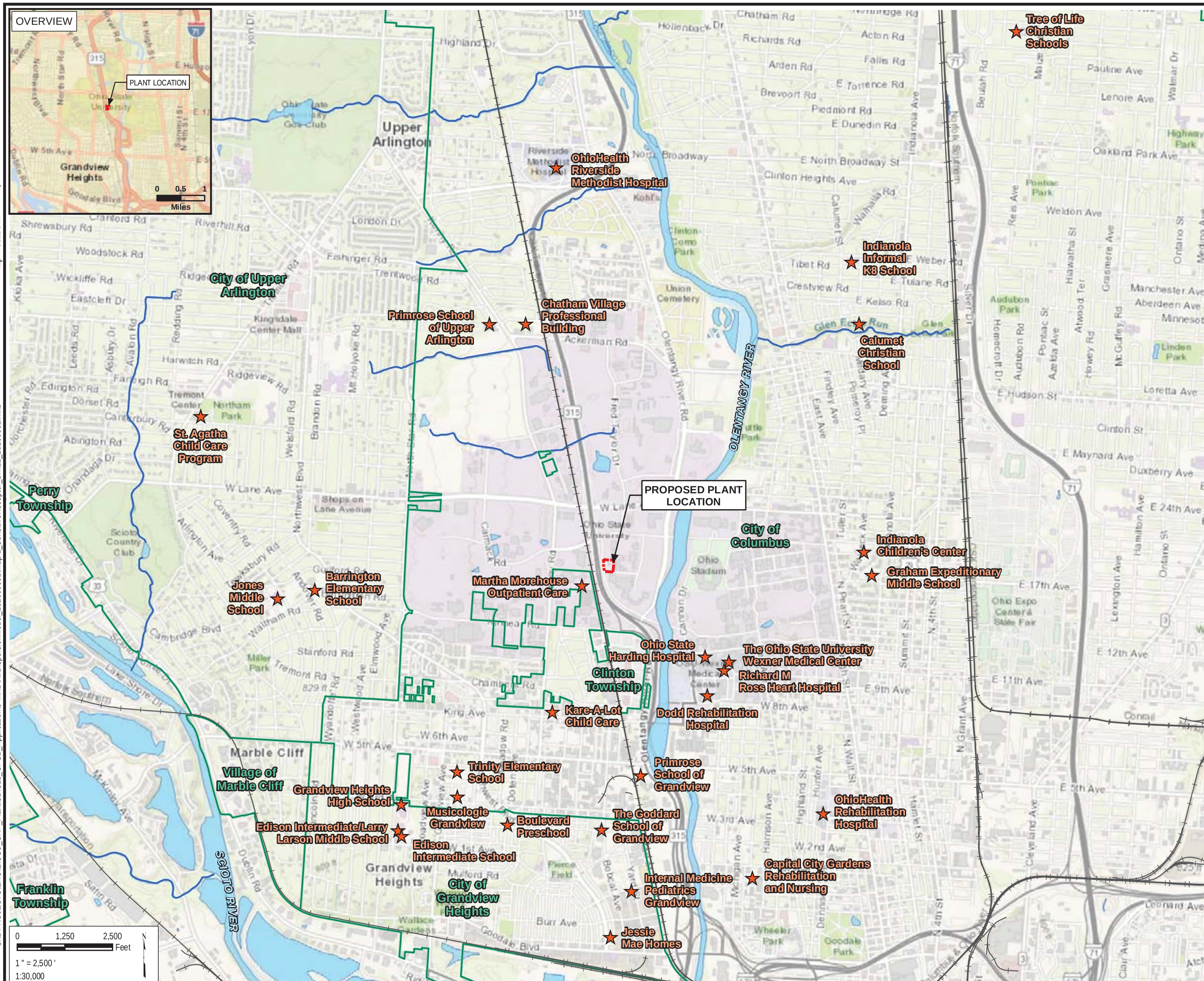
**Ozone**

| **Monitor Location** | **2017-2019 8-hr value** | **Project Impact 8-hr** | **Project Impact over Monitored Value** |
|---|---|---|---|
| **359 Main Rd.** | 0.063 | - | - |
| **7600 Fodor Rd.** | 0.068 | - | - |
| **5750 Maple Canyon** | 0.063 | - | - |
| **310 Licking View Dr.** | 0.062 | - | - |
| **8955 East Main St.** | 0.063 | - | - |
| **9940 Sr 38 Sw** | 0.065 | - | - |
| **Regional Average** | 0.064 | 0.000084 | 0.13% |
| ***NAAQS*** | ***0.07*** | | |

**All values in ppm**

## CONCLUSIONS

- The permitted annual emission levels of $SO_2$, $PM_{2.5}$, NOx and VOC are modest or similar in comparison to common industrial sources, but much less than utility scale sources.
- The model predicted project impacts are very small in comparison to the background concentrations and based upon current monitoring data would not be predicted to contribute to exceedances of any NAAQS. The small model predicted impacts met the Ohio EPA's de minimis impacts for air permitting.
- The model predicted project impacts at all impacted sensitive receptors, including the OSU Wexner Medical Center, are very small ($NO_2$ and $PM_{2.5}$) or trivial (ozone).
- The CHP project will have a negligible impact on the overall air quality of Franklin County.




## LEGEND

PROPOSED PLANT PROJECT AREA

POSSIBLE SENSITIVE RECEPTOR LOCATION

## NOTES

1. BASE MAP IMAGERY FRO M ESRI & CONTRIBUTORS, "WORLD TOPOGRAPHIC MAP " SERVICE LAYER.

PROJECT:

**THE OHIO STATE UNIVERSITY COMBINED HEAT AND POWER PROJECT COLUMBUS, OH**

TITLE:

**POSSIBLE SENSITIVE RECEPTOR LOCATIONS**

| | | | |
|---|---|---|---|
| DRAWN BY: | S. MOTURI | PROJ. NO.: | 314315 |
| CHECKED BY: | D. FOX | | |
| APPROVED BY: | M. SPONSLER | FIGURE 1 | |
| DATE: | JUNE 2020 | | |

TRC

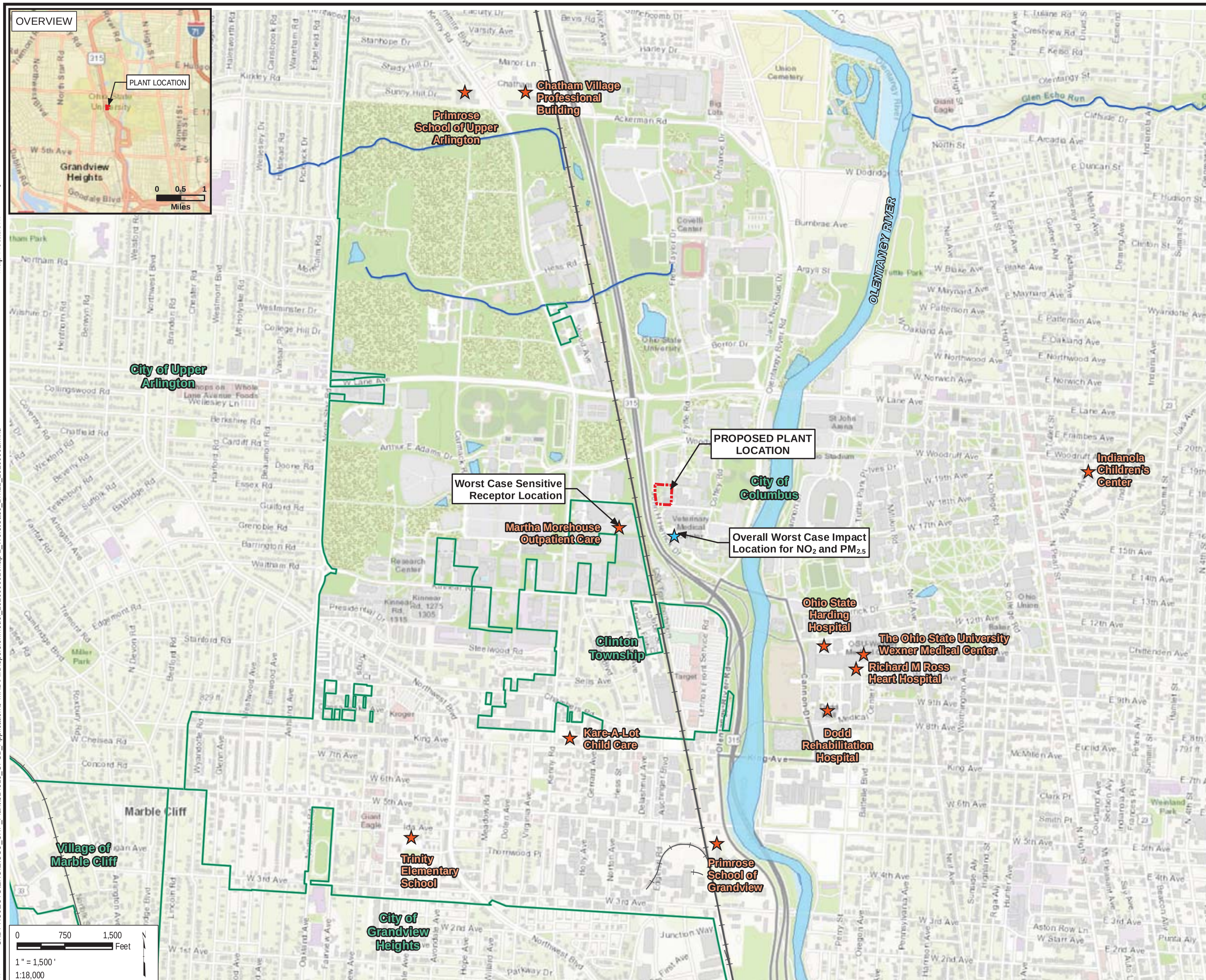
781 Science Blvd, Suite 200
Gahanna, OH 43230
Phone: 614.423.6353
www.trcsolutions.com

FILE NO.: Map 1_SensitiveReceptor_17x11_20200601.mxd

Plot Date: 6/2/2020, 16:25:51 PM by SMOTURI -- LAYOUT: ANSI B(11"x17")
Path: S:\1-PROJECTS\ENGIE\OSU_CHP_Plant\314315_OPSB_Application\9-MXD\AirDispersionModel_20200601\Map 1_SensitiveReceptor_17x11_20200601.mxd

Coordinate System: NAD 1983 StatePlane Ohio South FIPS 3402 Feet (Foot US)
Map Rotation: 0

TRC - GIS




## LEGEND

- PROPOSED PLANT PROJECT AREA
- POSSIBLE SENSITIVE RECEPTOR LOCATION
- OVERALL WORST CASE IMPACT LOCATION FOR $NO_2$ AND $PM_{2.5}$

## NOTES

1. BASE MAP IMAGERY FRO M ESRI & CONTRIBUTORS, "WORLD TOPOGRAPHIC MAP " SERVICE LAYER.

| | | | |
|---|---|---|---|
| PROJECT: THE OHIO STATE UNIVERSITY COMBINED HEAT AND POWER PROJECT COLUMBUS, OH | | | |
| TITLE: OVERALL WORST CASE IMPACT LOCATION FOR $NO_2$ AND $PM_{2.5}$ | | | |
| DRAWN BY: | S. MOTURI | PROJ. NO.: | 314315 |
| CHECKED BY: | D. FOX | FIGURE 2 | |
| APPROVED BY: | M. SPONSLER | | |
| DATE: | JUNE 2020 | | |
| TRC | | 781 Science Blvd, Suite 200 Gahanna, OH 43230 Phone: 614.423.6353 www.trcsolutions.com | |
| FILE NO.: | | Map 2_WorstCase_17x11_20200601.mxd | |

Coordinate System: NAD 1983 StatePlane Ohio South FIPS 3402 Feet (Foot US)
Map Rotation: 0

Plot Date: 6/4/2020, 09:25:46 AM by SMOTURI -- LAYOUT: ANSI B(11"x17")
Path: S:\1-PROJECTS\ENGIE\OSU_CHP_Plant\314315_OPSB_Application\9-MXD\AirDispersionModel_20200601\Map 2_WorstCase_17x11_20200601.mxd

TRC - GIS

# Exhibit RS-E

**CPV Valley Energy Center**
- Original Permit
- No changes requested with this submission for the Title V Application.

IDENTIFICATION INFORMATION

Permit Type: Air State Facility
Permit ID: 3-3356-00136/00001
Effective Date: 08/01/2013 Expiration Date: 07/31/2018

Permit Issued To: COMPETITIVE POWER VENTURES INC
50 BRAINTREE HILL OFFICE PARK
SUITE 300
BRAINTREE, MA 02184

Contact: STEVE REMILLARD
CPV VALLEY LLC
35 BRAINTREE HILL OFFICE PARK STE 400
BRAINTREE, MA 02184
(781) 817-8970

Facility: CPV VALLEY ENERGY CENTER
US RTE 6 , RTE 17 AND INTERSTATE 84
MIDDLETOWN, NY

Description:
pre-construction permit

By acceptance of this permit, the permittee agrees that the permit is contingent upon strict compliance with the ECL, all applicable regulations, the General Conditions specified and any Special Conditions included as part of this permit.

Permit Administrator: CHRISTOPHER M HOGAN
625 BROADWAY
ALBANY, NY 12233

Authorized Signature: ______________________________ Date: ___ / ___ / _____

**Notification of Other State Permittee Obligations**

Item A: Permittee Accepts Legal Responsibility and Agrees to Indemnification

The permittee expressly agrees to indemnify and hold harmless the Department of Environmental Conservation of the State of New York, its representatives, employees and agents ("DEC") for all claims, suits, actions, and damages, to the extent attributable to the permittee's acts or omissions in connection with the compliance permittee's undertaking of activities in connection with, or operation and maintenance of, the facility or facilities authorized by the permit whether in compliance or not in any compliance with the terms and conditions of the permit. This indemnification does not extend to any claims, suits, actions, or damages to the extent attributable to DEC's own negligent or intentional acts or omissions, or to any claims, suits, or actions naming the DEC and arising under article 78 of the New York Civil Practice Laws and Rules or any citizen suit or civil rights provision under federal or state laws.

Item B: Permittee's Contractors to Comply with Permit

The permittee is responsible for informing its independent contractors, employees, agents and assigns of their responsibility to comply with this permit, including all special conditions while acting as the permittee's agent with respect to the permitted activities, and such persons shall be subject to the same sanctions for violations of the Environmental Conservation Law as those prescribed for the permittee.

Item C: Permittee Responsible for Obtaining Other Required Permits

The permittee is responsible for obtaining any other permits, approvals, lands, easements and rights-of-way that may be required to carry out the activities that are authorized by this permit.

Item D: No Right to Trespass or Interfere with Riparian Rights

This permit does not convey to the permittee any right to trespass upon the lands or interfere with the riparian rights of others in order to perform the permitted work nor does it authorize the impairment of any rights, title, or interest in real or personal property held or vested in a person not a party to the permit.

## LIST OF CONDITIONS

**DEC GENERAL CONDITIONS**
****** General Provisions ******
**GENERAL CONDITIONS - Apply to ALL Authorized Permits.**

**Condition 1: Facility Inspection by the Department**
**Applicable State Requirement: ECL 19-0305**

**Item 1.1:**
The permitted site or facility, including relevant records, is subject to inspection at reasonable hours and intervals by an authorized representative of the Department of Environmental Conservation (the Department) to determine whether the permittee is complying with this permit and the ECL. Such representative may order the work suspended pursuant to ECL 71-0301 and SAPA 401(3).

**Item 1.2:**
The permittee shall provide a person to accompany the Department's representative during an inspection to the permit area when requested by the Department.

**Item 1.3:**
A copy of this permit, including all referenced maps, drawings and special conditions, must be available for inspection by the Department at all times at the project site or facility. Failure to produce a copy of the permit upon request by a Department representative is a violation of this permit.

**Condition 1: Facility Inspection by the Department**
**Applicable State Requirement: ECL 19-0305**

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A copy of this permit, including all referenced maps, drawings and special conditions, must be available for inspection by the Department at all times at the project site or facility. Failure to produce a copy of the permit upon request by a Department representative is a violation of this permit.

**Condition 2: Relationship of this Permit to Other Department Orders and Determinations**
**Applicable State Requirement: ECL 3-0301 (2) (m)**

**Item 2.1:**
Unless expressly provided for by the Department, issuance of this permit does not modify, supersede or rescind any order or determination previously issued by the Department or any of the terms, conditions or requirements contained in such order or determination.

**Condition 2: Relationship of this Permit to Other Department Orders and Determinations**
**Applicable State Requirement: ECL 3-0301 (2) (m)**

**Item 2.1:**
Unless expressly provided for by the Department, issuance of this permit does not modify, supersede or rescind any order or determination previously issued by the Department or any of the terms, conditions or requirements contained in such order or determination.

**Condition 2: Relationship of this Permit to Other Department Orders and Determinations**
**Applicable State Requirement: ECL 3-0301 (2) (m)**

**Item 2.1:**
Unless expressly provided for by the Department, issuance of this permit does not modify, supersede or rescind any order or determination previously issued by the Department or any of the terms, conditions or requirements contained in such order or determination.

**Condition 3: Applications for permit renewals, modifications and transfers**
**Applicable State Requirement: 6 NYCRR 621.11**

**Item 3.1:**
The permittee must submit a separate written application to the Department for renewal, modification or transfer of this permit. Such application must include any forms or supplemental information the Department requires. Any renewal, modification or transfer granted by the Department must be in writing.

**Item 3.2:**
The permittee must submit a renewal application at least 180 days before expiration of permits for Title V Facility Permits, or at least 30 days before expiration of permits for State Facility Permits.

**Item 3.3:**
Permits are transferrable with the approval of the department unless specifically prohibited by

submitted prior to actual transfer of ownership.

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**Item 3.3:**
Permits are transferrable with the approval of the department unless specifically prohibited by the statute, regulation or another permit condition. Applications for permit transfer should be submitted prior to actual transfer of ownership.

**Condition 4: Permit modifications, suspensions or revocations by the Department**
**Applicable State Requirement: 6 NYCRR 621.13**

**Item 4.1:**
The Department reserves the right to exercise all available authority to modify, suspend, or revoke this permit in accordance with 6NYCRR Part 621. The grounds for modification, suspension or revocation include:

a) materially false or inaccurate statements in the permit application or supporting papers;
b) failure by the permittee to comply with any terms or conditions of the permit;
c) exceeding the scope of the project as described in the permit application;
d) newly discovered material information or a material change in environmental conditions,

e) noncompliance with previously issued permit conditions, orders of the commissioner, any provisions of the Environmental Conservation Law or regulations of the Department related to the permitted activity.

**Condition 4: Permit modifications, suspensions or revocations by the Department**
**Applicable State Requirement: 6 NYCRR 621.13**

**Item 4.1:**
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a) materially false or inaccurate statements in the permit application or supporting papers;
b) failure by the permittee to comply with any terms or conditions of the permit;
c) exceeding the scope of the project as described in the permit application;
d) newly discovered material information or a material change in environmental conditions, relevant technology or applicable law or regulations since the issuance of the existing permit;
e) noncompliance with previously issued permit conditions, orders of the commissioner, any provisions of the Environmental Conservation Law or regulations of the Department related to the permitted activity.

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b) failure by the permittee to comply with any terms or conditions of the permit;
c) exceeding the scope of the project as described in the permit application;
d) newly discovered material information or a material change in environmental conditions, relevant technology or applicable law or regulations since the issuance of the existing permit;
e) noncompliance with previously issued permit conditions, orders of the commissioner, any provisions of the Environmental Conservation Law or regulations of the Department related to the permitted activity.

****** Facility Level ******

**Condition 5: Submission of application for permit modification or renewal-REGION 3 HEADQUARTERS**
**Applicable State Requirement: 6 NYCRR 621.6 (a)**

**Item 5.1:**
Submission of applications for permit modification or renewal are to be submitted to:
NYSDEC Regional Permit Administrator

Division of Environmental Permits
21 South Putt Corners Road
New Paltz, NY 12561-1696
(845) 256-3054

**Permit Under the Environmental Conservation Law (ECL)**

**ARTICLE 19: AIR POLLUTION CONTROL - AIR STATE FACILITY PERMIT**

**IDENTIFICATION INFORMATION**

Permit Issued To:COMPETITIVE POWER VENTURES INC
50 BRAINTREE HILL OFFICE PARK
SUITE 300
BRAINTREE, MA 02184

Facility: CPV VALLEY ENERGY CENTER
US RTE 6 , RTE 17 AND INTERSTATE 84
MIDDLETOWN, NY

Authorized Activity By Standard Industrial Classification Code:
4911 - ELECTRIC SERVICES

Permit Effective Date: 08/01/2013 Permit Expiration Date: 07/31/2018

## LIST OF CONDITIONS

### FEDERALLY ENFORCEABLE CONDITIONS
**Facility Level**

NOTE: * preceding the condition number indicates capping.

**FEDERALLY ENFORCEABLE CONDITIONS**
****** Facility Level ******

**NOTIFICATION OF GENERAL PERMITTEE OBLIGATIONS**
**This section contains terms and conditions which are federally enforceable. Permittees may also have other obligations under regulations of general applicability**

**Item A:** **Sealing - 6 NYCRR 200.5**

The Commissioner may seal an air contamination source to prevent its operation if compliance with 6 NYCRR Chapter III is not met within the time provided by an order of the Commissioner issued in the case of the violation. Sealing means labeling or tagging a source to notify any person that operation of the source is prohibited, and also includes physical means of preventing the operation of an air contamination source without resulting in destruction of any equipment associated with such source, and includes, but is not limited to, bolting, chaining or wiring shut control panels, apertures or conduits associated with such source.

No person shall operate any air contamination source sealed by the Commissioner in accordance with this section unless a modification has been made which enables such source to comply with all requirements applicable to such modification.

Unless authorized by the Commissioner, no person shall remove or alter any seal affixed to any contamination source in accordance with this section.

**Item B:** **Acceptable Ambient Air Quality - 6 NYCRR 200.6**

Notwithstanding the provisions of 6 NYCRR Chapter III, Subchapter A, no person shall allow or permit any air contamination source to emit air contaminants in quantities which alone or in combination with emissions from other air contamination sources would contravene any applicable ambient air quality standard and/or cause air pollution. In such cases where contravention occurs or may occur, the Commissioner shall specify the degree and/or method of emission control required.

**Item C:** **Maintenance of Equipment - 6 NYCRR 200.7**

Any person who owns or operates an air contamination source which is equipped with an emission control device shall operate such device and keep it in a satisfactory state of maintenance and repair in accordance with ordinary and necessary practices, standards and procedures, inclusive of manufacturer's specifications, required to operate such device effectively.

**Item D: Unpermitted Emission Sources - 6 NYCRR 201-1.2**

If an existing emission source was subject to the permitting requirements of 6 NYCRR Part 201 at the time of construction or modification, and the owner and/or operator failed to apply for a permit for such emission source then the following provisions apply:

(a) The owner and/or operator must apply for a permit for such emission source or register the facility in accordance with the provisions of Part 201.

(b) The emission source or facility is subject to all regulations that were applicable to it at the time of construction or modification and any subsequent requirements applicable to existing sources or facilities.

**Item E: Emergency Defense - 6 NYCRR 201-1.5**

An emergency constitutes an affirmative defense to an action brought for noncompliance with emissions limitations or permit conditions for all facilities in New York State.

(a) The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that:

(1) An emergency occurred and that the facility owner and/or operator can identify the cause(s) of the emergency;

(2) The equipment at the permitted facility causing the emergency was at the time being properly operated;

(3) During the period of the emergency the facility owner and/or operator took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit; and

(4) The facility owner and/or operator notified the Department within two working days after the event occurred. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

(b) In any enforcement proceeding, the facility owner and/or operator seeking to establish the occurrence of an emergency has the burden of proof.

(c) This provision is in addition to any emergency or upset provision contained in any applicable requirement.

**Item F:** **Recycling and Salvage - 6 NYCRR 201-1.7**

Where practical, any person who owns or operates an air contamination source shall recycle or salvage air contaminants collected in an air cleaning device according to the requirements of 6 NYCRR.

**Item G:** **Prohibition of Reintroduction of Collected Contaminants to the Air - 6 NYCRR 201-1.8**
No person shall unnecessarily remove, handle, or cause to be handled, collected air contaminants from an air cleaning device for recycling, salvage or disposal in a manner that would reintroduce them to the outdoor atmosphere.

**Item H:** **Proof of Eligibility for Sources Defined as Exempt Activities - 6 NYCRR 201-3.2 (a)**
The owner and/or operator of an emission source or unit that is eligible to be exempt, may be required to certify that it operates within the specific criteria described in 6 NYCRR Subpart 201-3. The owner or operator of any such emission source must maintain all required records on-site for a period of five years and make them available to representatives of the Department upon request. Department representatives must be granted access to any facility which contains emission sources or units subject to 6 NYCRR Subpart 201-3, during normal operating hours, for the purpose of determining compliance with this and any other state and federal air pollution control requirements, regulations, or law.

**Item I:** **Proof of Eligibility for Sources Defined as Trivial Activities - 6 NYCRR 201-3.3 (a)**
The owner and/or operator of an emission source or unit that is listed as being trivial in 6 NYCRR Part 201 may be required to certify that it operates within the specific criteria described in 6 NYCRR Subpart 201-3. The owner or operator of any such emission source must maintain all required records on-site for a period of five years and make them available to representatives of the Department upon request. Department representatives must be granted access to any facility which contains emission sources or units subject to 6 NYCRR Subpart 201-3, during normal operating hours, for the purpose of determining compliance with this and any other state and federal air pollution control requirements, regulations, or law.

**Item J:** **Required Emission Tests - 6 NYCRR 202-1.1**

An acceptable report of measured emissions shall be submitted, as may be required by the Commissioner, to ascertain compliance or noncompliance with any air pollution code, rule, or regulation. Failure to submit a report acceptable to the Commissioner within the time stated shall be sufficient reason for the Commissioner to suspend or deny an operating permit. Notification and acceptable procedures are specified in 6 NYCRR Subpart 202-1.

**Item K:** **Open Fires Prohibitions - 6 NYCRR 215.2**
Except as allowed by section 215.3 of 6 NYCRR Part 215, no person shall burn, cause, suffer, allowor permit the burning of any materials in an open fire.

**Item L:** **Permit Exclusion - ECL 19-0305**
The issuance of this permit by the Department and the receipt thereof by the Applicant does not and shall not be construed as barring, diminishing, adjudicating or in any way affecting any legal, administrative or equitable rights or claims, actions, suits, causes of action or demands whatsoever that the Department may have against the Applicant for violations based on facts and circumstances alleged to have occurred or existed prior to the effective date of this permit, including, but not limited to, any enforcement action authorized pursuant to the provisions of applicable federal law, the Environmental Conservation Law of the State of New York (ECL) and Chapter III of the Official Compilation of the Codes, Rules and Regulations of the State of New York (NYCRR). The issuance of this permit also shall not in any way affect pending or future enforcement actions under the Clean Air Act brought by the United States or any person.

**Item M:** **Federally Enforceable Requirements - 40 CFR 70.6 (b)**
All terms and conditions in this permit required by the Act or any applicable requirement, including any provisions designed to limit a facility's potential to emit, are enforceable by the Administrator and citizens under the Act. The Department has, in this permit, specifically designated any terms and conditions that are not required under the Act or under any of its applicable requirements as being enforceable under only state regulations.

**FEDERAL APPLICABLE REQUIREMENTS**
**The following conditions are federally enforceable.**

**Condition 1:** **Maintenance of Equipment**

**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 200.7**

**Item 1.1:**
Any person who owns or operates an air contamination source which is equipped with an emission control device shall operate such device and keep it in a satisfactory state of maintenance and repair in accordance with ordinary and necessary practices, standards and procedures, inclusive of manufacturer's specifications, required to operate such device effectively.

**Condition 2: Required Emissions Tests**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 202-1.1**

**Item 2.1:**
For the purpose of ascertaining compliance or non-compliance with any air pollution control code, rule or regulation, the commissioner may require the person who owns such air contamination source to submit an acceptable report of measured emissions within a stated time.

**Condition 3: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 200.7**

**Item 3.1:**
The Compliance Demonstration activity will be performed for the Facility.

Regulated Contaminant(s):
CAS No: 007664-41-7 AMMONIA

**Item 3.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: WORK PRACTICE INVOLVING SPECIFIC OPERATIONS
Monitoring Description:
The facility will maintain records to verify concentration of ammonia stored on-site is less than 19%.

Work Practice Type: PARAMETER OF PROCESS MATERIAL
Process Material: AMMONIA
Parameter Monitored: CONCENTRATION
Upper Permit Limit: 19 percent
Reference Test Method: EPA Approved
Monitoring Frequency: PER DELIVERY
Averaging Method: MAXIMUM - NOT TO BE EXCEEDED AT ANY TIME (INSTANTANEOUS/DISCRETE OR GRAB)
Reporting Requirements: ANNUALLY (CALENDAR)
Reports due 30 days after the reporting period.

The initial report is due 1/30/2014.
Subsequent reports are due every 12 calendar month(s).

**Condition 4: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 200.7**

**Item 4.1:**
The Compliance Demonstration activity will be performed for the facility:
The Compliance Demonstration applies to:

Emission Unit: U-00001 Emission Point: EP001

Emission Unit: U-00002 Emission Point: EP002

Regulated Contaminant(s):
CAS No: 007664-41-7 AMMONIA

**Item 4.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: CONTINUOUS EMISSION MONITORING (CEM)
Monitoring Description:
The facility shall install, calibrate, maintain and operate continuous emissions monitors for ammonia. The 5.0 ppmvd corrected to 15% Oxygen limit applies during all turbine loads, all fuels being fired and all duct burner operations.

Manufacturer Name/Model Number: Ammonia Analyzer
Parameter Monitored: AMMONIA
Upper Permit Limit: 5.0 parts per million by volume
(dry, corrected to 15% O2)
Reference Test Method: 40 CFR 60 Appendices B & F
Monitoring Frequency: CONTINUOUS
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: QUARTERLY (CALENDAR)
Reports due 30 days after the reporting period.
The initial report is due 10/30/2013.
Subsequent reports are due every 3 calendar month(s).

**Condition 5: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 201-1.4 (a)**

**Item 5.1:**
The Compliance Demonstration activity will be performed for the Facility.

**Item 5.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: RECORD KEEPING/MAINTENANCE PROCEDURES
Monitoring Description:

The owner or operator shall, within one year following the commencement of operation, submit a Title V permit application to the Department (as per the requirements of paragraph 201-6.3(a)(3)). This application must include start-up, shutdown, and fuel switching data to establish enforceable combustion turbine start-up, shutdown, and fuel switching emission rates for NOx, CO, and NH3, and confirm that such established rates would not result in a violation of applicable NAAQS.

In the event that a minimum of 15 start-ups and 15 shutdowns, while firing distillate oil, does not occur within the one year period defined above, the owner or operator will be required to submit start-up and shutdown data, with an application for permit modification, once the 15 start-ups and shutdowns while firing distillate oil occur.

Also, if a minimum of 15 fuel switches does not occur within the one year period defined above, the owner or operator will be required to submit fuel switching data with an application for permit modification once the 15 fuel switches occur.

Monitoring Frequency: CONTINUOUS
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 6: Title V Permit Requirement**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 201-6.3 (a) (2)**

**Item 6.1:**
A Title V permit application must be submitted to the Department within one year of commencement of operation of this facility.

**Condition 7: Facility Permissible Emissions**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR Subpart 201-7**

**Item 7.1:**
The sum of emissions from the emission units specified in this permit shall not equal or exceed the following
Potential To Emit (PTE) rate for each regulated contaminant:

CAS No: 0NY075-02-5 PTE: 190,000 pounds per year
Name: PM 2.5

**Condition 8: Capping Monitoring Condition**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR Subpart 201-7**

**Item 8.1:**
Under the authority of 6 NYCRR Part 201-7, this condition contains an emission cap for the purpose of limiting emissions from the facility, emission unit or process to avoid being subject to the following applicable requirement(s) that the facility, emission unit or process would otherwise be subject to:

6 NYCRR 231-2.2

**Item 8.2:**
Operation of this facility shall take place in accordance with the approved criteria, emission limits, terms, conditions and standards in this permit.

**Item 8.3:**
The owner or operator of the permitted facility must maintain all required records on-site for a period of five years and make them available to representatives of the Department upon request. Department representatives must be granted access to any facility regulated by this Subpart, during normal operating hours, for the purpose of determining compliance with this and any other state and federal air pollution control requirements, regulations or law.

**Item 8.4:**
On an annual basis, unless otherwise specified below, beginning one year after the granting of an emissions cap, the responsible official shall provide a certification to the Department that the facility has operated all emission units within the limits imposed by the emission cap. This certification shall include a brief summary of the emissions subject to the cap for that time period and a comparison to the threshold levels that would require compliance with an applicable requirement.

**Item 8.5:**
The emission of pollutants that exceed the applicability thresholds for an applicable requirement, for which the facility has obtained an emissions cap, constitutes a violation of Part 201 and of the Act.

**Item 8.6:**
The Compliance Demonstration activity will be performed for the Facility.

Regulated Contaminant(s):
CAS No: 0NY075-02-5 PM 2.5

**Item 8.7:**
Compliance Demonstration shall include the following monitoring:

Capping: Yes
Monitoring Type: WORK PRACTICE INVOLVING SPECIFIC OPERATIONS
Monitoring Description:
Monthly facility-wide emissions of PM-2.5 will be

calculated as the sum of monthly PM-2.5 emissions from individual emission units or source groups. Emissions will be calculated based on heat input (or, equivalently, from fuel use) and emission factors as described below. Annual facility-wide emissions will then be determined at the end of each month on a rolling 12-month basis in order to demonstrate compliance with the 95 ton per year cap.

The source groups included in the emissions cap along with their associated source indices and PM-2.5 emission factors, as used in subsequent equations, are listed in the following. For each source group, the parameter that will be monitored and the monitoring frequency. Continuous monitoring of heat input to the combustion turbines, auxiliary boiler and gas heater(s) will be provided by a digital data acquisition system (DAS).

| Unit | Op Load | Fuel | Grp | Emission Factor |
|---|---|---|---|---|
| CT only | > 80% | Gas | 1 | 0.0056 |
| CT only | < 80% | Gas | 2 | 0.0073 |
| CT + DB | > 80% | Gas | 3 | 0.0064 |
| CT only | > 85% | Oil | 4 | 0.0247 |
| CT only | < 85% | Oil | 5 | 0.0368 |
| Aux Boiler | All | Gas | 6 | 0.0063 |
| Gas Heater | All | Gas | 7 | 0.0076 |
| EDG | All | Oil | 8 | 0.0091 |
| EFP | All | Oil | 9 | 0.0429 |

Where CT = combustion turbines, DB = duct burners, Aux Boiler = auxiliary boiler, EDG = emergency diesel generator and EFP = emergency fire pump

For the combustion turbines, the proposed emission factors represent the maximum PM-2.5 emission factor over the specified normal operating loads for the associated fuel and category. In lieu of using the maximum PM-2.5 emission factors, the owner or operator may elect to use representative PM-2.5 stack test data to determine compliance with the annual PM-2.5 emissions cap.

For each source group (i), the PM-2.5 emissions in tons ($Q_{ij}$) for month j will be calculated as follows:
$Q_{ij} = EF_i \times H_{ij} / 2000$, where:

• $EF_i$ = PM-2.5 emission factor or representative PM-2.5 stack test data (lb/mmBtu) for source group i
• $H_{ij}$ = monthly heat input (mmBtu) for source group i in

month j

In cases where fuel use (gallons of oil or standard cubic feet of gas) for a source group is monitored directly rather than heat input, the equivalent heat input will be determined by multiplying the monthly fuel usage for the source group by the corresponding fuel heating value (mmBtu/gallon or mmBtu/scf), using the higher heating value (HHV) basis for the fuel.

The total facility PM-2.5 emissions in month j (Qj) will be calculated by summing over all source groups (i = 1 to 9) as follows: Qj = ∑ EFi x Hij / 2000 = ∑ Qij.

The facility-wide PM-2.5 emissions over the past 12 months (Qann) ending in month j will be determined by summing the facility-wide PM-2.5 emissions for the most recent 12 months (k = 0 to 11) as follows:

Qann = ∑ Qj-k

After each month, compliance will be demonstrated with the proposed 95 ton/year PM-2.5 emission limit by showing that Qann < 95.

The facility shall conduct periodic testing to demonstrate that emissions from the combustion turbines comply with the lb/mmBtu emission factors for PM-2.5. The combustion turbines will be tested once per year for the first two years of operation with the first test to be conducted within 180 days of startup.

Work Practice Type: PARAMETER OF PROCESS MATERIAL
Process Material: FUEL
Parameter Monitored: HEAT INPUT
Upper Permit Limit: 95 tons per year
Monitoring Frequency: CONTINUOUS
Averaging Method: 12-month total, rolled monthly
Reporting Requirements: ANNUALLY (CALENDAR)
Reports due 30 days after the reporting period.
The initial report is due 1/30/2014.
Subsequent reports are due every 12 calendar month(s).

**Condition 9: Air pollution prohibited**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 211.1**

**Item 9.1:**

No person shall cause or allow emissions of air contaminants to the outdoor atmosphere of such quantity, characteristic or duration which are injurious to human, plant or animal life or to property, or which unreasonably interfere with the comfortable enjoyment of life or property. Notwithstanding the existence of specific air quality standards or emission limits, this prohibition applies, but is not limited to, any particulate, fume, gas, mist, odor, smoke, vapor, pollen, toxic or deleterious emission, either alone or in combination with others.

**Condition 10: Facility PTE**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-5.3**

**Item 10.1:**
CPV Valley Energy Center
Facility-Wide Potential to Emit

VOC 65 tons/yr
NOx 186.8 tons/yr

**Condition 11: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-5.4**

**Item 11.1:**
The Compliance Demonstration activity will be performed for the facility:
The Compliance Demonstration applies to:

Emission Unit: U-00001 Emission Point: EP001
Process: P1A

Emission Unit: U-00001 Emission Point: EP001
Process: P2A

Emission Unit: U-00002 Emission Point: EP002
Process: P01

Emission Unit: U-00002 Emission Point: EP002
Process: P02

Regulated Contaminant(s):
CAS No: 0NY210-00-0 OXIDES OF NITROGEN

**Item 11.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: CONTINUOUS EMISSION MONITORING (CEM)
Monitoring Description:
LAER is 2.0 ppmvd corrected to 15% Oxygen. Will be achieved through use of Dry Low NOx combustion technology

and SCR.

The facility shall install, calibrate, maintain, and operate a continuous emission monitor.

The limit applies at all loads except during start up and shutdown.

Manufacturer Name/Model Number: CEM
Upper Permit Limit: 2.0 parts per million by volume
(dry, corrected to 15% O2)
Reference Test Method: 40 CFR Part 60 Appendix and Method 7E
Monitoring Frequency: CONTINUOUS
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: QUARTERLY (CALENDAR)
Reports due 30 days after the reporting period.
The initial report is due 10/30/2013.
Subsequent reports are due every 3 calendar month(s).

**Condition 12: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-5.4**

**Item 12.1:**
The Compliance Demonstration activity will be performed for the facility:
The Compliance Demonstration applies to:

Emission Unit: U-00001 Emission Point: EP001
Process: P2A

Emission Unit: U-00002 Emission Point: EP002
Process: P02

Regulated Contaminant(s):
CAS No: 0NY998-00-0 VOC

**Item 12.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
LAER is 1.8 ppmvd corrected to 15% O2. Will be achieved using good combustion controls and an oxidation catalyst. Emission testing to be performed within 180 days of startup.

Manufacturer Name/Model Number: CEM
Parameter Monitored: CONCENTRATION
Upper Permit Limit: 1.8 parts per million by volume
(dry, corrected to 15% O2)
Reference Test Method: Method 25A

Monitoring Frequency: SINGLE OCCURRENCE
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 13: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-5.4**

**Item 13.1:**
The Compliance Demonstration activity will be performed for the facility:
The Compliance Demonstration applies to:

Emission Unit: U-00001 Emission Point: EP001
Process: P3A

Emission Unit: U-00002 Emission Point: EP002
Process: P03

Regulated Contaminant(s):
CAS No: 0NY210-00-0 OXIDES OF NITROGEN

**Item 13.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: CONTINUOUS EMISSION MONITORING (CEM)
Monitoring Description:

LAER is 6.0 ppmvd corrected to 15% Oxygen. Will be achieved using water injection and SCR.

The facility shall install, calibrate, maintain, and operate a continuous emission monitor.

The limit applies at all loads except during start up and shutdown.

Manufacturer Name/Model Number: CEM
Upper Permit Limit: 6.0 parts per million by volume (dry, corrected to 15% O2)
Reference Test Method: 40 CFR Part 60 Appendix and Method 7E
Monitoring Frequency: CONTINUOUS
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: QUARTERLY (CALENDAR)
Reports due 30 days after the reporting period.
The initial report is due 10/30/2013.
Subsequent reports are due every 3 calendar month(s).

**Condition 14: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-5.4**

**Item 14.1:**
The Compliance Demonstration activity will be performed for the facility:
The Compliance Demonstration applies to:

Emission Unit: U-00001 Emission Point: EP001
Process: P1A

Emission Unit: U-00001 Emission Point: EP001
Process: P3A

Emission Unit: U-00002 Emission Point: EP002
Process: P01

Emission Unit: U-00002 Emission Point: EP002
Process: P03

Regulated Contaminant(s):
CAS No: 0NY998-00-0 VOC

**Item 14.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
LAER is 0.7 ppmvd corrected to 15% O2. Will be achieved using good combustion controls and an oxidation catalyst. Emission testing to be performed within 180 days of startup.

Manufacturer Name/Model Number: CEM
Parameter Monitored: CONCENTRATION
Upper Permit Limit: 0.7 parts per million by volume
(dry, corrected to 15% O2)
Reference Test Method: Method 25A
Monitoring Frequency: SINGLE OCCURRENCE
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 15: Emission offset**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-5.5**

**Item 15.1: The potential to emit Oxides of Nitrogen (NOx) from the facility has been limited to** 187 tons per year. NOx emissions must be offset at a ratio of 1.15 to 1. A total of 216 tons of offsets will be required. The facility will identify the sources of offsets at a later time but prior to construction. There will be a separate noticing at that time.

**Condition 16: Emission offsets**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-5.5**

**Item 16.1: The potential to emit Volatile Organic Compounds (VOC) from the facility has been** limited to 65 tons per year. VOC emissions must be offset at a ratio of 1.15 to 1. A total of 75 tons of offsets will be required. The facility will identify the sources of offsets at a later time but prior to construction. There will be a separate noticing at that time.

**Condition 17: offsets.**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-5.5**

INVALID FORMAT OF CONDITION IN LIBRARY

**Condition 18: Facility potential to emit**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-7.5**

**Item 18.1:**
CPV Valley Energy Center
Facility-Wide Potential to Emit

CO 344 tons /yr
$SO_2$ 42 Tons/yr
PM-2.5 95 tons/yr
$H_2SO_4$ 13 tons/yr
$CO_2$ 2,164,438 tons/yr

**Condition 19: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-7.6**

**Item 19.1:**
The Compliance Demonstration activity will be performed for the facility:
The Compliance Demonstration applies to:

Emission Unit: U-00001

Emission Unit: U-00002

**Item 19.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
The combined cycle units shall have a heat rate of 7605 Btu/kW-hr

(HHV) or less at ISO conditions without duct burner firing
to achieve
a design thermal efficiency of 57.4% (LHV).

Within 90 days of start-up of the facility and on an
annual basis
thereafter, the owner or operator shall conduct a
Department-approved
heat rate performance test on a combined cycle unit while
it is
operating at maximum load to determine heat rate.

The owner or operator shall conduct this heat rate
performance test
according to the requirements of the American Society of
Mechanical
Engineers Performance Test Code on Overall Plant
Performance, ASME PTC
46-1996.

Parameter Monitored: HEAT RATE
Upper Permit Limit: 7605 BTU per kilowatt-hour
Reference Test Method: ASME PTC 46-1996
Monitoring Frequency: ANNUALLY
Averaging Method: MAXIMUM - NOT TO EXCEED STATED VALUE -
SEE MONITORING DESCRIPTION
Reporting Requirements: SEMI-ANNUALLY (CALENDAR)
Reports due 30 days after the reporting period.
The initial report is due 1/30/2014.
Subsequent reports are due every 6 calendar month(s).

**Condition 20: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-7.6**

**Item 20.1:**
The Compliance Demonstration activity will be performed for the facility:
The Compliance Demonstration applies to:

Emission Unit: U-00001

Emission Unit: U-00002

Emission Unit: U-00003

Emission Unit: U-00004

Emission Unit: U-00005

Emission Unit: U-00006

**Item 20.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: RECORD KEEPING/MAINTENANCE PROCEDURES
Monitoring Description:

The owner or operators of the facility shall calculate the annual emissions (based on a monthly rolling average) of Carbon Dioxide equivalent (CO2e) emitted from the facility.

The Emissions factors will be based on either performance tests (as required by the permit) or developed emission factors from authorized sources (i.e. - AP-42). Fuel usage shall be monitored by fuel flow meters. The information will be kept on-site and available for review for a minimum of five years.

The facility will maintain records on-site for a minimum of five years.

Reference Test Method: As Described in condition
Monitoring Frequency: MONTHLY
Averaging Method: ANNUAL TOTAL ROLLED MONTHLY
Reporting Requirements: SEMI-ANNUALLY (CALENDAR)
Reports due 30 days after the reporting period.
The initial report is due 1/30/2014.
Subsequent reports are due every 6 calendar month(s).

**Condition 21: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-7.6**

**Item 21.1:**
The Compliance Demonstration activity will be performed for the facility:
The Compliance Demonstration applies to:

Emission Unit: U-00001

Emission Unit: U-00002

**Item 21.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: RECORD KEEPING/MAINTENANCE PROCEDURES
Monitoring Description:

The facility shall install, calibrate, maintain, and
operate a
continuous emission monitor for the total annual Carbon
Dioxide
equivalent (CO2e) emissions from the two combined-cycle
units.
The facility shall maintain records on-site for a minimum
of five
years.

Reference Test Method: 3A
Monitoring Frequency: CONTINUOUS
Averaging Method: ANNUAL TOTAL ROLLED MONTHLY
Reporting Requirements: SEMI-ANNUALLY (CALENDAR)
Reports due 30 days after the reporting period.
The initial report is due 1/30/2014.
Subsequent reports are due every 6 calendar month(s).

**Condition 22: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-7.6**

**Item 22.1:**
The Compliance Demonstration activity will be performed for the Facility.

Regulated Contaminant(s):
CAS No: 007446-09-5 SULFUR DIOXIDE

**Item 22.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: WORK PRACTICE INVOLVING SPECIFIC
OPERATIONS
Monitoring Description:
BACT FUEL SULFUR LIMIT OF 0.0015% BY
WEIGHT.

Work Practice Type: PARAMETER OF PROCESS MATERIAL
Process Material: FUEL OIL
Parameter Monitored: SULFUR CONTENT
Upper Permit Limit: 0.0015 percent by weight
Reference Test Method: ASTM D-2880-71
Monitoring Frequency: PER DELIVERY
Averaging Method: MAXIMUM - NOT TO BE EXCEEDED AT ANY
TIME (INSTANTANEOUS/DISCRETE OR GRAB)
Reporting Requirements: QUARTERLY (CALENDAR)
Reports due 30 days after the reporting period.
The initial report is due 10/30/2013.
Subsequent reports are due every 3 calendar month(s).

**Condition 23: Compliance Demonstration**

**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-7.6**

**Item 23.1:**
The Compliance Demonstration activity will be performed for the facility:
The Compliance Demonstration applies to:

Emission Unit: U-00001
Process: P1A

Emission Unit: U-00001
Process: P2A

Emission Unit: U-00002
Process: P01

Emission Unit: U-00002
Process: P02

Regulated Contaminant(s):
CAS No: 007446-09-5 SULFUR DIOXIDE

**Item 23.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
BACT is 0.0022 lb/mmBtu. Will be achieved through use of low sulfur fuels. Emission testing to be performed within 180 days of startup.

Upper Permit Limit: 0.0022 pounds per million Btus
Reference Test Method: EPA Approved
Monitoring Frequency: SINGLE OCCURRENCE
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 24: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-7.6**

**Item 24.1:**
The Compliance Demonstration activity will be performed for the facility:
The Compliance Demonstration applies to:

Emission Unit: U-00001
Process: P1A

Emission Unit: U-00001

Process: P2A

Emission Unit: U-00002
Process: P01

Emission Unit: U-00002
Process: P02

Regulated Contaminant(s):
CAS No: 007664-93-9 SULFURIC ACID

**Item 24.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
BACT is 0.0007 lb/mmBtu. Will be achieved through use of low sulfur fuels. Emission testing to be performed within 180 days of startup.

Upper Permit Limit: 0.0007 pounds per million Btus
Reference Test Method: EPA Approved
Monitoring Frequency: SINGLE OCCURRENCE
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 25: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-7.6**

**Item 25.1:**
The Compliance Demonstration activity will be performed for the facility:
The Compliance Demonstration applies to:

Emission Unit: U-00001
Process: P3A

Emission Unit: U-00002
Process: P03

Regulated Contaminant(s):
CAS No: 007664-93-9 SULFURIC ACID

**Item 25.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
BACT is 0.0005 lb/mmBtu. Will be achieved through use of low sulfur fuels. Emission testing to be performed within

180 days of startup.

Upper Permit Limit: 0.0005 pounds per million Btus
Reference Test Method: EPA Approved
Monitoring Frequency: SINGLE OCCURRENCE
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 26: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-7.6**

**Item 26.1:**
The Compliance Demonstration activity will be performed for the facility:
The Compliance Demonstration applies to:

Emission Unit: U-00001
Process: P3A

Emission Unit: U-00002
Process: P03

Regulated Contaminant(s):
CAS No: 007446-09-5 SULFUR DIOXIDE

**Item 26.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
BACT is 0.0015 lb/mmBtu. Will be achieved through use of low sulfur fuels. Emission testing to be performed within 180 days of startup.

Upper Permit Limit: 0.0015 pounds per million Btus
Reference Test Method: EPA Approved
Monitoring Frequency: SINGLE OCCURRENCE
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 27: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-7.6**

**Item 27.1:**
The Compliance Demonstration activity will be performed for the facility:
The Compliance Demonstration applies to:

Emission Unit: U-00001
Process: P3A

Emission Unit: U-00002
Process: P03

Regulated Contaminant(s):
CAS No: 0NY075-00-0 PARTICULATES
CAS No: 0NY075-00-5 PM-10

**Item 27.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
BACT is 0.0368 lb/mmBtu. Will be achieved through use of low sulfur fuels. Emission testing to be performed within 180 days of startup.

Upper Permit Limit: 0.0368 pounds per million Btus
Reference Test Method: Methods 201/201A and 202
Monitoring Frequency: SINGLE OCCURRENCE
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 28: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-7.6**

**Item 28.1:**
The Compliance Demonstration activity will be performed for the facility:
The Compliance Demonstration applies to:

Emission Unit: U-00001
Process: P2A

Emission Unit: U-00002
Process: P02

Regulated Contaminant(s):
CAS No: 000630-08-0 CARBON MONOXIDE

**Item 28.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: CONTINUOUS EMISSION MONITORING (CEM)
Monitoring Description:
BACT is 3.4 ppmvd corrected to 15% Oxygen. Will be achieved through good combustion controls and an oxidation catalyst.

The facility shall install, calibrate, maintain, and operate a continuous emission monitor.

The limit applies at all loads except during start up and shutdown.

Manufacturer Name/Model Number: CO analyzer
Parameter Monitored: CONCENTRATION
Upper Permit Limit: 3.4 parts per million by volume
(dry, corrected to 15% O2)
Reference Test Method: Method 10
Monitoring Frequency: CONTINUOUS
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: QUARTERLY (CALENDAR)
Reports due 30 days after the reporting period.
The initial report is due 10/30/2013.
Subsequent reports are due every 3 calendar month(s).

**Condition 29: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-7.6**

**Item 29.1:**
The Compliance Demonstration activity will be performed for the facility:
The Compliance Demonstration applies to:

Emission Unit: U-00001
Process: P1A

Emission Unit: U-00001
Process: P2A

Emission Unit: U-00002
Process: P01

Emission Unit: U-00002
Process: P02

Regulated Contaminant(s):
CAS No: 0NY075-00-0 PARTICULATES
CAS No: 0NY075-00-5 PM-10

**Item 29.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
BACT is 0.0073 lb/mmBtu. Will be achieved through use of low sulfur fuels. Emission testing to be performed within 180 days of startup.

Upper Permit Limit: 0.0073 pounds per million Btus
Reference Test Method: Methods 201/201A and 202
Monitoring Frequency: SINGLE OCCURRENCE
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 30: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-7.6**

**Item 30.1:**
The Compliance Demonstration activity will be performed for the facility:
The Compliance Demonstration applies to:

Emission Unit: U-00001
Process: P1A

Emission Unit: U-00001
Process: P3A

Emission Unit: U-00002
Process: P01

Emission Unit: U-00002
Process: P03

Regulated Contaminant(s):
CAS No: 000630-08-0 CARBON MONOXIDE

**Item 30.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: CONTINUOUS EMISSION MONITORING (CEM)
Monitoring Description:
BACT is 2.0 ppmvd corrected to 15% Oxygen. Will be achieved through good combustion controls and an oxidation catalyst.

The facility shall install, calibrate, maintain, and operate a continuous emission monitor.

The limit applies at all loads except during start up and shutdown.

Manufacturer Name/Model Number: CO analyzer
Parameter Monitored: CONCENTRATION
Upper Permit Limit: 2.0 parts per million by volume
(dry, corrected to 15% O2)
Reference Test Method: Method 10

Monitoring Frequency: CONTINUOUS
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: QUARTERLY (CALENDAR)
Reports due 30 days after the reporting period.
The initial report is due 10/30/2013.
Subsequent reports are due every 3 calendar month(s).

**Condition 31: Permit Requirements**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 243-1.6 (a)**

**Item 31.1:**
The CAIR designated representative of each CAIR NOx Ozone Season source shall:
(i) submit to the department a complete CAIR permit application under section 243-3.3 in accordance with the deadlines specified in section 243-3.2; and
(ii) submit in a timely manner any supplemental information that the department determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.

The owners and operators of each CAIR NOx Ozone Season source shall have a CAIR permit issued by the department under Subpart 243-3 for the source and operate the source and the unit in compliance with such CAIR permit.

**Condition 32: Monitoring requirements**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 243-1.6 (b)**

**Item 32.1:**
The emissions measurements recorded and reported in accordance with Subpart 243-8 shall be used to determine compliance by each CAIR NOx Ozone Season source with the CAIR NOx Ozone Season emissions limitation under subdivision (c) of this section.

**Condition 33: NOx Ozone Season Emission Requirements**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 243-1.6 (c)**

**Item 33.1:**
As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NOx Ozone Season source and each CAIR NOx Ozone Season unit at the source shall hold, in the source's compliance account, CAIR NOx Ozone Season allowances available for compliance deductions for the control period under section 243-6.5(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NOx Ozone Season units at the source, as determined in accordance with Subpart 243-8. The CAIR NOx ozone season is the period beginning May 1 of a calendar year, except as provided in section 243-1.6(c)(2), and ending on September 30 of the same year, inclusive.

A CAIR NOx Ozone Season unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of May 1, 2009 or the deadline for meeting the unit's monitor certification requirements under sections 243-8.1(b)(1), (2), (3), or (7) and for each control period thereafter.

A CAIR NOx Ozone Season allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the CAIR NOx Ozone Season allowance was allocated.

CAIR NOx Ozone Season allowances shall be held in, deducted from, or transferred into or among CAIR NOx Ozone Season Allowance Tracking System accounts in accordance with Subparts 243-6, 243-7, and 243-9.

A CAIR NOx Ozone Season allowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NOx Ozone Season Trading Program. No provision of the CAIR NOx Ozone Season Trading Program, the CAIR permit application, the CAIR permit, or an exemption under section 243-1.5 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.

A CAIR NOx Ozone Season allowance does not constitute a property right.

Upon recordation by the Administrator under Subpart 243-6, 243-7, or 243-9, every allocation, transfer, or deduction of a CAIR NOx Ozone Season allowance to or from a CAIR NOx Ozone Season source's compliance account is incorporated automatically in any CAIR permit of the source.

**Condition 34: Excess emission requirements**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 243-1.6 (d)**

**Item 34.1:**
If a CAIR NOx Ozone Season source emits nitrogen oxides during any control period in excess of the CAIR NOx Ozone Season emissions limitation, then:

(1) the owners and operators of the source and each CAIR NOx Ozone Season unit at the source shall surrender the CAIR NOx Ozone Season allowances required for deduction under section 243-6.5(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Act or applicable State law; and

(2) each ton of such excess emissions and each day of such control period shall constitute a separate violation of this Subpart, the Act, and applicable State law.

**Condition 35: Recordkeeping and reporting requirements**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 243-1.6 (e)**

**Item 35.1:**
Unless otherwise provided, the owners and operators of the CAIR NOx Ozone Season source and each CAIR NOx Ozone Season unit at the source shall keep on site at the source each of the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time before the end of five years, in writing by the department or the Administrator.

(i) The certificate of representation under section 243-2.4 for the CAIR designated representative for the source and each CAIR NOx Ozone Season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such five-year period until such documents are superseded because of the submission of a new certificate of representation under section 243-2.4 changing the CAIR designated representative.

(ii) All emissions monitoring information, in accordance with Subpart 243-8, provided that to the extent that Subpart 243-8 provides for a three-year period for recordkeeping, the three-year period shall apply.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NOx Ozone Season Trading Program.

(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NOx Ozone Season Trading Program or to demonstrate compliance with the requirements of the CAIR NOx Ozone Season Trading Program.

**Condition 36: Authorization and responsibilities of CAIR designated representative**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 243-2.1**

**Item 36.1:**
Except as provided under section 243-2.2, each CAIR NOx Ozone Season source, including all CAIR NOx Ozone Season units at the source, shall have one and only one CAIR designated representative, with regard to all matters under the CAIR NOx Ozone Season Trading Program concerning the source or any CAIR NOx Ozone Season unit at the source.

The CAIR designated representative of the CAIR NOx Ozone Season source shall be selected by an agreement binding on the owners and operators of the source and all CAIR NOx Ozone Season units at the source and shall act in accordance with the certification statement in section 243-2.4(a)(4)(iv).

Upon receipt by the Administrator of a complete certificate of representation under section 243-2.4, the CAIR designated representative of the source shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the CAIR NOx Ozone Season source represented and each CAIR NOx Ozone Season unit at the source in all matters pertaining to the CAIR NOx Ozone Season Trading Program, notwithstanding any agreement between the CAIR designated representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the CAIR designated representative by the department, the Administrator, or a court regarding the source or unit.

No CAIR permit will be issued, no emissions data reports will be accepted, and no CAIR NOx Ozone Season Allowance Tracking System account will be established for a CAIR NOx Ozone Season unit at a source, until the Administrator has received a complete certificate of representation under section 243-2.4 for a CAIR designated representative of the source and the CAIR NOx Ozone Season units at the source.

Each submission under the CAIR NOx Ozone Season Trading Program shall be submitted, signed, and certified by the CAIR designated representative for each CAIR NOx Ozone Season source on behalf of which the submission is made. Each such submission shall include the following certification statement by the CAIR designated representative: "I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

**Condition 37: Certificate of representation**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 243-2.4**

**Item 37.1:**
Unless otherwise required by the department or the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the department or the Administrator. Neither the department nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

**Condition 38: General requirements**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 243-8.1**

**Item 38.1:**
The owners and operators, and to the extent applicable, the CAIR designated representative, of a CAIR NOx Ozone Season unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this Subpart and in Subpart H of 40 CFR Part 75. For purposes of complying with such requirements, the definitions in section 243-1.2 and in 40 CFR 72.2 shall apply, and the terms "affected unit," "designated representative," and "continuous emission monitoring system" (or "CEMS") in 40 CFR Part 75 shall be deemed to refer to the terms "CAIR NOx Ozone Season unit," "CAIR designated representative," and "continuous emission monitoring system" (or "CEMS") respectively, as defined in section 243-1.2. The owner or operator of a unit that is not a CAIR NOx Ozone Season unit but that is monitored under 40 CFR 75.72(b)(2)(ii) shall comply with the same monitoring, recordkeeping, and reporting requirements as a CAIR NOx Ozone Season unit.

'Requirements for installation, certification, and data accounting.' The owner or operator of each CAIR NOx Ozone Season unit shall:

(1) install all monitoring systems required under this Subpart for monitoring NOx mass emissions and individual unit heat input (including all systems required to monitor NOx emission rate, NOx concentration, stack gas moisture content, stack gas flow rate, CO2 or O2 concentration, and fuel flow rate, as applicable, in accordance with 40 CFR 75.71 and 40 CFR 75.72);

(2) successfully complete all certification tests required under section 243-8.2 and meet all other requirements of this Subpart and 40 CFR Part 75 applicable to the monitoring systems under

paragraph (a)(1) of this section; and

(3) record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

**Condition 39: Prohibitions**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 243-8.1**

**Item 39.1:**
No owner or operator of a CAIR NOx Ozone Season unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this Subpart without having obtained prior written approval in accordance with section 243-8.6.

No owner or operator of a CAIR NOx Ozone Season unit shall operate the unit so as to discharge, or allow to be discharged, NOx emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this Subpart and 40 CFR Part 75.

No owner or operator of a CAIR NOx Ozone Season unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NOx mass emissions discharged into the atmosphere or heat input, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this Subpart and 40 CFR Part 75.

No owner or operator of a CAIR NOx Ozone Season unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this Subpart, except under any one of the following circumstances:
(i) during the period that the unit is covered by an exemption under section 243-1.5 that is in effect;
(ii) the owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this Subpart and 40 CFR Part 75, by the department for use at that unit that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or
(iii) the CAIR designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with section 243-8.2(d)(3)(i).

**Condition 40: Quarterly reports**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 243-8.5 (d)**

**Item 40.1:**
The CAIR designated representative shall submit quarterly reports, as follows:

If the CAIR NOx Ozone Season unit is subject to an Acid Rain emissions limitation or a CAIR NOx emissions limitation or if the owner or operator of such unit chooses to report on an annual basis under this Subpart, the CAIR designated representative shall meet the requirements of

Subpart H of 40 CFR Part 75 (concerning monitoring of NOx mass emissions) for such unit for the entire year and shall report the NOx mass emissions data and heat input data for such unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(i) for a unit that commences commercial operation before July 1, 2007, the calendar quarter covering May 1, 2008 through June 30, 2008;

(ii) for a unit that commences commercial operation on or after July 1, 2007, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under section 243-8.1(b), unless that quarter is the third or fourth quarter of 2007 or the first quarter of 2008, in which case reporting shall commence in the quarter covering May 1, 2008 through June 30, 2008.

The CAIR designated representative shall submit each quarterly report to the Administrator within 30 days following the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in 40 CFR 75.73(f).

For CAIR NOx Ozone Season units that are also subject to an Acid Rain emissions limitation or the CAIR NOx Annual Trading Program, CAIR SO2 Trading Program, or the Mercury Reduction Program for Coal-Fired Electric Utility Steam Generating Units (6 NYCRR Part 246), quarterly reports shall include the applicable data and information required by Subparts F through I of 40 CFR Part 75 as applicable, in addition to the NOx mass emission data, heat input data, and other information required by this Subpart.

**Condition 41: Compliance certification**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 243-8.5 (e)**

**Item 41.1:**
The CAIR designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:

(1) the monitoring data submitted were recorded in accordance with the applicable requirements of this Subpart and 40 CFR Part 75, including the quality assurance procedures and specifications;

(2) for a unit with add-on NOx emission controls and for all hours where NOx data are substituted in accordance with 40 CFR 75.34(a)(1), the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to 40 CFR Part 75 and the substitute data values do not systematically underestimate NOx emissions; and

(3) for a unit that is reporting on a control period basis under subparagraph (d)(2)(ii) of this section, the NOx emission rate and NOx concentration values substituted for missing data under Subpart D of 40 CFR Part 75 are calculated using only values from a control period and do not systematically underestimate NOx emissions.

**Condition 42: CAIR NOx Annual Trading Program General Conditions**

**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR Subpart 244-1**

**Item 42.1:**
1) As of midnight of March 1, or midnight of the first business day thereafter if March 1 is not a business day, the owners and operators shall hold, in their compliance account, Clean Air Interstate Rule (CAIR) NOx allowances available for compliance deductions for the previous control period (January 1 through December 31), in an amount not less than the total tons of nitrogen oxides emissions from all CAIR NOx units at the source during that control period. A CAIR NOx allowance shall not be deducted for a control period in a calendar year before the year for which the CAIR NOx allowance was allocated. [244-1.6(c)(1), 244-1.2(b)(5), 244-1.2(b)(36), 244-1.6(c)(3)]

2) The owners and operators shall hold in their compliance account, CAIR NOx allowances available for compliance deductions for the control period starting on the later of January 1, 2009 or the deadline for meeting a CAIR NOx unit's monitor certification requirements under section 244-8.1(b)(1), (2), or (5) and for each control period thereafter. [244-1.6(c)(2)]

3) If a CAIR NOx source emits nitrogen oxides during any control period in excess of the CAIR NOx emissions limitation, the owners and operators of the CAIR NOx source shall surrender the CAIR NOx allowances required for deduction under 6NYCRR Part 244-6.5(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Act or applicable State law. Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this permit, the Act, and applicable State law. [(244-1.6(d)]

4) Unless otherwise provided, the owners and operators of the CAIR NOx source shall keep on site each of the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time before the end of five years, in writing by the department or the Administrator: [244-1.6(e)]
(i) The certificate of representation under 6NYCRR Part 244-2.4 for the CAIR designated representative for the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such five year period until such documents are superseded because of the submission of a new certificate of representation under 6NYCRR Part 244-2.4 changing the CAIR designated representative.
(ii) All emissions monitoring information, in accordance with 6NYCRR Part 244-8, provided that to the extent that 6NYCRR Part 244-8 provides for a three year period for recordkeeping, the three year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NOx Annual Trading Program.
(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NOx Annual Trading Program or to demonstrate compliance with the requirements of the CAIR NOx Annual Trading Program.

**Condition 43:** **Designated CAIR Representative**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR Subpart 244-2**

**Item 43.1:**

1) Each Clean Air Interstate Rule (CAIR) NOx source shall have one CAIR designated representative and may have one alternate representative, as per 6NYCRR Part 244-2.2, with regard to all matters under the CAIR NOx Annual Trading Program. The CAIR designated representative shall be selected by an agreement binding on the owners and operators of the source and act in accordance with the certification statement in 6NYCRR Part 244-2.4(a)(4)(iv). Upon receipt by the Administrator of a complete certificate of representation under 6NYCRR Part 244-2.4, the CAIR designated representative of the source shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the CAIR NOx source represented in all matters pertaining to the CAIR NOx Annual Trading Program, notwithstanding any agreement between the CAIR designated representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the CAIR designated representative by the department, the Administrator, or a court regarding the source. [244-2.1(a), (b) & (c)]

(2) Each submission under the CAIR NOx Annual Trading Program shall be submitted, signed, and certified by the CAIR designated representative for each CAIR NOx source on behalf of which the submission is made. Each such submission shall include the following certification statement by the CAIR designated representative: "I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment." [244-2.1(e)]

**Condition 44: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR Subpart 244-8**

**Item 44.1:**
The Compliance Demonstration activity will be performed for the Facility.

Regulated Contaminant(s):
CAS No: 0NY210-00-0 OXIDES OF NITROGEN

**Item 44.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: RECORD KEEPING/MAINTENANCE PROCEDURES
Monitoring Description:
Monitoring and Reporting NOX emissions

(1) The owners and operators, and to the extent applicable, the CAIR designated representative shall comply with all recordkeeping and reporting requirements in this condition, the applicable recordkeeping and reporting requirements under 40 CFR 75, and the requirements of 6NYCRR Part 244-2.1(e)(1).

(2) The CAIR designated representative shall submit quarterly reports of the the NOx mass emissions data and heat input data for each CAIR NOx unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under 6NYCRR Part 244-8.1(b), unless that quarter is the third or fourth quarter of 2007, in which case reporting shall commence in the quarter covering January 1, 2008 through March 31, 2008.

(3) The CAIR designated representative shall submit each quarterly report to the Administrator within 30 days following the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in 40 CFR 75.73(f).

(4) For CAIR NOx units that are also subject to an Acid Rain emissions limitation or the CAIR NOx Ozone Season Trading Program, CAIR SO2 Trading Program, or the Mercury Reduction Program for Coal-Fired Electric Utility Steam Generating Units (6NYCRR Part 246), quarterly reports shall include the applicable data and information required by Subparts F through I of 40 CFR Part 75 as applicable, in addition to the NOx mass emission data, heat input data, and other information required by this Subpart.

(5) 'Compliance certification.' The CAIR designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:

(i) the monitoring data submitted were recorded in accordance with the applicable requirements of 6NYCRR Part 244 and 40 CFR Part 75, including the quality assurance procedures and specifications; and

(ii) for a unit with add-on NOx emission controls and for all hours where NOx data are substituted in accordance with 40 CFR 75.34(a)(1), the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to 40 CFR Part 75 and the substitute data values do not systematically underestimate NOx emissions.

(6) Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of 40 CFR part 75, data shall be substituted using the applicable missing data procedures in Subpart D or Subpart H of, or appendix D or appendix E to 40 CFR part 75. [ 244-8.3(a) ]

(7) Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under 6NYCRR Part 244-8.1(a)(1) that may significantly affect the ability of the system to accurately measure or record NOx mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of 40 CFR 75.21 or appendix B to 40 CFR Part 75, the owner or operator shall recertify the monitoring system in accordance with 40 CFR 75.20(b) . Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with 40 CFR 75.20(b). Examples of changes to a continuous emission monitoring system that require recertification include replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter system, and any excepted NOx monitoring system under appendix E to 40 CFR part 75, under 6NYCRR Part 244-8.1(a)(1) are subject to the recertification requirements in 40 CFR 75.20(g)(6). [224-8.2(d)(2)

Monitoring Frequency: CONTINUOUS
Averaging Method: ANNUAL TOTAL
Reporting Requirements: QUARTERLY (CALENDAR)
Reports due 30 days after the reporting period.
The initial report is due 10/30/2013.
Subsequent reports are due every 3 calendar month(s).

**Condition 45: CAIR SO2 Trading Program General Provisions**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR Subpart 245-1**

**Item 45.1:**
1) As of midnight of March 1, or midnight of the first business day thereafter (if March 1 is not a business day) for a control period, the owners and operators of each Clean Air Interstate Rule (CAIR) SO2 source shall hold, in the source's compliance account, a tonnage equivalent in CAIR SO2 allowances available for compliance deductions for the control period (January 1

through December 31) not less than the tons of total sulfur dioxide emissions for the control period from all CAIR SO2 units at the source. A CAIR SO2 allowance shall not be deducted, for compliance with the requirements under paragraph (2) of this section, for a control period in a calendar year before the year for which the CAIR SO2 allowance was allocated. [(245-1.2(b)(5), 245-1.6(c)(1), 245-1.2(b)(36), 245-1.6(c)(3)]

2) The owners and operators shall hold in their compliance account, CAIR SO allowances available for compliance deductions for the control period starting on the later of January 1, 2010 or the deadline for meeting a CAIR SO2 unit's monitor certification requirements under section 245-8.1(b)(1), (2), or (5) and for each control period thereafter. [245-1.6(c)(2)]

3) If a CAIR SO2 source emits sulfur dioxide during any control period in excess of the CAIR SO2 emissions limitation, the owners and operators of the source shall surrender the CAIR SO2 allowances required for deduction under 6NYCRR Part 245-6.5(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Act or applicable State law. Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this Subpart, the Act, and applicable State law. [(245-1.6(d)]

4) Unless otherwise provided, the owners and operators of the CAIR SO2 source shall keep on site at the source each of the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time before the end of five years, in writing by the department or the Administrator: [245-1.6(e)]

(i) The certificate of representation under 6NYCRR Part 245-2.4 for the CAIR designated representative for the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such five-year period until such documents are superseded because of the submission of a new certificate of representation under 6NYCRR Part 245-2.4 changing the CAIR designated representative.

(ii) All emissions monitoring information, in accordance with 6NYCRR Part 245-8, provided that to the extent that 6NYCRR Part 245-8 provides for a three-year period for recordkeeping, the three-year period shall apply.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR SO2 Trading Program.

(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR SO2 Trading Program or to demonstrate compliance with the requirements of the CAIR SO2 Trading Program.

**Condition 46: Designated CAIR Representative**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR Subpart 245-2**

**Item 46.1:**

1) Each CAIR SO2 source shall have one and only one CAIR designated representative and may have one alternate representative, as per 6NYCRR Part 245-2.2, with regard to all matters under the CAIR SO2 Trading Program. The CAIR designated representative of the CAIR SO2 source shall be selected by an agreement binding on the owners and operators of the source and all CAIR SO2 units at the source and shall act in accordance with the certification statement in 6NYCRR Part 245-2.4(a)(4)(iv). Upon receipt by the Administrator of a complete certificate of representation under 6NYCRR Part 245-2.4, the CAIR designated representative of the source shall represent and, by his or her representations, actions, inactions, or submissions, legally bind

each owner and operator of the CAIR SO2 source represented and each CAIR SO2 unit at the source in all matters pertaining to the CAIR SO2 Trading Program, notwithstanding any agreement between the CAIR designated representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the CAIR designated representative by the department, the Administrator, or a court regarding the source or unit. [245-2.1(a), (b) & (c)]

(2) Each submission under the CAIR SO2 Trading Program shall be submitted, signed, and certified by the CAIR designated representative for each CAIR SO2 source on behalf of which the submission is made. Each such submission shall include the following certification statement by the CAIR designated representative: "I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment." [245-2.1(e)]

**Condition 47: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR Subpart 245-8**

**Item 47.1:**
The Compliance Demonstration activity will be performed for the Facility.

Regulated Contaminant(s):
CAS No: 007446-09-5 SULFUR DIOXIDE

**Item 47.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: RECORD KEEPING/MAINTENANCE PROCEDURES
Monitoring Description:
Monitoring and Reporting SO2 emissions:

1) The owners and operators, and to the extent applicable, the Clean Air Interstate Rule (CAIR) designated representative, of a CAIR SO2 unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in Subpart 6 NYCRR Part 245-8 and in 40 CFR Part 75, Subparts F and G. For purposes of complying with such requirements, the definitions in section 245-1.2 and 40 CFR 72.2 shall apply, and the terms "affected unit," "designated representative," and "continuous emission monitoring system" (or "CEMS") in 40 CFR Part 75 shall be deemed to refer to the terms "CAIR SO2 unit," "CAIR designated representative," and "continuous emission monitoring system" (or "CEMS") respectively, as defined in section 245-1.2. The owner or operator of a unit that is

not a CAIR SO2 unit but that is monitored under 40 CFR 75.16(b)(2) shall comply with the same monitoring, recordkeeping, and reporting requirements as a CAIR SO2 unit. [245-8.1]

2)The owner or operator of each CAIR SO2 unit shall: [245-8.1(a)]
(i) install all monitoring systems required under this Subpart for monitoring SO2 mass emissions and individual unit heat input (including all systems required to monitor SO2 concentration, stack gas moisture content, stack gas flow rate, CO2 or O2 concentration, and fuel flow rate, as applicable, in accordance with 40 CFR 75.11 and 40 CFR 75.16);
(ii) successfully complete all certification tests required under Part 245-8.2 and meet all other requirements of this section and 40 CFR Part 75 applicable to the monitoring systems under this section; and
(iii) record, report, and quality-assure the data from the monitoring systems under paragraph of this section.

3) The owner or operator shall meet the monitoring system certification and other requirements of section 245-8.1(a)(1) and (2) on or before the following dates. The owner or operator shall record, report, and quality-assure the data from the monitoring systems under section 245-8.1(a)(1) on and after the following dates. [245-8.1(b)]
(i) For the CAIR SO2 unit that commences commercial operation before July 1, 2008, by January 1, 2009.
(ii) For the CAIR SO2 unit that commences commercial operation on or after July 1, 2008, by the later of the following dates: January 1, 2009; or 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which the unit commences commercial operation.

4) Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under section 245-8.1(a)(1) that may significantly affect the ability of the system to accurately measure or record SO2 mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of 40 CFR 75.21 or appendix B to 40 CFR Part 75, the owner or operator shall recertify the monitoring system in accordance with 40 CFR 75.20(b). Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each

continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with 40 CFR 75.20(b). Examples of changes to a continuous emission monitoring system that require recertification include: replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter system under section 245-8.1(a)(1) is subject to the recertification requirements in 40 CFR 75.20(g)(6). [245-8.2(d)(2)]

5) Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of 40 CFR Part 75, data shall be substituted using the applicable missing data procedures in Subpart D of or appendix D to 40 CFR Part 75. [245-8.3(a)]

6) The CAIR designated representative shall comply with all recordkeeping and reporting requirements in section 245-8.3, the applicable recordkeeping and reporting requirements in Subparts F and G of 40 CFR Part 75, and the requirements of section 245-2.1(e)(1). [245-8.5(a)]

7) The owner or operator of a CAIR SO2 unit shall comply with requirements of 40 CFR 75.62 for monitoring plans. [245-8.5(b)]

8) The CAIR designated representative shall submit an application to the department within 45 days after completing all initial certification or recertification tests required under section 245-8.2, including the information required under 40 CFR 75.63. [245-8.5(c) ]

9) The CAIR designated representative shall submit quarterly reports of the SO2 mass emissions data and heat input data for each CAIR SO2 unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with: [245-8.5(d)(1)]

i) the calendar quarter covering January 1, 2009 through March 31, 2009 for a unit that commences commercial operation before July 1, 2008; or

ii) for a unit that commences commercial operation on or after July 1, 2008, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under section 245-8.1(b), unless that quarter is the third or fourth quarter of 2008, in which case reporting shall commence in the quarter covering January 1, 2009 through

March 31, 2009.

10) The CAIR designated representative shall submit each quarterly report to the Administrator within 30 days following the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in 40 CFR 75.64. [245-8.5(d)(2)]

11) For CAIR SO2 units that are also subject to an Acid Rain emissions limitation or the CAIR NOX Annual Trading Program, CAIR NOX Ozone Season Trading Program, or the Mercury Reduction Program for Coal-Fired Electric Utility Steam Generating Units (6 NYCRR Part 246), quarterly reports shall include the applicable data and information required by Subparts F through I of 40 CFR Part 75 as applicable, in addition to the SO2 mass emission data, heat input data, and other information required by this Subpart. [245-8.5(d)(3)]

12) The CAIR designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that: [245-8.5(e)]

i) the monitoring data submitted were recorded in accordance with the applicable requirements of this Subpart and 40 CFR Part 75, including the quality assurance procedures and specifications; and

ii) for a unit with add-on SO2 emission controls and for all hours where SO2 data are substituted in accordance with 40 CFR 75.34(a)(1), the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to 40 CFR Part 75 and the substitute data values do not systematically underestimate SO2 emissions.

Monitoring Frequency: CONTINUOUS
Averaging Method: ANNUAL TOTAL
Reporting Requirements: QUARTERLY (CALENDAR)
Reports due 30 days after the reporting period.
The initial report is due 10/30/2013.
Subsequent reports are due every 3 calendar month(s).

**Condition 48: EPA Region 2 address.**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:40CFR 60.4, NSPS Subpart A**

**Item 48.1:**
All requests, reports, applications, submittals, and other communications to the Administrator

pursuant to this part shall be submitted in duplicate to the following address:

Director, Division of Enforcement and Compliance Assistance
USEPA Region 2
290 Broadway, 21st Floor
New York, NY 10007-1886

Copies of all correspondence to the administrator pursuant to this part shall also be submitted to the NYSDEC Regional Office issuing this permit (see address at the beginning of this permit) and to the following address:

NYSDEC
Bureau of Quality Assurance
625 Broadway
Albany, NY 12233-3258

**Condition 49: Date of construction notification - If a COM is not used.**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:40CFR 60.7(a), NSPS Subpart A**

**Item 49.1:**
Any owner or operator subject to this part shall furnish the Administrator with the following information:

1) a notification of the date construction or reconstruction commenced, post marked no later than 30 days after such date;

3) a notification of the actual date of initial start up, post marked within 15 days after such date;

4) a notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless the change is specifically exempted under this part. The notice shall be post marked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capability of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional information regarding the change;

5) a notification of the date upon which the demonstration of continuous monitoring system performance commences, post marked not less than 30 days prior to such date;

6) a notification of the anticipated date for conducting the opacity observations, post marked not less than 30 days prior to such date.

**Condition 50: Recordkeeping requirements.**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:40CFR 60.7(b), NSPS Subpart A**

**Item 50.1:**
Affected owners or operators shall maintain records of occurrence and duration of any startup,

shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.

**Condition 51: Facility files for subject sources.**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:40CFR 60.7(f), NSPS Subpart A**

**Item 51.1:**
The following files shall be maintained at the facility for all affected sources: all measurements, including continuous monitoring systems, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations;all continuous monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part, recorded in permanent form suitable for inspections. The file shall be maintained for at least two years following the date of such measurements, reports, and records.

**Condition 52: Performance testing timeline.**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:40CFR 60.8(a), NSPS Subpart A**

**Item 52.1:**
Within 60 days after achieving the maximum production rate, but not later than 180 days after initial startup of the facility, the owner or operator of the facility shall conduct performance testing and provide the results of such tests, in a written report, to the Administrator.

**Condition 53: Performance test methods.**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:40CFR 60.8(b), NSPS Subpart A**

**Item 53.1:**
Performance testing shall be conducted in accordance with the methods and procedures prescribed in 40 CFR 60 or by alternative methods and procedures approved by the Administrator.

**Condition 54: Prior notice.**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:40CFR 60.8(d), NSPS Subpart A**

**Item 54.1:**
The owner or operator shall provide the Administrator with prior notice of any performance test at least 30 days in advance of testing.

**Condition 55: Performance testing facilities.**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:40CFR 60.8(e), NSPS Subpart A**

**Item 55.1:**
The following performance testing facilities shall be provided during all tests:

1) sampling ports adequate for tests methods applicable to such facility;

2) a safe sampling platform;

3) a safe access to the sampling platform; and

4) utilities for sampling and testing equipment.

**Condition 56: Number of required tests.**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:40CFR 60.8(f), NSPS Subpart A**

**Item 56.1:**
Each performance test shall consist of three separate runs, at the specified duration required in the applicable test method. Compliance with all applicable standards shall be determined by using the arithmetic means of the results of the three runs.

**Condition 57: Applicability**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:40CFR 60, NSPS Subpart IIII**

**Item 57.1:**
This Condition applies to:

Emission Unit: U00004
Process: P04 Emission Source: EG001

Emission Unit: U00005
Process: P05 Emission Source: FP001

**Item 57.2:**
Facilities that have stationary compression ignition internal combustion engines must comply with applicable portions of 40 CFR 60 Subpart IIII.

**Condition 58: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:40CFR 60.4335, NSPS Subpart KKKK**

**Item 58.1:**
The Compliance Demonstration activity will be performed for the facility:
The Compliance Demonstration applies to:

Emission Unit: U-00001 Emission Point: EP001

Emission Unit: U-00002 Emission Point: EP002

Regulated Contaminant(s):
CAS No: 0NY210-00-0 OXIDES OF NITROGEN

**Item 58.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: RECORD KEEPING/MAINTENANCE PROCEDURES
Monitoring Description:
As an alternative to continuously monitoring the water or steam to fuel ratio, the facility shall install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NOx monitor and a diluents gas (oxygen or carbon dioxide) monitor, to determine hourly NOx emissions in parts per million (ppm).

Reference Test Method: EPA Approved
Monitoring Frequency: CONTINUOUS
Reporting Requirements: SEMI-ANNUALLY (CALENDAR)
Reports due 30 days after the reporting period.
The initial report is due 1/30/2014.
Subsequent reports are due every 6 calendar month(s).

**Condition 59: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:40CFR 60.4375(a), NSPS Subpart KKKK**

**Item 59.1:**
The Compliance Demonstration activity will be performed for the facility:
The Compliance Demonstration applies to:

Emission Unit: U-00001

Emission Unit: U-00002

**Item 59.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: RECORD KEEPING/MAINTENANCE PROCEDURES
Monitoring Description:
For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content, reports of excess emissions and monitor downtime shall be submitted in accordance with 40 CFR 60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

Monitoring Frequency: AS REQUIRED - SEE PERMIT MONITORING

DESCRIPTION
Reporting Requirements: SEMI-ANNUALLY (CALENDAR)
Reports due 30 days after the reporting period.
The initial report is due 1/30/2014.
Subsequent reports are due every 6 calendar month(s).

**Condition 60: Facility Subject to Title IV Acid Rain Regulations and Permitting**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:40 CFR Part 72**

**Item 60.1: This facility is subject to the Title IV Acid Rain Regulations found in 40 CFR Parts** 72, 73, 75, 76, 77 and 78. The Acid Rain Permit is an attachment to this permit.

****** Emission Unit Level ******

**Condition 61: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 227-1.3 (a)**

**Item 61.1:**
The Compliance Demonstration activity will be performed for the facility:
The Compliance Demonstration applies to:

Emission Unit: U-00001

Emission Unit: U-00002

Emission Unit: U-00003

Emission Unit: U-00004

Emission Unit: U-00005

Emission Unit: U-00006

**Item 61.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: MONITORING OF PROCESS OR CONTROL DEVICE PARAMETERS AS SURROGATE
Monitoring Description:
No owner or operator of a combustion installation shall operate the installation in such a way to emit greater than 20 percent opacity except for one six minute period per hour, not to exceed 27 percent, based upon the six minute average in reference test Method 9 in Appendix A of 40 CFR 60.

Parameter Monitored: OPACITY
Upper Permit Limit: 20 percent
Reference Test Method: Method 9
Monitoring Frequency: AS REQUIRED - SEE PERMIT MONITORING DESCRIPTION
Averaging Method: 6-MINUTE AVERAGE (METHOD 9)
Reporting Requirements: SEMI-ANNUALLY (CALENDAR)
Reports due 30 days after the reporting period.
The initial report is due 1/30/2014.
Subsequent reports are due every 6 calendar month(s).

**Condition 62: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 227-1.3 (a)**

**Item 62.1:**
The Compliance Demonstration activity will be performed for the facility:
The Compliance Demonstration applies to:

| | |
|---|---|
| Emission Unit: U-00001 | Emission Point: EP001 |
| Process: P3A | Emission Source: CT001 |
| Emission Unit: U-00002 | Emission Point: EP002 |
| Process: P03 | Emission Source: CT002 |

**Item 62.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: MONITORING OF PROCESS OR CONTROL DEVICE PARAMETERS AS SURROGATE
Monitoring Description:

No person shall operate a stationary combustion installation which exhibits greater than 20 percent opacity (six minute average), except for one-six-minute period per hour of not more than 27 percent opacity. The Department reserves the right to perform or require the performance of a Method 9 opacity evaluation at any time during facility operation.

The permittee will conduct observations of visible emissions from the emission unit, process, etc. to which this condition applies at the monitoring frequency stated below while the process is in operation. The permittee will investigate, in a timely manner, any instance where there is cause to believe that visible emissions have the potential to exceed the opacity standard.

The permittee shall investigate the cause, make any necessary corrections, and verify that the excess visible emissions problem has been corrected. If visible emissions with the potential to exceed the standard continue, the permittee will conduct a Method 9 assessment within the next operating day of the sources associated with the potential noncompliance to determine the degree of opacity and will notify the NYSDEC if the method 9 test indicates that the opacity standard is not met.

Records of visible emissions observations (or any follow-up method 9 tests), investigations and corrective actions will be kept on-site. Should the Department determine that permittee's record keeping format is inadequate to demonstrate compliance with this condition, it shall provide written notice to the permittee stating the inadequacies, and permittee shall have 90 days to revise its prospective record keeping format in a manner acceptable to the Department.

Parameter Monitored: OPACITY
Upper Permit Limit: 20 percent
Reference Test Method: EPA Method 9
Monitoring Frequency: When firing distillate fuel oil
Averaging Method: 6-MINUTE AVERAGE (METHOD 9)
Reporting Requirements: ANNUALLY (CALENDAR)
Reports due 30 days after the reporting period.
The initial report is due 1/30/2014.
Subsequent reports are due every 12 calendar month(s).

**Condition 63: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:40CFR 60.43c(c), NSPS Subpart Dc**

**Item 63.1:**
The Compliance Demonstration activity will be performed for:

Emission Unit: U-00003

**Item 63.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:

On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. The facility shall perfom a method 9 evaluation.

Parameter Monitored: OPACITY

Upper Permit Limit: 20 percent
Reference Test Method: Method 9
Monitoring Frequency: SINGLE OCCURRENCE
Averaging Method: 6 MINUTE AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 64: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:40CFR 60.48c(a), NSPS Subpart Dc**

**Item 64.1:**
The Compliance Demonstration activity will be performed for:

Emission Unit: U-00003

**Item 64.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: RECORD KEEPING/MAINTENANCE PROCEDURES
Monitoring Description:

The owner and operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup,
as provided by 40 CFR 60.7 of this part. This notification shall include:
(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.
(2) If applicable, a copy of any Federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under 40 CFR 60.42c., or 40 CFR 60.43c.
(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

Monitoring Frequency: SINGLE OCCURRENCE
Reporting Requirements: AS REQUIRED - SEE MONITORING DESCRIPTION

**Condition 65: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-5.4**

**Item 65.1:**
The Compliance Demonstration activity will be performed for:

Emission Unit: U-00003
Process: P3B

Regulated Contaminant(s):
CAS No: 0NY998-00-0 VOC
CAS No: 0NY210-00-0 OXIDES OF NITROGEN

**Item 65.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: WORK PRACTICE INVOLVING SPECIFIC OPERATIONS
Monitoring Description:
Operation of the Auxiliary boiler is restricted to 2000 hours per year. Facility will maintain usage records and fuel consumption.

Work Practice Type: HOURS PER YEAR OPERATION
Upper Permit Limit: 2000 hours
Monitoring Frequency: DAILY
Averaging Method: 12-month total, rolled monthly
Reporting Requirements: ANNUALLY (CALENDAR)
Reports due 30 days after the reporting period.
The initial report is due 1/30/2014.
Subsequent reports are due every 12 calendar month(s).

**Condition 66: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-5.4**

**Item 66.1:**
The Compliance Demonstration activity will be performed for:

Emission Unit: U-00003
Process: P3B

Regulated Contaminant(s):
CAS No: 0NY998-00-0 VOC

**Item 66.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
LAER is 0.0038 lb/mmBtu. Will be achieved using good combustion controls. Emission testing to be performed within 180 days of startup.

Upper Permit Limit: 0.0038 pounds per million Btus
Reference Test Method: Method 25A
Monitoring Frequency: SINGLE OCCURRENCE
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 67: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-5.4**

**Item 67.1:**
The Compliance Demonstration activity will be performed for:

Emission Unit: U-00003
Process: P3B

Regulated Contaminant(s):
CAS No: 0NY210-00-0 OXIDES OF NITROGEN

**Item 67.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
LAER is 0.0450 lb/mmBtu. Will be achieved using low NOx burners and flue gas re circulation. Emission testing to be performed within 180 days of startup.

Upper Permit Limit: 0.045 pounds per million Btus
Reference Test Method: Method 7E
Monitoring Frequency: SINGLE OCCURRENCE
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 68: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-7.6**

**Item 68.1:**
The Compliance Demonstration activity will be performed for:

Emission Unit: U-00003
Process: P3B

Regulated Contaminant(s):
CAS No: 0NY075-00-0 PARTICULATES
CAS No: 0NY075-00-5 PM-10

**Item 68.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
BACT is 0.0063 lb/mmBtu. Will be achieved using low sulfur fuel. Emission testing to be performed within 180

days of startup.

Upper Permit Limit: 0.0063 pounds per million Btus
Reference Test Method: Method 201/201A and 202
Monitoring Frequency: SINGLE OCCURRENCE
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 69: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-7.6**

**Item 69.1:**
The Compliance Demonstration activity will be performed for:

Emission Unit: U-00003
Process: P3B

Regulated Contaminant(s):
CAS No: 007446-09-5 SULFUR DIOXIDE

**Item 69.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
BACT is 0.0022 lb/mmBtu. Will be achieved using low sulfur fuel. Emission testing to be performed within 180 days of startup.

Upper Permit Limit: 0.0022 pounds per million Btus
Reference Test Method: EPA approved methods
Monitoring Frequency: SINGLE OCCURRENCE
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 70: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-7.6**

**Item 70.1:**
The Compliance Demonstration activity will be performed for:

Emission Unit: U-00003
Process: P3B

Regulated Contaminant(s):
CAS No: 007664-93-9 SULFURIC ACID

**Item 70.2:**

Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
BACT is 0.0002 lb/mmBtu. Will be achieved using low sulfur fuel. Emission testing to be performed within 180 days of startup.

Upper Permit Limit: 0.0002 pounds per million Btus
Reference Test Method: EPA approved methods
Monitoring Frequency: SINGLE OCCURRENCE
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 71: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-7.6**

**Item 71.1:**
The Compliance Demonstration activity will be performed for:

Emission Unit: U-00003
Process: P3B

Regulated Contaminant(s):
CAS No: 000630-08-0 CARBON MONOXIDE

**Item 71.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
BACT is 0.0721 lb/mmBtu. Will be achieved using good combustion controls. Emission testing to be performed within 180 days of startup.

Upper Permit Limit: 0.0721 pounds per million Btus
Reference Test Method: Method 10
Monitoring Frequency: SINGLE OCCURRENCE
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 72: Alternative recordkeeping**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:40CFR 60.48c(g)(2), NSPS Subpart Dc**

**Item 72.1:**
This Condition applies to Emission Unit: U-00003
Process: P3B Emission Source: AUX01

**Item 72.2:** As an alternative to meeting the requirements of 40 CFR 60.48c(g)(1), the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in 40 CFR 60.48c(f) to demonstrate compliance with the $SO_2$standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

**Condition 73: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-5.4**

**Item 73.1:**
The Compliance Demonstration activity will be performed for:

Emission Unit: U-00004
Process: P04

Regulated Contaminant(s):
CAS No: 0NY998-00-0 VOC

**Item 73.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
LAER is 0.0331 lb/mmBtu. Will be achieved using good combustion controls. Emission testing to be performed upon request of the Department.

Upper Permit Limit: 0.0331 pounds per million Btus
Reference Test Method: Method 25A
Monitoring Frequency: AS REQUIRED - SEE PERMIT MONITORING DESCRIPTION
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 74: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-5.4**

**Item 74.1:**
The Compliance Demonstration activity will be performed for:

Emission Unit: U-00004
Process: P04

Regulated Contaminant(s):
CAS No: 0NY210-00-0 OXIDES OF NITROGEN

**Item 74.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
LAER is 4.77 grams per brake horsepower-hour. Will be achieved using good combustion controls. Emission testing to be performed upon request of the Department.

Upper Permit Limit: 4.77 grams per brake horsepower-hour
Reference Test Method: Method 7E
Monitoring Frequency: AS REQUIRED - SEE PERMIT MONITORING DESCRIPTION
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 75: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-7.6**

**Item 75.1:**
The Compliance Demonstration activity will be performed for:

Emission Unit: U-00004
Process: P04

Regulated Contaminant(s):
CAS No: 0NY075-00-0 PARTICULATES
CAS No: 0NY075-00-5 PM-10

**Item 75.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
BACT is 0.03 g/hp-hr. Will be achieved using low sulfur fuel. Emission testing to be performed at the request of the Department..

Upper Permit Limit: 0.03 grams per brake horsepower-hour
Reference Test Method: Method 201/201A and 202
Monitoring Frequency: AS REQUIRED - SEE PERMIT MONITORING DESCRIPTION
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 76: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-7.6**

**Item 76.1:**
The Compliance Demonstration activity will be performed for:

Emission Unit: U-00004
Process: P04

Regulated Contaminant(s):
CAS No: 007446-09-5 SULFUR DIOXIDE

**Item 76.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
BACT is 0.0014 lb/mmBtu. Will be achieved using low sulfur fuel. Emission testing to be performed at the request of the Department..

Upper Permit Limit: 0.0014 pounds per million Btus
Reference Test Method: EPA approved methods
Monitoring Frequency: AS REQUIRED - SEE PERMIT MONITORING DESCRIPTION
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 77: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-7.6**

**Item 77.1:**
The Compliance Demonstration activity will be performed for:

Emission Unit: U-00004
Process: P04

Regulated Contaminant(s):
CAS No: 007664-93-9 SULFURIC ACID

**Item 77.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
BACT is 0.00003 lb/mmBtu. Will be achieved using low sulfur fuel. Emission testing to be performed at the request of the Department..

Upper Permit Limit: 0.00003 pounds per million Btus

Reference Test Method: EPA approved methods
Monitoring Frequency: AS REQUIRED - SEE PERMIT MONITORING DESCRIPTION
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 78: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-7.6**

**Item 78.1:**
The Compliance Demonstration activity will be performed for:

Emission Unit: U-00004
Process: P04

Regulated Contaminant(s):
CAS No: 000630-08-0 CARBON MONOXIDE

**Item 78.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
BACT is 0.45 g/hp-hr. Will be achieved using good combustion controls. Emission testing to be performed at the request of the Department..

Upper Permit Limit: 0.45 grams per brake horsepower-hour
Reference Test Method: Method 10
Monitoring Frequency: AS REQUIRED - SEE PERMIT MONITORING DESCRIPTION
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 79: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-5.4**

**Item 79.1:**
The Compliance Demonstration activity will be performed for:

Emission Unit: U-00005
Process: P05

Regulated Contaminant(s):
CAS No: 0NY210-00-0 OXIDES OF NITROGEN

**Item 79.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
LAER is 0.857 pounds per million Btus. Will be achieved using good combustion controls. Emission testing to be performed upon request of the Department.

Upper Permit Limit: 0.857 pounds per million Btus
Reference Test Method: Method 7E
Monitoring Frequency: AS REQUIRED - SEE PERMIT MONITORING DESCRIPTION
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 80: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-5.4**

**Item 80.1:**
The Compliance Demonstration activity will be performed for:

Emission Unit: U-00005
Process: P05

Regulated Contaminant(s):
CAS No: 0NY998-00-0 VOC

**Item 80.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
LAER is 0.3612 lb/mmBtu. Will be achieved using good combustion controls. Emission testing to be performed upon request of the Department.

Upper Permit Limit: 0.3612 pounds per million Btus
Reference Test Method: Method 25A
Monitoring Frequency: AS REQUIRED - SEE PERMIT MONITORING DESCRIPTION
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 81: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-7.6**

**Item 81.1:**
The Compliance Demonstration activity will be performed for:

Emission Unit: U-00005
Process: P05

Regulated Contaminant(s):
CAS No: 000630-08-0 CARBON MONOXIDE

**Item 81.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
BACT is 0.75 lbs/mmBtus.. Will be achieved using good combustion controls. Emission testing to be performed at the request of the Department..

Upper Permit Limit: 0.75 pounds per million Btus
Reference Test Method: Method 10
Monitoring Frequency: AS REQUIRED - SEE PERMIT MONITORING DESCRIPTION
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 82: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-7.6**

**Item 82.1:**
The Compliance Demonstration activity will be performed for:

Emission Unit: U-00005
Process: P05

Regulated Contaminant(s):
CAS No: 0NY075-00-0 PARTICULATES
CAS No: 0NY075-00-5 PM-10

**Item 82.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
BACT is 0.043 lb/mmBtus.. Will be achieved using low sulfur fuel. Emission testing to be performed at the request of the Department..

Upper Permit Limit: 0.043 pounds per million Btus
Reference Test Method: Method 201/201A and 202
Monitoring Frequency: AS REQUIRED - SEE PERMIT MONITORING DESCRIPTION
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 83: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-7.6**

**Item 83.1:**
The Compliance Demonstration activity will be performed for:

Emission Unit: U-00005
Process: P05

Regulated Contaminant(s):
CAS No: 007446-09-5 SULFUR DIOXIDE

**Item 83.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
BACT is 0.0014 lb/mmBtu. Will be achieved using low sulfur fuel. Emission testing to be performed at the request of the Department..

Upper Permit Limit: 0.0014 pounds per million Btus
Reference Test Method: EPA approved methods
Monitoring Frequency: AS REQUIRED - SEE PERMIT MONITORING DESCRIPTION
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 84: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-7.6**

**Item 84.1:**
The Compliance Demonstration activity will be performed for:

Emission Unit: U-00005
Process: P05

Regulated Contaminant(s):
CAS No: 007664-93-9 SULFURIC ACID

**Item 84.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
BACT is 0.00003 lb/mmBtu. Will be achieved using low sulfur fuel. Emission testing to be performed at the

request of the Department..

Upper Permit Limit: 0.00003 pounds per million Btus
Reference Test Method: EPA approved methods
Monitoring Frequency: AS REQUIRED - SEE PERMIT MONITORING DESCRIPTION
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 85: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-5.4**

**Item 85.1:**
The Compliance Demonstration activity will be performed for:

Emission Unit: U-00006
Process: P06

Regulated Contaminant(s):
CAS No: 0NY210-00-0 OXIDES OF NITROGEN

**Item 85.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
LAER is 0.058 pounds per million Btus for each individual gas heater. Will be achieved using forced draft low NOx Burner. Emission testing to be performed upon request of the Department.

Upper Permit Limit: 0.058 pounds per million Btus
Reference Test Method: Method 7E
Monitoring Frequency: AS REQUIRED - SEE PERMIT MONITORING DESCRIPTION
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 86: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-5.4**

**Item 86.1:**
The Compliance Demonstration activity will be performed for:

Emission Unit: U-00006
Process: P06

Regulated Contaminant(s):

CAS No: 0NY998-00-0 VOC

**Item 86.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
LAER is 0.011 lb/mmBtu. Will be achieved using good combustion controls. Emission testing to be performed upon request of the Department.

Upper Permit Limit: 0.011 pounds per million Btus
Reference Test Method: Method 25A
Monitoring Frequency: AS REQUIRED - SEE PERMIT MONITORING DESCRIPTION
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 87: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-7.6**

**Item 87.1:**
The Compliance Demonstration activity will be performed for:

Emission Unit: U-00006
Process: P06

Regulated Contaminant(s):
CAS No: 007664-93-9 SULFURIC ACID

**Item 87.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
BACT is 0.0002 lb/mmBtu. Will be achieved using low sulfur fuel. Emission testing to be performed at the request of the Department..

Upper Permit Limit: 0.0002 pounds per million Btus
Reference Test Method: EPA approved methods
Monitoring Frequency: AS REQUIRED - SEE PERMIT MONITORING DESCRIPTION
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 88: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-7.6**

**Item 88.1:**
The Compliance Demonstration activity will be performed for:

Emission Unit: U-00006
Process: P06

Regulated Contaminant(s):
CAS No: 000630-08-0 CARBON MONOXIDE

**Item 88.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
BACT is 0.084 lbs/mmBtus.. Will be achieved using good combustion controls. Emission testing to be performed at the request of the Department..

Upper Permit Limit: 0.084 pounds per million Btus
Reference Test Method: Method 10
Monitoring Frequency: AS REQUIRED - SEE PERMIT MONITORING DESCRIPTION
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 89: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-7.6**

**Item 89.1:**
The Compliance Demonstration activity will be performed for:

Emission Unit: U-00006
Process: P06

Regulated Contaminant(s):
CAS No: 0NY075-00-0 PARTICULATES
CAS No: 0NY075-00-5 PM-10

**Item 89.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
BACT is 0.0076 lb/mmBtus.. Will be achieved using low sulfur fuel. Emission testing to be performed at the request of the Department..

Upper Permit Limit: 0.0076 pounds per million Btus
Reference Test Method: Method 201/201A and 202

Monitoring Frequency: AS REQUIRED - SEE PERMIT MONITORING DESCRIPTION
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**Condition 90: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable Federal Requirement:6 NYCRR 231-7.6**

**Item 90.1:**
The Compliance Demonstration activity will be performed for:

Emission Unit: U-00006
Process: P06

Regulated Contaminant(s):
CAS No: 007446-09-5 SULFUR DIOXIDE

**Item 90.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: INTERMITTENT EMISSION TESTING
Monitoring Description:
BACT is 0.0022 lb/mmBtu. Will be achieved using low sulfur fuel. Emission testing to be performed at the request of the Department..

Upper Permit Limit: 0.0022 pounds per million Btus
Reference Test Method: EPA approved methods
Monitoring Frequency: AS REQUIRED - SEE PERMIT MONITORING DESCRIPTION
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: ONCE / BATCH OR MONITORING OCCURRENCE

**STATE ONLY ENFORCEABLE CONDITIONS**
****** Facility Level ******

**NOTIFICATION OF GENERAL PERMITTEE OBLIGATIONS**
**This section contains terms and conditions which are not federally enforceable. Permittees may also have other obligations under regulations of general applicability**

**Item A:** **Public Access to Recordkeeping for Facilities With State Facility Permits - 6 NYCRR 201-1.10 (a)**
Where facility owners and/or operators keep records pursuant to compliance with the requirements of 6 NYCRR Subpart 201-5.4, and/or the emission capping requirements of 6 NYCRR Subpart 201-7, the Department will make such records available to the public upon request in accordance with 6 NYCRR Part 616 - Public Access to Records. Facility owners and/or operators must submit the records required to comply with the request within sixty working days of written notification by the Department.

Item B: **General Provisions for State Enforceable Permit Terms and Condition - 6 NYCRR Part 201-5**
Any person who owns and/or operates stationary sources shall operate and maintain all emission units and any required emission control devices in compliance with all applicable Parts of this Chapter and existing laws, and shall operate the facility in accordance with all criteria, emission limits, terms, conditions, and standards in this permit. Failure of such person to properly operate and maintain the effectiveness of such emission units and emission control devices may be sufficient reason for the Department to revoke or deny a permit.

The owner or operator of the permitted facility must maintain all required records on-site for a period of five years and make them available to representatives of the Department upon request. Department representatives must be granted access to any facility regulated by this Subpart, during normal operating hours, for the purpose of determining compliance with this and any other state and federal air pollution control requirements, regulations or law.

**STATE ONLY APPLICABLE REQUIREMENTS**
**The following conditions are state only enforceable.**

**Condition 91:** **Contaminant List**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable State Requirement:ECL 19-0301**

**Item 91.1:**
Emissions of the following contaminants are subject to contaminant specific requirements in this permit(emission limits, control requirements or compliance monitoring conditions).

CAS No: 000124-38-9
Name: CARBON DIOXIDE

CAS No: 000630-08-0
Name: CARBON MONOXIDE

CAS No: 007446-09-5
Name: SULFUR DIOXIDE

CAS No: 007664-41-7
Name: AMMONIA

CAS No: 007664-93-9
Name: SULFURIC ACID

CAS No: 0NY075-00-0
Name: PARTICULATES

CAS No: 0NY075-00-5
Name: PM-10

CAS No: 0NY075-02-5
Name: PM 2.5

CAS No: 0NY210-00-0
Name: OXIDES OF NITROGEN

CAS No: 0NY998-00-0
Name: VOC

**Condition 92: Unavoidable noncompliance and violations**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable State Requirement:6 NYCRR 201-1.4**

**Item 92.1:**
At the discretion of the commissioner a violation of any applicable emission standard for necessary scheduled equipment maintenance, start-up/shutdown conditions and malfunctions or upsets may be excused if such violations are unavoidable. The following actions and recordkeeping and reporting requirements must be adhered to in such circumstances.

(a) The facility owner and/or operator shall compile and maintain records of all equipment maintenance or start-up/shutdown activities when they can be expected to result in an exceedance of any applicable emission standard, and shall submit a report of such activities to the commissioner's representative when requested to do so in writing or when so required by a condition of a permit issued for the corresponding air contamination source except where conditions elsewhere in this permit which contain more stringent reporting and notification provisions for an applicable requirement, in which case they supercede those stated here. Such reports shall describe why the violation was unavoidable and shall include the time, frequency and duration of the maintenance and/or start-up/shutdown activities and the identification of air contaminants, and the estimated emission rates. If a facility owner and/or operator is subject to continuous stack monitoring and quarterly reporting requirements, he need not submit reports for equipment maintenance or start-up/shutdown for the facility to the commissioner's representative.

(b) In the event that emissions of air contaminants in excess of any emission standard in 6 NYCRR Chapter III Subchapter A occur due to a malfunction, the facility owner and/or operator shall report such malfunction by telephone to the commissioner's representative as soon as possible during normal working hours, but in any event not later than two working days after becoming aware that the malfunction occurred. Within 30 days thereafter, when requested in writing by the commissioner's representative, the facility owner and/or operator shall submit a written report to the commissioner's representative describing the malfunction, the corrective action taken, identification of air contaminants, and an estimate of the emission rates. These reporting requirements are superceded by conditions elsewhere in this permit which contain reporting and notification provisions for applicable requirements more stringent than those above.

(c) The Department may also require the owner and/or operator to include in reports described under (a) and (b) above an estimate of the maximum ground level concentration of each air contaminant emitted and the effect of such emissions depending on the deviation of the malfunction and the air contaminants emitted.

(d) In the event of maintenance, start-up/shutdown or malfunction conditions which result in emissions exceeding any applicable emission standard, the facility owner and/or operator shall take appropriate action to prevent emissions which will result in contravention of any applicable ambient air quality standard. Reasonably available control technology, as determined by the commissioner, shall be applied during any maintenance, start-up/shutdown or malfunction condition subject to this paragraph.

(e) In order to have a violation of a federal regulation (such as a new source performance standard or national emissions standard for hazardous air pollutants) excused, the specific federal regulation must provide for an affirmative defense during start-up, shutdowns, malfunctions or upsets.

**Condition 93: Emission Unit Definition**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable State Requirement:6 NYCRR Subpart 201-5**

**Item 93.1:**
The facility is authorized to perform regulated processes under this permit for:
Emission Unit: U-00001
Emission Unit Description:
ONE F CLASS COMBUSTION TURBINE RATED AT 1998 MMBTU/HR AT 51 DEGREES F (2234 MMBTU/HR AT -5 DEGREES F) ON NATURAL GAS AND 2145 MMBTU/HR AT -5 DEGREES F ON FUEL

OIL (,0.0015% SULFUR). THE TURBINE IS
EQUIPPED WITH DRY LOW-NOX COMBUSTORS, STEAM
INJECTION, SCR AND OXIDATION CATALYST
EMISSION CONTROLS. THIS EMISSION UNIT ALSO
CONTAINS A NATURAL GAS-FIRED DUCT BURNER
RATED AT A MAXIMUM CAPACITY OF 500
MMBTU/HR.

Building(s): ACC01
GEN01
HRSG01

**Item 93.2:**
The facility is authorized to perform regulated processes under this permit for:
Emission Unit: U-00002
Emission Unit Description:
ONE CLASS-F COMBUSTION TURBINE RATED AT
1998 MMBTU/HR AT 51 DEGREES F (2234
MMBTU/HR AT -5 DEGREES F) ON NATURAL GAS
AND 2145 MMBTU/HR AT -5 DEGREES F ON FUEL
OIL (,0.0015% SULFUR). THE TURBINE IS
EQUIPPED WITH DRY LOW-NOX COMBUSTORS, STEAM
INJECTION, SCR AND OXIDATION CATALYST
EMISSION CONTROLS. THIS EMISSION UNIT ALSO
CONTAINS A NATURAL GAS-FIRED DUCT BURNER
RATED AT A MAXIMUM CAPACITY OF 500
MMBTU/HR.

Building(s): ACC02
GEN02
HRSG02

**Item 93.3:**
The facility is authorized to perform regulated processes under this permit for:
Emission Unit: U-00003
Emission Unit Description:
ONE 73.5 MMBTU/HR AUXILIARY BOILER THAT
WILL FIRE NATURAL GAS EXCLUSIVELY. THE
BOILER HOURS WILL BE LIMITED TO 2000 HOURS
PER YEAR. THE BOILER WILL OPERATE
PRIMARILY TO ASSIST WITH STARTUPS AND
SHUTDOWNS OF THE TURBINES.

Building(s): GEN01

**Item 93.4:**
The facility is authorized to perform regulated processes under this permit for:
Emission Unit: U-00004
Emission Unit Description:
Emergency Diesel Generator operating less than 500 hours
per year.

**Item 93.5:**
The facility is authorized to perform regulated processes under this permit for:
Emission Unit: U-00005
Emission Unit Description:
Emergency Fire water Pump

**Item 93.6:**
The facility is authorized to perform regulated processes under this permit for:
Emission Unit: U-00006
Emission Unit Description:
Two Fuel Gas Heaters

**Condition 94: Visible Emissions Limited**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable State Requirement:6 NYCRR 211.2**

**Item 94.1:**
Except as permitted by a specific part of this Subchapter and for open fires for which a restricted burning permit has been issued, no person shall cause or allow any air contamination source to emit any material having an opacity equal to or greater than 20 percent (six minute average) except for one continuous six-minute period per hour of not more than 57 percent opacity.

**Condition 95: CO2 Budget Trading Program - Excess emission requirements**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable State Requirement:6 NYCRR 242-1.5**

**Item 95.1:**
The owners and operators of a CO2 budget source that has excess emissions in any control period shall:
(1) forfeit the CO2 allowances required for deduction under 6 NYCRR Part 242-6.5(d)(1), provided CO2 offset allowances may not be used to cover any part of such excess emissions; and
(2) pay any fine, penalty, or assessment or comply with any other remedy imposed under 6 NYCRR Part 242-6.5(d)(2).

**Condition 96: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable State Requirement:6 NYCRR 242-1.5**

**Item 96.1:**
The Compliance Demonstration activity will be performed for the Facility.

**Item 96.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: RECORD KEEPING/MAINTENANCE PROCEDURES
Monitoring Description:
The owners and operators and, to the extent applicable, the CO2 authorized account representative of each CO2 budget source and each CO2 budget unit at the source shall

comply with the monitoring requirements of Subpart 242-8. The emissions measurements recorded and reported in accordance with Subpart 242-8 of this Part shall be used to determine compliance by the unit with the following CO2 requirements:

(1) The owners and operators of each CO2 budget source and each CO2 budget unit at the source shall hold CO2 allowances available for compliance deductions under Section 242-6.5, as of the CO2 allowance transfer deadline, in the source's compliance account in an amount not less than the total CO2 emissions for the control period from all CO2 budget units at the source, as determined in accordance with Subparts 242-6 and 242-8.

(2) Each ton of CO2 emitted in excess of the CO2 budget emissions limitation shall constitute a separate violation of this Part and applicable state law.

(3) A CO2 budget unit shall be subject to the requirements specified in item 1 starting on the later, of January 1, 2009 or the date on which the unit commences operation.

(4) CO2 allowances shall be held in, deducted from, or transferred among CO2 Allowance Tracking System accounts in accordance with Subparts 242-5, 242-6, and 242-7, and Section 242-10.7.

(5) A CO2 allowance shall not be deducted, in order to comply with the requirements specified in item 1, for a control period that ends prior to the allocation year for which the CO2 allowance was allocated. A CO2 offset allowance shall not be deducted, in order to comply with the requirements under item 1, beyond the applicable percent limitations set out in 6NYCRR Part 242-6.5(a)(3).

(6) A CO2 allowance under the CO2 Budget Trading Program is a limited authorization by the Department or a participating state to emit one ton of CO2 in accordance with the CO2 Budget Trading Program. No provision of the CO2 Budget Trading Program, the CO2 budget permit application, or the CO2 budget permit or any provision of law shall be construed to limit the authority of the Department or a participating state to terminate or limit such authorization.

(7) A CO2 allowance under the CO2 Budget Trading Program does not constitute a property right.

Monitoring Frequency: AS REQUIRED - SEE PERMIT MONITORING DESCRIPTION
Reporting Requirements: SEMI-ANNUALLY (CALENDAR)
Reports due 30 days after the reporting period.
The initial report is due 1/30/2014.
Subsequent reports are due every 6 calendar month(s).

**Condition 97: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable State Requirement:6 NYCRR 242-1.5**

**Item 97.1:**
The Compliance Demonstration activity will be performed for the Facility.

**Item 97.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: RECORD KEEPING/MAINTENANCE PROCEDURES
Monitoring Description:

The owners and operators of the CO2 budget source and each CO2 budget unit at the source shall keep on site at the source each of the following documents for a period of 10 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 10 years, in writing by the department.

(i) The account certificate of representation for the CO2 authorized account representative for the source and each CO2 budget unit at the source and all documents that demonstrate the truth of the statements in the account certificate of representation, in accordance with 6 NYCRR Part 242-2.4, provided that the certificate and documents shall be retained on site at the source beyond such 10-year period until such documents are superseded because of the submission of a new account certificate of representation.

(ii) All emissions monitoring information, in accordance with Subpart 242-8 and 40 CFR 75.57.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CO2 Budget Trading Program.

(iv) Copies of all documents used to complete a CO2 budget permit application and any other submission under the CO2 Budget Trading Program or to demonstrate compliance with the requirements of the CO2 Budget Trading Program.

The CO2 authorized account representative of a CO2 budget source and each CO2 budget unit at the source shall submit the reports and compliance certifications required under the CO2 Budget Trading Program, including those under Subpart 242-4.

Monitoring Frequency: AS REQUIRED - SEE PERMIT MONITORING DESCRIPTION
Reporting Requirements: SEMI-ANNUALLY (CALENDAR)
Reports due 30 days after the reporting period.
The initial report is due 1/30/2014.
Subsequent reports are due every 6 calendar month(s).

****** Emission Unit Level ******

**Condition 98: Emission Point Definition By Emission Unit**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable State Requirement:6 NYCRR Subpart 201-5**

**Item 98.1:**
The following emission points are included in this permit for the cited Emission Unit:

Emission Unit: U-00001

Emission Point: EP001
Height (ft.): 275 Diameter (in.): 228
NYTMN (km.): 4584.693 NYTME (km.): 546.98

**Item 98.2:**
The following emission points are included in this permit for the cited Emission Unit:

Emission Unit: U-00002

Emission Point: EP002
Height (ft.): 275 Diameter (in.): 228
NYTMN (km.): 4584.655 NYTME (km.): 546.991

**Item 98.3:**
The following emission points are included in this permit for the cited Emission Unit:

Emission Unit: U-00003

Emission Point: EP003
Height (ft.): 275 Diameter (in.): 228
NYTMN (km.): 4584.655 NYTME (km.): 546.991

**Item 98.4:**
The following emission points are included in this permit for the cited Emission Unit:

Emission Unit: U-00004

Emission Point: EP004
Height (ft.): 50 Diameter (in.): 18
NYTMN (km.): 4584.651 NYTME (km.): 547.129

**Item 98.5:**
The following emission points are included in this permit for the cited Emission Unit:

Emission Unit: U-00005

Emission Point: EP006
Height (ft.): 50 Diameter (in.): 6
NYTMN (km.): 4584.669 NYTME (km.): 546.815

**Item 98.6:**
The following emission points are included in this permit for the cited Emission Unit:

Emission Unit: U-00006

Emission Point: EP005
Height (ft.): 125 Diameter (in.): 24
NYTMN (km.): 4584.58 NYTME (km.): 546.958

**Condition 99: Process Definition By Emission Unit**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable State Requirement:6 NYCRR Subpart 201-5**

**Item 99.1:**
This permit authorizes the following regulated processes for the cited Emission Unit:

Emission Unit: U-00001
Process: P1A Source Classification Code: 2-01-002-01
Process Description:
REPRESENTS NATURAL GAS FIRING IN THE CLASS-F COMBUSTION TURBINE, WHICH IS RATED AT 2,234 mmBTU/hr AT -5 DEGREES F (MAXIMUM HEAT INPUT SCENARIO). DRY LOW-NOX COMBUSTION TECHNOLOGY, SELECTIVE CATALYTIC REDUCTION (SCR) AND OXIDATION CATALYST WILL BE USED TO MINIMIZE EMISSIONS OF NOX, CO, AND VOC. THE QUANTITY PER HOUR THROUGHPUT LISTED BELOW REPRESENTS THE MAXIMUM FIRING RATE (2,234 MMBtu/hr AT -5 DEGREES F) AND THE QUANTITY PER YEAR THROUGHPUT REPRESENTS THE TURBINE AT THE FIRING RATE AT THE ANNUAL AVERAGE AMBIENT TEMPERATURE OF 51 DEGREES F (1,998 MMBtu/hr). NATURAL GAS HIGHER HEATING VALUE IS ASSUMED TO BE 1,048 BTU/CUBIC FOOT.

Emission Source/Control: CT001 - Combustion
Design Capacity: 2,234 million Btu per hour

Emission Source/Control: DLN01 - Control
Control Type: DRY LOW NOx BURNER

Emission Source/Control: OXY01 - Control
Control Type: CATALYTIC OXIDATION

Emission Source/Control: SCR01 - Control
Control Type: SELECTIVE CATALYTIC REDUCTION (SCR)

**Item 99.2:**
This permit authorizes the following regulated processes for the cited Emission Unit:

Emission Unit: U-00001
Process: P2A Source Classification Code: 2-01-002-01
Process Description:
REPRESENTS COMBINED NATURAL GAS FIRING IN THE CLASS-F COMBUSTION TURBINE, WHICH IS RATED AT 2,234 mmBTU/hr AT -5 DEGREES F (MAXIMUM HEAT INPUT SCENARIO) AND NATURAL GAS FIRING IN THE DUCT BURNER, WHICH IS RATED AT 500 mmBTU/hr. DRY LOW-NOX COMBUSTION TECHNOLOGY, SELECTIVE CATALYTIC REDUCTION (SCR) AND OXIDATION CATALYST WILL BE USED TO MINIMIZE EMISSIONS OF NOX, CO, AND VOC. THE QUANTITY PER HOUR THROUGHPUT LISTED BELOW REPRESENTS THE MAXIMUM FIRING RATE (2,234 MMBtu/hr AT -5 DEGREES F) OF THE TURBINE PLUS THE DUCT BURNER AT RATED CAPACITY (500 mmBTU/hr) AND THE QUANTITY PER YEAR THROUGHPUT REPRESENTS 8,760 HOURS OF NATURAL GAS FIRING IN THE TURBINE AT THE ANNUAL AVERAGE AMBIENT TEMPERATURE OF 51 DEGREES F (1,998 MMBtu/hr). NATURAL GAS HIGHER HEATING VALUE IS ASSUMED TO BE 1,048 BTU/CUBIC FOOT.

Emission Source/Control: CT001 - Combustion
Design Capacity: 2,234 million Btu per hour

Emission Source/Control: DB001 - Combustion
Design Capacity: 500 million Btu per hour

Emission Source/Control: DLN01 - Control
Control Type: DRY LOW NOx BURNER

Emission Source/Control: OXY01 - Control
Control Type: CATALYTIC OXIDATION

Emission Source/Control: SCR01 - Control
Control Type: SELECTIVE CATALYTIC REDUCTION (SCR)

**Item 99.3:**
This permit authorizes the following regulated processes for the cited Emission Unit:

Emission Unit: U-00001
Process: P3A Source Classification Code: 2-01-001-01
Process Description:
REPRESENTS FUEL OIL FIRING IN THE CLASS-F COMBUSTION TURBINE, WHICH IS RATED AT 2,145 mmBTU/hr AT -5 DEGREES F (MAXIMUM HEAT INPUT SCENARIO). DRY LOW-NOX COMBUSTION TECHNOLOGY, STEAM OR WATER INJECTION, SELECTIVE CATALYTIC REDUCTION (SCR) AND OXIDATION CATALYST WILL BE USED TO MINIMIZE EMISSIONS OF NOX, CO, AND VOC. THE QUANTITY PER HOUR THROUGHPUT LISTED BELOW REPRESENTS THE MAXIMUM FIRING RATE (2,145 MMBtu/hr AT -5 DEGREES F) AND THE QUANTITY PER YEAR THROUGHPUT REPRESENTS 720 HOURS OF FUEL OIL FIRING AT THE FIRING RATE AT -5 DEGREES F AMBIENT TEMPERATURE. FUEL OIL HIGHER HEATING VALUE IS ASSUMED TO BE 139,728 BTU/GALLON.

Emission Source/Control: CT001 - Combustion
Design Capacity: 2,234 million Btu per hour

Emission Source/Control: DLN01 - Control
Control Type: DRY LOW NOx BURNER

Emission Source/Control: OXY01 - Control
Control Type: CATALYTIC OXIDATION

Emission Source/Control: SCR01 - Control
Control Type: SELECTIVE CATALYTIC REDUCTION (SCR)

Emission Source/Control: ST101 - Control
Control Type: STEAM OR WATER INJECTION

**Item 99.4:**
This permit authorizes the following regulated processes for the cited Emission Unit:

Emission Unit: U-00002
Process: P01 Source Classification Code: 2-01-002-01
Process Description:
REPRESENTS NATURAL GAS FIRING IN THE CLASS-F COMBUSTION TURBINE, WHICH IS RATED AT 2,234 mmBTU/hr AT -5 DEGREES F (MAXIMUM HEAT INPUT SCENARIO). DRY LOW-NOX COMBUSTION TECHNOLOGY, SELECTIVE CATALYTIC REDUCTION (SCR) AND OXIDATION CATALYST WILL BE USED TO MINIMIZE EMISSIONS OF NOX, CO, AND VOC. THE QUANTITY PER HOUR THROUGHPUT

LISTED BELOW REPRESENTS THE MAXIMUM FIRING
RATE (2,234 MMBtu/hr AT -5 DEGREES F) AND
THE QUANTITY PER YEAR THROUGHPUT REPRESENTS
THE TURBINE AT THE FIRING RATE AT THE
ANNUAL AVERAGE AMBIENT TEMPERATURE OF 51
DEGREES F (1,998 MMBtu/hr). NATURAL GAS
HIGHER HEATING VALUE IS ASSUMED TO BE 1,048
BTU/CUBIC FOOT.

Emission Source/Control: CT002 - Combustion
Design Capacity: 2,234 million Btu per hour

Emission Source/Control: DLN02 - Control
Control Type: DRY LOW NOx BURNER

Emission Source/Control: OXY02 - Control
Control Type: CATALYTIC OXIDATION

Emission Source/Control: SCR02 - Control
Control Type: SELECTIVE CATALYTIC REDUCTION (SCR)

**Item 99.5:**
This permit authorizes the following regulated processes for the cited Emission Unit:

Emission Unit: U-00002
Process: P02 Source Classification Code: 2-01-002-01
Process Description:
REPRESENTS COMBINED NATURAL GAS FIRING IN
THE CLASS-F COMBUSTION TURBINE, WHICH IS
RATED AT 2,234 mmBTU/hr AT -5 DEGREES F
(MAXIMUM HEAT INPUT SCENARIO) AND NATURAL
GAS FIRING IN THE DUCT BURNER, WHICH IS
RATED AT 500 mmBTU/hr. DRY LOW-NOX
COMBUSTION TECHNOLOGY, SELECTIVE CATALYTIC
REDUCTION (SCR) AND OXIDATION CATALYST WILL
BE USED TO MINIMIZE EMISSIONS OF NOX, CO,
AND VOC. THE QUANTITY PER HOUR THROUGHPUT
LISTED BELOW REPRESENTS THE MAXIMUM FIRING
RATE (2,234 MMBtu/hr AT -5 DEGREES F) OF
THE TURBINE PLUS THE DUCT BURNER AT RATED
CAPACITY (500 mmBTU/hr) AND THE QUANTITY
PER YEAR THROUGHPUT REPRESENTS 8,760 HOURS
OF NATURAL GAS FIRING IN THE TURBINE AT THE
ANNUAL AVERAGE AMBIENT TEMPERATURE OF 51
DEGREES F (1,998 MMBtu/hr). NATURAL GAS
HIGHER HEATING VALUE IS ASSUMED TO BE 1,048
BTU/CUBIC FOOT.

Emission Source/Control: CT002 - Combustion
Design Capacity: 2,234 million Btu per hour

Emission Source/Control: DB002 - Combustion

Design Capacity: 500 million Btu per hour

Emission Source/Control: DLN02 - Control
Control Type: DRY LOW NOx BURNER

Emission Source/Control: OXY02 - Control
Control Type: CATALYTIC OXIDATION

Emission Source/Control: SCR02 - Control
Control Type: SELECTIVE CATALYTIC REDUCTION (SCR)

**Item 99.6:**
This permit authorizes the following regulated processes for the cited Emission Unit:

Emission Unit: U-00002
Process: P03 Source Classification Code: 2-01-001-01
Process Description:
REPRESENTS FUEL OIL FIRING IN THE CLASS-F COMBUSTION TURBINE, WHICH IS RATED AT 2,145 mmBTU/hr AT -5 DEGREES F (MAXIMUM HEAT INPUT SCENARIO). DRY LOW-NOX COMBUSTION TECHNOLOGY, STEAM OR WATER INJECTION, SELECTIVE CATALYTIC REDUCTION (SCR) AND OXIDATION CATALYST WILL BE USED TO MINIMIZE EMISSIONS OF NOX, CO, AND VOC. THE QUANTITY PER HOUR THROUGHPUT LISTED BELOW REPRESENTS THE MAXIMUM FIRING RATE (2,145 MMBtu/hr AT -5 DEGREES F) AND THE QUANTITY PER YEAR THROUGHPUT REPRESENTS 720 HOURS OF FUEL OIL FIRING AT THE FIRING RATE AT -5 DEGREES F AMBIENT TEMPERATURE. FUEL OIL HIGHER HEATING VALUE IS ASSUMED TO BE 139,728 BTU/GALLON.

Emission Source/Control: CT002 - Combustion
Design Capacity: 2,234 million Btu per hour

Emission Source/Control: DLN02 - Control
Control Type: DRY LOW NOx BURNER

Emission Source/Control: OXY02 - Control
Control Type: CATALYTIC OXIDATION

Emission Source/Control: SCR02 - Control
Control Type: SELECTIVE CATALYTIC REDUCTION (SCR)

Emission Source/Control: ST102 - Control
Control Type: STEAM OR WATER INJECTION

**Item 99.7:**
This permit authorizes the following regulated processes for the cited Emission Unit:

Emission Unit: U-00003
Process: P3B Source Classification Code: 1-02-006-02
Process Description:
REPRESENTS NATURAL GAS FIRING IN THE AUXILIARY BOILER, WHICH IS RATED AT 73.5 MMBTU/HR. TOTAL NATURAL GAS USAGE WILL NOT EXCEED 2,000 FULL LOAD BOILER HOURS PER YEAR. NATURAL GAS HIGHER HEATING VALUE IS ASSUMED TO BE 1,048 BTU/CUBIC FOOT

Emission Source/Control: AUX01 - Combustion
Design Capacity: 73.5 million Btu per hour

Emission Source/Control: FGR01 - Control
Control Type: FLUE GAS RECIRCULATION

Emission Source/Control: LNB01 - Control
Control Type: LOW NOx BURNER

**Item 99.8:**
This permit authorizes the following regulated processes for the cited Emission Unit:

Emission Unit: U-00004
Process: P04
Process Description: Emergency generator firing diesel fuel

Emission Source/Control: EG001 - Combustion
Design Capacity: 15.43 million BTUs per hour

**Item 99.9:**
This permit authorizes the following regulated processes for the cited Emission Unit:

Emission Unit: U-00005
Process: P05
Process Description: Fire pump firing diesel fuel.

Emission Source/Control: FP001 - Combustion
Design Capacity: 2.27 million Btu per hour

**Item 99.10:**
This permit authorizes the following regulated processes for the cited Emission Unit:

Emission Unit: U-00006
Process: P06
Process Description: gas heater operating on natural gas

Emission Source/Control: FGH01 - Combustion
Design Capacity: 5.02 million Btu per hour

Emission Source/Control: FHG02 - Combustion
Design Capacity: 5.02 million Btu per hour

**Condition 100: Compliance Demonstration**
**Effective between the dates of 08/01/2013 and 07/31/2018**

**Applicable State Requirement:6 NYCRR 251.3 (a)**

**Item 100.1:**
The Compliance Demonstration activity will be performed for the facility:
The Compliance Demonstration applies to:

Emission Unit: U-00001 Emission Point: EP001

Emission Unit: U-00002 Emission Point: EP002

Regulated Contaminant(s):
CAS No: 000124-38-9 CARBON DIOXIDE

**Item 100.2:**
Compliance Demonstration shall include the following monitoring:

Monitoring Type: CONTINUOUS EMISSION MONITORING (CEM)
Monitoring Description:

Owners or operators of boilers that are permitted to fire greater than 70 percent fossil fuel, combined cycle combustion turbines, or stationary internal combustion engines that fire only gaseous fuel, except for those emission sources directly attached to a gasifier, are required to meet an emission rate of 925 pounds of CO2 per MW hour gross electrical output (output-based limit). These emission limits are measured on a 12-month rolling average basis, calculated by dividing the annual total of CO2 emissions over the relevant 12-month period by the annual total (gross) MW generated (output-based limit). The owner or operator must maintain all records associated with these requirements on site or at a location acceptable to the Department for a minimum of five years.

Manufacturer Name/Model Number: CO2 Continous Monitor
Parameter Monitored: CARBON DIOXIDE
Upper Permit Limit: 925 pounds per megawatt hour
Monitoring Frequency: CONTINUOUS
Averaging Method: 12 MONTH AVERAGE - ROLLED MONTHLY
Reporting Requirements: QUARTERLY (CALENDAR)
Reports due 30 days after the reporting period.
The initial report is due 10/30/2013.
Subsequent reports are due every 3 calendar month(s).

# Exhibit RS-F

Q1

# State of the Market Report for PJM

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

5.14.2020

2020

# Preface

The PJM Market Monitoring Plan provides:

> The Market Monitoring Unit shall prepare and submit contemporaneously to the Commission, the State Commissions, the PJM Board, PJM Management and to the PJM Members Committee, annual state-of-the-market reports on the state of competition within, and the efficiency of, the PJM Markets, and quarterly reports that update selected portions of the annual report and which may focus on certain topics of particular interest to the Market Monitoring Unit. The quarterly reports shall not be as extensive as the annual reports. In its annual, quarterly and other reports, the Market Monitoring Unit may make recommendations regarding any matter within its purview. The annual reports shall, and the quarterly reports may, address, among other things, the extent to which prices in the PJM Markets reflect competitive outcomes, the structural competitiveness of the PJM Markets, the effectiveness of bid mitigation rules, and the effectiveness of the PJM Markets in signaling infrastructure investment. These annual reports shall, and the quarterly reports may include recommendations as to whether changes to the Market Monitoring Unit or the Plan are required.[1]

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit (MMU) for PJM Interconnection, L.L.C. (PJM),[2] and is also known as the Independent Market Monitor for PJM (IMM), submits this *2020 Quarterly State of the Market Report for PJM: January through March*.[3]

1 PJM Open Access Transmission Tariff (OATT) Attachment M (PJM Market Monitoring Plan) § VI.A. Capitalized terms used herein and not otherwise defined have the meaning provided in the OATT, PJM Operating Agreement, PJM Reliability Assurance Agreement or other tariffs that PJM has on file with the Federal Energy Regulatory Commission (FERC or Commission).
2 OATT Attachment M.
3 All references to this report should refer to the source as Monitoring Analytics, LLC, and should include the complete name of the report: *2020 Quarterly State of the Market Report for PJM: January through March*.

## Market Behavior

- **Supply and Demand: Load and Spot Market.** Companies that serve load in PJM do so using a combination of self-supply, bilateral market purchases and spot market purchases. In the first three months of 2020, 16.9 percent of real-time load was supplied by bilateral contracts, 24.1 percent by spot market purchases and 59.0 percent by self-supply. Compared to the first three months of 2019, reliance on bilateral contracts increased by 1.6 percentage points, reliance on spot market purchases decreased by 1.4 percentage points and reliance on self-supply decreased by 0.1 percentage points.
- **Generator Offers.** Generator offers are categorized as pool scheduled and self scheduled. Units which are available for economic commitment are pool scheduled. Units which are self scheduled to generate fixed output are categorized as self scheduled. Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are categorized as self scheduled and dispatchable. Of all generator offered MW up to their economic maximum in the first three months of 2020, 65.9 percent were offered to be pool scheduled, 33.7 percent above economic minimum and 32.2 percent up to economic minimum. For self scheduled units, 14.1 percent were offered as self scheduled at a fixed output, and 20.0 percent were offered as self scheduled and dispatchable.
- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. The hourly average submitted increment offer MW increased by 10.7 percent and cleared MW decreased by 13.0 percent in the first three months of 2020. The hourly average submitted decrement offer MW increased by 0.2 percent and cleared MW decreased by 17.8 percent in the first three months of 2020. The hourly average submitted up to congestion bid MW decreased by 42.9 percent and cleared MW decreased by 11.0 percent in the first three months of 2020.

## Market Performance

- **Generation Fuel Mix.** In the first three months of 2020, coal units provided 18.0 percent, nuclear units 34.5 percent and natural gas units 39.7 percent of total generation. Compared to the first three months of 2019, generation from coal units decreased 36.6 percent, generation from natural gas units increased 14.0 percent and generation from nuclear units decreased 0.9 percent. The trend toward more energy from natural gas and less from coal accelerated in the first three months of 2020.
- **Fuel Diversity.** The fuel diversity of energy generation in the first three months of 2020, measured by the fuel diversity index for energy ($FDI_e$), decreased 2.9 percent compared to the first three months of 2019.
- **Marginal Resources.** In the PJM Real-Time Energy Market, in the first three months of 2020, coal units were 17.5 percent and natural gas units were 73.2 percent of marginal resources. In the first three months of 2019, coal units were 24.4 percent and natural gas units were 69.4 percent of marginal resources.

  In the PJM Day-Ahead Energy Market, in the first three months of 2020, up to congestion transactions were 48.5 percent, INCs were 16.2 percent, DECs were 12.6 percent, and generation resources were 22.5 percent of marginal resources. In the first three months of 2019, up to congestion transactions were 59.9 percent, INCs were 11.9 percent, DECs were 16.7 percent, and generation resources were 11.4 percent of marginal resources.
- **Prices.** PJM real-time and day-ahead energy market prices were at the lowest level in PJM history during the first three months of 2020. Both the weather and COVID-19 played a role in this significant drop in prices.

  PJM real-time energy market prices decreased in the first three months of 2020. The load-weighted, average real-time LMP was 34.2 percent lower in the first three months of 2020 than in the first three months of 2019, $19.85 per MWh versus $30.16 per MWh.

  PJM day-ahead energy market prices decreased in the first three months of 2020. The load-weighted, average day-ahead LMP was 34.6 percent lower in the first three months of 2020 than in the first three months of 2019, $20.12 per MWh versus $30.76 per MWh.

# Exhibit RS-G

# NIPSCO Integrated Resource Plan 2018 Update

# Public Advisory Meeting Three

July 24, 2018

# Welcome and Introductions

# Process for Today’s Webinar

- In order to best facilitate today’s discussion, we are asking that you use the “chat” feature on the webinar to ask questions.
- Please type your question at any point and it will be read to the audience by the facilitator.
- When entering your question, please include your name and organization you are representing (if applicable).
- If time permits, we will have an open discussion after the material has been presented.
- You may also email questions to nipsco_irp@nisource.com and those questions will be answered as they are received.
- We look forward to your thoughts and questions!

# Agenda

| Time | Topic |
|---|---|
| 12:30 – 12:45 | Welcome, Introductions, and Safety Moment |
| 12:45 – 1:00 | Update on the Integrated Resource Plan (“IRP”) Process |
| 1:00 – 1:30 | All-Source Request for Proposals (“RFP”) Results Overview |
| 1:30 – 1:45 | Incorporating the RFP Results |
| 1:45 – 2:25 | Stakeholder Presentations / Contingency |
| 2:25 – 2:30 | Next Meeting / Wrap Up |

# Safety Moment:

- **Slips, trips, and falls are the most common form of injury to office workers, and is also a common injury among non-office workers.**

- **Across all of private industry, there were 229,240 injuries involving days away from work in 2016 due to slips, trips, and falls.**

- **Several practices can help reduce or avoid slips, trips, and falls:**

  – Stay Clutter Free: Look for boxes or other impediments in walkways.

  – Step on Up:  Standing on office chairs is a common source of falls.  Be especially careful of office chairs with casters or rollers.  Use a specifically designed step-stool or ladder instead.

  – Maintain a Clear Line of Vision: workers can run into each other around blind corners.

  – Slippery Flooring: Skid resistant flooring or carpeting can help prevent slips, trips, and falls. Be especially careful of liquid spills or runoff from rain and snow on flooring.

# NIPSCO’s Planning and the Public Advisory Process

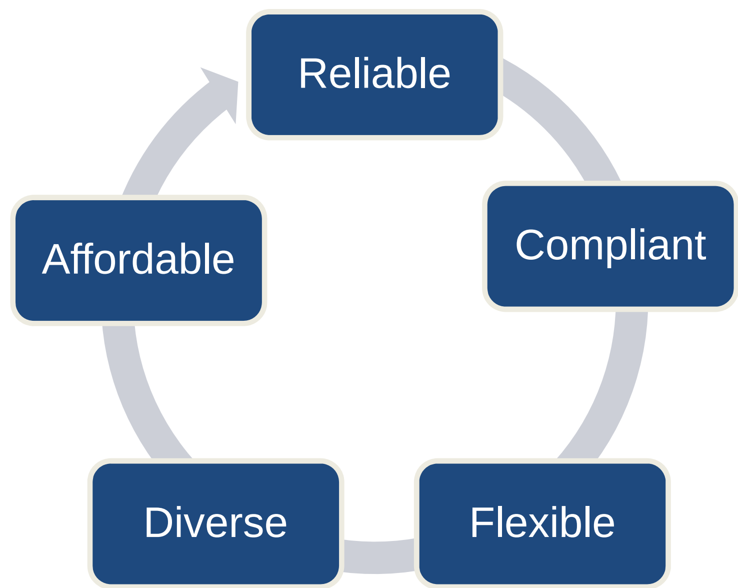
*Dan Douglas*
*Vice President, Corporate Strategy & Development*

# How Does NIPSCO Plan for the Future?

## Charting The Long-Term Course for Electric Generation

### About the IRP Process

- Every three years, NIPSCO outlines its long-term plan to supply electricity to customers over the next 20 years
- This study – known as an Integrated Resource Plan (IRP) – is required of all electric utilities in Indiana
- IRP process includes extensive analysis of a range of generation scenarios, with criteria such as reliable, affordable, compliant, diverse and flexible




**Requires Careful Planning and Consideration for:**
- All NIPSCO's stakeholders
- Environmental regulations
- Changes in the local economy (property tax, supplier spend, employee base)

# Stakeholder Engagement Roadmap

| | Meeting 1 (March 23) | Meeting 2 (May 11) | Meeting 3* (July 24th) | Meeting 4 (September 19) | Meeting 5 (October 18) |
|---|---|---|---|---|---|
| Key Questions | -Why has NIPSCO decided to file an IRP update in 2018?<br>-What has changed from the 2016 IRP?<br>-What are the key assumptions driving the 2018 IRP update?<br>-How is the 2018 IRP process different from 2016? | -What is NIPSCO existing generation portfolio and what are the future supply needs?<br>-Are there any new developments on retirements?<br>-What are the key environmental considerations for the IRP?<br>-How are DSM resources considered in the IRP? | -What are the preliminary results from the all source RFP Solicitation? | -What are the preliminary findings from the modeling? | -What is NIPSCO's preferred plan?<br>-What is the short term action plan? |
| Meeting Goals | -Communicate and explain the rationale and decision to file in 2018<br>-Articulate the key assumptions that will be used in the IRP<br>-Explain the major changes from the 2016 IRP<br>-Communicate the 2018 process, timing and input sought from stakeholders | -Common understanding of DSM resources as a component of the IRP and the methodology that will be used to model DSM<br>-Understanding of the NIPSCO resources, the supply gap and alternatives to fill the gap<br>-Key environmental issues in the IRP | -Communicate the preliminary results of the RFP and next steps | -Stakeholder feedback and shared understanding of the modeling and preliminary results<br>-Review stakeholder modeling and analysis requests | -Communicate NIPSCO's preferred resource plan and short term action plan<br>-Obtain feedback from stakeholders on preferred plan |

*Webinar

# Stakeholder Interactions

- Since the May 11 Public Advisory meeting, NIPSCO has met with stakeholder groups

| Stakeholder | Subject Area/Discussion Topic |
|---|---|
| Sierra Club | IRP Modelling and Scenarios |
| OUCC | All-Source RFP, IRP Modelling and Scenarios, Load Forecasting |
| CAC | IRP Modelling and Demand Side Management (DSM) |
| IURC | All-Source RFP and IRP Modelling |

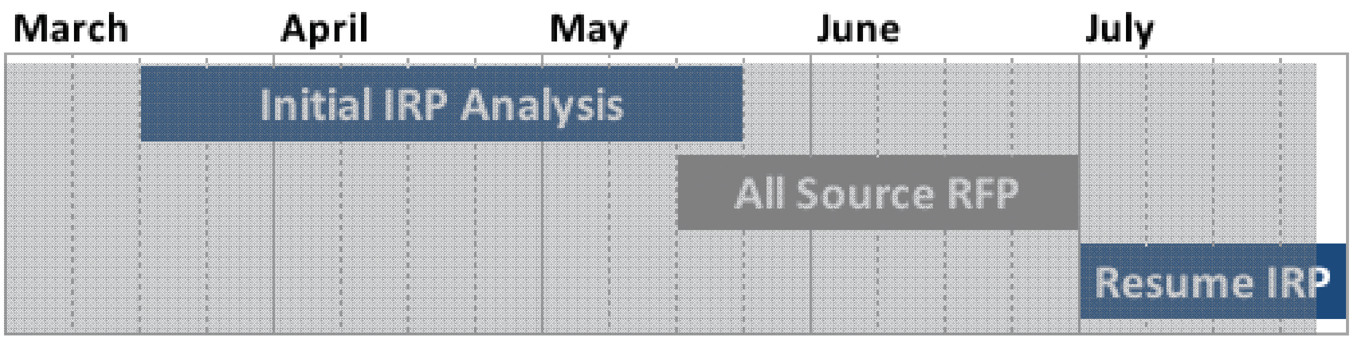
# All-Source RFP Results Summary

*Paul Kelly*
*Director, Federal Regulatory Policy*

*Andy Campbell*
*Director, Regulatory Support and Planning*

*Bob Lee*
*Charles River Associates*

# Timeline for the RFP




| Date | Event |
|---|---|
| March 23rd | Overview RFP design with stakeholders |
| April 6th | RFP Design Summary document shared with stakeholders to request feedback |
| April 20th | Stakeholder feedback on Design Summary due back to NIPSCO |
| May 14th | RFP initiated |
| May 28th | Notice of Intent and Pre-qualifications due from potential bidders |
| June 29th | RFP closes |
| July 24th | Summary of RFP bids presented at Public Advisory Meeting webinar; IRP resumes analysis incorporating results of RFP |

# Key Design Elements of the All-Source RFP

- **Technology - All solutions regardless of technology**
- **Size**
  - Minimum total need of 600 megawatts (“MW”) for the portfolio but without a cap
  - Allows smaller resources to offer their solution as a piece of the total need
  - Also encourages larger resources to offer their solution for consideration
- **Ownership Arrangements**
  - Seeking bids for asset purchases (new or existing) and purchase power agreements
  - Resource must qualify as Midcontinent Independent System Operator (“MISO”) internal generation (not pseudo-tied) or load (demand response or “DR”)
- **Duration**
  - Requesting delivery beginning June 1, 2023 but will evaluate deliveries before 2023
  - Minimum contractual term and/or estimated useful life of 5 years (except for DR, which is 1 year)
- **Deliverability**
  - Must have firm transmission delivery to MISO Zone 6
  - Must meet N-1-1 reliability criteria or show cost estimate to achieve that quality
- **Participants & Pre-Qualification**
  - Marketed RFP to broad bidder audience and Bidder Conference
    - Platts Megawatt Daily, North American Energy Marketers Association (NAEMA), NIPSCO Press Release
  - Required credit-worthy counterparties to ensure ability to fulfill resource obligation

# Participating Bidders – Thank you!

Inovateus Solar
Development Partners
Apex Clean Energy
edp renováveis
Big Rivers Electric Corporation
Cypress Creek Renewables
EDF renewables
enel Green Power
NextEra Energy
ALLETE clean energy
e.on
Calpine Energy Solutions
EmberClear – An Innovative Project Development Company
ibV energy partners – an ib vogt company
Invenergy
Hecate Energy
J. Ranck Electric, Inc.
juwi
Rockland Capital
Origis Energy – Powering the Solar Revolution
res
Ranger Power
bp
Southern Current
JET JNG US
Voltus – Less Energy • More Cash
ARES
PSG Energy Group
Tenaska
EDF Energy
Glidepath – Advanced Energy Solutions

# Overview of Proposals Received

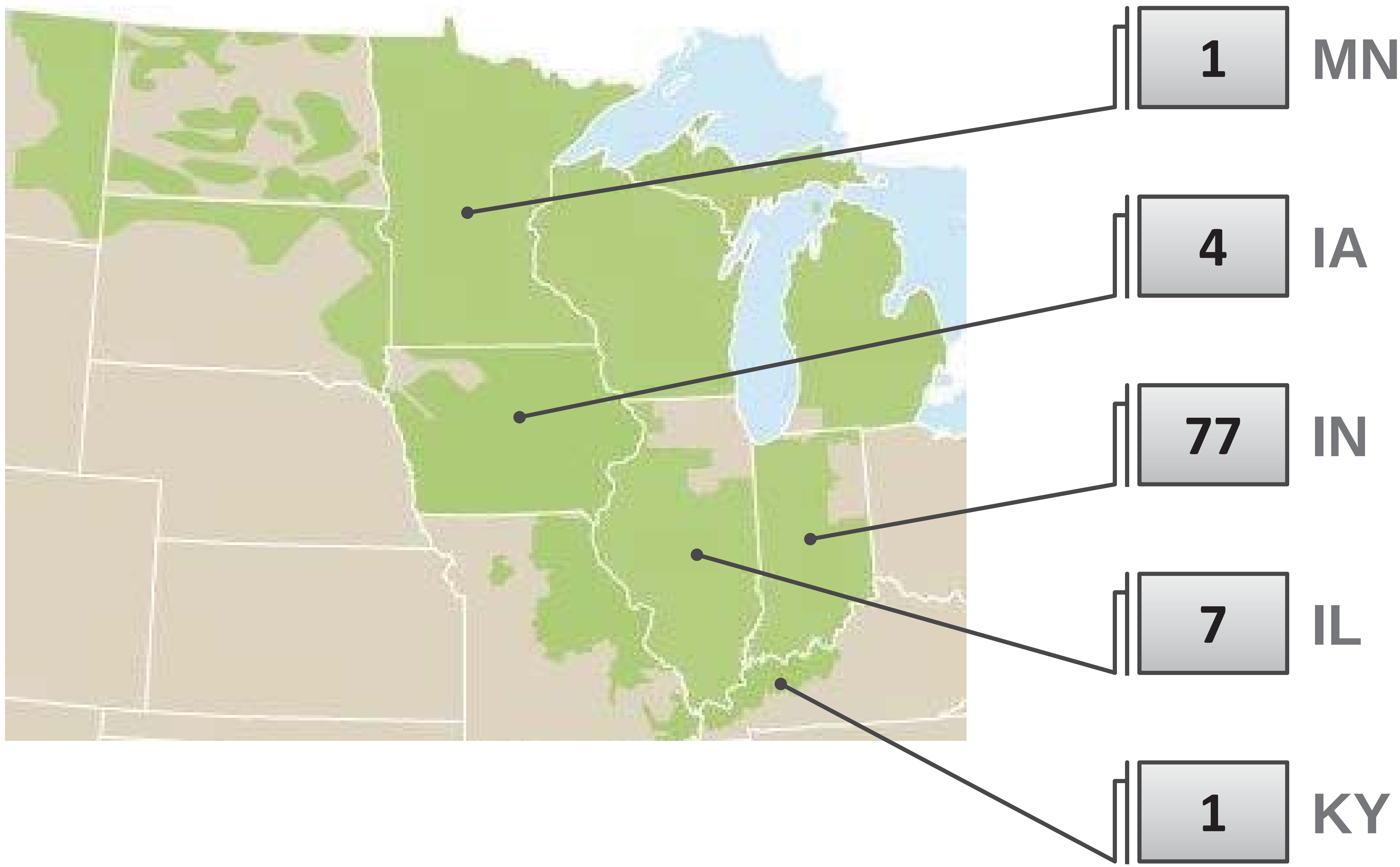
## Count of Proposals

| Technology | CCGT* | CT** | Other Fossil | Wind | Wind + Solar + Storage | Solar | Solar + Storage | Storage | Demand Response | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| **Asset Sale** | 4 | - | - | 1 | - | 1 | - | - | - | 6 |
| **PPA*** ** | 8 | - | 3 | 6 | - | 26 | 7 | 8 | 1 | 59 |
| **Option** | 3 | 1 | - | 7 | 1 | 8 | 4 | 1 | - | 25 |
| **Total** | 15 | 1 | 3 | 14 | 1 | 35 | 11 | 9 | 1 | 90 |
| **Locations** | IN, IL | IN | IN, KY | IA, IN, IL, MN | IN | IL, IN, IA | IN | IN | IN | |

- **The RFP generated a tremendous amount of bidder interest**
- **90 total proposals were received across a range of deal structures**
  - ❖ **59 individual projects across five states with ~13.3 gigawatts (“GW”) ( installed capacity or “ICAP”) represented**
  - ❖ Many of the proposals offering variations on pricing structure and term length
  - ❖ Several instances of renewables paired with storage
  - ❖ Majority of the projects are in various stages of development

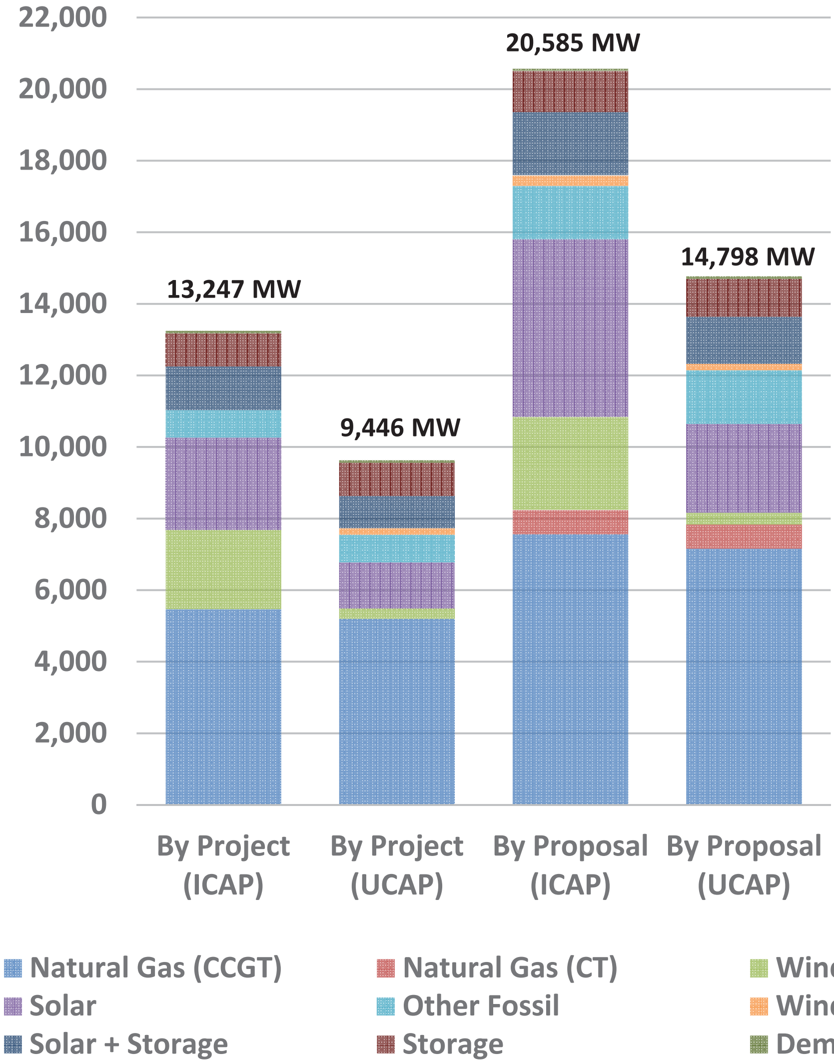
*Combined Cycle Gas Turbine **Combustion Turbine ***Purchase Power Agreement

# Distribution of Proposals Received



# Proposals Received by Technology (MW)

## Note: Unforced capacity ("UCAP") MW are estimated using MISO class averages by technology




| | ICAP by Project | | ICAP by Proposal | |
|---|---|---|---|---|
| | (MW) | % | (MW) | % |
| Natural Gas (CCGT) | 5,470 | 40% | 7,561 | 37% |
| Natural Gas (CT) | - | 0% | 685 | 3% |
| Wind | 2,209 | 16% | 2,594 | 13% |
| Solar | 2,580 | 19% | 4,965 | 24% |
| Other Fossil / Coal | 772 | 6% | 1,494 | 7% |
| Wind + Solar + Storage | - | 0% | 300 | 1% |
| Solar + Storage | 1,220 | 9% | 1,760 | 9% |
| Storage | 925 | 7% | 1,155 | 6% |
| Demand Response | 70 | 1% | 70 | 0.3% |

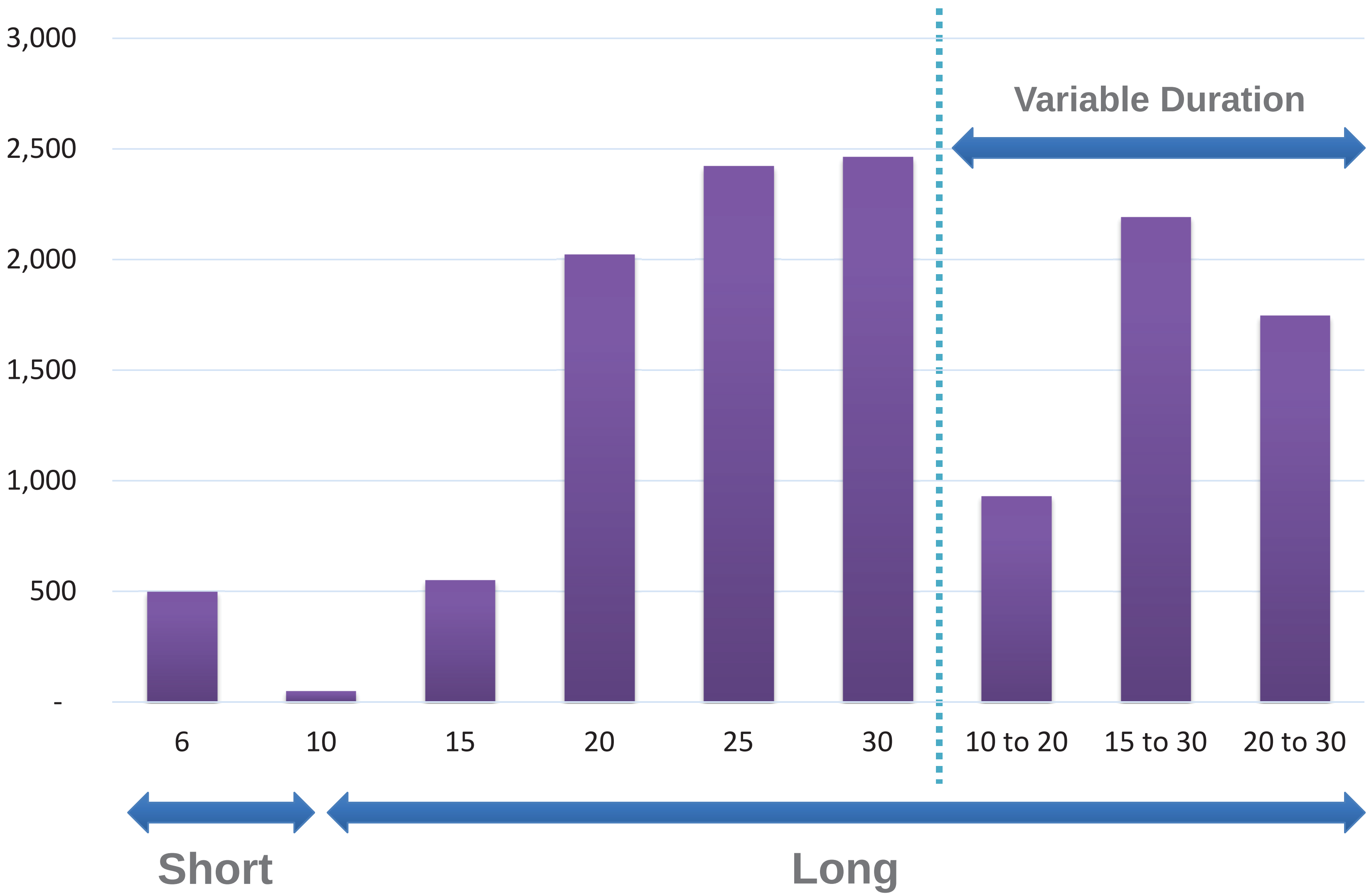
| | UCAP by Project | | UCAP by Proposal | |
|---|---|---|---|---|
| | (MW) | % | (MW) | % |
| Natural Gas (CCGT) | 5,199 | 55% | 7,157 | 48% |
| Natural Gas (CT) | - | 0% | 678 | 5% |
| Wind | 287 | 3% | 329 | 2% |
| Solar | 1,291 | 14% | 2,483 | 17% |
| Other Fossil / Coal | 772 | 8% | 1,494 | 10% |
| Wind + Solar + Storage | - | 0% | 110 | 1% |
| Solar + Storage | 902 | 10% | 1,322 | 9% |
| Storage | 925 | 10% | 1,155 | 8% |
| Demand Response | 70 | 1% | 70 | 0.5% |

# Proposals Received by Technology (MW) “UCAP”

**Note: UCAP MW are estimated using MISO class averages by technology**

| Technology | CCGT | CT | Other Fossil | Wind | Wind + Solar + Storage | Solar | Solar + Storage | Storage | Demand Response | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| **Asset Sale** | 2,020 | - | - | 30 | - | 25 | - | - | - | 2,075 |
| **PPA** | 2,574 | - | 1,494 | 119 | - | 1,796 | 810 | 1,055 | 70 | 7,917 |
| **Option** | 2,563 | 678 | - | 180 | 110 | 662 | 513 | 100 | - | 4,806 |
| **Total** | 7,157 | 678 | 1,494 | 329 | 110 | 2,483 | 1,322 | 1,155 | 70 | 14,798 |
| **Locations** | IN, IL | IN | IN, KY | IA, IN, IL, MN | IN | IL, IN, IA | IN | IN | IN | |

# PPA Range of Durations (MW) “UCAP”



# Overall Summary and Pricing Received

| | Technology | # of Bids | Bid MW (ICAP) | # of Projects | Project MW | Average Bid Price | Pricing Units | Comments |
|---|---|---|---|---|---|---|---|---|
| Asset Sale or Option | Combine Cycle Gas (CCGT) | 7 | 4,846 | 4 | 3,055 | $959.61 | $/kW | |
| | Combustion Turbine (CT) | 1 | | | | | | |
| | Solar | 9 | 1,374 | 5 | 669 | $1,151.01 | $/kW | |
| | Wind | 8 | 1,807 | 7 | 1,607 | $1,457.07 | $/kW | |
| | Solar + Storage | 4 | 705 | 3 | 465 | $1,182.79 | $/kW | |
| | Wind + Solar + Storage | 1 | | | | | | |
| | Storage | 1 | | | | | | |
| Purchase Power Agreement | Combine Cycle Gas (CCGT) | 8 | 2,715 | 6 | 2,415 | $7.86 | $/kW-Mo | + fuel and variable O&M |
| | Solar + Storage | 7 | 1,055 | 5 | 755 | $5.90 | $/kW-Mo | + $35/MWh (Average) |
| | Storage | 8 | 1,055 | 5 | 925 | $11.24 | $/kW-Mo | |
| | Solar | 26 | 3,591 | 16 | 1,911 | $35.67 | $/MWh | |
| | Wind | 6 | 788 | 4 | 603 | $26.97 | $/MWh | |
| | Fossil | 3 | 1,494 | 2 | 772 | N/A | | Structure not amenable to price comparison |
| | Demand Response | 1 | | | | | | |
| | **Total** | **90** | **20,585** | **59** | **13,247** | | | |

## Preliminary – Subject to Due Diligence

# RFP Evaluation Process

## Determining a list of finalists by technology

- **Representative cost and performance characteristics by technology were developed based on RFP bids and provided to the IRP team for portfolio optimization modeling**
  - ❖ IRP to determine the preferred portfolio for execution
- **Bid evaluation considered both cost and non-cost factors (non-DR)**
  - ❖ Tier 1 factors – Asset Cost and Facility Reliability & Deliverability
  - ❖ Tier 2 factors – Development Risk
  - ❖ Tier 3 factors – Asset Specific Risk
- **List of finalists by technology for possible definitive agreement(s)**

# Incorporating the RFP Results into the IRP

*Dan Douglas*
*Vice President, Corporate Strategy & Development*

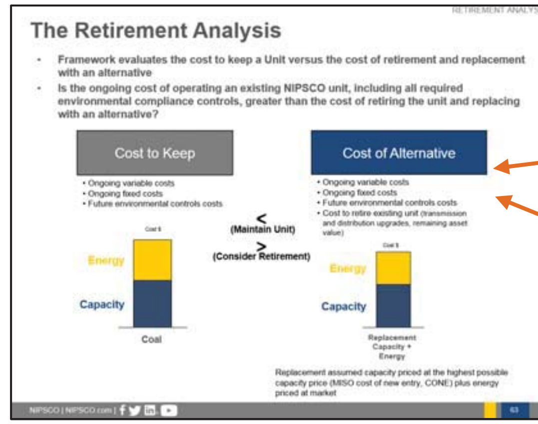
*Pat Augustine*
*Charles River Associates (CRA)*

# How Will The RFP Feed Into The IRP?

*The results of the RFP will feed back into the IRP to inform both the retirement analysis and the replacement analysis*

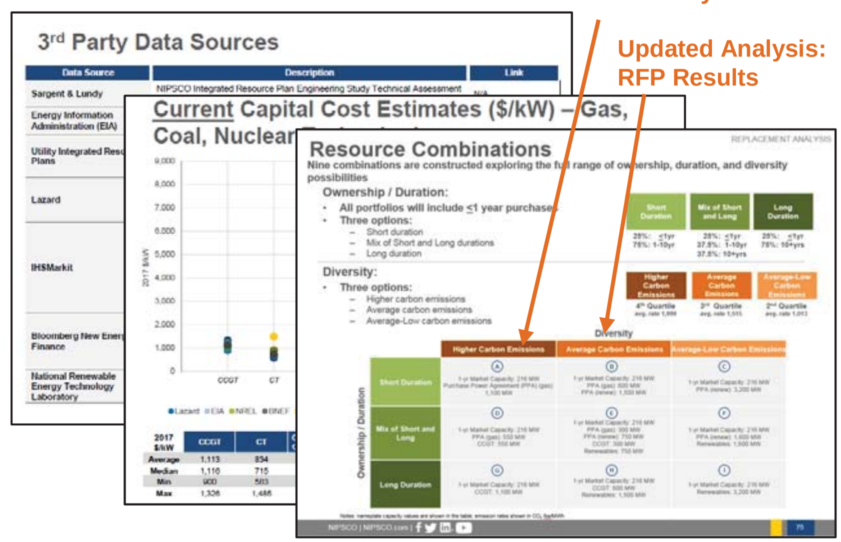
- **Retirement Analysis**
  – MISO Cost of New Entry (“CONE”) plus market energy was used in the initial IRP analysis as a proxy for replacement costs
  – RFP results provide known and visible replacement costs and volumes
  – Representative project groups will be constructed from RFP results, assembled by technology and ownership, for use in the updated IRP analysis
  – Retirement analysis will be re-run using the representative RFP projects as selected by the optimization model

- **Replacement Analysis**
  – Initial IRP replacement costs used estimates from multiple third-party data sources; no visibility into actual replacement costs for projects available to NIPSCO
  – RFP results provide visibility into executable alternatives for NIPSCO
  – Replacement analysis will be run using somewhat simplified and anonymized RFP results




**Initial Analysis: CONE + modeled market energy**

**Updated Analysis: RFP Results + modeled market energy**




**Initial Analysis: 3rd Party Estimates**

**Updated Analysis: RFP Results**

# How Will The RFP Feed Into The IRP?

- The RFP responses provide key input data for supply-side portfolio costs
- A three-step process to update and run the IRP models will be carried out over the next two months

1

**Develop Model Inputs**

- Specify input assumptions by resource type “tranche” based on RFP results
- Develop specific resource options (supply and demand) in Aurora model format

2

**Run Aurora Portfolio Optimization**

- Evaluate least-cost portfolios for retirement and replacement analyses
  - Portfolios to fill each potential retirement capacity gap
  - Replacement portfolios for various levels of diversity and ownership (renewables vs. fossil, owned vs. PPA)

3

**Run Full IRP Analysis**

- Evaluate each portfolio against all scenarios *and* stochastics in Aurora and PERFORM models
- Complete scorecard with metrics across all objectives

# Stakeholder Presentations/Comments

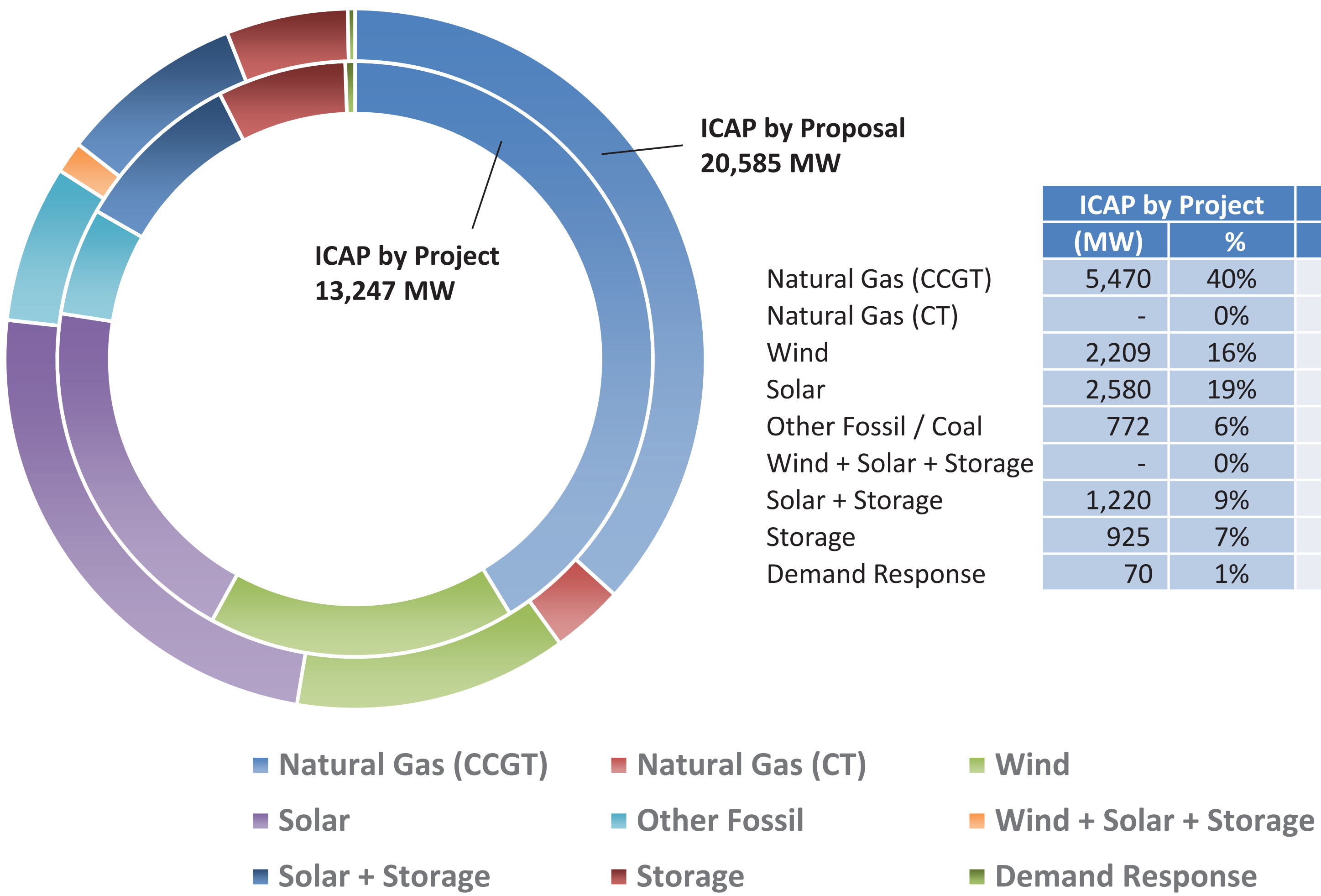
# Next Steps / Wrap Up

# Next Steps for RFP and IRP

| RFP | IRP |
|---|---|
| • Continue to vet and evaluate the proposals received in accordance with the evaluation criteria<br><br>• Determine a list of finalists by technology for possible definitive agreements once the preferred replacement path is determined | • Integrate results from the RFP into the IRP for the retirement and replacement analysis to be presented at the September 19th meeting<br><br>• Setup and run stakeholder requested scenarios |

# Appendix

# Proposals Received by Technology (MW) “ICAP”

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# Proposals Received by Technology (MW) “UCAP”

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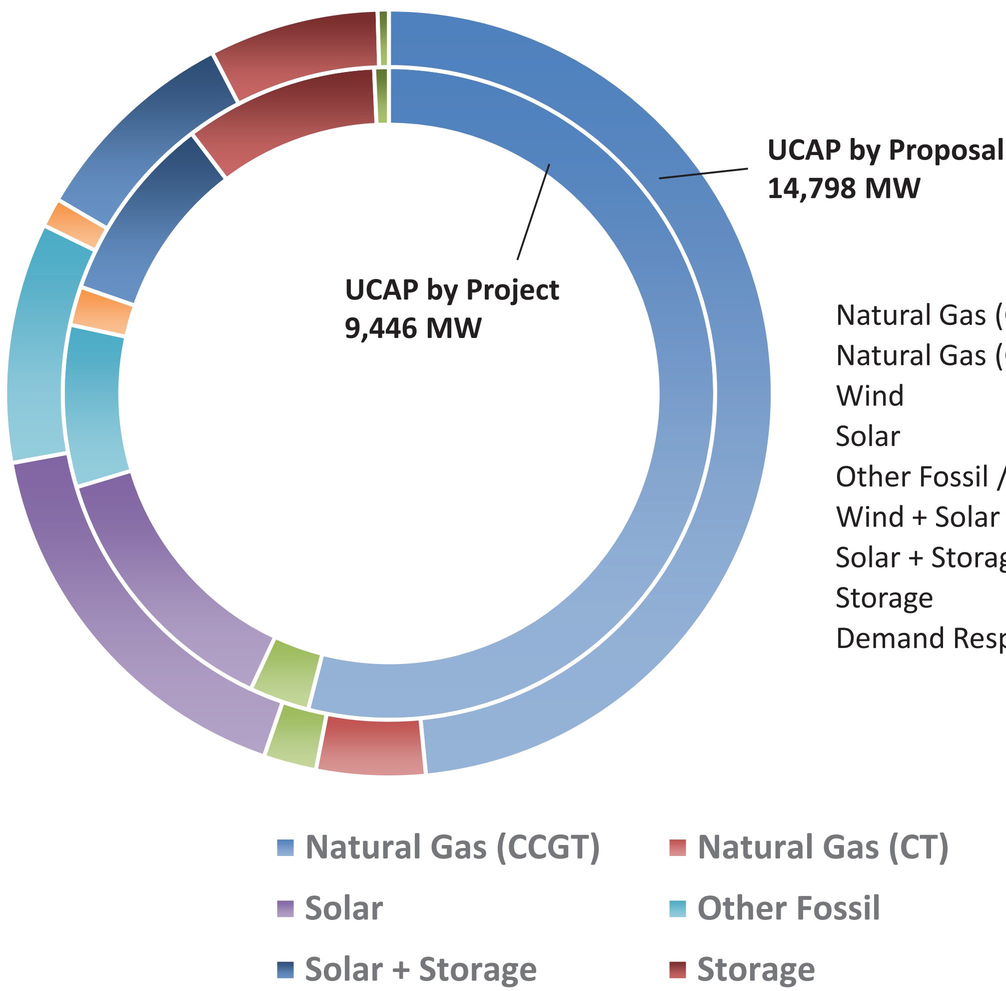


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| Solar + Storage | 902 | 10% | 1,322 | 9% |
| Storage | 925 | 10% | 1,155 | 8% |
| Demand Response | 70 | 1% | 70 | 0.5% |

# Exhibit RS-H

INSIGHTS

# Levelized Cost of Energy and Levelized Cost of Storage 2019

NOV 7 2019

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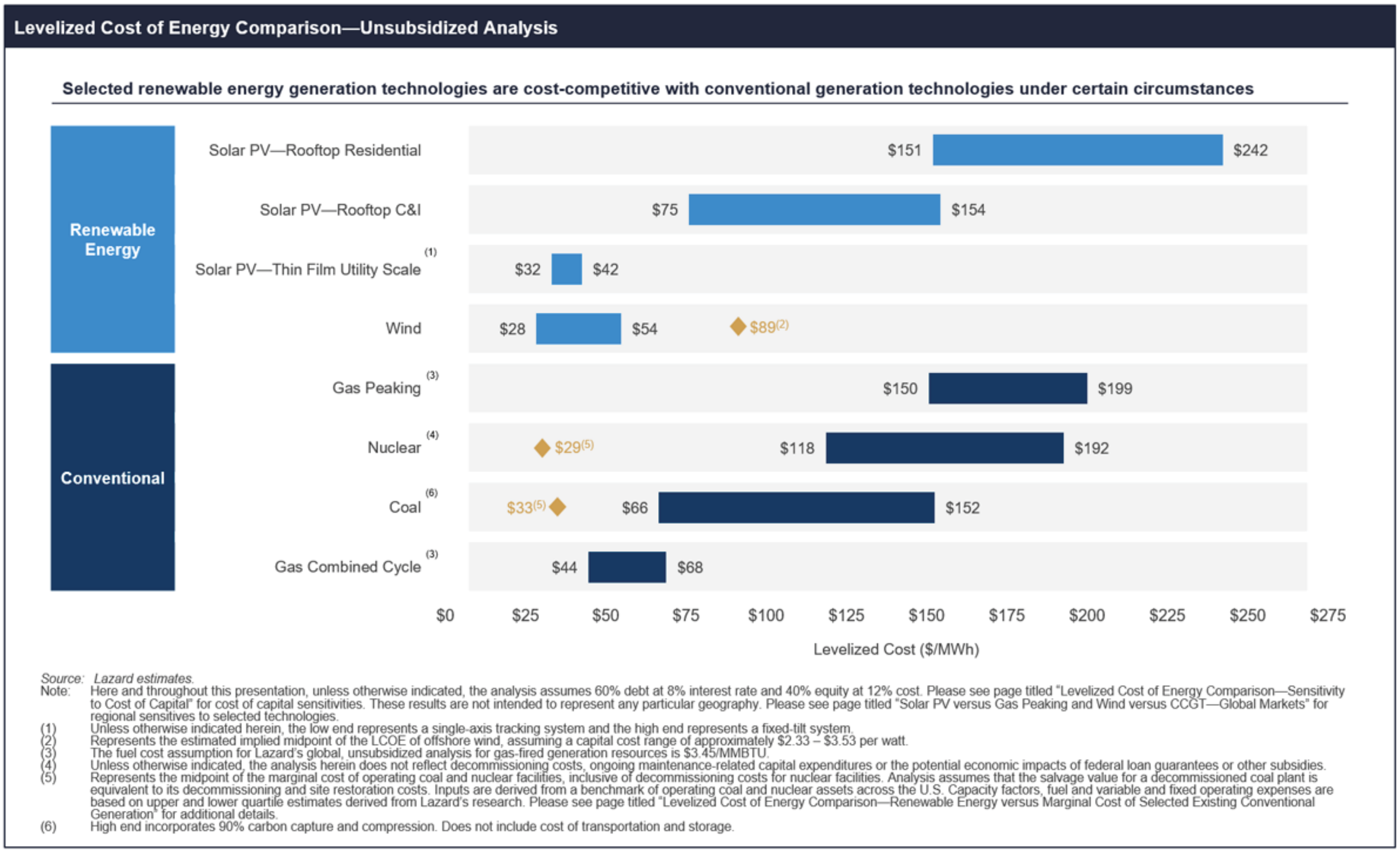
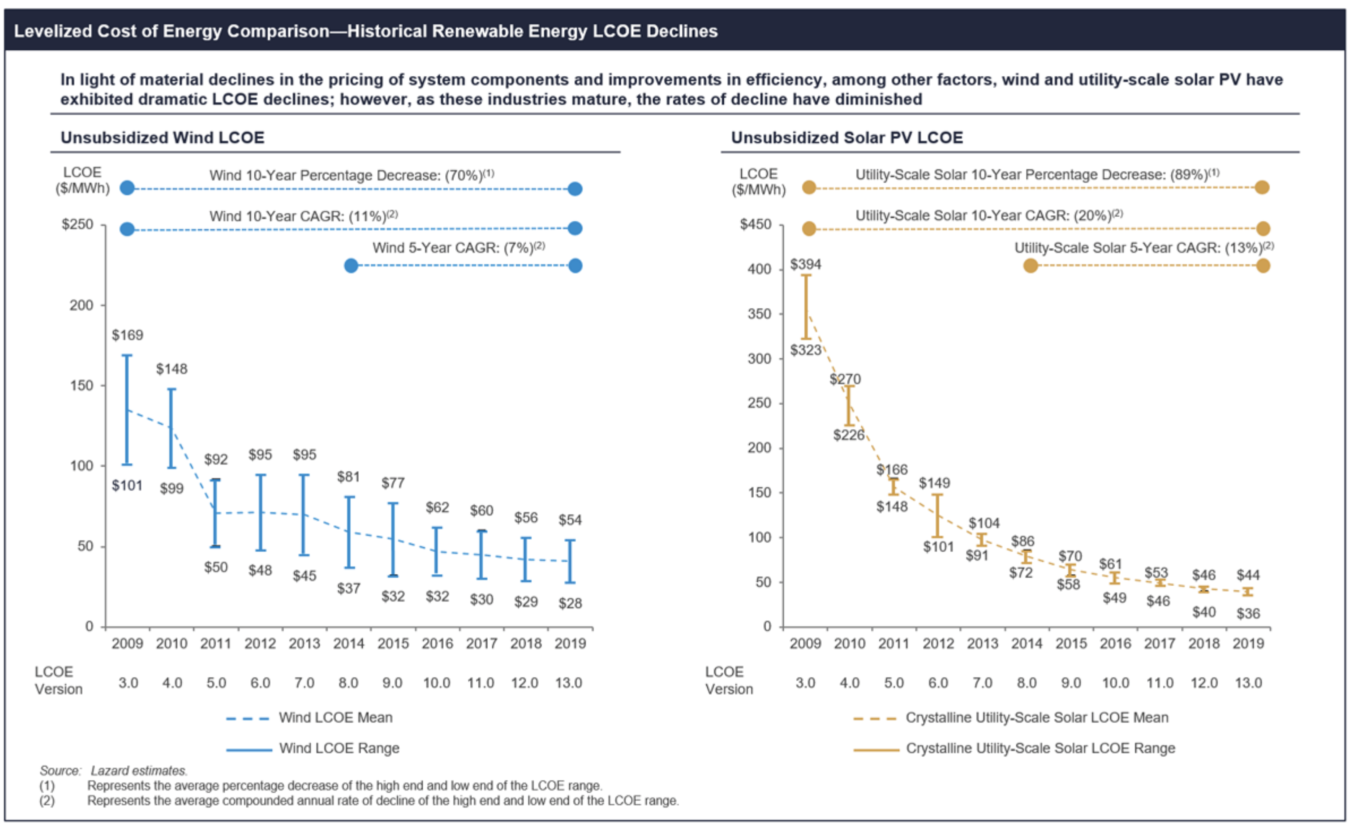
[/MEDIA/451086/LAZARDS-LEVELIZED-COST-OF-ENERGY-VERSION-130-VF.PDF]

[/MEDIA/451087/LAZARDS-LEVELIZED-COST-OF-STORAGE-VERSION-50-VF.PDF]

Lazard's latest annual Levelized Cost of Energy Analysis (LCOE 13.0) shows that as the cost of renewable energy continues to decline, certain technologies (e.g., onshore wind and utility-scale solar), which became cost-competitive with conventional generation several years ago on a new-build basis, continue to maintain competitiveness with the marginal cost of existing conventional generation technologies.



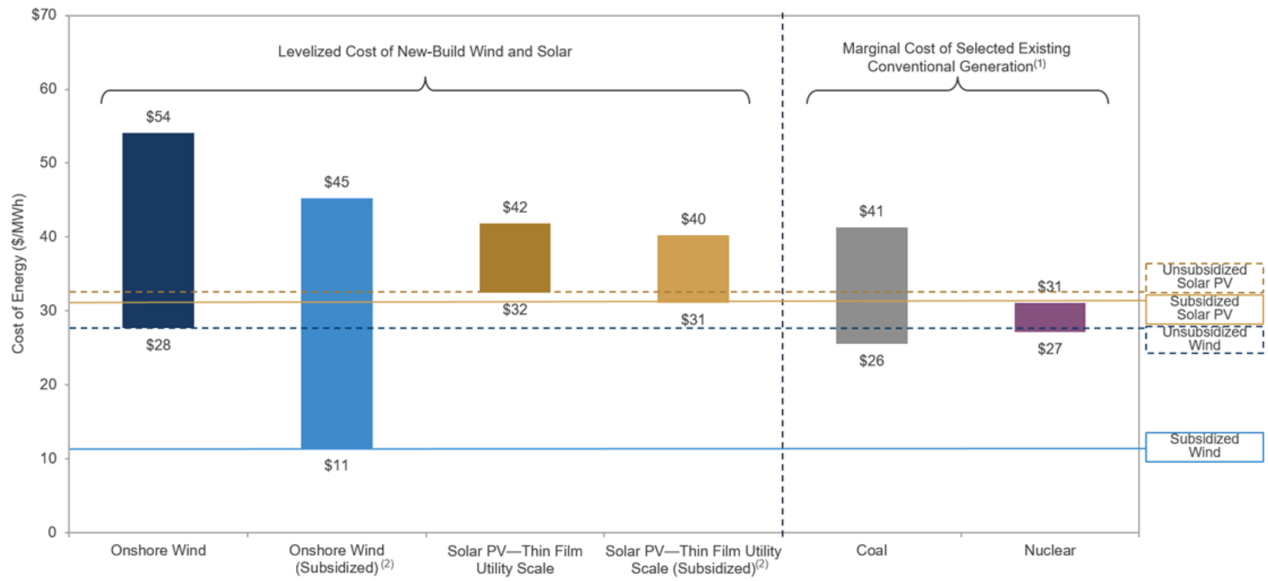

**Additional highlights from LCOE 13.0:**




While the reductions in costs continue, their rate of decline has slowed, especially for onshore wind. Costs for utility-scale solar have been falling more rapidly (about 13 percent per year) compared to onshore wind (about 7 percent per year) over the past five years.

**Levelized Cost of Energy Comparison—Renewable Energy versus Marginal Cost of Selected Existing Conventional Generation**

**Certain renewable energy generation technologies are approaching an LCOE that is competitive with the marginal cost of existing conventional generation**

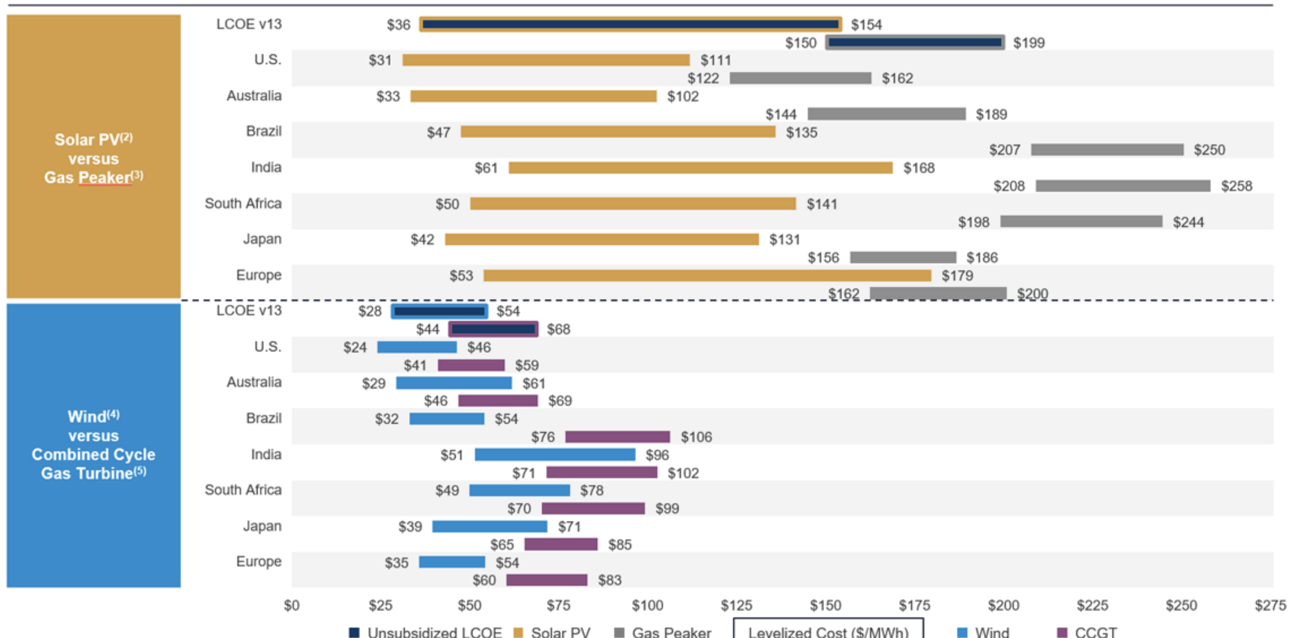



*Source: Lazard estimates.*
Note: Unless otherwise noted, the assumptions used in this sensitivity correspond to those used in the global, unsubsidized analysis as presented on the page titled "Levelized Cost of Energy Comparison—Unsubsidized Analysis".
(1) Represents the marginal cost of operating coal and nuclear facilities, inclusive of decommissioning costs for nuclear facilities. Analysis assumes that the salvage value for a decommissioned coal plant is equivalent to its decommissioning and site restoration costs. Inputs are derived from a benchmark of operating coal and nuclear assets across the U.S. Capacity factors, fuel and variable and fixed operating expenses are based on upper and lower quartile estimates derived from Lazard's research.
(2) The subsidized analysis includes sensitivities related to the TCJA and U.S. federal tax subsidies. Please see page titled "Levelized Cost of Energy Comparison—Sensitivity to U.S. Federal Tax Subsidies" for additional details.

When US government subsidies are included, the cost of building new onshore wind and utility-scale solar (with values averaging $28/MWh and $36/MWh, respectively) is competitive with the marginal cost of coal and nuclear generation (with values averaging $34/MWh and $29/MWh, respectively).

**Solar PV versus Gas Peaking and Wind versus CCGT—Global Markets(1)**

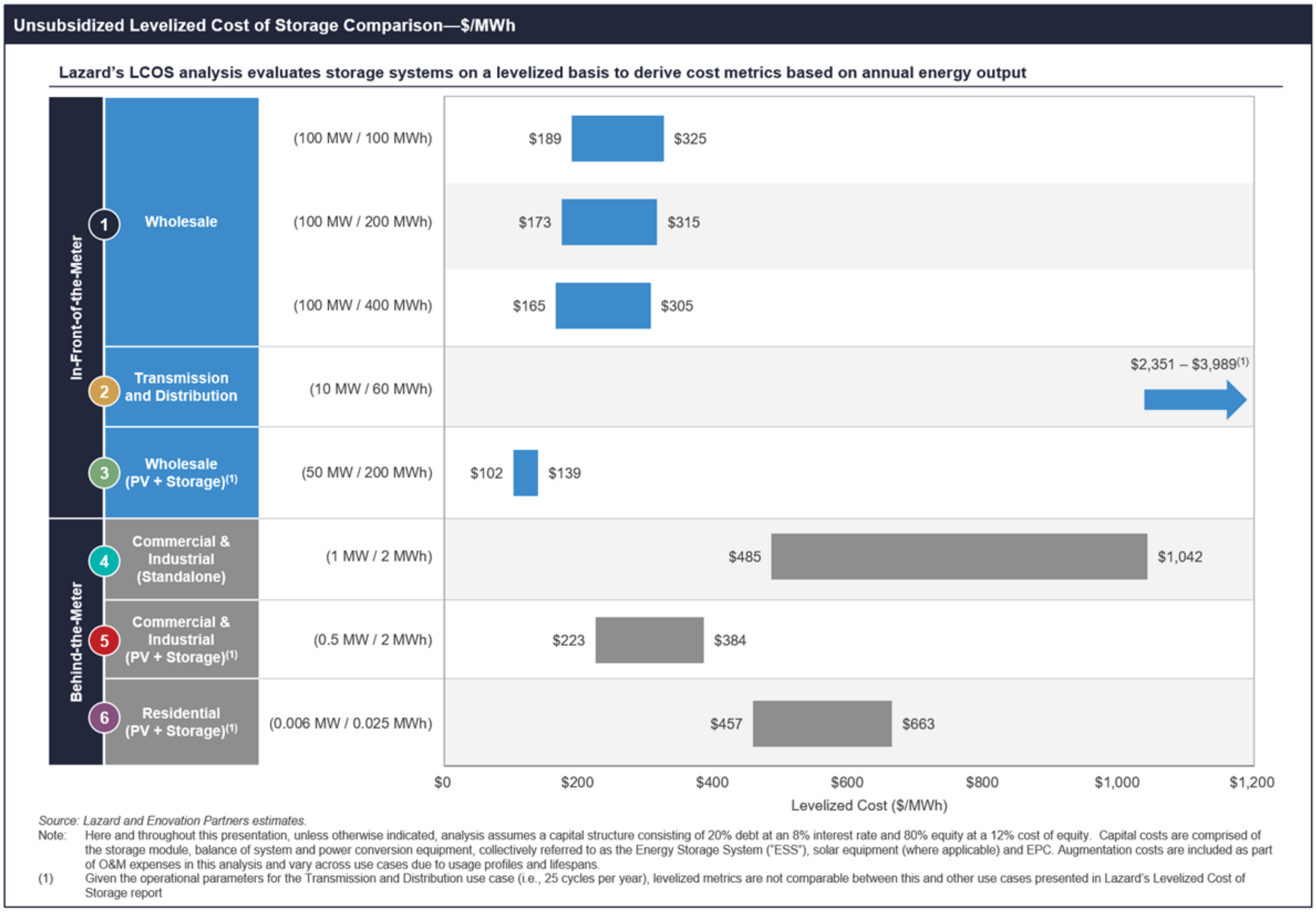
**Solar PV and wind have become increasingly competitive with conventional technologies with similar generation profiles; without storage, however, these resources lack the dispatch characteristics, and associated benefits, of such conventional technologies**




*Source: Lazard estimates.*
Note: The analysis presented on this page assumes country-specific or regionally-applicable tax rates.
(1) Equity IRRs are assumed to be 10.0% – 12.0% for Australia, 15.0% for Brazil and South Africa, 13.0% – 15.0% for India, 8.0% – 10.0% for Japan, 7.5% – 12.0% for Europe and 7.5% – 9.0% for the U.S. Cost of debt is assumed to be 5.0% – 5.5% for Australia, 10.0% – 12.0% for Brazil, 12.0% – 13.0% for India, 3.0% for Japan, 4.5% – 5.5% for Europe, 12.0% for South Africa and 4.0% – 4.5% for the U.S.
(2) Low end assumes crystalline utility-scale solar with a single-axis tracker. High end assumes rooftop C&I solar. Solar projects assume illustrative capacity factors of 21% – 28% for the U.S., 26% – 30% for Australia, 26% – 28% for Brazil, 22% – 23% for India, 27% – 29% for South Africa, 16% – 18% for Japan and 13% – 16% for Europe.
(3) Assumes natural gas prices of $3.45 for the U.S., $4.00 for Australia, $8.00 for Brazil, $7.00 for India, South Africa and Japan and $6.00 for Europe (all in U.S.$ per MMBtu). Assumes a capacity factor of 10% for all geographies.
(4) Wind projects assume illustrative capacity factors of 38% – 55% for the U.S., 29% – 46% for Australia, 45% – 55% for Brazil, 25% – 35% for India, 31% – 36% for South Africa, 22% – 30% for Japan and 33% – 38% for Europe.
(5) Assumes natural gas prices of $3.45 for the U.S., $4.00 for Australia, $8.00 for Brazil, $7.00 for India, South Africa and Japan and $6.00 for Europe (all in U.S.$ per MMBtu). Assumes capacity factors of 55% – 70% on the high and low ends, respectively, for all geographies.

Regional differences in resource availability and fuel costs can drive meaningful variance in the LCOE of certain technologies, although some of this variance can be mitigated by adjustments to a project's capital structure, reflecting the availability, and cost, of debt and equity.

Lazard's latest annual Levelized Cost of Storage Analysis (LCOS 5.0) shows that storage costs, particularly for lithium-ion technology, have continued to decline faster than for alternate storage technologies.

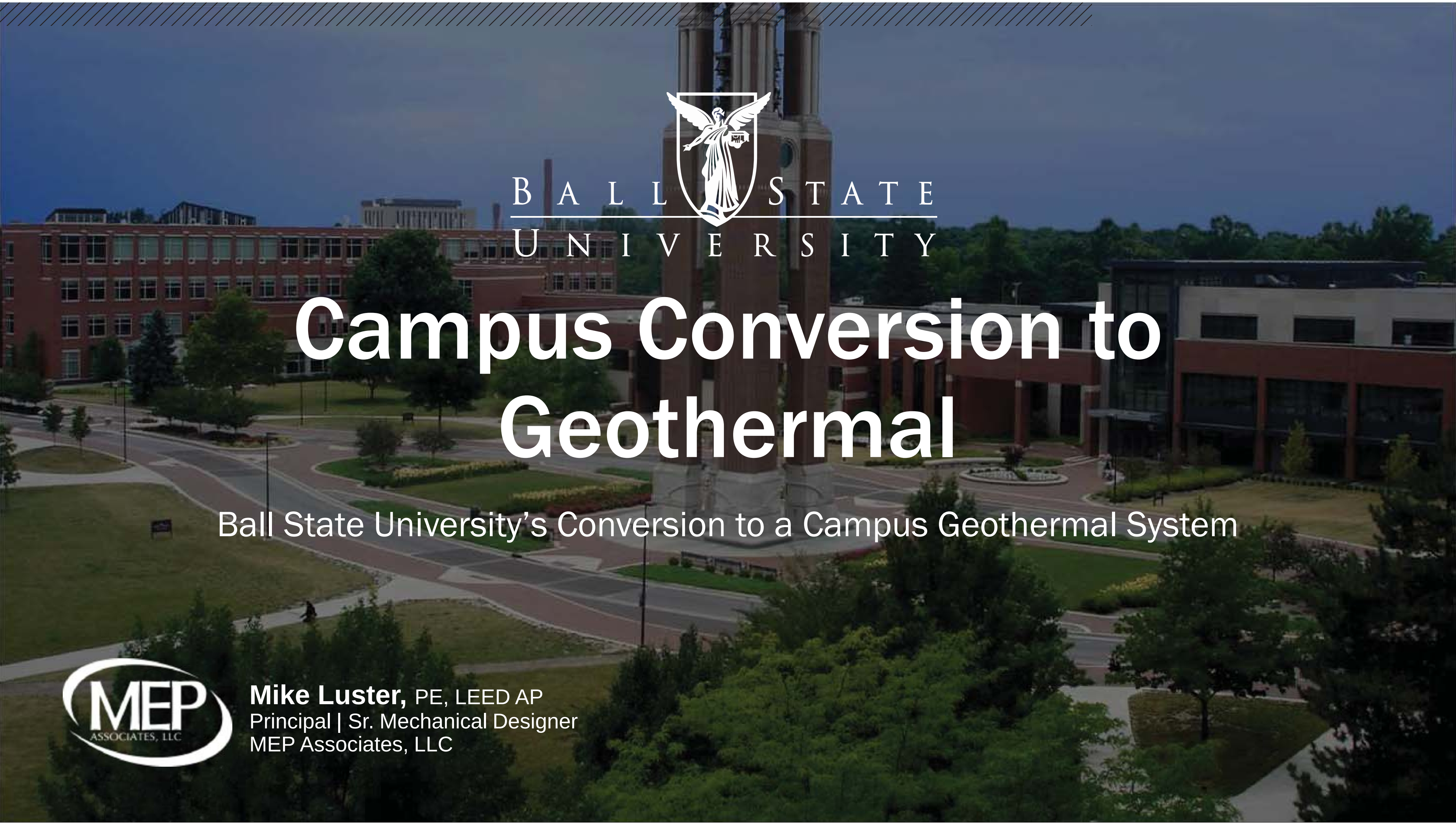



**Additional highlights from LCOS 5.0:**

Lithium-ion, particularly for shorter duration applications, remains the least expensive of energy storage technologies analyzed and continues to decrease in cost, thanks to improving efficiencies and a maturing supply chain.

Solar PV + storage systems are economically attractive for short-duration wholesale and commercial use cases, though they remain challenged for residential and longer-duration wholesale use cases.

# Exhibit RS-I


BALL STATE UNIVERSITY
Campus Conversion to Geothermal
Ball State University's Conversion to a Campus Geothermal System
Mike Luster, PE, LEED AP
Principal | Sr. Mechanical Designer
MEP Associates, LLC

# Learning Objectives

- History of the Ball State Project
- Applying Geothermal to a campus
- Benefits of the Ball State Project
- Lessons Learned

# History of Ball State University


- Founded in 1918
- 7.1 Million SF
- 47 Major Buildings
- 731 acres
- 22,113 students
- *Beneficence* is a 6 ft. bronze statue that has graced the BSU campus since 1937. Her name, means the quality of performing acts of kindness and charity.

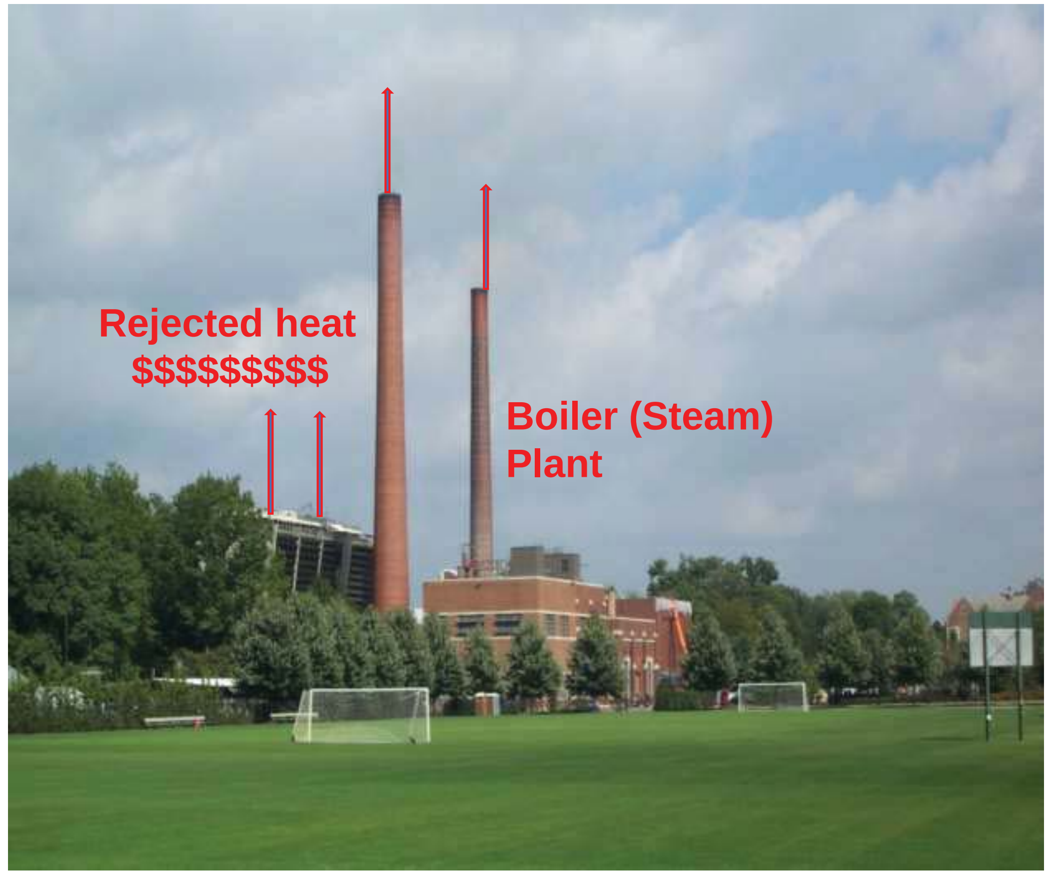
# Steam and Chilled Water Plant Operations

**Steam Plant:**

- 4 Coal Fired Boilers
- 3 Natural Gas Fired Boilers
- 320,000 Lbs./Hr. nameplate
- 700,000,000 Lbs./Year

**Chilled Water Plant:**

- 5 Electrical Centrifugal Chillers
- 9,300 ton capacity
- 25,000,000 Ton Hours/Year



# Pollutants / Waste Produced from Burning 36,000 tons of Coal

| | | |
|---|---|---|
| • Carbon Dioxide | 85,000 tons | (Global Warming) |
| • Sulfur Dioxide | 1,400 tons | (Acid Rain) |
| • Nitrogen Oxide | 240 tons | (Smog) |
| • Particulate Matter | 200 tons | (Breathing) |
| • Carbon Monoxide | 80 tons | (Headache) |

- Multiple Hazardous Air Pollutants now regulated by EPA’s Boiler MACT rules: Mercury
- 3,600 tons of coal ash

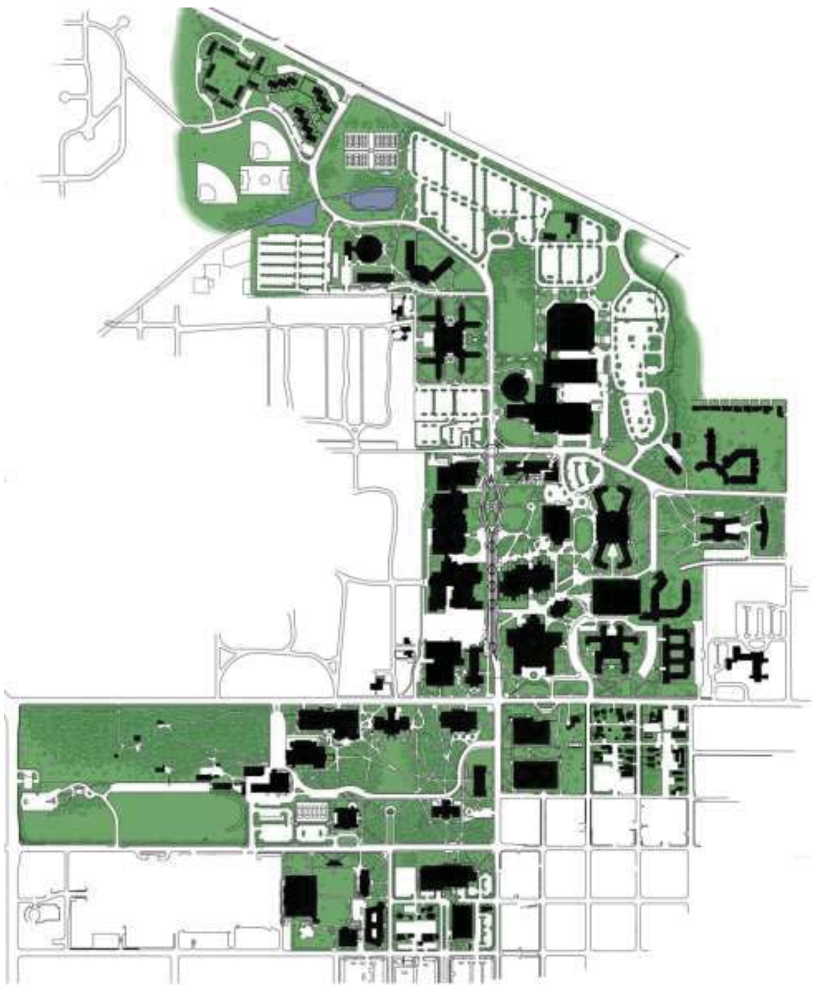
# Alternatives Evaluated

| Fossil Fuel Boiler (CFB) | All Natural Gas Boiler | Ground Source Geothermal Heat Pump |
|---|---|---|
| High capital cost | Low capital cost | Highest capital cost |
| No $CO_2$ reduction | $CO_2$ half that of coal | Campus $CO_2$ reduced 50% |
| High maintenance costs | Low maintenance cost | Low maintenance cost |
| Emission control equipment | No emission control | No emission control |
| Alternative fuel capable | High fuel costs | Electric power dependent |

## BSU needed to make changes due to:

- Age/condition of equipment
- EPA regulations
- Growth in campus
- reduction in equipment capacity

# Geothermal for Campus Systems



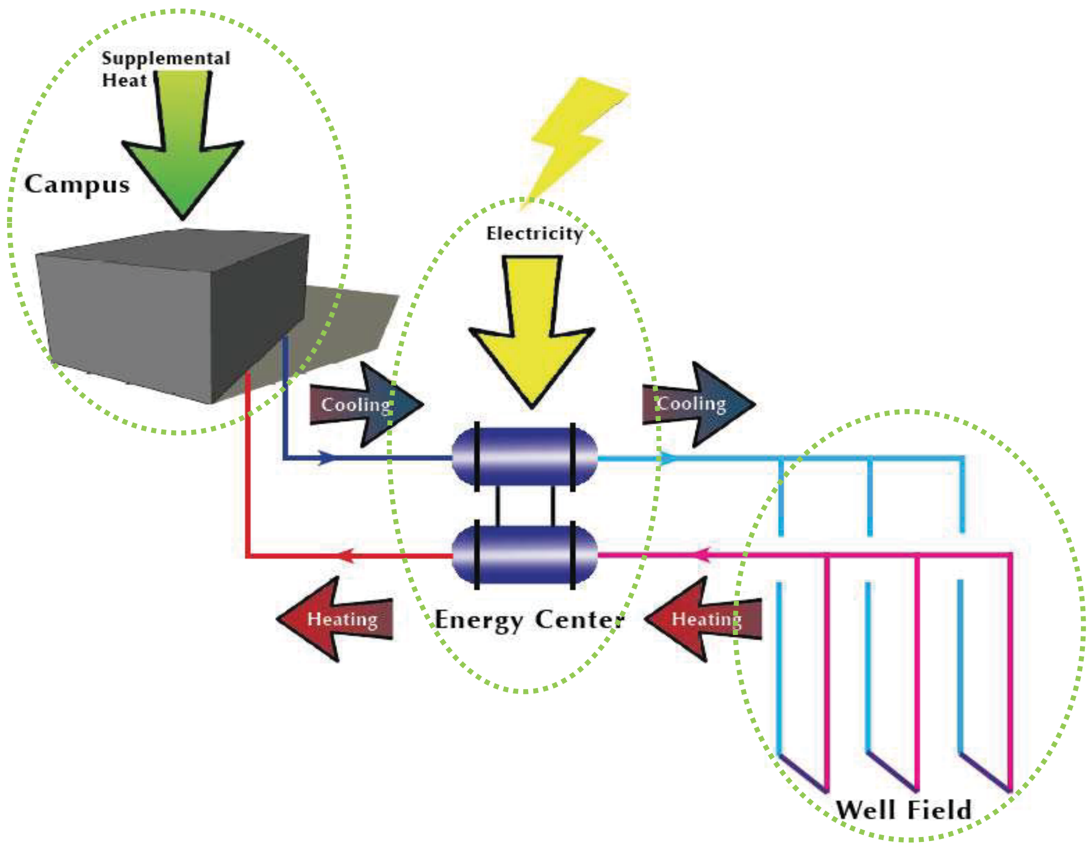
- Appling Geothermal Systems in a New Way
- Take Advantage of Campus Simultaneous Heating and Cooling Loads
- Potential to Eliminate Coal and Gas Fired Boilers
- Reduce Energy Footprint, Carbon Emissions and Utility Costs
- Reduce Water Usage

# Many Different Ways to Apply Geothermal to a Campus

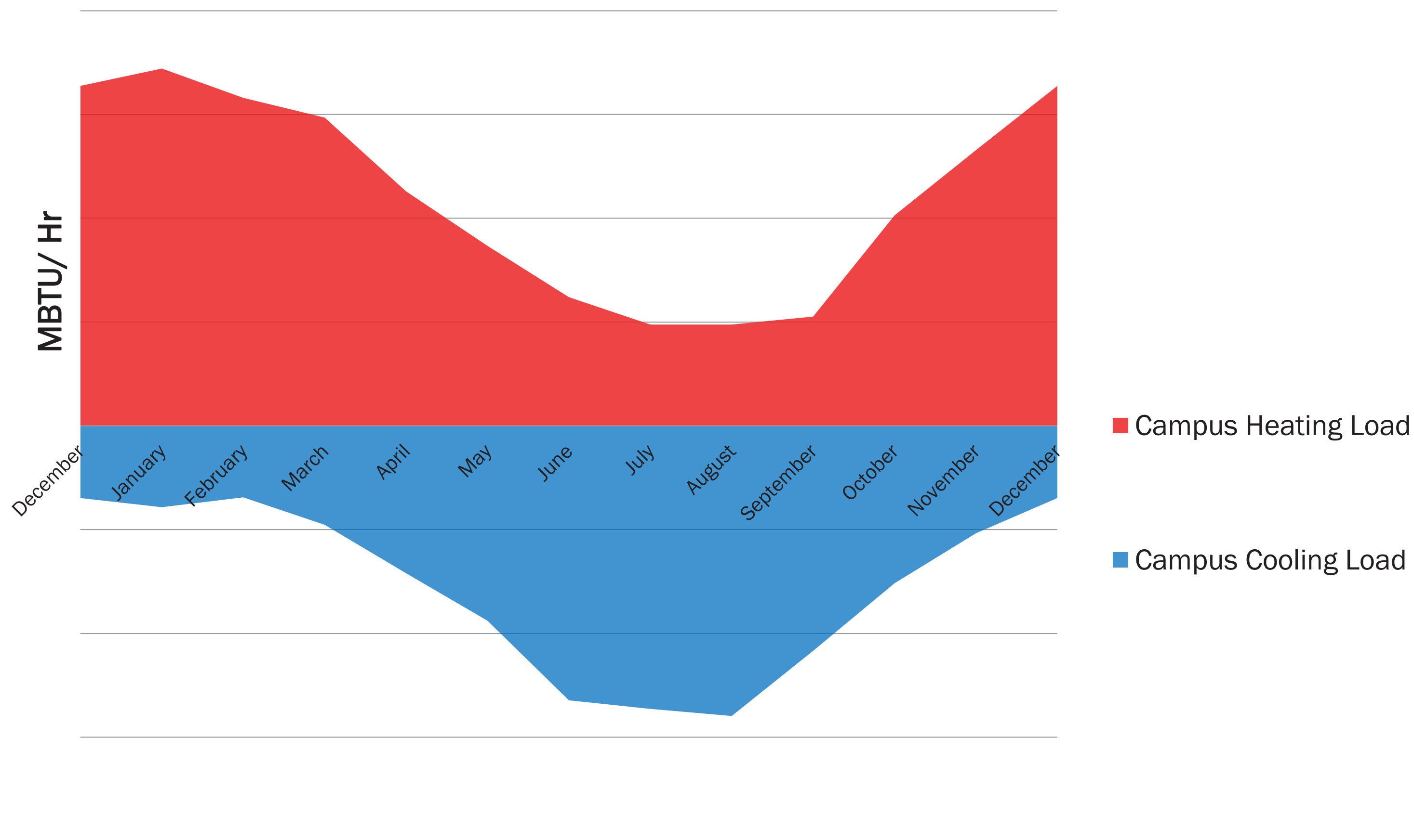
Key pieces of information to evaluate to decide what is best for the campus

- Identify the Campus Thermal Profile
  - 3 years of monthly energy consumption with peak rate
- Existing Infrastructure
- Master Plan
- Phasing and Funding
- Potential Bore Location
- Geology
- Well Field Model
- Building Conversions and Hot Water Temp
- Equipment Selection

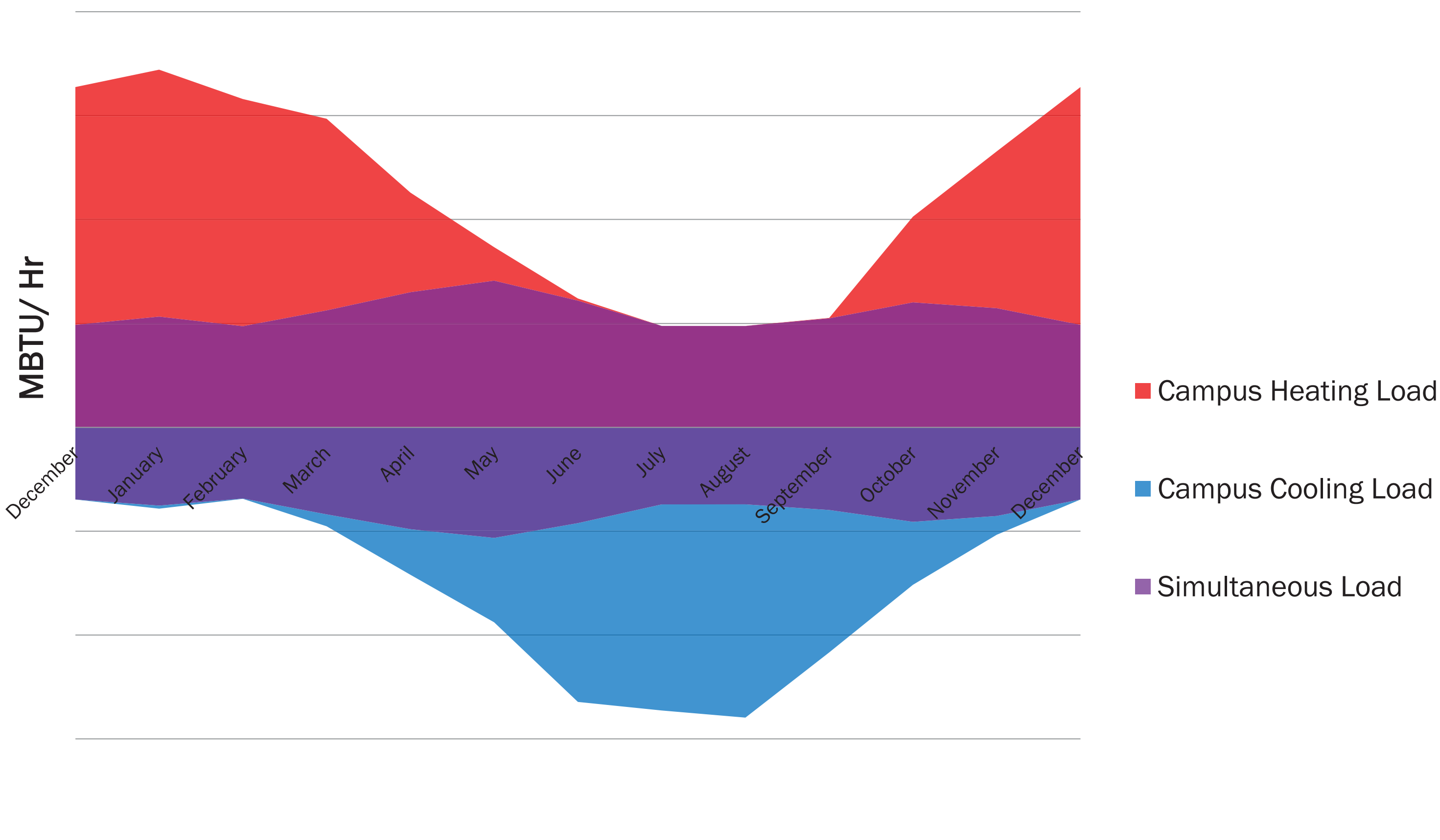
# Heating & Cooling Loads for the Campus



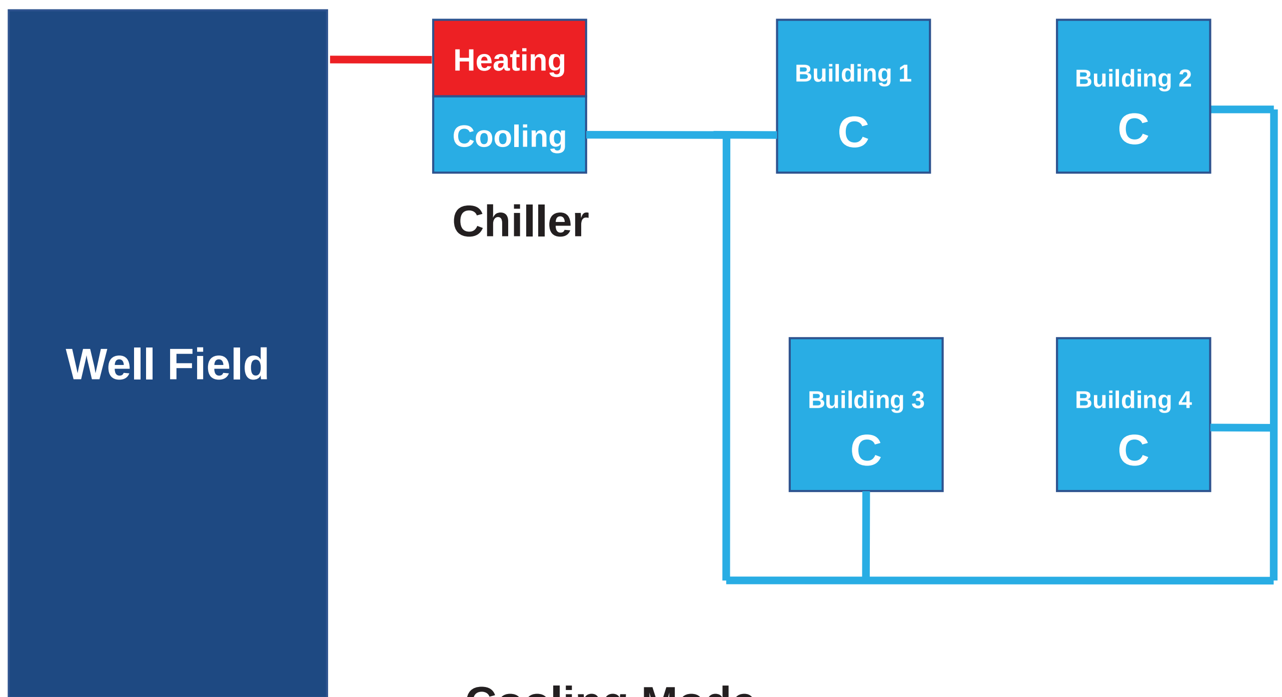
# Campus Heating & Cooling Loads



# Campus Heating & Cooling Loads

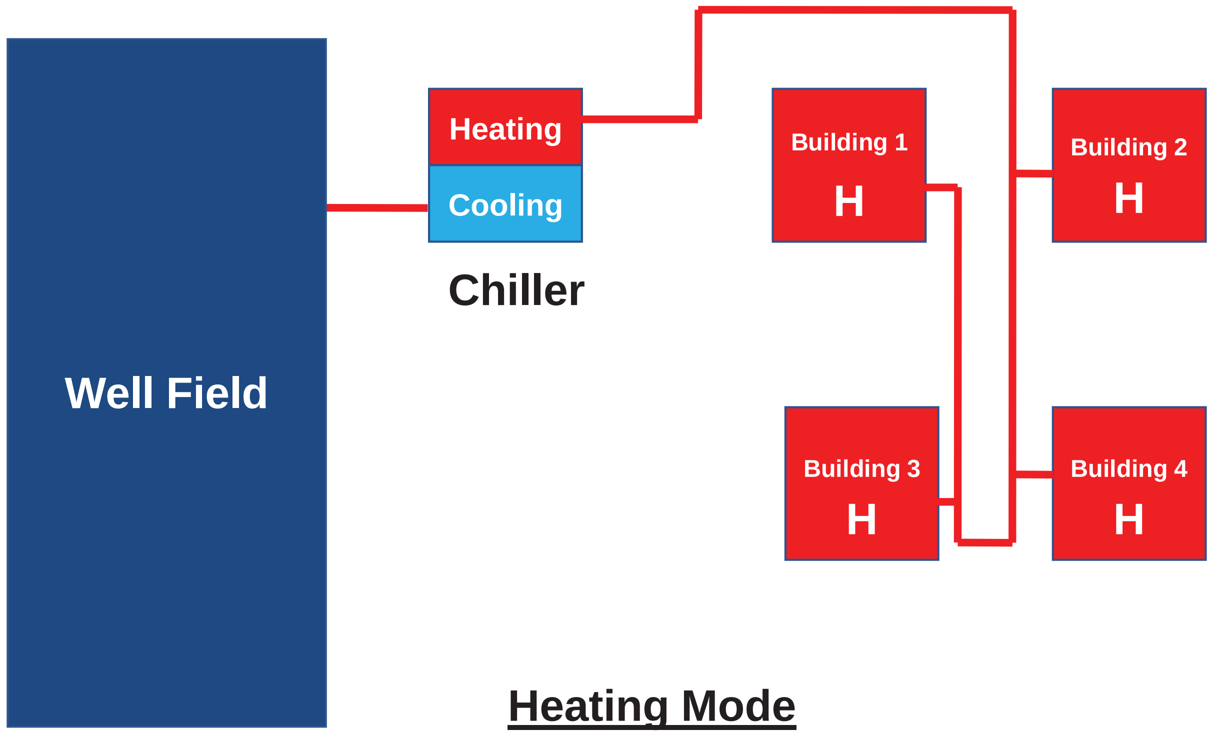


# Central Energy Plan



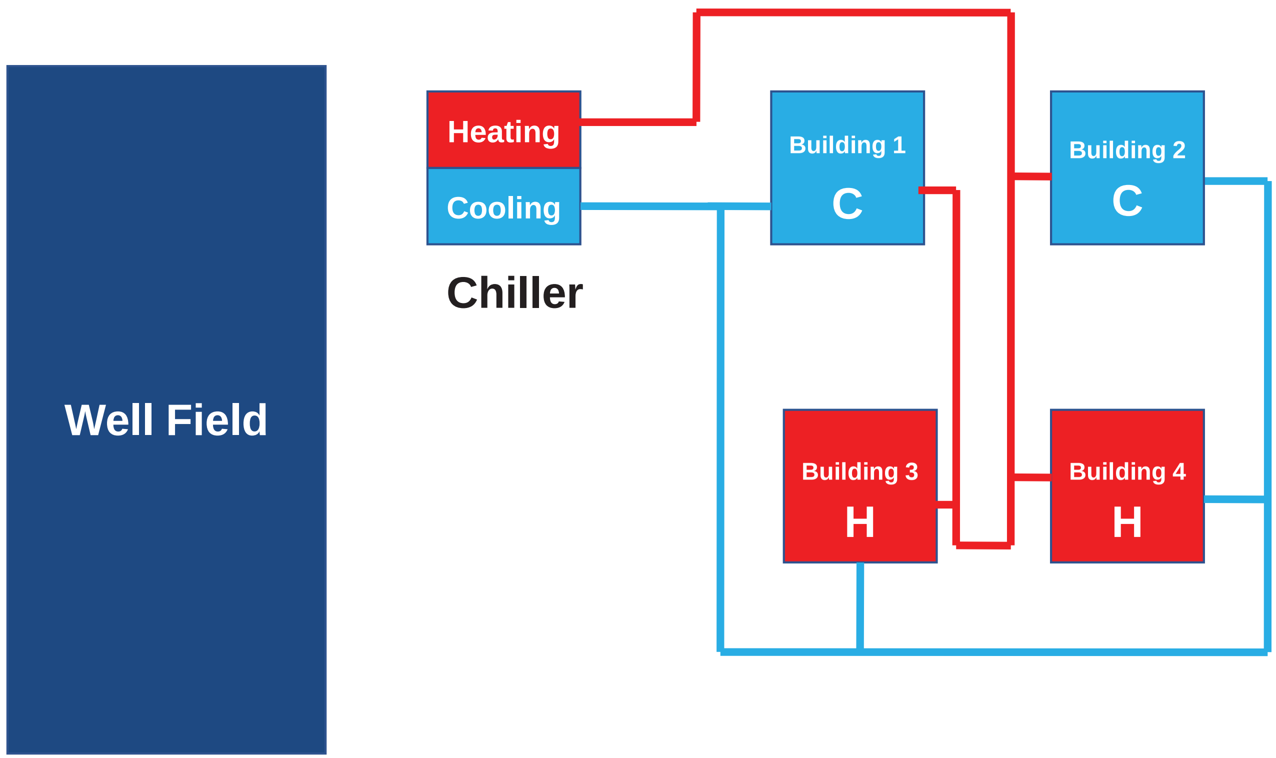

**Cooling Mode**
**COP = 5.93 / EER 20.23 (Avg.)**

# Central Energy Plan




**<u>Heating Mode</u>**
**COP = 3.4**

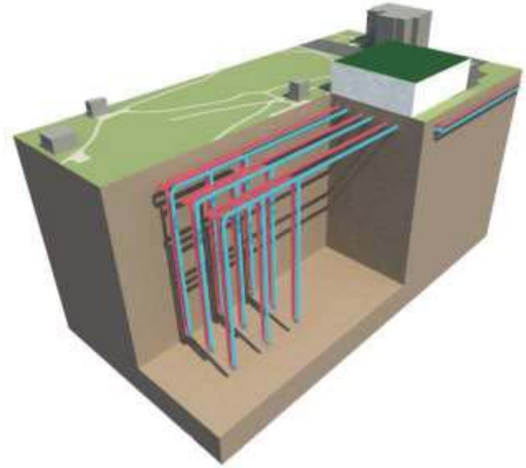
# Central Energy Plan




<u>Simultaneous Heating/Cooling</u>

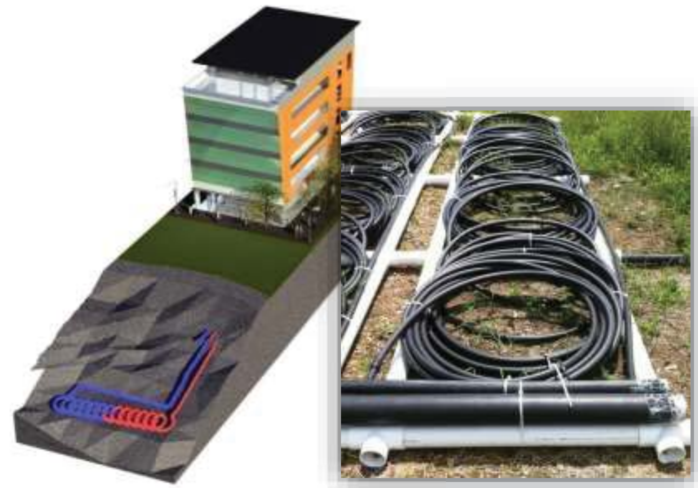
COP > 7

# Heat Exchanger Options



- Vertical Heat Exchanger

- Open Pit Horizontal
- Directional Bore Horizontal

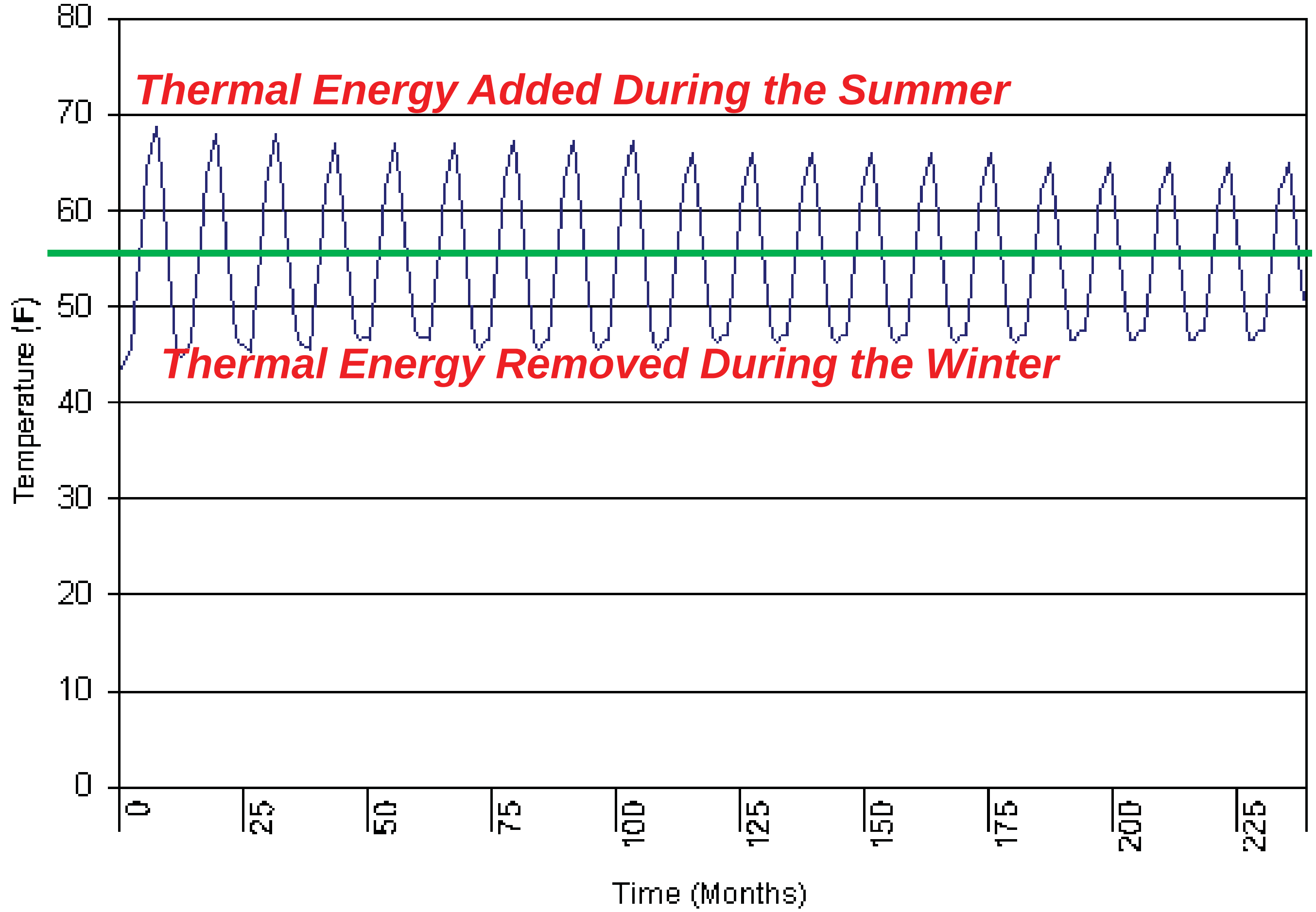


- Closed Loop Pond/Lake
- Open Loop Pond/Lake

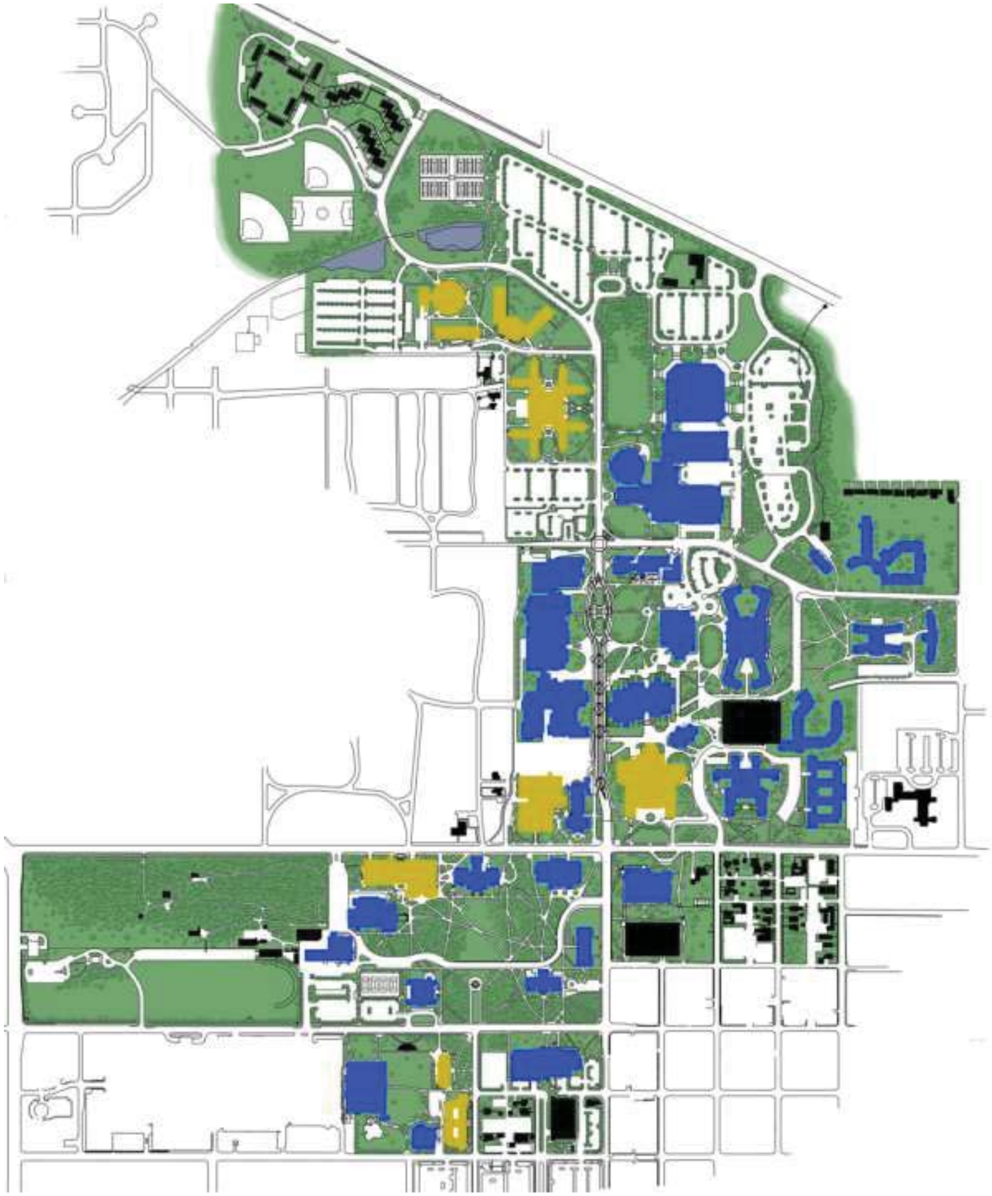
# Drill Test Well

- **Outcomes of Test Well**
  - Geological Conditions
  - Conductivity
  - Diffusivity
  - Earth Temperature

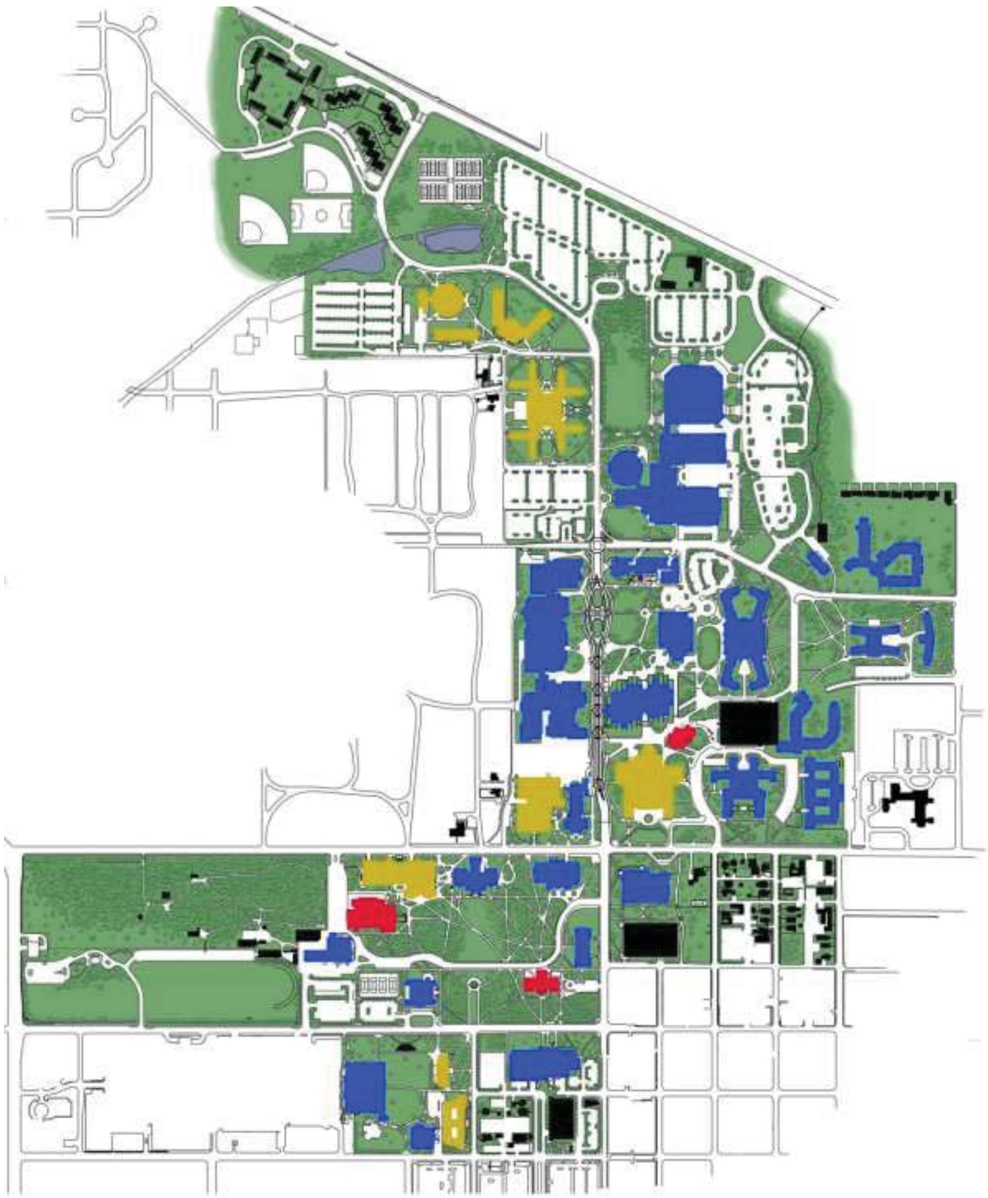
# Ground Temperature Model



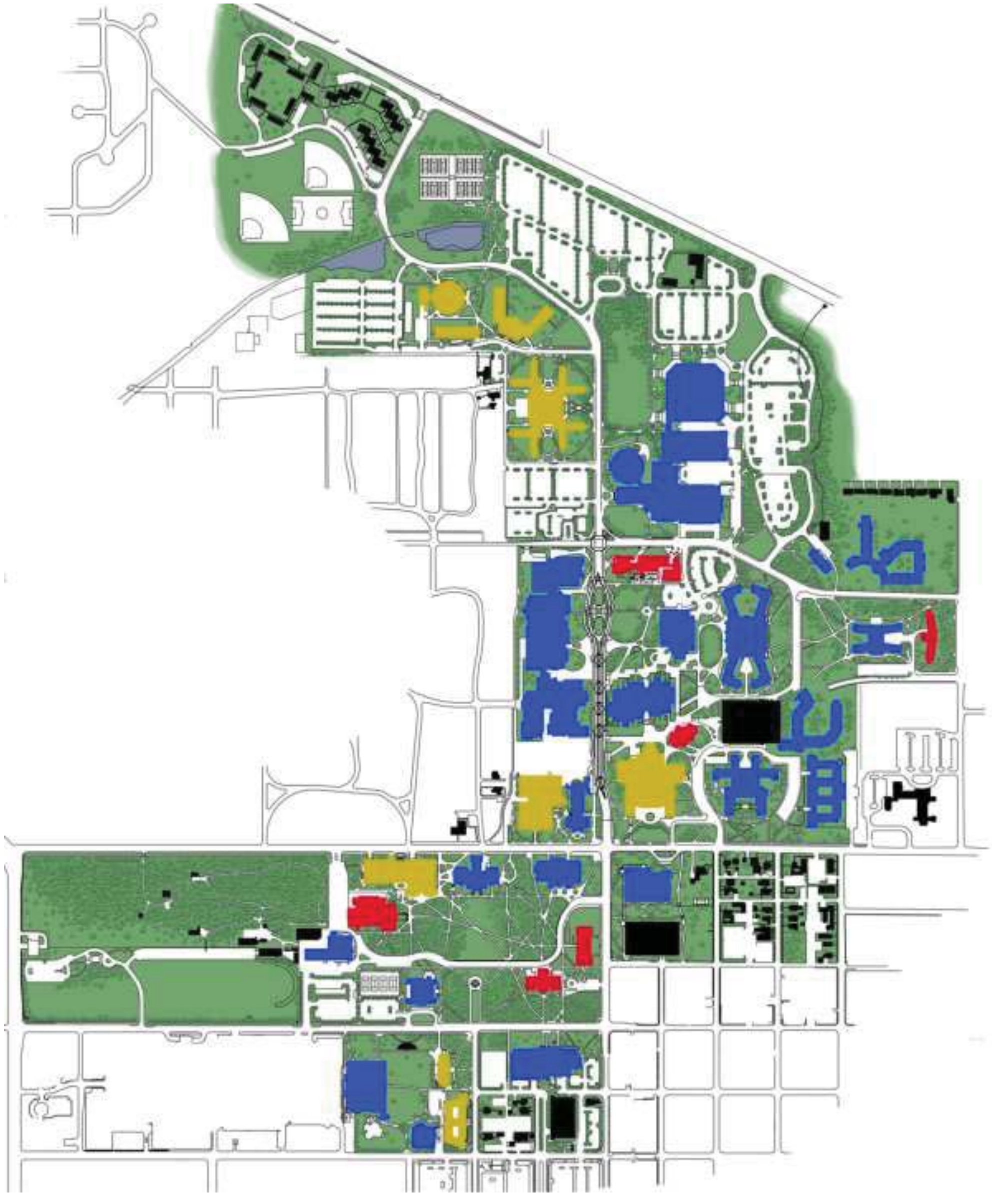
# Effects of Different Hot Water Temps



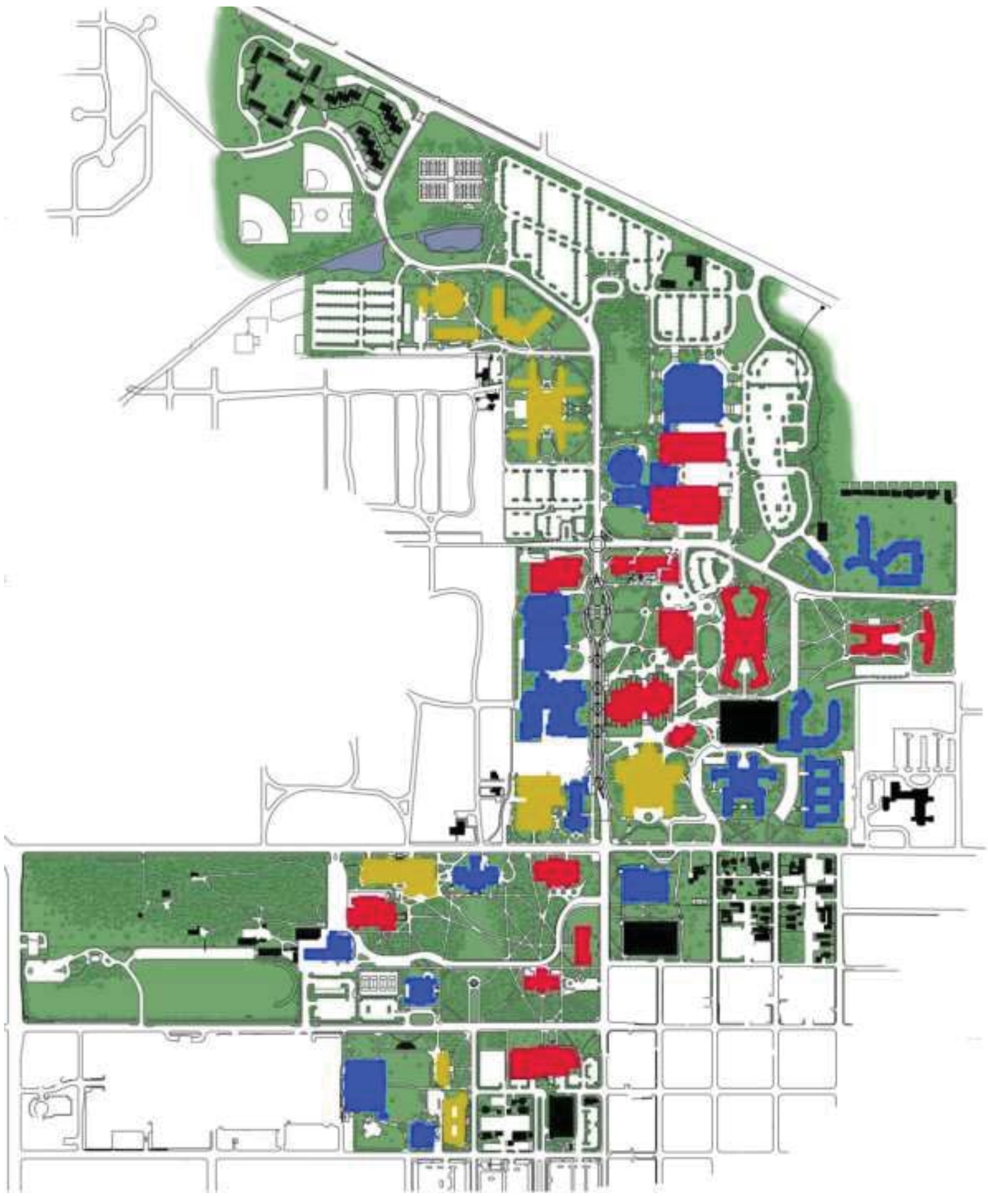
# 170° Hot Water Temperature



# 150° Hot Water Temperature



# 135° Hot Water Temperature

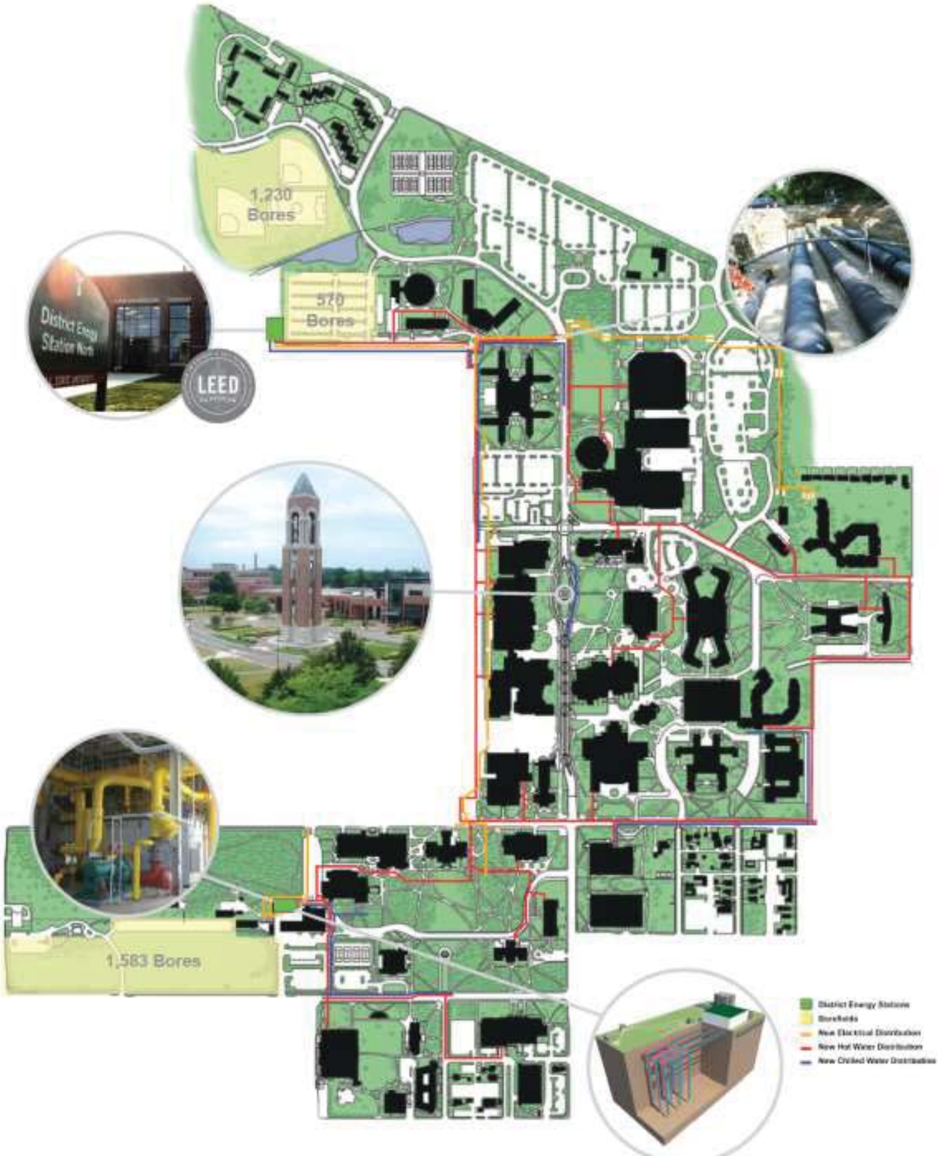


# Heat Pump Chillers

- **Centrifugal Chillers**
  - 600 - 2500 Tons
  - Up to 155 F HW temp
  - Up to 170 F HW temp

- **Screw Chillers**
  - 50 to 430 Tons
  - Up to 140 F HW temp

- **Scroll Chillers**
  - Up to 150 Tons
  - Up to 120 F HW temp




# Conversion Facts

- 5,600,000 GSF Heating Conversion
- 47 Building Heating Conversion
- Includes 300,000 GSF of Expansion
- 1,800 - 400 ft. Bore Holes
- 1,583 - 500 ft. Bore Holes
- 2 Well Fields
- 152,000,000 BTU/HR Heating
- 150°F HWS
- 20°F HW Delta T
- 10,000 Tons Cooling
- 2 Major Phases

# North & South Bore Hole Site

- 3,383 Total Bore Holes
- North Bores completed 2010
- South Bores completed 2014
- Over 1,000 miles of pipe

# Bore Hole Construction

## Drilling 400/500 Feet

## Installing the Pipe

*One borehole per day per rig*

# Bore Hole Design


- 15 feet apart
- 225 SF per borehole
- 400/500  feet deep
- Double and Single Loop
- 1-1/4 inch diameter pipe
- High Density Polyethylene
- **Final borehole drilled October 17, 2014**

# District Energy Station – North

Completed June 30, 2011

# District Energy Station – North

- 12,000 SF
- (2) 2,500 Ton Compound Centrifugal Compressor Heat Pump Chillers
  - 38,000,000 BTU/HR
- Accessory Components
- 1,000 Ton Fluid Cooler
- Heating - 150° Hot Water
- Cooling - 42° Chilled Water
- LEED Gold Certified

# District Energy Station – South

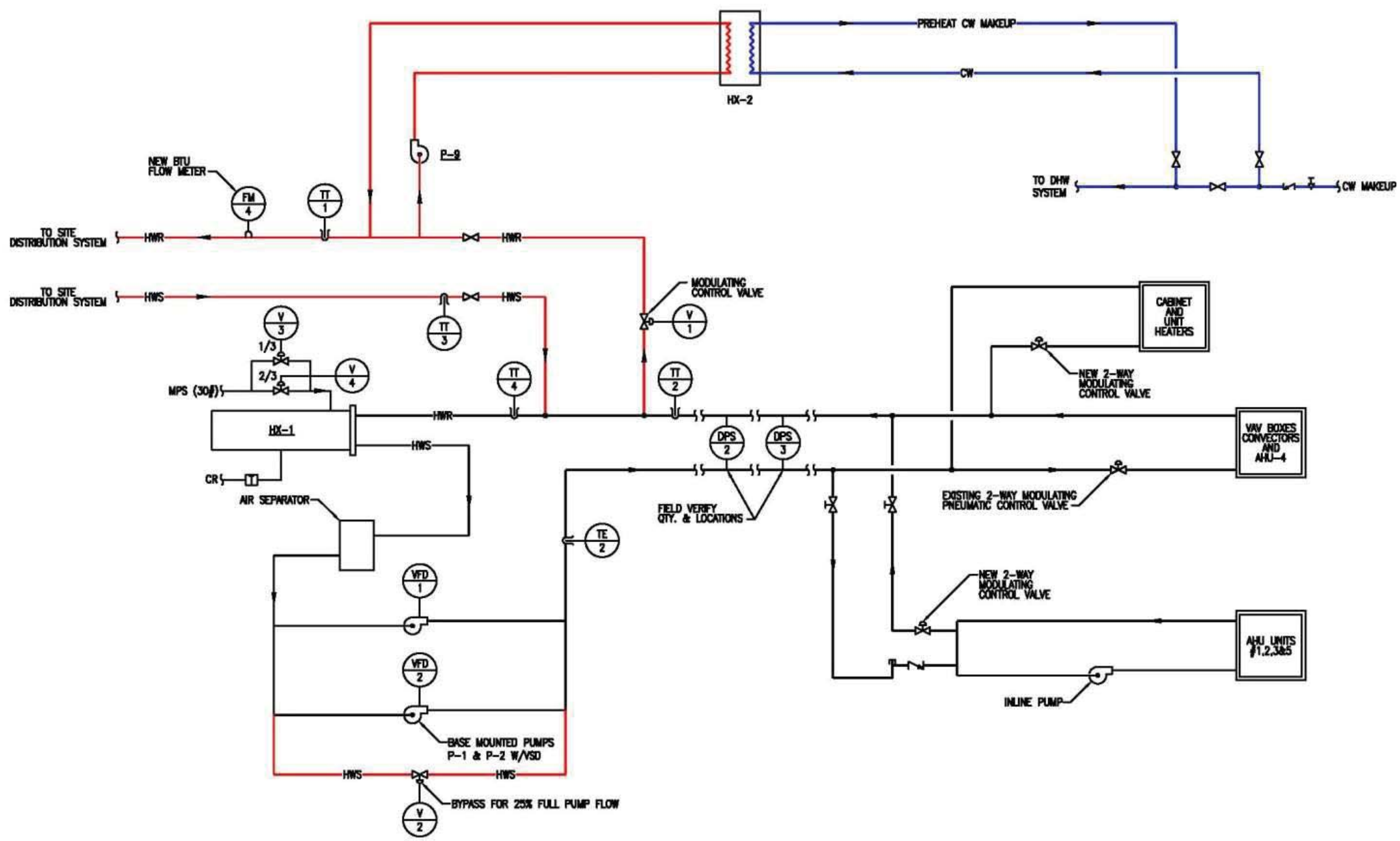
# District Energy Station – South

- 16,480 SF
- (2) 2,500 Ton Compound Centrifugal Compressor Heat Pump Chillers
- Accessory components
- (4) 1,000 Ton Cooling Towers
- Reuse (2) existing Water-Cooled Chillers
- Anticipated LEED Silver

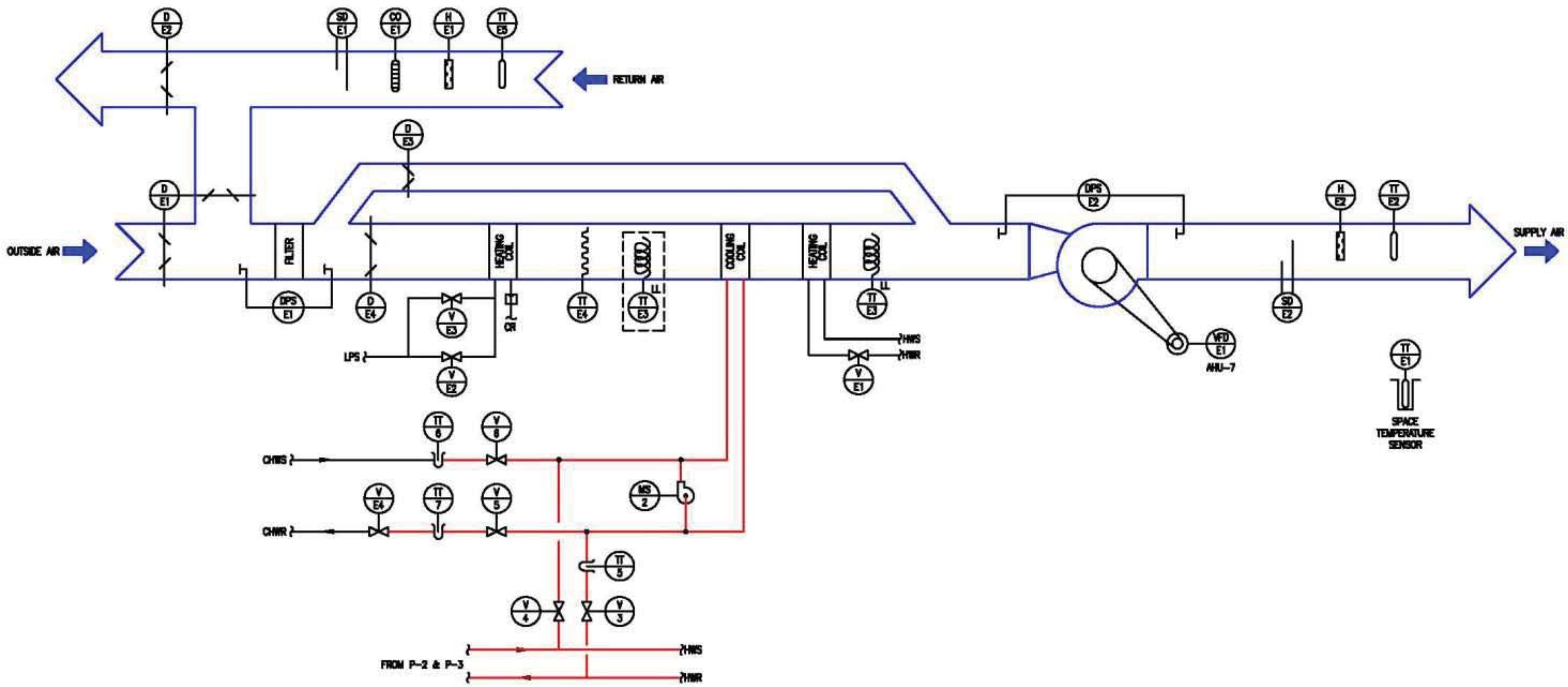
# Distribution Utilities

- **8 Utility Packages**
- **10 Miles of Hot & Chilled Water piping installed**

# Building Interface Connections



# Building AHU Connections



# BSU Geothermal Benefits

**Reduction in Emissions**

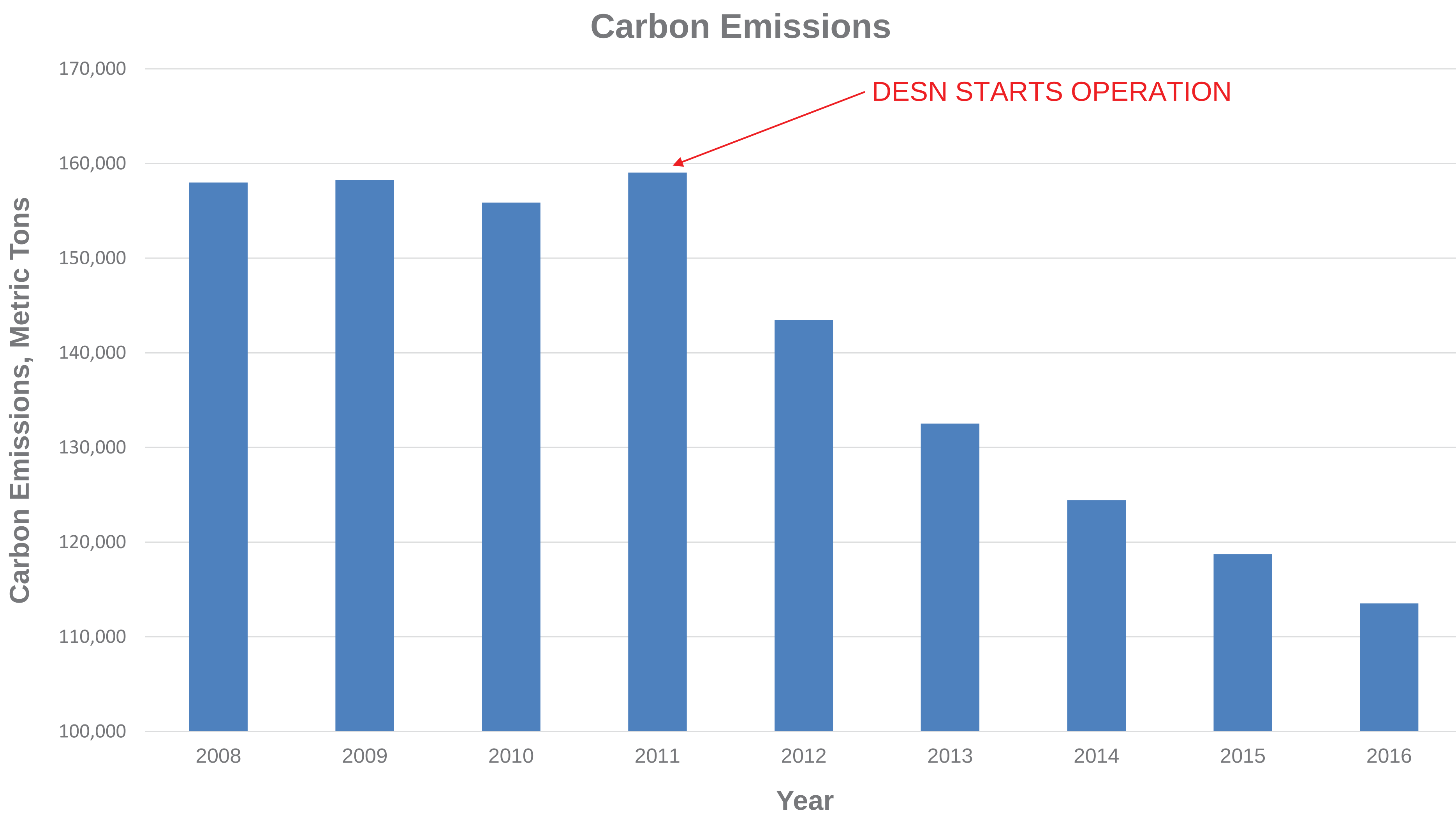
| | |
|---|---|
| • Carbon Dioxide | 75,000 tons |
| • Sulfur Dioxide | 1,400 tons |
| • Nitrogen Oxide | 240 tons |
| • Particulate Matter | 200 tons |
| • Carbon Monoxide | 80 tons |
| • Coal ash | 3,600 tons |

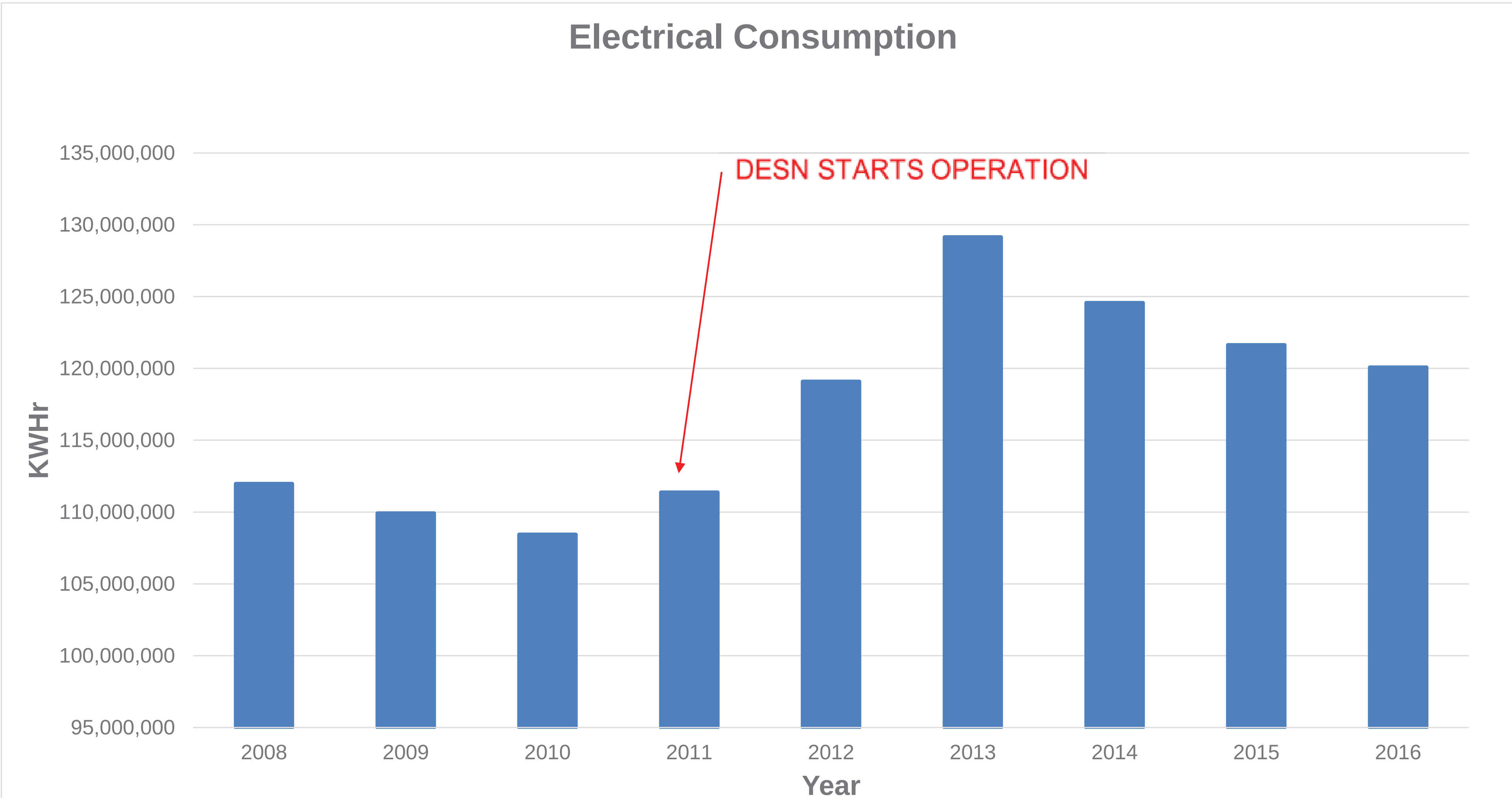
**Other Benefits**

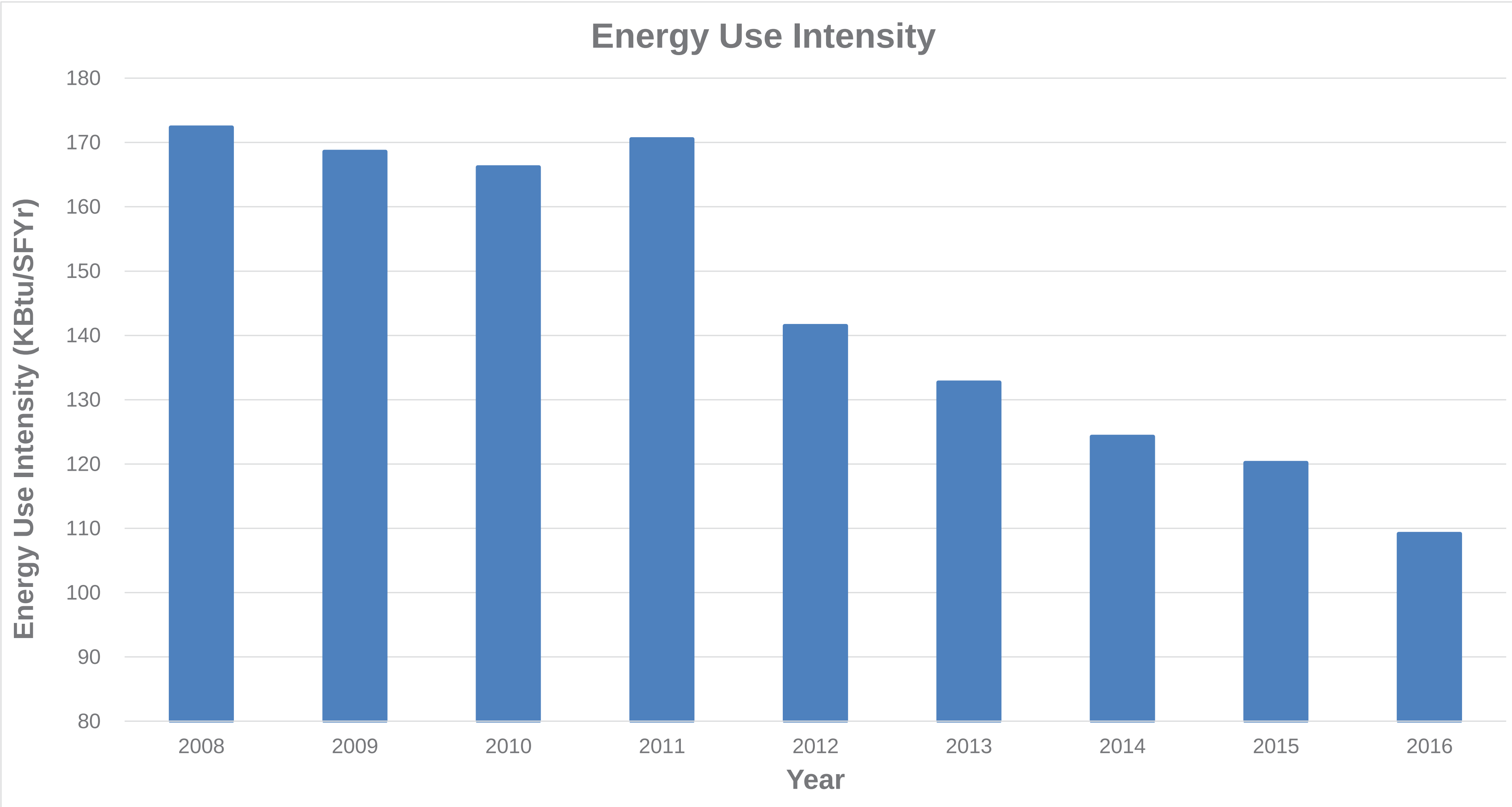
| | | |
|---|---|---|
| BTUs per year reduction: | 500,000,000,000 | |
| BTUs/SF/Year reduction: | 175,000 to 105,000 | *( FY 15/16: 109,088)* |
| Water reduction: | 45,000,000 gallons | |
| Dollars Saved: | $2,200,000 | |

# Geothermal Conversion Costs ($ Millions)

| | |
|---|---|
| Bore Holes | $27 |
| Distribution Pipe | $18 |
| Building HVAC Modifications | $8 |
| District Energy Buildings | $18.4 |
| Heat Pump Chillers | $7.5 |
| High Voltage Improvements | $4 |
| Total Construction Cost | $82.9* |
| | |
| * US Department of Energy | $5 |
| * State of Indiana | $77.9 |


Carbon Emissions
DESN STARTS OPERATION
Carbon Emissions, Metric Tons
170,000
160,000
150,000
140,000
130,000
120,000
110,000
100,000
2008
2009
2010
2011
2012
2013
2014
2015
2016
Year


Electrical Consumption
DESN STARTS OPERATION
KWHr
135,000,000
130,000,000
125,000,000
120,000,000
115,000,000
110,000,000
105,000,000
100,000,000
95,000,000
2008
2009
2010
2011
2012
2013
2014
2015
2016
Year



Energy Use Intensity
Energy Use Intensity (KBtu/SFYr)
180
170
160
150
140
130
120
110
100
90
80
2008
2009
2010
2011
2012
2013
2014
2015
2016
Year

# Lessons Learned

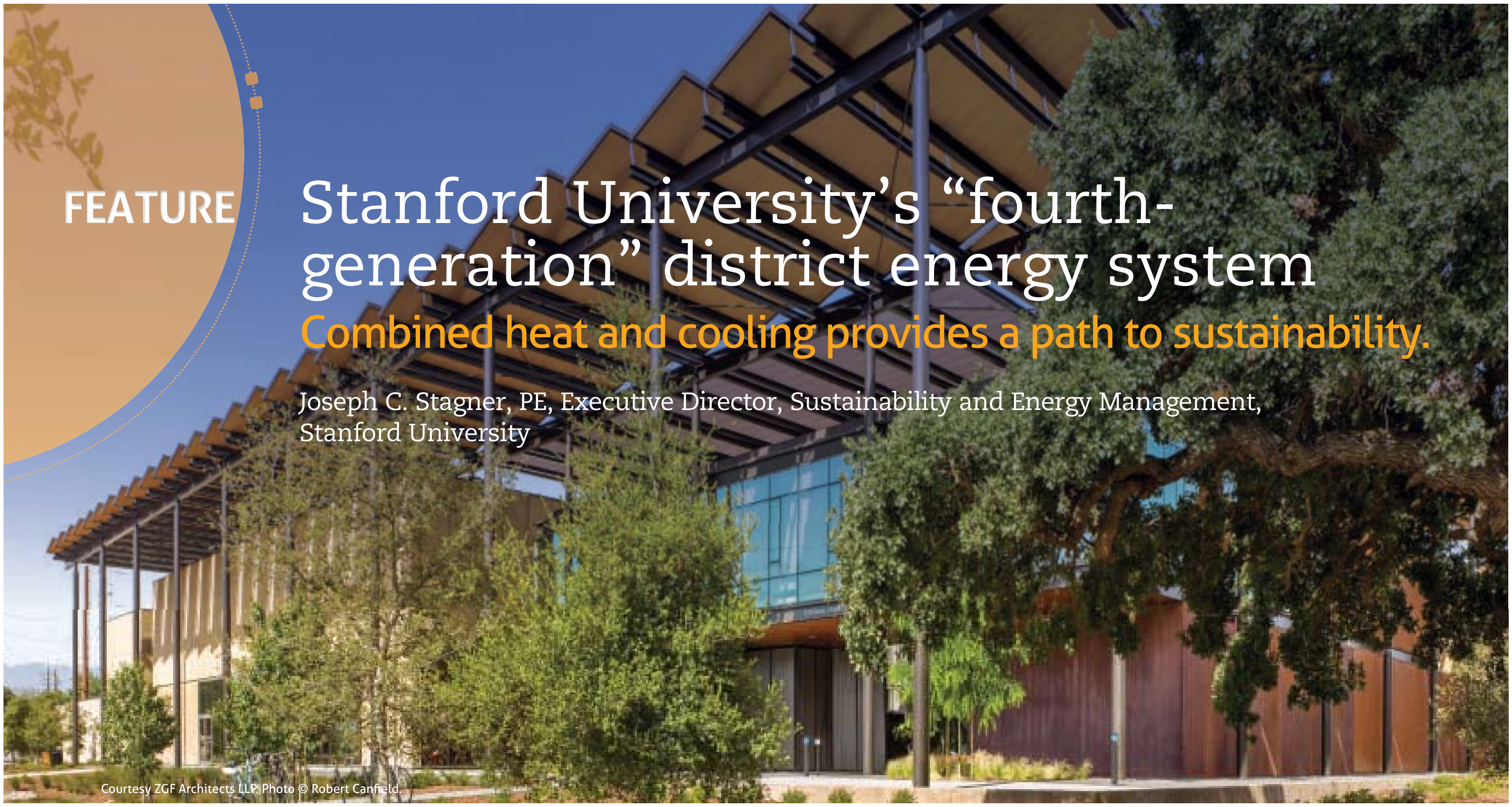
- Keep the System Clean!
- Know your true heating and cooling loads for good balance
- Equipment Turn Down & Phasing of Construction
- Obtaining Hot Water Delta T at the Buildings
- Campus can operate at lower hot water temperature then predicted.

# Purging Equipment

# Debris Moved from Well Field


BALL STATE UNIVERSITY
Questions?
Ball State University's Conversion to a Campus Geothermal System
MEP ASSOCIATES, LLC
Mike Luster, PE, LEED AP
Principal | Sr. Mechanical Designer
MEP Associates, LLC

# Exhibit RS-J



FEATURE

# Stanford University's "fourth-generation" district energy system

## Combined heat and cooling provides a path to sustainability.

Joseph C. Stagner, PE, Executive Director, Sustainability and Energy Management, Stanford University

Courtesy ZGF Architects LLP. Photo © Robert Canfield

Stanford's new Central Energy Facility uses renewable electricity as a primary fuel source to heat and cool the university. The facility's net-positive-energy administration building is equipped with a 176 kW rooftop solar array.

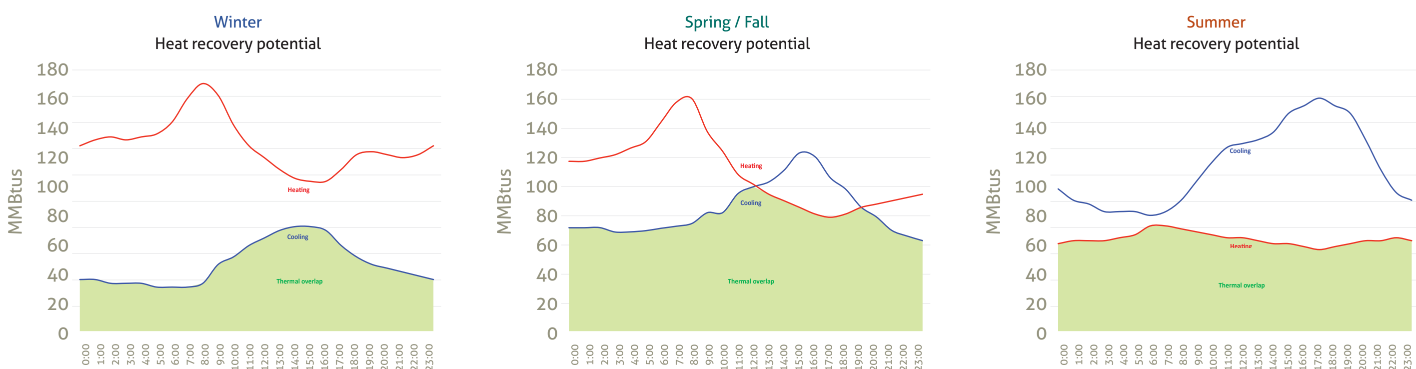
Stanford University is at the heart of one of the birthplaces of innovation, California's Silicon Valley, but you won't find one of its latest creations in lines of code, on a printed circuit board or in a miracle genome. It's in plain sight on the university campus in the form of an attractive architectural interpretation of Stanford's rich history and technological innovation. What's under the hood is even more eye-catching.

In 1987 Stanford took a giant step forward in efficiency and environmental stewardship with the installation of a 50 MW natural gas-fired cogeneration plant to provide electricity, steam and chilled water for its campus. Three decades later, the Cardinal Cogeneration plant has been replaced by the new $468 million Stanford Energy System Innovations (SESI) project, which has taken Stanford into the 21st century with an even more efficient system that immediately reduces campus greenhouse gas emissions by 68 percent, decreases total campus water use by 18 percent and is expected to save the university hundreds of millions of dollars over the next three decades compared to other options. Shifting from gas cogeneration to grid electricity may be contrary to current trends, but heat recovery and renewable power are the keys to economic and sustainable energy for Stanford University.

### HEAT RECOVERY

The cornerstone of SESI is the recovery of waste heat from the campus district chilled-water system to meet building heating and hot water needs. This opportunity was

**Figure 1.** Typical daily heating and cooling profiles and thermal overlap by season, Stanford University, 2008.




**Source: Stanford University.**

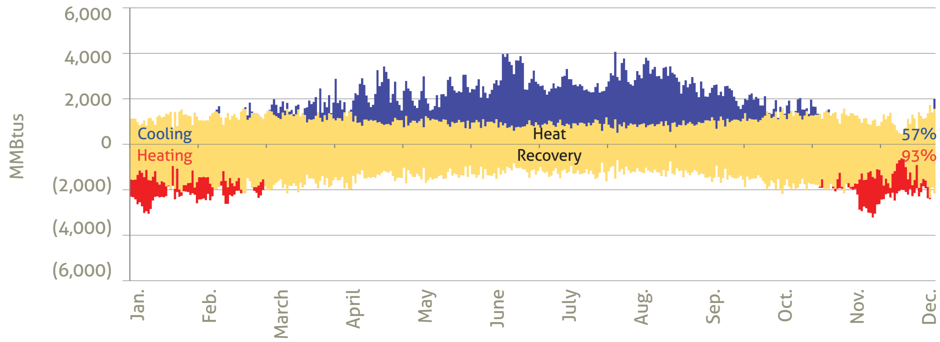
 

discovered in 2008 upon the review of hourly energy production data by Stanford's Utilities engineering staff as they began exploring options to replace the university's aging gas-fired cogeneration plant, scheduled for decommissioning in 2015.

With cooling occurring mostly in summer and heating in winter, the opportunity for heat recovery was assumed to be modest until Stanford engineers compared the simultaneous delivery of heating and cooling from the cogeneration plant over all hours of the year (fig. 1). The large thermal overlap that was revealed opened up a major new opportunity for improvement in the efficiency, economics and sustainability of the university's energy system – namely, a heat recovery-based heating and cooling system that could be powered by renewable electricity instead of natural gas.

Viewed on an annual basis, the thermal overlap and corresponding opportunity for heat recovery totals 75 percent, with 93 percent of campus heating and hot water needs able to be met by recovering 57 percent of the waste heat from the chilled-water system as shown in figure 2.

**Figure 2.** Annual heat recovery potential: heating and cooling overlap, Stanford University, 2016.




**Source: Stanford University.**

## COMBINED HEATING AND COOLING

Stanford refers to its new heat recovery system, which began operation in March 2015, as "CHC" (combined heating and cooling) in contrast to the more widely known SHP (separate heat and power, e.g., gas boilers, electric chillers and grid electricity) and CHP (combined heat and power, e.g., gas-fired cogeneration) district energy options. Key features of the CHC system include replacing steam production and distribution with hot water; large heat recovery chillers (heat pumps); both hot and cold water thermal energy storage; and advanced "model predictive control" energy management software.

## GETTING INTO HOT WATER

Since standard heat pumps can't produce temperatures high enough for steam production, the new CHC system uses hot water, with large reductions in heat distribution line loss and O&M cost compounding the base savings from heat recovery to help justify the switch. To determine required hot water supply temperatures for the new system, engineers examined campus building HVAC designs and performed winter operational tests. It was determined that temperatures of 160 degrees F would suffice most of the time, with 170 F potentially required for periods of extreme cold, followed by return hot water temperatures of 130 F to 140 F. It was noted that a lower hot water supply temperature of 150 F could be used if several laboratory building HVAC systems were modified; however, since those changes could not be made in time for SESI commissioning planned for March 2015, and to provide flexibility in future operations, it was decided that the CHC system would include the ability to provide the higher temperatures. Chilled-water system temperatures were unaffected by the change.

## OPTIMIZING DESIGN AND OPERATION

Developing the CHC design required determining how such a system should be configured and operated to meet loads so that its economics, efficiency and environmental impacts could be compared with those of SHP and CHP options. Stanford could not find commercial energy management software for modeling a CHC system so it developed the patented Central Energy Plant Optimization Model (CEPOM) itself for this purpose.

CEPOM incorporates model predictive control to look at least 168 hours (seven days so as to always include weekends) into the future at any given time to predict hourly system energy loads and grid electricity prices and then produce the optimal hourly dispatch plan for the central energy facility over that period to meet projected loads at the lowest possible cost.

Using this tool, the performance of different CHC system configurations was modeled for an entire year and used to optimize the heat pump, chiller and hot water generator fleets along with hot and cold water thermal energy storage tank sizes to meet the forecasted loads. This design process was performed for multiple years from 2015 to 2050 to develop an optimal plant design and expansion plan to meet campus energy loads over the long term.

Given the usefulness of CEPOM for conceptual planning and detailed design, Stanford realized that it could also be used for actual real-time system operation if it could be translated into an industrial platform and integrated with the base energy plant operating control system. Before investing in migrating CEPOM from Excel spreadsheet to an industrial software platform, Stanford retained consultants to study whether such a software program was commercially available; their conclusion confirmed

Courtesy Todd Quam, Digital Sky Aerial Imaging.

Stanford University's new Central Energy Facility.

Courtesy ZGF Architects LLP. Photo © Robert Canfield.

Natural gas-fired hot water generators are highly efficient at 85 percent higher heating value but are used only part-time from November through February to supply less than 10 percent of annual system heat.

**System Snapshot: Stanford University**

| | Hot water system | Chilled-water system |
|---|---|---|
| **Startup year** | 2015 | 1960s |
| **Number of buildings served** | 300 | 360 |
| **Total square footage served** | 12 million sq ft | 11 million sq ft |
| **Central plant capacity** | 2.2 million MMBtu/year, max peak 300 MMBtu/hr | 75 million ton-hr/year, max peak 25,000 tons/hr |
| **Number of heat pumps** | 3 (heat recovery chillers) | 3 (same heat pumps as serve hot water system) |
| **Number of boilers/chillers** | 3 hot water generators | 4 chillers |
| **Fuel types** | Electricity, natural gas | Electricity |
| **Distribution network length** | 22 miles | 25 miles |
| **Piping type** | Preinsulated welded steel | Welded steel, PVC |
| **Piping diameter range** | 2 to 36 inches | 2 to 42 inches |
| **System pressure** | 65 psi | 68 psi |
| **System temperatures** | 150 F-170 F supply/130 F-140 F return | 42 F-44 F supply/56 F-58 F return |
| **System water volume** | 6 million gal (including thermal energy storage) | 18 million gal (including thermal energy storage) |

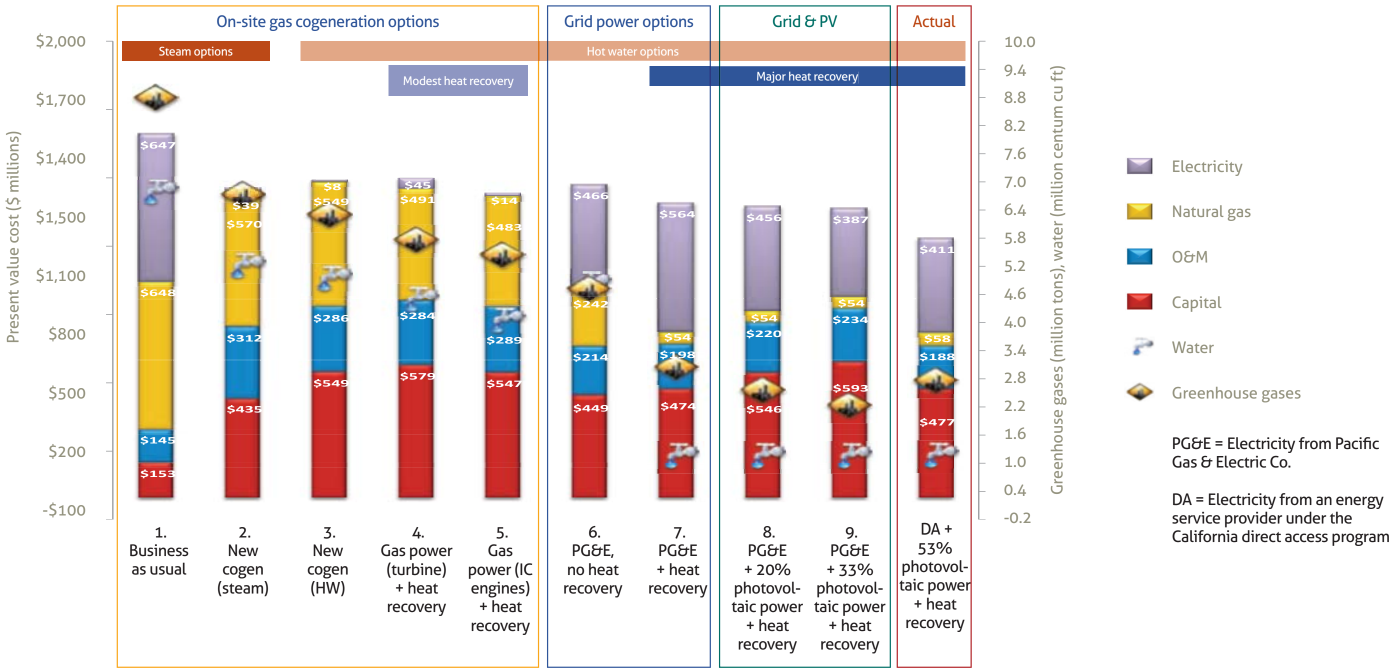
**Source: Stanford University.**

Stanford's own earlier assessment that it was not. Stanford then partnered with Johnson Controls Inc. (JCI), which had already been selected to provide the base energy plant control system, to do this. The resulting program developed by JCI in 2014, known as the Enterprise Optimization Solution (EOS), was deployed to provide real-time optimization and dispatch control of Stanford's new energy system. EOS also includes a planning module that replicates and improves upon CEPOM for system planning and design.

## CENTRAL ENERGY FACILITY

An optimal design for the new Central Energy Facility was developed by Stanford using CEPOM between 2010 and 2012. It improves the reliability of the campus district energy system through simplification by eliminating gas and steam turbines, steam and ice production from the process. This also allows for a much smaller plant staff and greatly reduced O&M cost. The design includes the following

**Figure 3.** Comparison of energy supply replacement options, Stanford University, 2011 with August 2015 update. (Update added for the selected CHC option after the system had become operational, showing actual additional savings achieved through low-cost, long-term solar power purchases.)




**Source: Stanford University.**

initial equipment plus room for expansion through 2050:

- 7,500 tons heat pumps (three 2,500-ton units)
- 12,000 tons chillers (four 3,000-ton units)
- 180 MMBtu gas hot water generators (three 60-MMBtu units)
- 14,500 tons cooling towers
- 90,000 ton-hr cold water thermal energy storage (two tanks totaling 9.5 million gal)
- 600 MMBtu hot water thermal energy storage (one 2.3 million-gal tank)

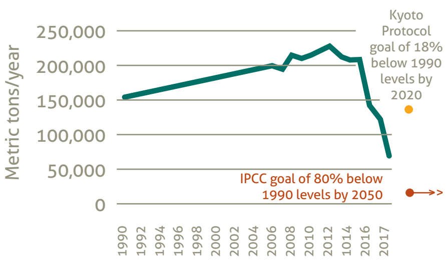
## CHC VS. SHP VS. CHP

Prior to proceeding with CHC, Stanford also developed SHP and CHP system options and compared all using a total lifecycle present value cost analysis including fuel, O&M and capital costs. Long-term gas and electricity prices, inflation and discount rates have a large impact on the comparisons; so to assure objectivity, multiple sources for these were utilized, including consultants, the U.S. Energy Information Administration and Stanford faculty. Assumptions for these and other key factors were then developed for the analysis, including sensitivity bands. Multiple internal and external peer reviews of the models were also performed, and the comparison of long-term energy supply options for Stanford was completed in 2011 and presented as shown in figure 3. The best gas-based option was a hybrid internal combustion engine and heat recovery scheme that presented long-term costs similar to that of CHC. Given the better sustainability performance of the CHC option and the long-term flexibility it provides in energy sourcing by using electricity instead of gas, Stanford selected the combined heating and cooling option.

## SUSTAINABILITY

Construction of the CHC system was approved by Stanford's Board of Trustees in December 2011, and construction began in October 2012. That same year, Stanford achieved "direct access" to California electricity markets and in April 2014 executed long-term power purchase agreements with SunPower Corp. for the development of 73 MW of on- and off-campus photovoltaic solar power generation. (SunPower and its partners own and operate these PV projects.) The 5 MW of rooftop panels on campus buildings, including a 176 kW system at the new Central Energy Facility, and the 68 MW off-site at the Stanford Solar Generating Station located near Mojave, Calif., will be operational by the end of 2016 and supply around 53 percent of Stanford's electricity. This reduces the cost of the CHC option by another $156 million, as shown in the August 2015 cost update in figure 3, and boosts SESI's initial 50 percent greenhouse gas reduction to 68 percent. Greenhouse gas reductions will grow to at least 73 percent as the remainder of Stanford's power from the general grid is cleaned up under state renewable portfolio standards, which advance to 50 percent by 2030. (See Stanford's green-

**Figure 4.** Greenhouse gas emissions trend, Stanford University, 1990-2017. (Graph reflects actual emissions through 2014 and estimated for 2015-2017.)




**Source: Stanford University.**

house gas emissions trends in figure 4.) In addition, SESI saves at least 18 percent of the university's drinking water supply by greatly reducing the use of evaporative cooling towers for heat rejection.

## IMPLEMENTATION

After project approval was granted in December 2011, the task of designing and building the new system in time to meet the March 31, 2015, planned shutdown of the cogeneration plant was a monumental challenge. Components of the $468 million SESI project include the new Central Energy Facility; a 100 MVA, 60 kV high-voltage substation located on the edge of campus one-half mile from the existing cogeneration plant; 22 miles of new hot water piping; conversion of 155 buildings to receive hot water instead of steam; extension and tie-in of existing chilled-water and high-voltage distribution systems to the new Central Energy Facility; and demolition of the cogeneration plant.

As the largest single construction project in Stanford history – with more than two years of disruption touching all areas of the campus – SESI required the full support of the campus community, adept project management and fully committed equipment suppliers and contractors for success. In a remarkable achievement, the project was completed on time and under budget. The new system was started up March 24, 2015, and the cogeneration plant was shut down simultaneously. Over its first year of operation, SESI has exceeded expectations in service reliability and quality with no interruptions in energy supply or significant building heating or cooling problems. Annual energy and O&M costs were $9.9 million, or 21 percent less than anticipated in the 2011 pro forma due to lower-than-expected electricity cost and a 2 percent underrun in O&M cost.

***THE LARGEST SINGLE CONSTRUCTION PROJECT IN STANFORD HISTORY, SESI REQUIRED FULL CAMPUS COMMUNITY SUPPORT, ADEPT PROJECT MANAGEMENT, AND COMMITTED SUPPLIERS AND CONTRACTORS.***

## "FOURTH-GENERATION" DISTRICT ENERGY

In its recently released report, *District Energy in Cities – Unlocking the Potential of Energy Efficiency and Renewable Energy*, the United Nations Environment Programme envisions an evolution from 2020 to 2050 to "fourth-generation" district energy systems. These systems of the future will rely far more on waste heat recovery, heat pumping from ground and water bodies, and renewable energy than on the use of fossil fuels for powering, heating and cooling buildings in order to achieve needed greenhouse gas reductions. UNEP has found that optimizing production, use and delivery of thermal energy for heating and cooling buildings is an essential and often overlooked segment of energy use in cities. Moving to fourth-generation district heating and cooling will enable the use of low-grade thermal energy as a means to reduce regional greenhouse gas emissions. Low-carbon technologies such as heat recovery, deep lake water cooling and thermal storage are valuable strategies to facilitate effective deployment of district energy in cities, communities and campuses. Where waste heat recovery, ground and water body heat exchange, and renewable energy cannot meet the entire energy needs of a district energy system, CHP systems, especially those using sustainable fuels, may also be valuable elements in a district energy system optimized for economics, efficiency and sustainability. These are also the findings of the International Energy Agency in its *Technology Roadmap: Energy-efficient Buildings: Heating and Cooling Equipment.* Stanford's new district energy system may be one of the first large examples of that evolution in a university setting. It has enabled the university to achieve huge reductions in greenhouse gas emissions and exceed state, federal and international goals several decades early and has opened the path to 100 percent reductions in the future.

## TRANSFERABILITY

Stanford conducted a review of thermal load studies done by campus utilities engineers at several major universities including in the Midwest and Northeast – very different climates than that of the university in California. All indicated a 50 percent or more annual overlap in heating and cooling and a greater-than-expected opportunity for a renewable electricity-based heat recovery system, ratifying the findings of Stanford, the IEA and UNEP. At first this seems counterintuitive given the extremely cold winters in the Midwest and Northeast; however, the studies reveal that much of the opportunity for heat recovery occurs in the summer and shoulder seasons, which makes sense given that the lower 48 states have a net environmental heat surplus for half the year.

During that time there is no need to generate additional heat, and heat recovery can typically meet 100 percent of heating and hot water needs in most locations. The magnitude of heat recovery potential in the colder half of the year varies by location, but it is present everywhere year-round and not to an insignificant degree. In colder climates, large-scale ground source heat exchange, such as is implemented at Ball State University, offers a great complement to heat recovery by utilizing the same equipment that is used for heat recovery from campus buildings. Ground source heat exchange can boost annual sustainable heat supply from 50 percent up to almost 100 percent via building heat recovery alone.

While such systems are probably technically feasible in most locations, the economics and sustainability must be analyzed over the long term, given the capital required to make the transition and the projected long-term cost and carbon-intensity of the local electricity supply. The optimal time for making such a transformation is probably when major components of an existing district energy system are near or past their useful lives so as to minimize stranded assets. Stanford's analysis of potential new district energy system schemes revealed that at balanced power, heating and cooling loads, an electricity-based system with moderate amounts of heat recovery and/or renewable power supply in the mix could result in lower overall emissions than new high-efficiency natural gas alternatives even in higher-carbon-intensity regional grids. Currently, the probability of adequate supplies of cost-competitive, sustainable combustion fuels or small-scale carbon capture and storage appears slim over the next decade or more. Given that fossil fuel boilers and cogeneration units typically last 30 years and beyond, this means that any such new equipment installed in the coming years may foreclose an institution's ability to achieve significant greenhouse gas emissions to levels prescribed for minimizing the consequences of climate change. Therefore, when opportunities for major changes in a district energy system present themselves, a transition to an electricity-based system should be seriously considered.

SESI has been recognized at local, state, national and international levels for its innovation and sustainable design. Its various honors include the state of California Governor's Environmental and Economic Leadership Award, the *Engineering News-Record* (ENR) Editor's Choice Best of the Best Projects 2015 award in the United States, the Alliance to Save Energy's Energy Efficiency Visionary Award and, most recently, ENR's Global Best Green Project Award for 2016.

***Joseph C. Stagner, PE,*** *is executive director of the Sustainability and Energy Management Department at Stanford University, where he is responsible for advancing sustainability in campus operations through leadership of the university's Office of Sustainability and Facilities Energy Management; Utilities Services; and Parking and Transportation Services departments. Prior to joining Stanford in 2007, Stagner served on the facilities management team at the University of California, Davis, for 14 years and spent 10 years in various engineering roles on nuclear, geothermal, coal and hydroelectric projects with the Pacific Gas & Electric Co., Sacramento Municipal Utility District and Morrison Knudsen Co. Stagner led development of SESI and created the Central Energy Plant Optimization Model software. He earned a bachelor's degree in civil engineering from the University of Florida and is a registered professional engineer in California. He can be reached at jstagner@stanford.edu*



# Exhibit RS-K

# Carleton College Utility Master Plan

## The Utility Master Plan

Carleton College Heating Plant (c.1910)

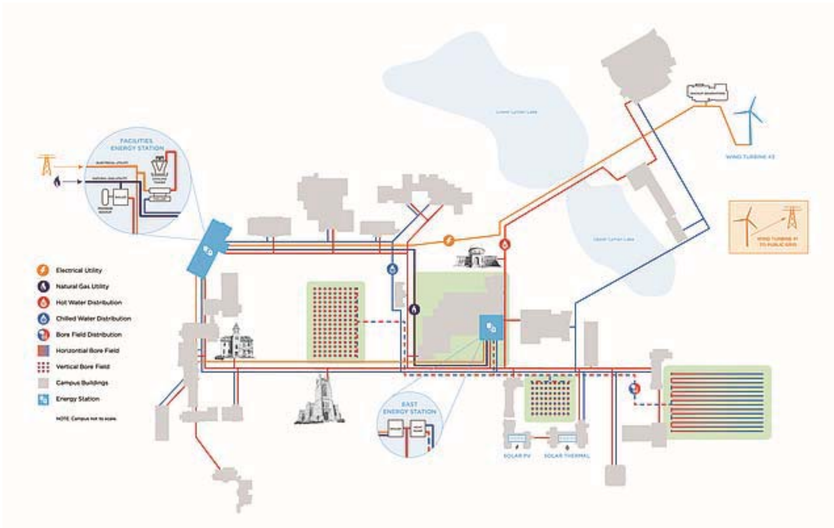
Associate Dean of the College, Gretchen Hofmeister, points to a dashboard that models the UMP system

### Objectives

1. Replace the aging and outdated central plant facilities and provide for future loads as envisioned in the Facility Master Plan
2. Replace the outdated and failing campus steam distribution network and controls
3. Reduce our operating costs and carbon emissions significantly and permanently

### System Overview

1. Transition the existing steam distribution system to a **hot water distribution system**
2. Install a heat pump to take advantage of **simultaneous heating and cooling** loads
3. Tie the heat pump to **geothermal bore fields**
4. Add efficient and/or **renewable onsite electrical generation** system(s)




## Project Timeline

# Exhibit RS-L

# Brown launches three-year, $24 million project to boost thermal efficiency

Conversion from steam to hot-water heating on campus will increase energy efficiency and assist the University in meeting its goals for reduced greenhouse gas emissions by 2020.


Brown University Chief Engineer Thomas Demanche looks over decades-old equipment in the central heating plant. The plant will undergo a complete overhaul as part of the University's three-year thermal efficiency project.

**PROVIDENCE, R.I.** [Brown University] — As part of its continued work to reduce greenhouse gas emissions to 42 percent below 2007 levels by 2020, Brown University will embark on a three-year, $24 million project to increase energy efficiency across campus by replacing its central heating system with one that will generate heat using hot water instead of steam.

“When this project is complete, we will go a long way toward our 42 percent reduction goal,” said Christopher Powell, assistant vice president for sustainable energy and environmental initiatives. “Taking this approach signals that sustainability is a University priority, and Brown is showing significant leadership on this issue — proving that even in a cold climate, large institutions can operate much more efficiently with strategic investments.”

Brown’s 50-year-old steam heating system was due for replacement already, a project that would have cost the University approximately $17 million even with little upgrade in efficiency. Powell says the conversion to a medium-temperature hot water system will markedly increase the thermal efficiency of campus while creating the building blocks for future heat recovery and the use of low-carbon energy sources.

“The reality is that if we had just spent that $17 million, we would simply be implementing old technology,” Powell said. “By spending an additional $7 million, we expect to save more than $1 million in energy costs each year, based upon current utility costs, and help reach our important greenhouse emissions goals.”

Those savings will come in the form of reduced heating costs as well as energy incentives from National Grid, Rhode Island’s natural gas and electricity company.

The thermal efficiency project builds on a series of initiatives led by the Office of Sustainable Energy and Environmental Initiatives after the University launched its ambitious greenhouse gas reduction plan (https://news.brown.edu/articles/2008/01/carbon-reduction) in 2008. In the years since, Brown has decreased its energy-related carbon footprint by 27.4 percent.

This reduction has been accomplished by switching from carbon-intensive No. 6 fuel oil to natural gas at the central heating plant, along with energy efficiency investments across campus including lighting upgrades, laboratory ventilation optimization, insulation repairs and cooling system performance optimization. Since 2008, Brown has invested approximately $32 million in energy efficiency initiatives, which have resulted in annual savings of more than $5 million in energy expenses.

Additionally, Brown’s design and construction staff have implemented high-energy-performance design goals for all new construction, major renovations and acquired facilities on campus. This includes a minimum certification of Leadership in Energy and Environmental Design (LEED) Silver and energy use standards that exceed building code by a minimum of 25 percent.

Not only will the conversion to hot water further decrease Brown's energy consumption by approximately 11 percent, it will enable the future implementation of other efficiency measures such as recovery systems in which emitted heat is captured and reused, Powell said. In addition, a hot water system, unlike a steam-based one, could potentially be supplied by high-tech heating and cooling technology, which in turn could be powered by non-fossil fuel energy sources such as solar, wind or geothermal.

That possibility is the most important long-term advantage of a conversion from steam to hot water, said Stephen Porder, an associate professor of ecology and evolutionary biology and fellow at the Institute at Brown for Environment and Society.

"This is a great first step for Brown, but it's not the final one," Porder said. "Essentially, converting to a hot water system opens up options for potentially getting our campus emissions down to zero."

Porder is also the co-chair of the Sustainability Planning Study Committee, which has been charged with developing a process for creating new University greenhouse gas emissions goals once the existing goals have been achieved. He said that Brown's work to reduce emissions is playing a small but important role in the larger worldwide effort to halt global warming.

"In order to avoid catastrophic climate change, worldwide greenhouse emissions need to be at net zero by the middle of this century," Porder said. "At Brown, we are opening up a pathway to move beyond our goals of 2020 and position the University as a leader, not just among our peers, but also as a leader in confronting climate change, the biggest issue that we face as a global community in the 21st century."

With funding for the project approved by the Corporation of Brown University's Budget and Finance Committee last month, the conversion work will begin in the current academic year with a target completion date of October 2020.

# Exhibit RS-M

# District Energy 101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Integral Group Vancouver

# Contents

# Introduction

Use of district energy systems is gaining momentum across North America. This trend, led by institutional campuses, such as universities or hospitals, and larger-scale commercial developments includes a wide array of individual drivers and ultimate goals including basic performance improvement to existing steam or hot water networks to more ambitious targets, such as a full transition to renewable and zero-carbon energy sources and technologies.

Optimal district energy solutions vary but the traditional approach to district energy typically provides "heating only" service, involving some form of central heating plant — such as a natural gas heat source — and either a steam or high temperature hot water distribution network. This approach no longer meets current trends, needs or goals for the built environment.

Northern European countries are leaders in the district energy trend, focusing on district heating. Since its initial inception, district heating has evolved into four steps, or "Generations" (as coined by EU's Strategic Energy Technologies Information System, or SETIS). These Generations are:

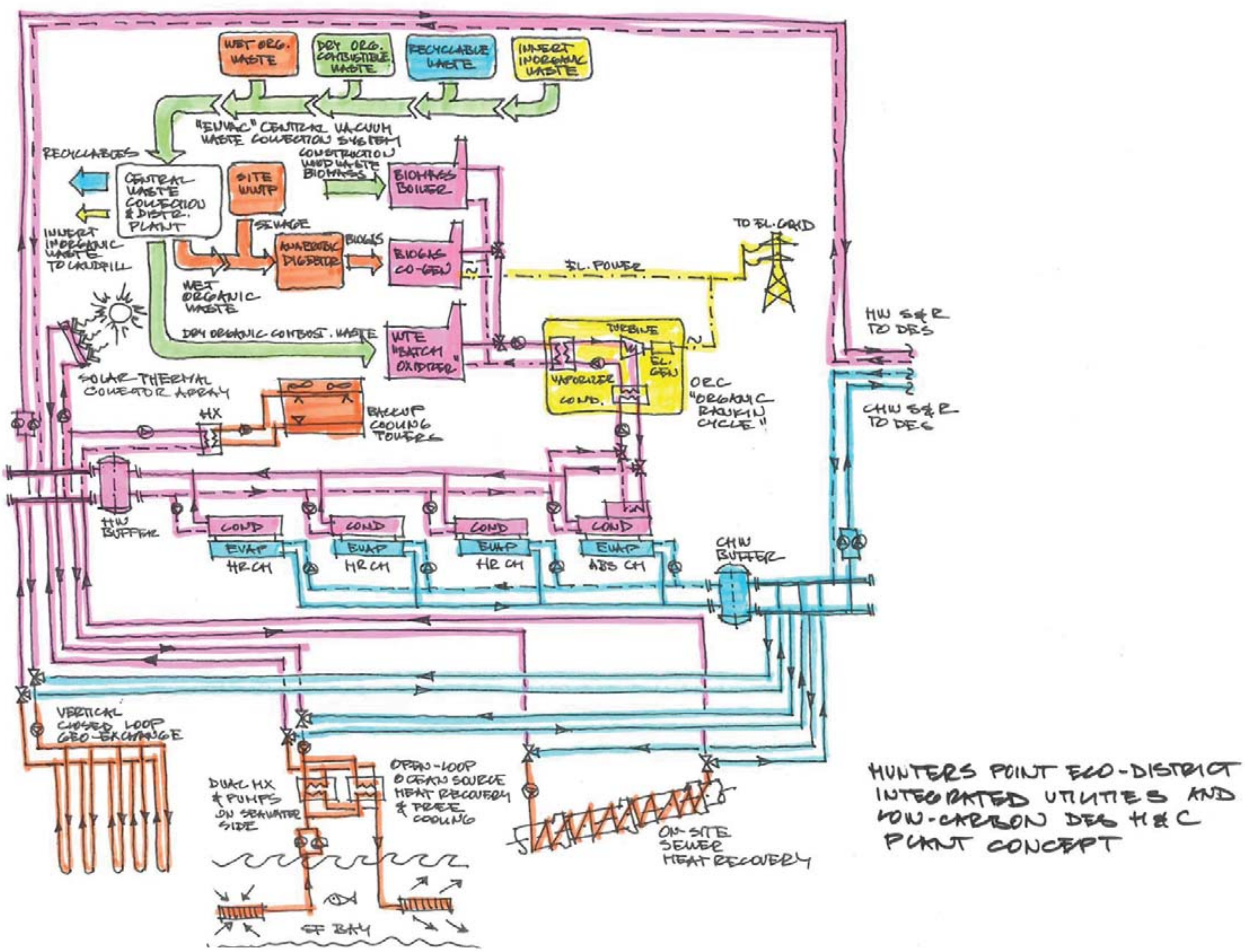
- 1st Generation District Heating: using steam
- 2nd Generation District Heating: using high pressure & high temperature water (>212F/ 100C)
- 3rd Generation District Heating: using high temperature water (<212F/ 100C)
- 4th Generation District Heating: using low temperature water (<140F/ 60C range)

In spite of the evident increase in summertime global temperatures and the corresponding increased need for cooling, the focus of the 4th Generation District Heating approach is still — as the name indicates — heating only.

As an industry leader, Integral Group takes a very different approach. By integrating innovation and creativity, and still adhering to the fundamental laws of physics, we have developed "5th Generation" district energy solutions. These systems provide heating and cooling, are technically sound, have stellar environmental performance (some capable of achieving Net Zero Carbon), and are cost competitive.

Unlike strategies developed by academics, our 5th Generation approach is based on "boots on the ground" experience on a number of our projects. Our innovative district energy solutions form a backbone for the future "6th Generation Multi-Energy Systems," which aim for the flexibility to include a multitude of energy sources and end-use forms including multiple energy conversion technologies, thermal (heating and cooling) and electrical distribution networks, and thermal and electrical storage.

The approach and methodology Integral Group has developed and used successfully for designing many of our innovative 5th and 6th Generation district energy systems can be applied systematically to any district energy project, whether it is an energy masterplan for a university campus or a lean "spartan" district energy project for a neighborhood-scale development. The only variation in approach is the depth and detail into which each of the steps would be developed.




*Low-carbon DES Concept*

# Recommended District Energy Approach & Methodology

## 1. Understand the Project Context and the Client Goals

Understanding the project context and your client's goals is the first and most critical step. To start designing without having clarity on the client's goals or expectations and without understanding project constraints is inefficient and costly. Take the project the wrong direction and result is a mess of unnecessary complications that undermine not only the technical, but also the financial performance of the project. This can lead to the loss of the client's trust in competency, and potentially a ruined relationship.

Being proactive in helping clients to first understand what they are asking for can prevent this from happening. For most clients, the subject of district energy with all of the associated considerations (technical, environmental, financial, regulatory, and so on.) is new and quite often confusing. Clients typically have one or two main goals they are able to define and communicate directly, but are often unaware of the multitude of other indirect elements, constraints and potential consequences that must be considered. Asking the right questions and leading them through the process of clarifying their own project goals while also making them fully aware of all associated implications is our responsibility. After the full set and hierarchy of the project goals and constraints has been clarified and agreed upon with the client, the design team can follow the steps below to develop an optimal district energy solution.



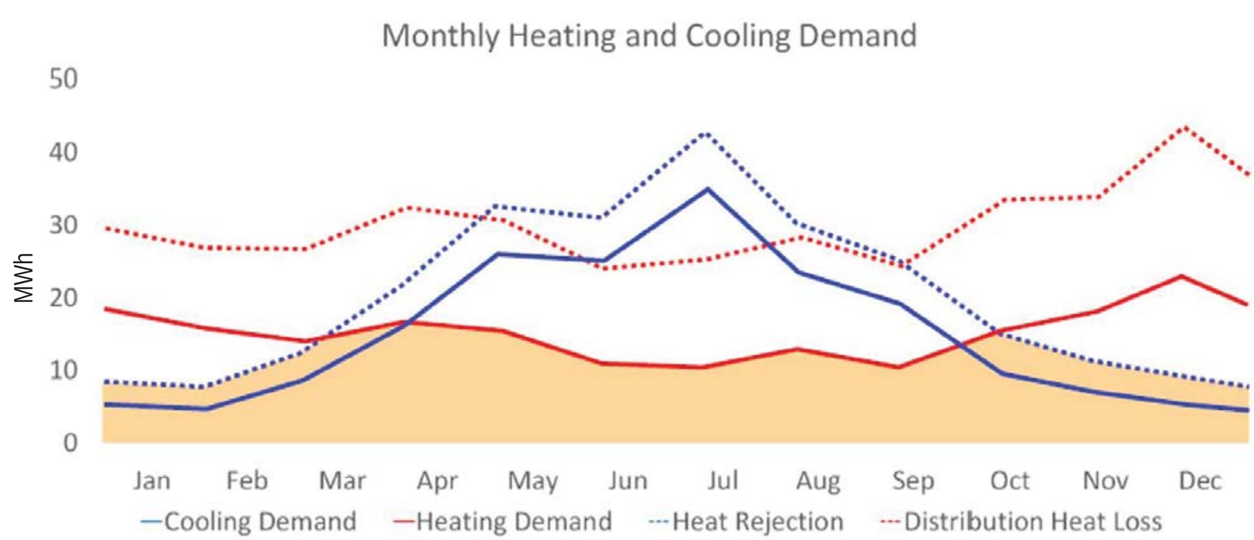
*Key Considerations*

One of the most challenging elements on any district energy project is the financial context and pro-forma. In many cases, the client's expectation is that the new district energy system will be able to compete not only in terms of low energy use, low carbon emissions, and low energy cost, but also in terms of the overall cost. It is expected for a client to compare district energy options with a "business as usual" (BAU) scenario. The BAU scenario is typically represented by a stand-alone building system using conventional energy sources (electricity and natural gas) alongside energy conversion technologies. However, electrical and natural gas distribution infrastructure has been largely paid for and the initial cost was recovered long ago. Any new district energy system requires investment not only in the new energy technologies but also in the new energy distribution infrastructure, and therefore will always cost more than the BAU scenario. Consequently, the only meaningful financial pro-forma for a new district energy system is always based on long-term overall financial performance. This could include life-cycle cost analysis, such as a "levelized energy cost" comparison with the BAU scenario.performance. This could include life-cycle cost analysis, such as a "levelized energy cost" comparison with the BAU scenario.

## 2. Develop & Understand the Energy Demand Profile

Heating-only district energy systems and their heating plant capacities have traditionally been sized based on peak heating design conditions. They can be downsized by a certain amount to account for diversity in the heating demand and "load duration" curve, an approach which is adequate for heating-only systems. However, for the 5th and 6th Generation district energy systems — which often include both heating and cooling, energy recovery, co-generation or even tri-generation, and various low-grade (low-exergy) energy sources — require a much more comprehensive understanding of the energy demand.

A full annual energy demand and availability profile (i.e. monthly, daily, hourly) of all included energy forms needs to be developed. For new developments, this energy demand profile will be generated by energy modeling based on the anticipated building typology mix, occupancy schedule and local hourly weather data. For existing developments, such energy demand profiles can be generated based on available measured energy uses and/or utility billing records.

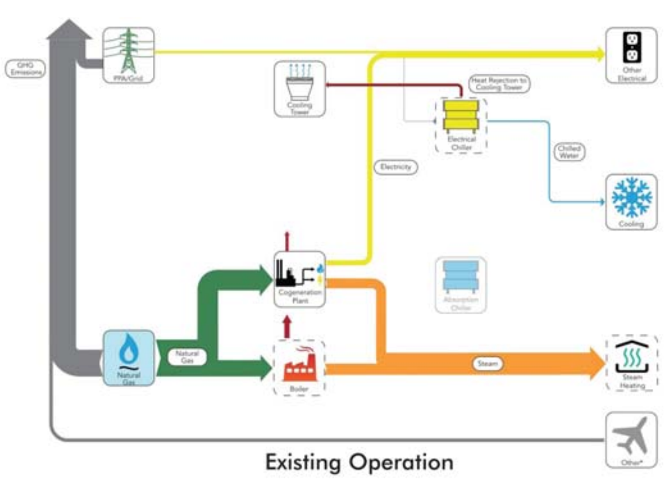



*Energy Demand Profile*
*Heat Source and Heat Sink*

# 3. Identify, Review & Understand Existing Infrastructure

Many institutional campuses across North America have some form of district energy infrastructure in place. They are typically a heating-only district energy system, and use steam or high-pressure and high-temperature water as the heating medium (1st or 2nd Generation District Heating.) Some also include a central chiller plant and chilled water distribution network, or even on-site electrical power generation, occasionally configured as a co-generation system. For those that do incorporate cooling, the heating and cooling plants and distribution networks are typically independent from each other. For these projects, it is important to gain a good understanding of the existing energy components and infrastructure, especially their operating condition and remaining service life. With this information, we are able to develop the recommended solution that could combine upgrades and replacements within the existing system with new district energy components.

Given that constructing brand new district scale energy distribution networks within existing campuses or developments pose numerous technical and financial challenges, re-use and upgrade of existing energy distribution networks should always be carefully considered. For any new developments, district energy options are typically unrestrained by these considerations.




*Existing Campus Energy Demand*

## Smith College Campus Energy Decarbonization Study

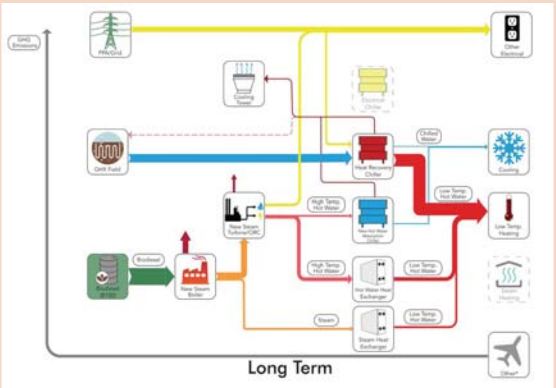
Location: Northampton, MA
Area: 147 Acres
Sustainability: Zero Emissions Campus Target
Completion Date: 2016

Smith College had committed to being a Zero Emissions campus by 2030. Integral Group developed and evaluated available options and recommend a clear strategy and comprehensive technical concept that would enable Smith College to achieve its 2030 Climate Targets.

The study had carefully considered a multitude of technical, economic, environmental, and logistical factors, opportunities and limitations in the specific context of Smith College existing energy infrastructure and its ultimate goals.

The recommended strategy comprised the following short, medium, and long term progression steps:

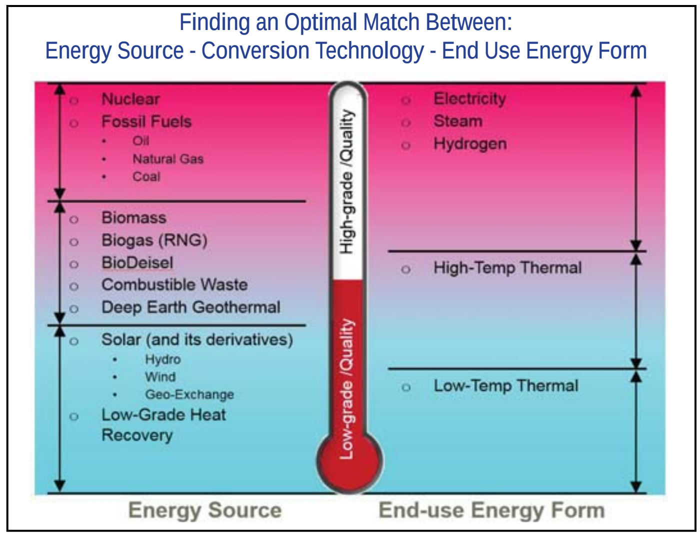
1. Switching from natural gas to renewable biodiesel in the existing central plant steam boilers;
2. Implementation of the initial stage of the new campus scale geo-exchange system with heat recovery chillers and new low-temperature heating distribution network;
3. Extending, completing and eventual complete switch-over to the new campus scale low-temperature heating distribution network and addition of new tri-generation system based on renewable biodiesel, and decommissioning of the existing steam heating and CHP plants and steam heating distribution network.



# 4. Develop & Evaluate High-Level District Energy Strategies

It is important to develop and evaluate high-level district energy strategies before diving into design details. Too often we dive into detail too soon and too deep, evaluating specific energy sources and technologies and their combinations, or we will defer to our favorite universal district energy solution. These approaches are, at best, less effective, or at worst, completely misaligned with the client's expectations. It is a much more effective approach to break down and evaluate the possible district energy strategies at a high-level.


*High-Level DE Evaluation Approach*




*Usability of Energy-Exergy*

These strategies are rooted in two key district energy approaches (as categorized and coined by Integral Group):

- **Centralized vs. Distributed**
- **High-Exergy vs. Low-Exergy (High-Ex, Low-Ex)**

These approaches combine for four possible strategies:

A. **Centralized High-Ex (DE heating systems with central plant and steam or high-temp water)**
B. **Distributed High-Ex (building-level plants using high temp water)**
C. **Centralized Low-Ex (DE heating systems with central plant and low- temp water; <140F/ 60C)**
D. **Distributed Low-Ex (building-level plants using low-temp water; <140F/ 60C)**

**Centralized vs. Distributed**

The centralized approach is best suited for upgrades or expansions to an existing district energy distribution network or for new district energy networks serving large and relatively compact developments where new district energy network is relatively small in relation to the large energy load it will serve. The distributed approach is best suited for new and sparse developments with relatively low load density, where the cost of constructing a new district energy network outweighs the other benefits of a centralized district energy system.

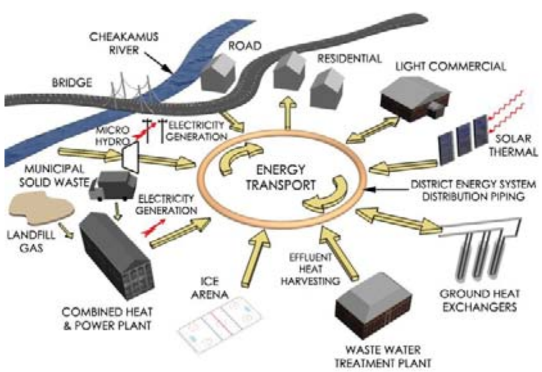
**Low-Ex vs. High-Ex**

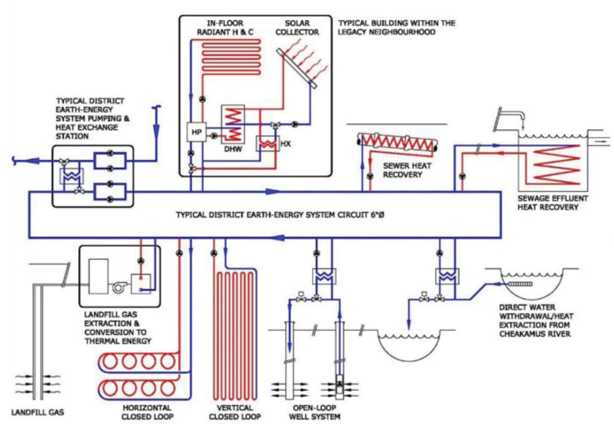
The term Exergy (Ex) describes the quality or usability of energy in any given form. In the context of district energy systems, the High-Ex category encompasses all systems that distribute high-grade forms of energy, such as steam, high-temperature hot water, or electricity. In a High-Ex district energy system, the heating portion of the system operates with temperatures higher than 140F/ 60C. In this category, the possibilities for integrating recovery of various forms of low-grade (Low-Ex) "free waste" thermal energy or low-grade renewable energy, is limited.

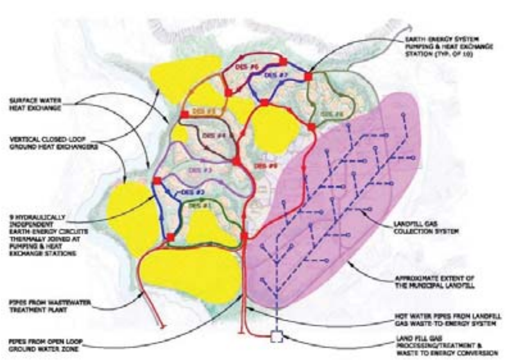
The Low-Ex district energy category includes all versions of district energy systems that distribute low-temperature heating water (<140F/60C) as the heating medium. Using low-temperature water opens the possibilities for integrating recovery of various forms of free low-grade waste energy or low-grade renewable energy.

Many large-scale developments have a significant amount of heating and cooling demand simultaneously. Low-Ex systems are ideally suited for these applications as they effectively provide both services with a single technology: heat-recovery chillers or heat pumps capable of utilizing available low-grade thermal energy sources or sinks (i.e. recovered waste heat from cooling, or from the surrounding environment; ambient air, geo-exchange, sewer, or solar thermal). In the Centralized Low-Ex district energy system, the heat recovery chillers or heat pumps are the core of the central plant, and are the common technology serving two parallel distribution networks — a low-temp heating network and a chilled water network.

A Distributed Low-Ex district energy system is quite unique. It is best configured as an **"Ambient Temperature Loop"** system — a term coined by our team in 2005 when we developed the concept for the Whistler Olympic Village. This system connects multiple low-grade heat sources and sinks via an uninsulated piping network with distributed heating and cooling heat pump plants extracting and rejecting thermal energy from/into it. It is worth noting that this particular district energy system also provides the most versatile backbone for the **6th Generation Multi-Energy District Systems.**



*Whistler Olympic Village Original Ambient Loop Concept*

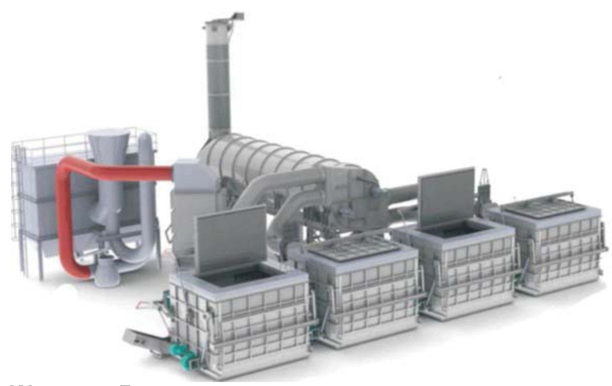
## 5. Identify & Review Applicable Energy Sources & Technologies

Evaluation of the four possible high-level strategies can be done quickly and effectively, provided there is clarity on the client's objectives. Once the project context is evaluated, the best high-level strategy can be explored in more detail. This involves identifying and evaluating all applicable energy sources and technologies, and their combinations that work well with the chosen district energy strategy. A project's specific requirements and constraints could include energy or carbon emission targets, capital, and life cycle (or "levelized energy" cost). Depending on these requirements and constraints, a number of different complementary energy source and technology combinations can be identified.

## 6. Develop & Analyze Specific DE Options

Once the specific energy source and technology combinations are selected for consideration, they need to be developed into district energy system options. This needs to be done to a sufficient level of technical detail to allow for side-by-side comparison. At a minimum, the individual systems should be evaluated in the context of their technical feasibility, economic viability (financial pro-forma) and environmental impacts. The outcome of this step is the recommendation of the district energy option that is best suited for the project.

**Biomass Tri-Generation**
Heathrow Airport T2 10MW Biomass Cogeneration Plant



**Waste-to-Energy**
"Batch Oxidization System" by WTEC

**Absorption Chillers**
University of Lund DES, Sweden

*YVR & Sea Island DES: Considered DES Technologies*

## Vancouver International Airport & Sea Island DES Concept & Feasibility Study

Location: Richmond, BC

Integral Group was engaged by the Vancouver Airport Authority to conduct a feasibility assessment for developing a Sea Island district energy system. The goal of the study was to identify and evaluate the most appropriate district energy system concepts for YVR and Sea Island.

We developed two DES concepts; 'Ultimate' and 'Minimal', that set the outer limits of what was feasible for a Sea Island district energy system. With complete resource self-sufficiency on one end and the bare minimum necessary on the other, these two concepts represented the most and least the Airport Authority would be able to do. Based on our analysis and the Airport Authority's interest in reducing its energy use, carbon emissions and operating costs, we also developed the Optimal DES concept best meeting the overall Airport Authority's objectives. The Optimal DES concept includes tri-generation system (electricity, heating and absorption cooling) powered by biomass, and was sized to meet the Airport Authority's current annual electrical demand and 60% of Sea Island's forecasted electricity demand and over 70% of its forecasted heating and cooling demand, without creating an island wide network. It can serve as a backup electricity source for YVR if necessary, thereby offering YVR a level of redundancy that it currently does not have. As the next step, we are now conducting a more detailed evaluation of the technical solution along with a business case for the optimal concept.

# 7. Develop Design & Implementation Steps for the Recommended DE Option

The final step is developing the recommended district energy strategy into detailed construction documents. These must be fully coordinated with all involved disciplines, and must include costing and a specific implementation phasing plan. Phasing is especially crucial for projects involving upgrades or modifications to existing district energy plants or distribution networks, as they often require minimized shutdowns of plant components and loss of service to existing buildings. In most cases involving transition from High-Ex to Low-Ex district energy systems, this step will also include design for upgrades of the existing in-building HVAC systems.

# Conclusion

The approach outlined above is simple in its basic structure. However, when followed and complemented with a well-balanced level of innovation, pragmatic engineering design and financial analysis, it can be used as a solid and effective framework for any district energy system design, including even the most ambitious 5th and 6th Generation Multi-Energy District Systems.

## About Integral Group

Integral Group is an interactive global network of design professionals collaborating under a single deep green engineering umbrella. We provide a full range of building system design and energy analysis services, with a staff regarded as innovative leaders in their fields.

Our organization is designed to specifically meet the challenge of accelerating critical change in sustainable building practices. Our integrated approach to building systems design allows us to enhance opportunities that nature provides, working in harmony with a building's environment to reduce its reliance on outside energy sources. We specialize in the design of simple, elegant, cost-effective systems for high performance building environments and provide comprehensive analyses that help prioritize their energy saving potential and carbon reduction effect.

www.integralgroup.com

# Exhibit RS-N

Ohio Environmental Protection Agency

**Mike DeWine**, Governor
**Jon Husted**, Lt. Governor
**Laurie A. Stevenson**, Director

10/25/2019

Certified Mail

| | |
|---|---|
| No | TOXIC REVIEW |
| No | PSD |
| No | SYNTHETIC MINOR TO AVOID MAJOR NSR |
| No | CEMS |
| No | MACT/GACT |
| Yes | NSPS |
| No | NESHAPS |
| No | NETTING |
| No | MAJOR NON-ATTAINMENT |
| No | MODELING SUBMITTED |
| No | MAJOR GHG |
| No | SYNTHETIC MINOR TO AVOID MAJOR GHG |

Gregg Garbesi
ENGIE Services, Inc.
2001 Millikin Road
Suite 200
Columbus, OH 43210

RE: FINAL AIR POLLUTION PERMIT-TO-INSTALL
Facility ID: 0125044324
Permit Number: P0126155
Permit Type: Initial Installation
County: Franklin

Dear Permit Holder:

Enclosed please find a final Ohio Environmental Protection Agency (EPA) Air Pollution Permit-to-Install (PTI) which will allow you to install or modify the described emissions unit(s) in a manner indicated in the permit. Because this permit contains several conditions and restrictions, we urge you to read it carefully. Because this permit contains conditions and restrictions, please read it very carefully. In this letter you will find the information on the following topics:

- **How to appeal this permit**
- **How to save money, reduce pollution and reduce energy consumption**
- **How to give us feedback on your permitting experience**
- **How to get an electronic copy of your permit**
- **What should you do if you notice a spill or environmental emergency?**

**How to appeal this permit**

The issuance of this PTI is a final action of the Director and may be appealed to the Environmental Review Appeals Commission pursuant to Section 3745.04 of the Ohio Revised Code. The appeal must be in writing and set forth the action complained of and the grounds upon which the appeal is based. The appeal must be filed with the Commission within thirty (30) days after notice of the Director's action. The appeal must be accompanied by a filing fee of $70.00, made payable to "Ohio Treasurer Robert Sprague," which the Commission, in its discretion, may reduce if by affidavit you demonstrate that payment of the full amount of the fee would cause extreme hardship. Notice of the filing of the appeal shall be filed with the Director within three (3) days of filing with the Commission. Ohio EPA requests that a copy of the appeal be served upon the Ohio Attorney General's Office, Environmental Enforcement Section. An appeal may be filed with the Environmental Review Appeals Commission at the following address:

Environmental Review Appeals Commission
30 East Broad Street, 4th Floor
Columbus, OH 43215

**How to save money, reduce pollution and reduce energy consumption**

The Ohio EPA is encouraging companies to investigate pollution prevention and energy conservation. Not only will this reduce pollution and energy consumption, but it can also save you money. If you would like to learn ways you can save money while protecting the environment, please contact our Office of Compliance Assistance and Pollution Prevention at (614) 644-3469. Additionally, all or a portion of the capital expenditures related to installing air pollution control equipment under this permit may be eligible for financing and State tax exemptions through the Ohio Air Quality Development Authority (OAQDA) under Ohio Revised Code Section 3706. For more information, see the OAQDA website: www.ohioairquality.org/clean_air

**How to give us feedback on your permitting experience**

Please complete a survey at www.epa.ohio.gov/survey.aspx and give us feedback on your permitting experience. We value your opinion.

**How to get an electronic copy of your permit**

This permit can be accessed electronically via the eBusiness Center: Air Services in Microsoft Word format or in Adobe PDF on the Division of Air Pollution Control (DAPC) Web page, www.epa.ohio.gov/dapc by clicking the "Search for Permits" link under the Permitting topic on the Programs tab.

**What should you do if you notice a spill or environmental emergency?**

Any spill or environmental emergency which may endanger human health or the environment should be reported to the Emergency Response 24-HOUR EMERGENCY SPILL HOTLINE toll-free at (800) 282-9378. Report non-emergency complaints to the appropriate district office or local air agency.

If you have any questions regarding your permit, please contact Ohio EPA DAPC, Central District Office at (614)728-3778 or the Office of Compliance Assistance and Pollution Prevention at (614) 644-3469.

Sincerely,

Michael E. Hopkins

Michael E. Hopkins, P.E.
Assistant Chief, Permitting Section, DAPC

cc: U.S. EPA
Ohio EPA-CDO

**FINAL**

# Division of Air Pollution Control
# Permit-to-Install
for
ENGIE Services, Inc.

| | |
|---|---|
| Facility ID: | 0125044324 |
| Permit Number: | P0126155 |
| Permit Type: | Initial Installation |
| Issued: | 10/25/2019 |
| Effective: | 10/25/2019 |

Ohio Environmental Protection Agency

**Division of Air Pollution Control**
**Permit-to-Install**
for
ENGIE Services, Inc.

**Table of Contents**

**Final Permit-to-Install**
ENGIE Services, Inc.
**Permit Number:** P0126155
**Facility ID:** 0125044324
**Effective Date:** 10/25/2019

# Authorization

| | |
|---|---|
| Facility ID: | 0125044324 |
| Facility Description: | |
| Application Number(s): | A0061672, A0064024 |
| Permit Number: | P0126155 |
| Permit Description: | ENGIE Services, Inc. (ENGIE) is the contract operator of utility and steam production facilities at the Ohio State University (OSU). This permitting action is for a Combined Heat and Power facility (CHP), which is part of the Smart Campus Project. This initial installation PTI is for two CHP units which consist of a combustion turbine and a duct burner/heat recovery steam generator (HRSG). Two noncontact water-cooling towers that are de minimis and trivial units will also be installed as part of this project. |
| Permit Type: | Initial Installation |
| Permit Fee: | $2,000.00 |
| Issue Date: | 10/25/2019 |
| Effective Date: | 10/25/2019 |

This document constitutes issuance to:

ENGIE Services, Inc.
2003 Millikin Rd
Columbus, OH 43210

of a Permit-to-Install for the emissions unit(s) identified on the following page.

Ohio Environmental Protection Agency (EPA) District Office or local air agency responsible for processing and administering your permit:

Ohio EPA DAPC, Central District Office
50 West Town St., 5th Floor
P.O. Box 1049
Columbus, OH 43216-1049
(614)728-3778

The above named entity is hereby granted a Permit-to-Install for the emissions unit(s) listed in this section pursuant to Chapter 3745-31 of the Ohio Administrative Code. Issuance of this permit does not constitute expressed or implied approval or agreement that, if constructed or modified in accordance with the plans included in the application, the emissions unit(s) of environmental pollutants will operate in compliance with applicable State and Federal laws and regulations, and does not constitute expressed or implied assurance that if constructed or modified in accordance with those plans and specifications, the above described emissions unit(s) of pollutants will be granted the necessary permits to operate (air) or NPDES permits as applicable.

This permit is granted subject to the conditions attached hereto.

Ohio Environmental Protection Agency

Laurie A. Stevenson

Laurie A. Stevenson
Director

# Authorization (continued)

Permit Number: P0126155
Permit Description: ENGIE Services, Inc. (ENGIE) is the contract operator of utility and steam production facilities at the Ohio State University (OSU). This permitting action is for a Combined Heat and Power facility (CHP), which is part of the Smart Campus Project. This initial installation PTI is for two CHP units which consist of a combustion turbine and a duct burner/heat recovery steam generator (HRSG). Two noncontact water-cooling towers that are de minimis and trivial units will also be installed as part of this project.

Permits for the following Emissions Unit(s) or groups of Emissions Units are in this document as indicated below:

**Group Name: CHP Units**

| | |
|---|---|
| **Emissions Unit ID:** | **B271** |
| Company Equipment ID: | CHP Unit #1 |
| Superseded Permit Number: | |
| General Permit Category and Type: | Not Applicable |
| **Emissions Unit ID:** | **B272** |
| Company Equipment ID: | CHP Unit #2 |
| Superseded Permit Number: | |
| General Permit Category and Type: | Not Applicable |

# A. Standard Terms and Conditions

**1. Federally Enforceable Standard Terms and Conditions**

a) All Standard Terms and Conditions are federally enforceable, with the exception of those listed below which are enforceable under State law only:

(1) Standard Term and Condition A.2.a), Severability Clause

(2) Standard Term and Condition A.3.c) through A. 3.e) General Requirements

(3) Standard Term and Condition A.6.c) and A. 6.d), Compliance Requirements

(4) Standard Term and Condition A.9., Reporting Requirements

(5) Standard Term and Condition A.10., Applicability

(6) Standard Term and Condition A.11.b) through A.11.e), Construction of New Source(s) and Authorization to Install

(7) Standard Term and Condition A.14., Public Disclosure

(8) Standard Term and Condition A.15., Additional Reporting Requirements When There Are No Deviations of Federally Enforceable Emission Limitations, Operational Restrictions, or Control Device Operating Parameter Limitations

(9) Standard Term and Condition A.16., Fees

(10) Standard Term and Condition A.17., Permit Transfers

**2. Severability Clause**

a) A determination that any term or condition of this permit is invalid shall not invalidate the force or effect of any other term or condition thereof, except to the extent that any other term or condition depends in whole or in part for its operation or implementation upon the term or condition declared invalid.

b) All terms and conditions designated in parts B and C of this permit are federally enforceable as a practical matter, if they are required under the Act, or any of its applicable requirements, including relevant provisions designed to limit the potential to emit of a source, are enforceable by the Administrator of the U.S. EPA and the State and by citizens (to the extent allowed by section 304 of the Act) under the Act. Terms and conditions in parts B and C of this permit shall not be federally enforceable and shall be enforceable under State law only, only if specifically identified in this permit as such.

**3. General Requirements**

a) Any noncompliance with the federally enforceable terms and conditions of this permit constitutes a violation of the Act, and is grounds for enforcement action or for permit revocation, revocation and re-issuance, or modification.

b) It shall not be a defense for the permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the federally enforceable terms and conditions of this permit.

c) This permit may be modified, revoked, or revoked and reissued, for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or revocation, or of a notification of planned changes or anticipated noncompliance does not stay any term and condition of this permit.

d) This permit does not convey any property rights of any sort, or any exclusive privilege.

e) The permittee shall furnish to the Director of the Ohio EPA, or an authorized representative of the Director, upon receipt of a written request and within a reasonable time, any information that may be requested to determine whether cause exists for modifying or revoking this permit or to determine compliance with this permit. Upon request, the permittee shall also furnish to the Director or an authorized representative of the Director, copies of records required to be kept by this permit. For information claimed to be confidential in the submittal to the Director, if the Administrator of the U.S. EPA requests such information, the permittee may furnish such records directly to the Administrator along with a claim of confidentiality.

**4. Monitoring and Related Record Keeping and Reporting Requirements**

a) Except as may otherwise be provided in the terms and conditions for a specific emissions unit, the permittee shall maintain records that include the following, where applicable, for any required monitoring under this permit:

(1) The date, place (as defined in the permit), and time of sampling or measurements.

(2) The date(s) analyses were performed.

(3) The company or entity that performed the analyses.

(4) The analytical techniques or methods used.

(5) The results of such analyses.

(6) The operating conditions existing at the time of sampling or measurement.

b) Each record of any monitoring data, testing data, and support information required pursuant to this permit shall be retained for a period of five years from the date the record was created. Support information shall include, but not be limited to all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Such records may be maintained in computerized form.

c) Except as may otherwise be provided in the terms and conditions for a specific emissions unit, the permittee shall submit required reports in the following manner:

(1) Reports of any required monitoring and/or recordkeeping of federally enforceable information shall be submitted to the Ohio EPA DAPC, Central District Office.

(2) Quarterly written reports of (i) any deviations from federally enforceable emission limitations, operational restrictions, and control device operating parameter limitations, excluding deviations resulting from malfunctions reported in accordance with OAC rule 3745-15-06, that have been detected by the testing, monitoring and recordkeeping requirements specified in this permit, (ii) the probable cause of such deviations, and (iii) any corrective actions or preventive measures taken, shall be made to the Ohio EPA DAPC, Central District Office. The written reports shall be submitted (i.e., postmarked) quarterly, by January 31, April 30, July 31, and October 31 of each year and shall cover the previous calendar quarters. See A.15. below if no deviations occurred during the quarter.

(3) Written reports, which identify any deviations from the federally enforceable monitoring, recordkeeping, and reporting requirements contained in this permit shall be submitted to the Ohio EPA DAPC, Central District Office every six months, by January 31 and July 31 of each year for the previous six calendar months. If no deviations occurred during a six-month period, the permittee shall submit a semi-annual report, which states that no deviations occurred during that period.

(4) This permit is for an emissions unit located at a Title V facility. Each written report shall be signed by a responsible official certifying that, based on information and belief formed after reasonable inquiry, the statements and information in the report are true, accurate, and complete.

d) The permittee shall report actual emissions pursuant to OAC Chapter 3745-78 for the purpose of collecting Air Pollution Control Fees.

## 5. Scheduled Maintenance/Malfunction Reporting

Any scheduled maintenance of air pollution control equipment shall be performed in accordance with paragraph (A) of OAC rule 3745-15-06. The malfunction, i.e., upset, of any emissions units or any associated air pollution control system(s) shall be reported to the Ohio EPA DAPC, Central District Office in accordance with paragraph (B) of OAC rule 3745-15-06. (The definition of an upset condition shall be the same as that used in OAC rule 3745-15-06(B)(1) for a malfunction.) The verbal and written reports shall be submitted pursuant to OAC rule 3745-15-06.

Except as provided in that rule, any scheduled maintenance or malfunction necessitating the shutdown or bypassing of any air pollution control system(s) shall be accompanied by the shutdown of the emission unit(s) that is (are) served by such control system(s).

## 6. Compliance Requirements

a) All applications, notifications or reports required by terms and conditions in this permit to be submitted or "reported in writing" are to be submitted to Ohio EPA through the Ohio EPA's eBusiness Center: Air Services web service ("Air Services"). Ohio EPA will accept hard copy submittals on an as-needed basis if the permittee cannot submit the required documents through the Ohio EPA eBusiness Center. In the event of an alternative hard copy submission in lieu of the eBusiness Center, the post-marked date or the date the document is delivered in person will be recognized as the date submitted. Electronic submission of applications, notifications or reports required to be submitted to Ohio EPA fulfills the requirement to submit the required information to the Director, the appropriate Ohio EPA District Office or contracted local air agency, and/or any other individual or organization specifically identified as an additional recipient identified in this permit unless otherwise specified. Consistent with OAC rule 3745-15-03, the electronic signature date shall constitute the date that the required application, notification or report is considered to be "submitted". Any document requiring signature may be represented by entry of the personal identification number (PIN) by responsible official as part of the electronic submission process or by the scanned attestation document signed by the Authorized Representative that is attached to the electronically submitted written report.

Any document (including reports) required to be submitted and required by a federally applicable requirement in this permit shall include a certification by a Responsible Official that, based on information and belief formed after reasonable inquiry, the statements in the document are true, accurate, and complete.

b) Upon presentation of credentials and other documents as may be required by law, the permittee shall allow the Director of the Ohio EPA or an authorized representative of the Director to:

(1) At reasonable times, enter upon the permittee's premises where a source is located or the emissions-related activity is conducted, or where records must be kept under the conditions of this permit.

(2) Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit, subject to the protection from disclosure to the public of confidential information consistent with ORC section 3704.08.

(3) Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit.

(4) As authorized by the Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit and applicable requirements.

c) The permittee shall submit progress reports to the Ohio EPA DAPC, Central District Office concerning any schedule of compliance for meeting an applicable requirement. Progress reports shall be submitted semiannually or more frequently if specified in the applicable requirement or by the Director of the Ohio EPA. Progress reports shall contain the following:

(1) Dates for achieving the activities, milestones, or compliance required in any schedule of compliance, and dates when such activities, milestones, or compliance were achieved.

(2) An explanation of why any dates in any schedule of compliance were not or will not be met, and any preventive or corrective measures adopted.

**7. Best Available Technology**

As specified in OAC Rule 3745-31-05, new sources that must employ Best Available Technology (BAT) shall comply with the Applicable Emission Limitations/Control Measures identified as BAT for each subject emissions unit.

**8. Air Pollution Nuisance**

The air contaminants emitted by the emissions units covered by this permit shall not cause a public nuisance, in violation of OAC rule 3745-15-07.

**9. Reporting Requirements**

The permittee shall submit required reports in the following manner:

a) Reports of any required monitoring and/or recordkeeping of state-only enforceable information shall be submitted to the Ohio EPA DAPC, Central District Office.

b) Except as otherwise may be provided in the terms and conditions for a specific emissions unit, quarterly written reports of (a) any deviations (excursions) from state-only required emission limitations, operational restrictions, and control device operating parameter limitations that have been detected by the testing, monitoring, and recordkeeping requirements specified in this permit, (b) the probable cause of such deviations, and (c) any corrective actions or preventive measures which have been or will be taken, shall be submitted to the Ohio EPA DAPC, Central District Office. If no deviations occurred during a calendar quarter, the permittee shall submit a quarterly report, which states that no deviations occurred during that quarter. The reports shall be submitted quarterly, by January 31, April 30, July 31, and October 31 of each year and shall cover the previous calendar quarters. (These quarterly reports shall exclude deviations resulting from malfunctions reported in accordance with OAC rule 3745-15-06.)

**10. Applicability**

This Permit-to-Install is applicable only to the emissions unit(s) identified in the Permit-to-Install. Separate application must be made to the Director for the installation or modification of any other emissions unit(s) not exempt from the requirement to obtain a Permit-to-Install.

**11. Construction of New Sources(s) and Authorization to Install**

a) This permit does not constitute an assurance that the proposed source will operate in compliance with all Ohio laws and regulations. This permit does not constitute expressed or implied assurance that the proposed facility has been constructed in accordance with the application and terms and conditions of this permit. The action of beginning and/or completing construction prior to obtaining the Director's approval constitutes a violation of OAC rule 3745-31-02. Furthermore, issuance of this permit does not constitute an assurance that the proposed source will operate in compliance with all Ohio laws and regulations. Issuance of this permit is not to be construed as a waiver of any rights that the Ohio Environmental Protection Agency (or other persons) may have against the applicant for starting construction prior to the effective date of the permit. Additional facilities shall be installed upon orders of the Ohio Environmental Protection Agency if the proposed facilities cannot meet the requirements of this permit or cannot meet applicable standards.

b) If applicable, authorization to install any new emissions unit included in this permit shall terminate within eighteen months of the effective date of the permit if the owner or operator has not undertaken a continuing program of installation or has not entered into a binding contractual obligation to undertake and complete within a reasonable time a continuing program of installation. This deadline may be extended by up to 12 months if application is made to the

Director within a reasonable time before the termination date and the permittee shows good cause for any such extension.

c) The permittee may notify Ohio EPA of any emissions unit that is permanently shut down (i.e., the emissions unit has been physically removed from service or has been altered in such a way that it can no longer operate without a subsequent "modification" or "installation" as defined in OAC Chapter 3745-31) by submitting a certification from the authorized official that identifies the date on which the emissions unit was permanently shut down. Authorization to operate the affected emissions unit shall cease upon the date certified by the authorized official that the emissions unit was permanently shut down. At a minimum, notification of permanent shut down shall be made or confirmed by marking the affected emissions unit(s) as "permanently shut down" in "Air Services" along with the date the emissions unit(s) was permanently removed and/or disabled. Submitting the facility profile update electronically will constitute notifying the Director of the permanent shutdown of the affected emissions unit(s).

d) The provisions of this permit shall cease to be enforceable for each affected emissions unit after the date on which an emissions unit is permanently shut down (i.e., emissions unit has been physically removed from service or has been altered in such a way that it can no longer operate without a subsequent "modification" or "installation" as defined in OAC Chapter 3745-31). All records relating to any permanently shutdown emissions unit, generated while the emissions unit was in operation, must be maintained in accordance with law. All reports required by this permit must be submitted for any period an affected emissions unit operated prior to permanent shut down. At a minimum, the permit requirements must be evaluated as part of the reporting requirements identified in this permit covering the last period the emissions unit operated.

Unless otherwise exempted, no emissions unit certified by the responsible official as being permanently shut down may resume operation without first applying for and obtaining a permit pursuant to OAC Chapter 3745-31 and OAC Chapter 3745-77 if the restarted operation is subject to one or more applicable requirements.

e) The permittee shall comply with any residual requirements related to this permit, such as the requirement to submit a deviation report, air fee emission report, or other any reporting required by this permit for the period the operating provisions of this permit were enforceable, or as required by regulation or law. All reports shall be submitted in a form and manner prescribed by the Director. All records relating to this permit must be maintained in accordance with law.

**12. Permit-To-Operate Application**

The permittee is required to apply for a Title V permit pursuant to OAC Chapter 3745-77. The permittee shall submit a complete Title V permit application or a complete Title V permit modification application within twelve (12) months after commencing operation of the emissions units covered by this permit. However, if operation of the proposed new or modified source(s) as authorized by this permit would be prohibited by the terms and conditions of an existing Title V permit, a Title V permit modification of such new or modified source(s) pursuant to OAC rule 3745-77-04(D) and OAC rule 3745-77-08(C)(3)(d) must be obtained before operating the source in a manner that would violate the existing Title V permit requirements.

**13. Construction Compliance Certification**

The applicant shall identify the following dates in the "Air Services" facility profile for each new emissions unit identified in this permit.

a) Completion of initial installation date shall be entered upon completion of construction and prior to start-up.

b) Commence operation after installation or latest modification date shall be entered within 90 days after commencing operation of the applicable emissions unit.

**14. Public Disclosure**

The facility is hereby notified that this permit, and all agency records concerning the operation of this permitted source, are subject to public disclosure in accordance with OAC rule 3745-49-03.

**15. Additional Reporting Requirements When There Are No Deviations of Federally Enforceable Emission Limitations, Operational Restrictions, or Control Device Operating Parameter Limitations**

If no deviations occurred during a calendar quarter, the permittee shall submit a quarterly report, which states that no deviations occurred during that quarter. The reports shall be submitted quarterly by January 31, April 30, July 31, and October 31 of each year and shall cover the previous calendar quarters.

**16. Fees**

The permittee shall pay fees to the Director of the Ohio EPA in accordance with ORC section 3745.11 and OAC Chapter 3745-78. The permittee shall pay all applicable permit-to-install fees within 30 days after the issuance of any permit-to-install. The permittee shall pay all applicable permit-to-operate fees within thirty days of the issuance of the invoice.

**17. Permit Transfers**

Any transferee of this permit shall assume the responsibilities of the prior permit holder. The new owner must update and submit the ownership information via the "Owner/Contact Change" functionality in "Air Services" once the transfer is legally completed. The change must be submitted through "Air Services" within thirty days of the ownership transfer date.

**18. Risk Management Plans**

If the permittee is required to develop and register a risk management plan pursuant to section 112(r) of the Clean Air Act, as amended, 42 U.S.C. 7401 et seq. ("Act"), the permittee shall comply with the requirement to register such a plan.

**19. Title IV Provisions**

If the permittee is subject to the requirements of 40 CFR Part 72 concerning acid rain, the permittee shall ensure that any affected emissions unit complies with those requirements. Emissions exceeding any allowances that are lawfully held under Title IV of the Act, or any regulations adopted thereunder, are prohibited.

# B. Facility-Wide Terms and Conditions

1. All the following facility-wide terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only:

   a) None.

2. The following emissions units (EUs) contained in this permit are subject to 40 CFR Part 60, Subpart KKKK, Standards of Performance for Stationary Combustion Turbines: **B271** and **B272**. The complete NSPS requirements, including the NSPS General Provisions may be accessed via the internet from the Electronic Code of Federal Regulations (e-CFR) website http://www.ecfr.gov or by contacting Ohio EPA, Central District Office.

3. The permittee shall permanently shut-down the following EU as part of the proposed project: **B132** - Boiler 5. This shutdown is necessary to consider the emissions decreases associated with the proposed project during the Step 1 analysis (significant emissions increase) of the New Source Review (NSR) major modification applicability test. This emissions unit shall be permanently shut-down within 30 days following the commercial operation date once the thermal reliability reaches 95% for a minimum of four weeks. The reliability of the steam system shall be measured as the continuous reliable operation of the steam line from the CHP boundary to the point of interconnection with existing steam distribution system. At no time will EUs **B271 and B272** - CHP Units #1 and 2 operate concurrently with EU **B132** - Boiler 5.

4. Unless other arrangements have been approved by the Director, all notifications and reports shall be submitted through the Ohio EPA's eBusiness Center: Air Services online web portal.

5. EUs **B271** and **B272** are $NO_X$ budget units as identified in OAC Chapter 3745-14 (non-EGU, cogeneration units).

   Due to the CAIR vacatur and replacement, by U.S. EPA, there is no longer a trading program for non-EGUs. OAC Chapter 3745-14 provisions that outline the mechanisms and requirements for emission allocations, deduction, transfer, and/or surrender of allowances are obsolete. The permittee shall comply with the compliance certification, monitoring, and reporting provisions of OAC Chapter 3745-14 for owner/operators of non-EGU $NO_X$ budget units until such time as OAC Chapter 3745-14 is amended and/or the permittee is notified by Ohio EPA that a replacement program has been adopted by Ohio EPA and approved by U.S. EPA.

# C. Emissions Unit Terms and Conditions

**1. Emissions Unit Group - CHP Units: B271, B272**

| EU ID | Operations, Property and/or Equipment Description |
|---|---|
| B271 | Natural gas fired cogeneration (combined heat and power) plant - combustion turbine and duct burner/HRSG, capable of producing nominal maximums of 105.5 MW of electricity and 346,400 lb/hr of steam with the duct burner firing at full rate. |
| B272 | Natural gas fired cogeneration (combined heat and power) plant - combustion turbine and duct burner/HRSG, capable of producing nominal maximums of 105.5 MW of electricity and 346,400 lb/hr of steam with the duct burner firing at full rate. |

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only:

(1) See b)(1)g., d)(9) through d)(12), and e)(3) below.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

| | Applicable Rules/Requirements | Applicable Emissions Limitations/Control Measures |
|---|---|---|
| a. | OAC rule 3745-31-05(A)(3) | **EMISSIONS LIMITATIONS WITHOUT DUCT BURNER FIRING:**<br><br>Emissions of particulate matter less than or equal to 10 microns in diameter and less than or equal to 2.5 microns in diameter, ($PM_{10}$ and $PM_{2.5}$), each, shall not exceed 1.26 tons per month averaged over a rolling, 12-month period.<br><br>The emissions unit shall be designed to meet the following:<br><br>4.0 ppmvd nitrogen oxides ($NO_X$) at 15% oxygen;<br><br>0.003 lb carbon monoxide (CO)/million British thermal units (MMBtu); and<br><br>0.005 lb volatile organic compounds (VOC)/MMBtu. |

| | Applicable Rules/Requirements | Applicable Emissions Limitations/Control Measures |
|---|---|---|
| | | **EMISSIONS LIMITATIONS WITH DUCT BURNER FIRING:**<br>$PM_{10}$ and $PM_{2.5}$ emissions, each, shall not exceed 1.67 tons per month averaged over a rolling, 12-month period.<br><br>The emissions unit shall be designed to meet the following:<br><br>4.0 ppmvd nitrogen oxides ($NO_X$) at 15% oxygen;<br><br>0.015 lb CO/MMBtu; and<br><br>0.015 lb VOC/MMBtu.<br><br>See b)(2)a. and b)(2)c. below. |
| b. | OAC rule 3745-31-05(A)(3)(a)(ii) | The Best Available Technology (BAT) requirements under OAC rule 3745-31-05(A)(3) do not apply to the $SO_2$ emissions from this air contaminant source because the uncontrolled potential to emit for $SO_2$ emissions is less than 10 tons/year. |
| c. | OAC rule 3745-17-07(A) | Visible particulate emissions from the stack serving this emissions unit shall not exceed 20 percent opacity as a six-minute average, except as provided by rule. |
| d. | OAC rule 3745-17-11(B)(4) | Particulate emissions (PE) shall not exceed 0.040 lb/MMBtu of actual heat input. |
| e. | OAC rule 3745-18-31(A)(2) | Sulfur dioxide ($SO_2$) emissions shall not exceed 1.50 lb/MMBtu actual heat input. |
| f. | OAC rule 3745-110-03(E)(2)(c)(i) | See b)(2)d. below. |
| g. | ORC rule 3704.03(F) | See d)(9) through d)(12) and e)(3) below. below. |
| h. | OAC Chapter 3745-14 | See B.5. above. |
| i. | 40 CFR Part 60, Subpart KKKK | See b)(2)b. through b)(2)d. below. |
| j. | 40 CFR Part 60, Subpart A | The permittee shall demonstrate compliance with the applicable requirements identified in 40 CFR Part 60, Subpart KKKK in accordance with 40 CFR Part 60, Subpart A. |

(2) Additional Terms and Conditions

a. The limitations established for $PM_{10}$ and $PM_{2.5}$ emissions represent the potential to emit for this emissions unit for each pollutant. It is not necessary to develop monitoring, recordkeeping, or reporting requirements to ensure compliance with these limitations.

b. The permittee shall comply with the applicable requirements established pursuant to 40 CFR part 60, Subpart KKKK, including, but not limited to the following relevant sections:

| Applicable Rule | Requirement |
|---|---|
| 60.4300 | What is the purpose of this subpart? |
| 60.4305 | Does this subpart apply to my stationary combustion turbine? |
| 60.4310 | What types of operations are exempt from these standards of performance? |
| 60.4315 | What pollutants are regulated by this subpart? |
| 60.4320 and Table 1 | What emission limits must I meet for nitrogen oxides ($NO_X$)?<br><br>For new combustion turbines firing natural gas with heat input at peak load between 50 and 850 MMBtu/hr:<br>Combined $NO_X$ emissions from each combustion turbine (**B271** and **B272**) and its associated HRSG/duct burner shall not exceed 25 ppm at 15 percent oxygen or 150 ng/J of useful output (1.2 lb/MWh). |
| 60.4330(a)(1) and (a)(2) | What emission limits must I meet for sulfur dioxide ($SO_2$)?<br><br>The permittee shall comply with one of the following requirements for each emissions unit:<br><br>The permittee must not cause to be discharged into the atmosphere any gases which contain $SO_2$ in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output from the combustion turbine and associated HRSG/duct burner; or<br><br>The permittee must not burn any fuel which contains total potential sulfur emissions in excess of 26 ng $SO_2$/J (0.060 lb $SO_2$/MMBtu) heat input. |

c. This emissions unit is determined to be subject to the provisions of 40 CFR Part 60, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines. As identified above, the applicable $NO_X$ emissions limitation identified in Subpart KKKK of 25 ppm is less stringent than $NO_X$ emissions limitation established pursuant to OAC rule 3745-31-05(A)(3) of 4.0 ppm; however, the assignment of the more stringent emissions rate does not relieve the permittee of the requirement to demonstrate compliance (including the applicable monitoring, recordkeeping, reporting and initial compliance demonstration requirements) with the provisions of Subpart KKKK.

d. As provided in OAC rule 3745-110-02(A)(2)(b), the requirements in Subpart KKKK were determined to be more stringent than the requirements in OAC Chapter 3745-110 for this emissions unit. Therefore, this emissions unit shall comply with the Subpart KKKK requirements for $NO_X$ in lieu of the requirements of OAC rule 3745-110-03(E)(2)(c)(i) for the stationary combustion turbine.

c) Operational Restrictions

(1) The permittee shall only burn natural gas in this emissions unit.

d) Monitoring and/or Recordkeeping Requirements

(1) For each day during which the permittee burns a fuel other than natural gas, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

(2) The permittee shall comply with the applicable monitoring and recordkeeping requirements established pursuant to 40 CFR part 60, Subpart KKKK, including, but not limited to the following relevant sections:

| Applicable Rule | Requirement |
|---|---|
| 60.4333 | What are my general requirements for complying with this subpart?<br><br>The permittee must operate and maintain the stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction. |
| 60.4340 | How do I demonstrate continuous compliance for $NO_X$ if I do not use water or steam injection?<br><br>You must perform annual performance tests in accordance with 60.4400(a) **or** install, calibrate, maintain and operate a continuous monitoring system in accordance with 60.4340(b) to demonstrate continuous compliance. |
| 60.4355 | How do I establish and document a proper parameter monitoring plan? |

| Applicable Rule | Requirement |
|---|---|
| | If you elect to demonstrate continuous compliance using a continuous monitoring system, you must establish a monitoring plan in accordance with 60.4355(a) or (b). |
| 60.4360 | How do I determine the total sulfur content of the turbine's combustion fuel?<br><br>You must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in 60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in 60.4415.<br><br>If the permittee chooses to comply with the $SO_2$ emissions limitation using fuel analysis, a current, valid purchase contract, tariff sheet or transportation contract for the natural gas burned in this emissions unit shall specify that the total sulfur content is 20 grains of sulfur or less per 100 standard cubic feet and has potential sulfur emissions of less than 26 ng $SO_2$/J (0.060 lb $SO_2$/MMBtu) heat input. |
| 60.4365 | How can I be exempted from monitoring the total sulfur content of the fuel?<br><br>The permittee may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng $SO_2$/J (0.060 lb $SO_2$/MMBtu) heat input. You must use one of the following sources of information to make the required demonstration:<br><br>The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and has potential sulfur emissions of less than less than 26 ng $SO_2$/J (0.060 lb $SO_2$/MMBtu) heat input; or<br>Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng $SO_2$/J (0.060 lb $SO_2$/MMBtu) heat input. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required. |
| 60.4370(b) and (c) | How often must I determine the sulfur content of the fuel?<br><br>The frequency of determining the sulfur content of the fuel must be as follows:<br><br>*Gaseous fuel*. If you elect not to demonstrate sulfur content using options in 60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the |

| Applicable Rule | Requirement |
|---|---|
| | gaseous fuel must be determined and recorded once per unit operating day;<br>and<br>*Custom schedules*. Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in 60.4330. |

(3) The permittee shall properly install, operate and maintain the oxidation catalyst in accordance with the manufacturer’s recommendations, instructions, and/or operating manual(s).

(4) The permittee shall maintain documentation of the manufacturer's recommendations, instructions, and/or operating manual(s) for the oxidation catalyst. These documents shall be maintained at the facility and shall be made available to the Ohio EPA, Central District Office upon request.

(5) The permittee shall maintain the following information for maintenance and repairs performed on each oxidation catalyst:

a. the date of the maintenance and/or repair;

b. a description of the maintenance and/or repairs performed; and

c. the name of person(s) who performed the maintenance and/or repair.

(6) The permittee shall properly install, operate and maintain the selective catalytic reduction (SCR) system in accordance with the manufacturer’s recommendations, instructions, and/or operating manual(s).

(7) The permittee shall maintain documentation of the manufacturer's recommendations, instructions, and/or operating manual(s) for the SCR system. These documents shall be maintained at the facility and shall be made available to the Ohio EPA, Central District Office upon request.

(8) The permittee shall maintain the following information for maintenance and repairs performed on each SCR system:

a. the date of the maintenance and/or repair;

b. a description of the maintenance and/or repairs performed; and

c. the name of person(s) who performed the maintenance and/or repair.

(9) The permit-to-install (PTI) application for this/these emissions unit(s), **B271** and **B272**, was evaluated based on the actual materials and the design parameters of the emissions unit's(s') exhaust system, as specified by the permittee. The "Toxic Air Contaminant Statute", ORC 3704.03(F), was applied to this/these emissions unit(s) for each toxic air contaminant listed in OAC rule 3745-114-01, using data from the permit application; and modeling was performed for each toxic air contaminant(s) emitted at over one ton per year using an air dispersion model such as SCREEN3, AERMOD, or ISCST3, or other Ohio EPA approved model. The predicted 1-hour maximum ground-level concentration result(s) from the approved air dispersion model, was compared to the Maximum Acceptable Ground-Level Concentration (MAGLC), calculated as described in the Ohio EPA guidance document entitled "Review of New Sources of Air Toxic Emissions, Option A", as follows:

a. the exposure limit, expressed as a time-weighted average concentration for a conventional 8-hour workday and a 40-hour workweek, for each toxic compound(s) emitted from the emissions unit(s), (as determined from the raw materials processed and/or coatings or other materials applied) has been documented from one of the following sources and in the following order of preference (TLV was and shall be used, if the chemical is listed):

i. threshold limit value (TLV) from the American Conference of Governmental Industrial Hygienists (ACGIH) "Threshold Limit Values for Chemical Substances and Physical Agents Biological Exposure Indices"; or

ii. STEL (short term exposure limit) or the ceiling value from the American Conference of Governmental Industrial Hygienists (ACGIH) "Threshold Limit Values for Chemical Substances and Physical Agents Biological Exposure Indices"; the STEL or ceiling value is multiplied by 0.737 to convert the 15-minute exposure limit to an equivalent 8-hour TLV.

b. The TLV is divided by ten to adjust the standard from the working population to the general public (TLV/10).

c. This standard is/was then adjusted to account for the duration of the exposure or the operating hours of the emissions unit(s), i.e., "24" hours per day and "7" days per week, from that of 8 hours per day and 5 days per week. The resulting calculation was (and shall be) used to determine the Maximum Acceptable Ground-Level Concentration (MAGLC):

$$TLV/10 \times 8/X \times 5/Y = 4\ TLV/XY = MAGLC$$

d. The following summarizes the results of dispersion modeling for the significant toxic contaminants (emitted at 1 or more tons/year) or "worst case" toxic contaminant(s):

Toxic Contaminant: Ammonia
TLV (mg/m$^3$): 17
Maximum Hourly Emissions Rate (lb/hr): 6.05
Predicted 1-Hour Maximum Ground-Level Concentration (ug/m$^3$): 12.4
MAGLC (ug/m$^3$): 405

The permittee, has demonstrated that emissions of ammonia, from emissions unit(s) **B271** and **B272**, are calculated to be less than eighty per cent of the maximum acceptable ground level concentration (MAGLC); any new raw material or processing agent shall not be applied without evaluating each component toxic air contaminant in accordance with the "Toxic Air Contaminant Statute", ORC 3704.03(F).

(10) Prior to making any physical changes to or changes in the method of operation of the emissions unit(s), that could impact the parameters or values that were used in the predicted 1-hour maximum ground-level concentration, the permittee shall re-model the change(s) to demonstrate that the MAGLC has not been exceeded. Changes that can affect the parameters/values used in determining the 1-hour maximum ground-level concentration include, but are not limited to, the following:

a. changes in the composition of the materials used or the use of new materials, that would result in the emissions of a new toxic air contaminant with a lower Threshold Limit Value (TLV) than the lowest TLV previously modeled;

b. changes in the composition of the materials, or use of new materials, that would result in an increase in emissions of any toxic air contaminant listed in OAC rule 3745-114-01, that was modeled from the initial (or last) application; and

c. physical changes to the emissions unit(s) or its/their exhaust parameters (e.g., increased/ decreased exhaust flow, changes in stack height, changes in stack diameter, etc.).

If the permittee determines that the "Toxic Air Contaminant Statute" will be satisfied for the above changes, the Ohio EPA will not consider the change(s) to be a "modification" under OAC rule 3745-31-01 solely due to a non-restrictive change to a parameter or process operation, where compliance with the "Toxic Air Contaminant Statute", ORC 3704.03(F), has been documented. If the change(s) meet(s) the definition of a "modification", the permittee shall apply for and obtain a final PTI prior to the change. The Director may consider any significant departure from the operations of the emissions unit, described in the permit application, as a modification that results in greater emissions than the emissions rate modeled to determine the ground level concentration; and he/she may require the permittee to submit a permit application for the increased emissions.

(11) The permittee shall collect, record, and retain the following information for each toxic evaluation conducted to determine compliance with the "Toxic Air Contaminant Statute", ORC 3704.03(F):

a. a description of the parameters/values used in each compliance demonstration and the parameters or values changed for any re-evaluation of the toxic(s) modeled (the composition of materials, new toxic contaminants emitted, change in stack/exhaust parameters, etc.);

b. the Maximum Acceptable Ground-Level Concentration (MAGLC) for each significant toxic contaminant or worst-case contaminant, calculated in accordance with the "Toxic Air Contaminant Statute", ORC 3704.03(F);

c. a copy of the computer model run(s), that established the predicted 1-hour maximum ground-level concentration that demonstrated the emissions unit(s) to be in compliance with the “Toxic Air Contaminant Statute”, ORC 3704.03(F), initially and for each change that requires re-evaluation of the toxic air contaminant emissions; and

d. the documentation of the initial evaluation of compliance with the “Toxic Air Contaminant Statute”, ORC 3704.03(F), and documentation of any determination that was conducted to re-evaluate compliance due to a change made to the emissions unit(s) or the materials applied.

(12) The permittee shall maintain a record of any change made to a parameter or value used in the dispersion model, used to demonstrate compliance with the “Toxic Air Contaminant Statute”, ORC 3704.03(F), through the predicted 1-hour maximum ground-level concentration. The record shall include the date and reason(s) for the change and if the change would increase the ground-level concentration.

e) Reporting Requirements

(1) The permittee shall submit deviation (excursion) reports that identify each day when a fuel other than natural gas was burned in this emissions unit. Each report shall be submitted within 30 days after the deviation occurs.

(2) The permittee shall comply with the applicable reporting requirements established pursuant to 40 CFR part 60, Subpart KKKK, including, but not limited to the following relevant sections:

| Applicable Rule | Requirement |
|---|---|
| 60.4375(a) and (b) | What reports must I submit?<br><br>For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with 60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.<br><br>For each affected unit that performs annual performance tests in accordance with 60.4340(a), the 60-day reporting requirement established by this rule is less stringent than the 30-day reporting requirement established in f)(3) below. |
| 60.4380(c) | How are excess emissions and monitor downtime defined for $NO_X$?<br><br>For turbines required to monitor combustion parameters or parameters that document proper operation of the $NO_X$ emission controls: |

| Applicable Rule | Requirement |
|---|---|
| | An excess emission is a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.<br><br>A period of monitor downtime is a unit operating hour in which any of the required parametric data are either not recorded or are invalid. |
| 60.4385 | How are excess emissions and monitoring downtime defined for $SO_2$?<br><br>If you choose the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined in 60.4385(a) through 60.4385(c). |
| 60.4395 | When must I submit my reports?<br><br>All reports required under 60.7(c) must be postmarked by the 30$^{th}$ day following the end of each 6-month period. |

(3) The permittee shall submit annual reports that include any changes to any parameter or value used in the dispersion model used to demonstrate compliance with the “Toxic Air Contaminate Statute”, ORC 3704.03(F), through the predicted 1-hour maximum concentration. The report should include:

a. the original model input;

b. the updated model input;

c. the reason for the change(s) to the input parameter(s); and

d. a summary of the results of the updated modeling, including the input changes; and

e. a statement that the model results indicate that the 1-hour maximum ground-level concentration is less than 80% of the MAGLC.

If no changes to the emissions, emissions unit(s), or the exhaust stack have been made during the reporting period, then the report shall include a statement to that effect. This report shall be postmarked or delivered no later than January 31 following the end of each calendar year.

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Emissions Limitation:

Visible particulate emissions shall not exceed 20 percent opacity as a six-minute average, except as specified by rule.

Applicable Compliance Method:

If required, compliance with the visible particulate emissions limitation from the stack shall be determined through visible emissions observations performed in accordance with U.S. EPA Method 9.

b. Emissions Limitation:

PE shall not exceed 0.040 lb/MMBtu of actual heat input.

Applicable Compliance Method:

Compliance is demonstrated through the use of the combined manufacturer's guaranteed emissions rate of 0.017 lb PM/MMBtu multiplied by the AP-42, Section 3.1, Table 3.1-2a ratio of PE to PM (i.e., 1.9 PE / 6.6 PM).

If required, compliance shall be demonstrated through emissions testing conducted in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 5.

c. Emissions Limitation:

$SO_2$ emissions shall not exceed 1.50 lb/MMBtu actual heat input.

Applicable Compliance Method:

Compliance is demonstrated through the use of the manufacturer's guaranteed emissions rate of 0.0060 lb $SO_2$/MMBtu.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1-4, and 6, 6A, 6B, or 6C, as appropriate, and the procedures specified in OAC rule 3745-18-04(E). Alternative EPA approved test methods may be used with prior approval from Ohio EPA.

**EMISSIONS LIMITATIONS WITHOUT DUCT BURNER FIRING**

d. Emissions Limitation:

The emissions unit shall be designed to meet the following:

4.0 ppmvd $NO_X$ at 15% oxygen;
0.003 lb CO/ MMBtu; and
0.005 lb VOC/MMBtu.

Applicable Compliance Method:

If required, the permittee shall demonstrate compliance with the $NO_X$ emissions limitation through emissions tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1-4, and 7E or 20. Alternative EPA approved test methods may be used with prior approval from Ohio EPA;

If required, the permittee shall demonstrate compliance with the CO emissions limitation through emissions tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1-4, and 10. Alternative EPA approved test methods may be used with prior approval from Ohio EPA; and

If required, the permittee shall demonstrate compliance with the VOC emissions limitation through emissions tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1-4, and 18, 25, or 25A, as appropriate. Alternative EPA approved test methods may be used with prior approval from Ohio EPA.

e. <u>Emissions Limitation:</u>

$PM_{10}$ and $PM_{2.5}$ emissions, each, shall not exceed 1.26 tons per month averaged over a rolling, 12-month period.

<u>Applicable Compliance Method:</u>

The $PM_{10}$ and $PM_{2.5}$ emissions limitations were established to reflect the potential to emit based on the maximum capacity of the combustion turbine (341.8 MMBtu/hr), the manufacturer's guaranteed emissions rate (0.007 lb/MMBtu), and 1 lb/hr estimated post-SCR particulate from ammonia salt generation, as follows:

$PM_{10}/PM_{2.5}$ = [[(0.007 lb/MMBtu) * (341.8 MMBtu/hr) + (1 lb/hr)] * (8,760 hr/yr) / (2,000 lb/ton) / (12 month/yr)] + (0.23 ton/yr SU/SD emissions) / (12month/yr) = 1.26 ton/month

**EMISSIONS LIMITATIONS WITH DUCT BURNER FIRING**

f. <u>Emissions Limitation:</u>

The emissions unit shall be designed to meet the following:

4.0 ppmvd $NO_X$ at 15% oxygen;
0.015 lb CO/MMBtu; and
0.015 lb VOC/MMBtu.

<u>Applicable Compliance Method:</u>

The permittee shall demonstrate compliance with the $NO_X$ emissions limitation during the initial compliance demonstration performed in accordance with 40 CFR Part 60, Subpart KKKK and the requirements established in f)(3) below;

If required, the permittee shall demonstrate compliance with the CO emissions limitation through emissions tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1-4, and 10. Alternative EPA approved test methods may be used with prior approval from Ohio EPA; and

If required, the permittee shall demonstrate compliance with the VOC emissions limitation through emissions tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1-4, and 18, 25, or 25A, as appropriate. Alternative EPA approved test methods may be used with prior approval from Ohio EPA.

g. Emissions Limitation:

$PM_{10}$ and $PM_{2.5}$ emissions, each, shall not exceed 1.67 tons per month averaged over a rolling, 12-month period.

Applicable Compliance Method:

The $PM_{10}$ and $PM_{2.5}$ emissions limitations were established to reflect the potential to emit based on the emissions from the combustion turbine and the maximum capacity of the duct burner (110.8 MMBtu/hr), the manufacturer's guaranteed emissions rate (0.010 lb/MMBtu), and 1 lb/hr estimated post-SCR particulate from ammonia salt generation, as follows:

$PM_{10}/PM_{2.5}$ = [[(2.4 lb/hr) + (0.010 lb/MMBtu) * (110.8 MMBtu/hr) + (1lb/hr)] * (8,760 hr/yr) / (2,000 lb/ton) / (12 month/yr)] + (0.23 ton/yr SU/SD emissions) / (12 month/yr) = 1.67 ton/month

(2) The permittee shall comply with the applicable testing requirements established pursuant to 40 CFR part 60, Subpart KKKK, including, but not limited to the following relevant sections:

| Applicable Rule | Requirement |
|---|---|
| 60.4400 | How do I conduct the initial and subsequent performance tests, regarding $NO_X$?<br><br>You must conduct the initial and subsequent performance tests in accordance with 60.4400(a) and (b). |
| 60.4410 | How do I establish a valid parameter range if I have chosen to continuously monitor parameters?<br><br>If you have chosen to monitor combustion parameters or parameters indicative of proper operation of $NO_X$ emission controls in accordance with 60.4340, the appropriate parameters must be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in 60.4355. |
| 60.4415 | How do I conduct the initial and subsequent performance tests for sulfur?<br><br>You must conduct the initial and subsequent performance tests in accordance with 60.4400(a)(1), (2), or (3). |

| Applicable Rule | Requirement |
|---|---|
| | If you have elected not to monitor the total sulfur content of the fuel combusted in the turbine in accordance with 60.4365, initial and subsequent performance tests for sulfur are not required. |

(3) The permittee shall conduct, or have conducted, emissions testing for this emissions unit in accordance with 40 CFR 60.8, 60.4340(a), 60.4400, and 60.4415 and the following requirements:

The permittee shall conduct, or have conducted, emission testing for this emissions unit in accordance with the following requirements:

a. Initial Compliance Demonstration:

i. The initial emissions testing shall be conducted within 60 days after achieving the maximum production rate at which the emissions unit will be operated, but not later than 180 days after initial startup of the emissions unit.

ii. The initial emissions testing shall be conducted to demonstrate compliance with the $NO_X$ emissions limitations established pursuant to 40 CFR Part 60, Subpart KKKK and OAC rule 3745-31-05(A)(3) (with duct burner firing) and the $SO_2$ emissions limitation established pursuant to 40 CFR Part 60, Subpart KKKK.

The permittee shall be exempt from the initial $SO_2$ emissions testing when complying with the 40 CFR Part 60, Subpart KKKK $SO_2$ emissions limitation through the documentation required in 60.4365(a).

b. Subsequent Compliance Demonstrations:

i. Subsequent emissions testing shall be conducted on an annual basis and no more than 14 calendar months following the previous emissions test.

Pursuant to 40 CFR 60.4340(a), if the $NO_X$ emissions result from the performance test is less than or equal to 75 percent of the $NO_X$ emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years and no more than 26 calendar months following the previous performance test.

ii. The subsequent annual emissions testing shall be conducted to demonstrate compliance with the $NO_X$ and $SO_2$ emissions limitations established pursuant to 40 CFR Part 60, Subpart KKKK.

The permittee shall be exempt from the annual $SO_2$ emissions testing when complying with the 40 CFR Part 60, Subpart KKKK $SO_2$ emissions limitation through the documentation required in 60.4365(a).

c. The following test method(s) shall be employed to demonstrate compliance with the allowable mass emission rate(s):

Initial Compliance Demonstration:

$NO_X$: Method 7E or Method 20 and the provisions identified in 40 CFR 60.4400(a)(1)(i); or

Method 7E and Method 3(A) or Method 20 and the provisions identified in 40 CFR 60.4400(a)(1)(ii).

Subsequent Compliance Demonstrations:

$NO_X$: Method 7E or Method 20 and the provisions identified in 40 CFR 60.4400(a)(1)(i); or

Method 7E and Method 3(A) or Method 20 and the provisions identified in 40 CFR 60.4400(a)(1)(ii).

d. The test(s) shall be conducted in accordance with the test methods and procedures specified in 40 CFR 60.4400 for $NO_X$ and 40 CFR 60.4415 for sulfur (unless exempted pursuant to 40 CFR 60.4365). For the purpose of demonstrating compliance with the requirements of 40 CFR Part 60, Subpart KKKK, the HRSG/duct burner shall be in operation during the emissions testing and the $NO_X$ emissions shall be measured only when the combustion turbine and HRSG/duct burner are in operation.

e. During the emissions testing, the emissions unit shall be operated under operational conditions approved in advance by the Ohio EPA, Central District Office. Operational conditions that may need to be approved include, but are not limited to, the production rate, the type of material processed, material make-up (solvent content, etc.), or control equipment operational limitations (burner temperature, precipitator voltage, etc.). In general, testing shall be done under "worst case" conditions expected during the life of the permit. As part of the information provided in the "Intent to Test" notification form described below, the permittee shall provide a description of the emissions unit operational conditions they will meet during the emissions testing and describe why they believe "worst case" operating conditions will be met. Prior to conducting the test(s), the permittee shall confirm with the Ohio EPA, Central District Office that the proposed operating conditions constitute "worst case". Failure to test under the approved conditions may result in Ohio EPA not accepting the test results as a demonstration of compliance.

f. Not later than 30 days prior to the proposed test date(s), the permittee shall submit an "Intent to Test" notification to the Ohio EPA, Central District Office. The "Intent to Test" notification shall describe in detail the proposed test methods and procedures, the emissions unit operating parameters, the time(s) and date(s) of the test(s), and the person(s) who will be conducting the test(s). Failure to submit such notification for review and approval prior to the test(s) may result in the Ohio EPA, Central District Office's refusal to accept the results of the emissions test(s).

g. Personnel from the Ohio EPA, Central District Office shall be permitted to witness the test(s), examine the testing equipment, and acquire data and information necessary to ensure that the operation of the emissions unit and the testing procedures provide a valid characterization of the emissions from the emissions unit and/or the performance of the control equipment.

h. A comprehensive written report on the results of the emissions test(s) shall be signed by the person or persons responsible for the tests and submitted to the Ohio EPA, Central District Office within 30 days following completion of the test(s). The permittee may request additional time for the submittal of the written report, where warranted, with prior approval from the Ohio EPA, Central District Office.

g) Miscellaneous Requirements

(1) None.

**Exhibit RS-O**

ENGIE North America
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December 20, 2018

Mr. Craig W. Butler
Director
Ohio Environmental Protection Agency
50 West Town Street, Suite 700
Columbus, Ohio 43215

Re: Ohio State University, ENGIE NA, Inc., Smart Campus Project
Request for Director's Discretionary Exemption from Requirements Applicable to Major Modifications in an Attainment Area

Dear Director Butler:

ENGIE NA, Inc., on behalf of The Ohio State University, submits the following information and respectfully requests your discretionary exemption granted pursuant to OAC rule 3745-31-13(D)(1) for a project planned at The Ohio State University. The Smart Campus Project, which consists of a Combined Heat and Power (CHP) facility and a District Heating and Cooling (DHC) facility, is a result of our commitment to OSU to responsibly and efficiently manage campus steam and energy production. Representatives of Ohio State and ENGIE met with Mike Hopkins and his team in August of this year and discussed the project in its conceptual form.

The CHP facility will be a natural gas-fired cogeneration plant consisting of two combustion turbine and duct burner/heat recovery steam generator (HRSG) units followed by a common steam turbine generator. The CHP plant will have nominal capacities of 105.5 MW (summer) and 85.1 MW (winter) at full firing rate. The power produced will be used on campus and will displace a substantial portion of the total demand currently purchased from the utility grid. Steam produced by the CHP plant will be distributed on campus and to the University's medical buildings, displacing current steam production from several older natural gas and oil-fired boilers.

The discretionary exemption at OAC rule 3745-31-13(D)(1) is provided for non-profit health and non-profit educational institutions and specifically exempts projects that would otherwise undergo review as a major modification pursuant to Ohio's prevention of significant deterioration (PSD) program (OAC rules 3745-31-10 through 3745-13-20) from those requirements.

We have recently made final selections of the turbine and HRSG equipment as well as the proposed location of the physical buildings. We have also begun preparation of the air permit application for the CHP facility. Our preliminary finding is the project will be subject to PSD review for two criteria pollutants and greenhouse gases as a result of PSD applicability for another pollutant. Our emissions analysis indicates the project will cause significant net emissions increase(s) for $PM_{10}$ and direct $PM_{2.5}$. Proposed $NO_X$ emissions from the turbines and duct burners, including estimated startup and shutdown emissions, exceed its significant emission rate. Project net $NO_X$ emissions when accounting for the shutdown of existing boilers are well below 40 tons per year.

We will submit a complete permit application, which will address the two primary requirements under PSD for $PM_{10}$/$PM_{2.5}$, best available control technology (BACT) and an air quality analysis and BACT for GHG. The requirement under OAC 3745-31-05 to employ best available technology (BAT) will satisfy the general PSD requirement to employ best available control technology (BACT).

- The combustion turbines and duct burners will be permitted to burn natural gas only to minimize particulate and sulfur dioxide ($SO_2$) emissions.
- The combustion turbines and duct burners will be equipped with dry low-$NO_X$ burner technology.
- Post-combustion $NO_X$ emissions will be controlled by a urea-based selective catalytic reduction (SCR) system.
- Post-combustion emissions of carbon monoxide (CO), volatile organic compound (VOC), and organic hazardous air pollutants (HAP) will be controlled by an oxidation catalyst system.
- Sequestration of GHG emissions is not practically feasible or cost-effective.

An air quality analysis will be prepared in accordance with Engineering Guide #69. We will model $PM_{10}$ and $PM_{2.5}$ emissions against the Generally Acceptable Incremental Impact (GAII) concentrations for the 24-hour and annual averaging times. We believe this modeling will clearly demonstrate protection of air quality in the area near the CHP plant as the GAII are generally set at one-quarter of the full PSD air quality increment.

We look forward to any questions you or your staff have regarding the project and our request. We left our August meeting with Ohio EPA with a very positive outlook and believe the approvability of this project has not changed with the final design.

If there are questions, please do not hesitate to contact me at 614-247-1902 or gregg.garbesi@engine.com.

Sincerely,

ENGIE NA, Inc.

Vinton Gregg Garbesi
Managing Director

Cc: Mike Hopkins, Ohio EPA, Central Office
Sudhir Singhal, Ohio EPA, Central Office
Kelly Saavedra, Ohio EPA, CDO
Ben Halton, Ohio EPA, CDO

Bcc: Tom Novotny, OSU
Janice Fry, OSU
Robert Dawkins, ENGIE NA
Laura Scott, ENGIE NA
Bob Maggiani, ENGIE NA
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# Exhibit RS-P

| | As-Is | W/ CHP | Reduction | Reduction (%) |
|---|---|---|---|---|
| Base | 429,533 | 314,570 | 114,963 | 27% |
| HHW Synergies Only | 468,864 | 314,570 | 154,294 | 33% |
| DHC Synergies (Heating and Cooling) | 486,534 | 314,570 | 171,963 | 35% |

Assumptions

No export, minimum of 500 kW import for each of 3 buses at OSU substation, natural gas carbon footprint of 117 lb/MMBTU and grid carbon footprint of 1510 lb/MWh

(all values in metric ton)

| **Midwest and West Campus Synergies** | | |
|---|---|---|
| Incremental Steam Demand | 60 | MMBTU/h |
| Fuel Factor, McCracken | 1.41 | |
| Additional Fuel Consumed | 741096 | MMBTU/yr |
| Carbon Value, Natural Gas | 117 | lb $CO_2$ / MMBTU, NG |
| Annual Metric Ton | 39,330 | MT |
| Cooling | | |
| Centralized Efficiency | 0.8 | kW/ton |
| Standalone Efficiency | 1.3 | kW/ton |
| Average Cooling, MW+W | 5890 | ton |
| Add'l Energy Consumption, Standalone | 25,798,200 | kWh |
| Annual Metric Ton | 17,670 | MT |