PM$_{2.5}$ SIP Evaluation Report – University of Utah

UTAH PM$_{2.5}$ SERIOUS SIP

Salt Lake City Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

July 1, 2018

DAQ-2018-006821

PM$_{2.5}$ SIP EVALUATION REPORT
UNIVERSITY OF UTAH

1.0. Introduction

The following is an updated BACT version of the original RACT evaluation that was completed on October 1, 2016 as a part of the Technical Support Documentation (TSD) for Section IX, Parts H.11, 12 and 13 of the Utah SIP; to address the Salt Lake City PM$_{2.5}$ and Provo, Utah PM$_{2.5}$ Nonattainment Areas.

This TSD describes the controls and measures to be implemented from the period of 2018 through 2024. Controls implemented in whole by December 31, 2019 are considered BACT and are discussed in Section 2 of this document. Controls implemented in whole or in part between January 1, 2020 and December 31, 2024 are considered MSM/additional feasible measures and are discussed in Section 3 of this document.

1.1. Facility Identification

Name: University of Utah (U of U)
Address: Building 605
125 South Fort Douglas Blvd
Salt Lake City, UT 84112
Owner/Operator: U of U
UTM coordinates: 429,440 m Easting, 4,512,800 m Northing, UTM Zone 12

1.2. Facility Process Summary

The University of Utah (U of U) is a higher education institution located in Salt Lake City. The U of U campus consists of several different types of buildings and facilities, including classroom buildings, hospitals and clinics, research facilities, student housing, sports facilities, libraries, museums, and a concert hall. The emission sources at the U of U are primarily boilers, comfort heating equipment, and emergency generator engines.

Industrial high temperature boilers that provide approximately 400°F water for distribution heating systems are located in the two main heating plants on campus: Building 302, the Upper Campus High Temperature Water Plant (UCHTWP) and Building 303, the Lower Campus High Temperature Water Plant (LCHTWP). A Cogeneration Plant consisting of a natural gas-fired turbine and waste heat recovery unit (WHRU) duct burner is also located in Building 303.

In addition to the heating plants in Buildings 302 and 303, several other small boilers are operated to support individual building needs. These small boilers are fueled primarily by natural gas and use diesel as backup fuel.

Emergency generator engines are installed at several buildings around campus. Both diesel and natural gas-fired engines are operated at the U of U.

Other small emission sources include the print shop, paint booth, parts washers, carpentry shop with a baghouse (dust collector), storage tanks, ethylene oxide sterilizer, ironmaking bench reactor system.

1.3. Facility 2016 Baseline Emissions

Actual emissions and current PTE from the U of U processes and equipment are summarized below. The actual emissions for individual pieces of equipment are listed in Sections 2.1.1 through 2.1.10.

Facility-wide 2016 Actual Emissions (tpy)				
$PM_{2.5}$	**NO_x**	**SO_2**	**VOC**	**NH_3**
15.45	73.25	0.80	10.49	3.38

Current Potential to Emit (tpy)*				
$PM_{2.5}$	**NO_x**	**SO_2**	**VOC**	**NH_3**
19.29	100.05	3.85	14.07	N/A

1.4. Facility Criteria Air Pollutant Emissions Sources

The PTE by emission unit (EU) after implementation of BACT is summarized below.

Emission Unit	Potential to Emit (tpy)				
	$PM_{2.5}$	**NO_x**	**SO_2**	**VOC**	**NH_3[1]**
Building 302 UCHWTP Boilers	2.71	13.67	0.16	1.46	0.85
Hospital Expansion Boilers	0.40	5.66	0.09	0.53	0.17
Building 303 LCHWTP Boilers and Cogeneration Plant	9.60	36.86	0.47	6.24	2.48
Small Boilers	0.46	6.03	0.04	0.33	0.19
Small Diesel Emergency Generator Engines (<600 hp)	0.94	13.98	1.3	1.59	0.00
Large Diesel Emergency Generator Engines (≥600 hp)	0.59	46.39	0.03	1.63	0.00
Natural Gas Emergency Generator Engines	0.00	0.70	0.00	0.20	0.00
Carpentry Shop	0.86	--	--	--	--
Paint Booth and Print Plant	--	--	--	0.71	--
Ethylene Oxide Sterilizer	--	--	--	1.0	--
Underground and Fuel Storage Tanks	--	--	--	0.25	--
Parts Washer	--	--	--	0.1	--
Total	**15.73**	**121.90**	**2.06**	**13.92**	**3.77**

Notes:
-- Not estimated/not applicable
Source: (Trinity Consultants, 2018a)

2.0 BACT Selection Methodology

The general procedure for identifying and selecting BACT is through use of a process commonly referred to as the "top-down" BACT analysis. The top-down process consists of five steps which consecutively identify control measures, and gradually eliminate less effective or infeasible options until only the best option remains. This process is performed for each emission unit and each pollutant of concern. The five steps are as follows:

1. Identify All Existing and Potential Emission Control Technologies: UDAQ evaluated various resources to identify the various controls and emission rates. These include, but are not limited to: federal regulations, Utah regulations, regulations of other states, the RBLC, recently issued permits, and emission unit vendors.

2. Eliminate Technically Infeasible Options: Any control options determined to be technically infeasible are eliminated in this step. This includes eliminating those options with physical or technological problems that cannot be overcome, as well as eliminating those options that cannot be installed in the projected attainment timeframe.

3. Evaluate Control Effectiveness of Remaining Control Technologies: The remaining control options are ranked in the third step of the BACT analysis. Combinations of various controls are also included.

4. Evaluate Most Effective Controls and Document Results: The fourth step of the BACT analysis evaluates the economic feasibility of the highest ranked options. This evaluation includes energy, environmental, and economic impacts of the control option.

5. Selection of BACT: The fifth step in the BACT analysis selects the "best" option. This step also includes the necessary justification to support the UDAQ's decision.

Should a particular step reduce the available options to zero (0), no additional analysis is required. Similarly, if the most effective control option is already installed, no further analysis is needed.

The final BACT/MSM evaluations for the U of U were performed using data submitted by the U of U, AOs and supporting documentation, and the Title V permit.

2.1 EU and Existing Controls

2.1.1 Building 302 UCHWTP Boilers

Description

The UCHWTP located in Building 302 has three natural gas-fired boilers (Boilers 1, 3, and 4) that are each rated at 87.5 MMBTU/hr with 15% fluid gas recirculation (FGR). Diesel is used as backup fuel during periods of natural gas curtailment. In 2012, all boilers were upgraded with a burner management system with automated O_2 trim.

The U of U plans to reduce the usage of the UCHTWP boilers by the second quarter of 2019 as part of the hospital expansion project, which will de-centralize the heating demand of Upper Medical Campus by installing several new boilers. The expansion project at the University hospital will occur in three phases. Phase I Ambulatory Care Center (ACC) and Phase II Rehabilitation are addressed in this BACT analysis. Phase III will take place after 2024 and is, therefore, not addressed in this BACT analysis.

During Phase I of the expansion, ten boilers with a combined heat rating of 96 MMBtu/hr will be installed, ranging from 5 to 12 MMBtu/hr. The U of U also plans to install several steam boilers with a total capacity of 4 MMBtu/hr. During Phase II of the expansion, one 8.84 MMBtu/hr boiler will be installed with an identical redundant unit for emergency purposes. These new boilers will be used to supplement the heat demand from the UCTWP boilers.

Emissions Summary

The 2016 actual emissions (TPY) for all three boilers (Boilers 1, 3, and 4) are as follows:

UCHWTP Boilers 2016 Actual Emissions (tpy)				
$PM_{2.5}$	NO_x	SO_2	VOC	NH_3
3.00	15	0.19	1.75	1.02

Control Options

NO_x is the primary pollutant emitted from natural gas-fired boilers. $PM_{2.5}$, VOCs, and SO_x are emitted at lower levels. Thus, the discussion of control options is organized into two sections. One section describes control options for NO_x emissions and the other section for $PM_{2.5}$, VOCs, and SO_x emissions.

[Pollutant - NO_x]

Available Control Technology

Available control technologies for NO_x emissions include:

- Good combustion practices
- Pre-combustion modifications (oven fire air, low excess air, air staging, etc)
- Combustion Controls
- FGR
- Low NO_x burners
- Ultra-low NO_x burners
- SCR
- SNCR

Technological Feasibility

Low NOx and Ultra-Low NOx Burners

The UCHTWP boilers are currently using FGR and are estimated to achieve an emission rate of 0.05 lb of NO_x/MMBtu (or approximately 50 ppmv). The lowest NO_x emission levels technically feasible for boilers of this size is 9 ppmvd. In order for a burner to achieve a 9 ppmvd NO_x rating, the burner must be designed with appropriate blast tube lengths and combustion chamber geometry (Hansen & Hanson, 2017). Ample space is required to accommodate an ultra-low NO_x burner design.

As previously mentioned, the usage of the existing UCHTWP boilers will be reduced due to the hospital expansion project, which will consist of the installation of several new boilers. The installation of ultra-low NOx burners is assumed to be technically feasible for the existing UCHTWP boilers and an economic analysis was performed. However, ultra-low NOx burners are not technically feasible for the proposed new hospital boilers due to space limitations and other building code requirements for accreditation as an Adult Level 1 Trauma 1 Center.

The U of U hospital has obtained an accreditation as an Adult Level 1 Trauma Center from Det Norske Veritas (DMV) Healthcare, Inc. To maintain this accreditation, the boilers at the U of U hospital are required to reserve capacity for heating sources and essential accessories both in number and arrangement that are sufficient to accommodate facility needs even when any one of the heat sources is not operating due to breakdown, natural gas curtailment, or routine maintenance. This requirement is specified in the 2010 Facility Guidelines Institute (FGI) Guidelines for Design and Construction of Health Care Facilities, which includes building codes from the American Society of Heating and Air-Conditioning Engineers (ASHRAE) and American Institute of Architects (AIA). (Trinity Consultants, 2018b)

The U of U is installing dual fuel boilers to provide the reserve capacity during breakdowns, natural gas curtailment, and maintenance activities required as per the 2010 FGI Guidelines for Design and Construction of Health Care Facilities. There are three burner design options for dual fuel boilers:

1) One burner with interchangeable nozzles specific to fuel type;
2) Two burners, one with nozzle for natural gas and another nozzle for diesel fuel; and
3) One burner with dual fuel compatible nozzles.

Dual fuel compatible nozzles are covered in a fine mesh-like material for combustion of natural gas. This mesh material must be removed prior to burning diesel fuel. This mesh removal process can take up to two hours to allow for boiler cool down and burner assembly. This changeover time is unacceptable and does not meet the building code requirements previously mentioned for accreditation of a Level 1 Trauma Center. (Trinity Consultants, 2018b)

Installing two burners, one for each fuel type, would significantly increase the size of the combustion chamber. Due to the limited space allocated for the boilers, this option is not technically feasible. (Trinity Consultants, 2018b)

The installation of one burner with dual fuel interchangeable nozzles also requires additional space to accommodate combustion chamber design, which includes a special mixing assembly and chamber geometry. Due to the limited space allocated for the boilers, this option is also not technically feasible. (Trinity Consultants, 2018b)

Given the accreditation requirements of the U of U hospital and the space limitations of the buildings housing the boilers, the lowest NO_x rating technically feasible for the new hospital boilers is 30 ppmvd. (Trinity Consultants, 2018b)

Pre-Combustion Modifications

Pre-combustion modifications are technically feasible, but will often result in minimal emission reductions. Additionally, these modifications will reduce burner efficiency and increase fuel demand, which can consequentially negate emissions reductions obtained by the modification (Hansen & Hanson, 2017). Therefore, these modifications will not be further considered as standalone control options.

Combustion Controls

Combustion controls improve the fuel to air ratio and the combustion efficiency of the burner, which reduces the fuel consumption of the burner (Hansen & Hanson, 2017). NO_x emissions will be reduced as a consequence of reducing the fuel consumption. However, the NO_x concentration of the exhaust will remain the same. For instance, if a boiler operates a burner with a NO_x rating of 60 ppmvd, combustion controls will reduce how much fuel the burner consumes but the burner emissions will remain at 60 ppmvd. Combustion controls will reduce actual emissions through fuel consumption; however, this decrease cannot be effectively quantified for permitting purposes. Therefore, combustion controls will not be further evaluated as a standalone control option despite being technically feasible.

SCR

SCR is an add-on technology that chemically reduces NO_x compounds from the stack flue gas. The NO_x compounds are reduced by injection of ammonia into the flue gas, which then passes through a thermal catalytic reactor which forms N_2 and water. NO_x reduction in SCR is only effective at high temperatures (450°F to 840°F), so additional heating of the emission stream may be required to meet optimal operating temperatures. SCR NO_x removal efficiencies are between 70 to 90% (Oland, 2002). The obstacles of SCR at the UCHTWP are physical limitations, safety considerations, and ammonia slip.

- Physical Limitations: The installation SCR would be constrained by the space limitation of Building 302. The boilers are housed in an area of Building 302 that may not be able not accommodate an add-on control. (Trinity Consultants, 2017a)
- Safety Considerations: SCR requires that storage and handling of ammonia, a hazardous chemical. Building 302 is located in a densely-packed area, close to the Red Butte Amphitheater and student dormitories. Storing large quantities of ammonia in an area used by University of Utah staff, faculty, students, and the general public poses a significant health risk in the event of a leak or other unexpected event. (Trinity Consultants, 2017a)

- Ammonia slip (i.e ammonia emissions from unreacted ammonia) pose additional environmental and safety concerns (Oland, 2002).

Although there are many obstacles with an SCR system at the UCHTWP, this technology has been demonstrated as an available control option for natural gas-fired boilers of similar size as the UCHTWP boilers in the RBCL database. Therefore, SCR is considered a technically feasible option and an economic analysis of this technology was conducted for the UCHTWP boilers.

SCR is not considered technically feasible for the new hospital boilers since this technology has not been demonstrated as a control option for boiler ranging between 5 and 12 MMBtu/hr.

SNCR

SNCR is similar to SCR in the use of ammonia as a reductant to reduce NO_x compounds to molecular N_2 and water but the technology does not utilize a catalyst. The ammonia is injected directly into the primary combustion zone where temperatures reach 1,400°F to 2,000°F. NO_x reduction in SNCR is only effective at high temperatures (1,400°F to 2,000°F), so additional heating of the emission stream may be required to meet optimal operating temperatures. NO_x concentration levels required for an effective SNCR are 200-400 ppm. SCNR NO_x removal efficiencies vary between 30% and 70% (Oland, 2002). The same physical, safety, and environmental considerations described for the SCR system apply to SNCR. Due to these considerations and the fact that SNCR has not been widely demonstrated as an effective control technology for natural gas-fired boilers of similar size, SNCR is not considered a technically feasible option and will not be further evaluated. (Trinity Consultants, 2017b)

Economic Feasibility

The economic feasibility of ultra-low NO_x burners and SCR for the UCHTWP boilers was evaluated as part of this BACT analysis and is summarized in this section. Detailed cost estimates are provided in the BACT Analysis provided by the U of U (Trinity Consultants, 2017a) (Trinity Consultants, 2018b).

Ultra-low NO_x burners for the UCHTWP boilers have an estimated annualized cost of $180,981 and a NO_x reduction rate of 1.74 tons, resulting in $103,791 per ton of NO_x removed (Trinity Consultants, 2018b). This is economically infeasible. The costs for retrofitting the burners with low NO_x burners were not specifically determined but are expected to be similar to the cost of ultra-low NO_x burners.

The SCR system has an estimated annualized cost of $506, 072 and a NO_x reduction rate of 3.19 tons at a control efficiency of 70%, resulting in $158,660 per ton of NO_x removed (Trinity Consultants, 2018b). This is economically infeasible. This estimate does not include costs for building expansion or other changes required to accommodate an SCR system under the current configuration.

[Pollutant $PM_{2.5}$, VOC, and SO_2]

Available Control Technology
Available control technologies for $PM_{2.5}$, VOCs, and SO_2 emissions include:

- Use of pipeline quality natural gas
- Good combustion practices
- Post-combustion controls for $PM_{2.5}$ emissions, such as baghouses, cyclones, wet scrubbers, electrostatic precipitators
- Post-combustion controls for VOC emissions, such as carbon adsorption, thermal oxidizers, and catalytic oxidizers
- Post-combustion controls for SO_2 emissions, such as wet scrubbers

Technically Feasibility
Use of pipeline quality natural gas and good combustion practices are technically feasible options to control $PM_{2.5}$, VOC, and SO_2 emissions from combustion.

Post-combustion controls for $PM_{2.5}$ emissions, such as baghouses, cyclones, and scrubbers, have not been demonstrated as technically feasible options for natural-gas fired boilers due to the $PM_{2.5}$ low emissions from boilers of similar size as the UCHWTP boilers.

Post-combustion controls, such as adsorption, thermal incinerators, and catalytic oxidizers, have not been demonstrated as technically feasible for natural-gas fired boilers due to the low VOC emissions from boilers of similar size as the UCHWTP boilers.

West scrubbers are typically used to control SO_2 emissions from electrical utilities and industrial sources generating streams with high SO_2 contents, such as coal-fired power plants. The SO_2 emissions from natural gas burners in boilers are too low for scrubbers to be technically feasible.

BACT Selection

NO_x Summary
The UCHTWP boilers are currently equipped with FGR and O_2 trim system. The economic analysis showed that add-on controls and burner retrofits with low NO_x and ultra-low NO_x burners are not economically feasible options given the low usage of these boilers.

$PM_{2.5}$, VOC, and SO_2 Summary
Use of pipeline quality natural gas and good combustion practices are the only control options available for boilers.

BACT consists of controls implemented in whole by December 31, 2019. Prior to the end of 2019, new boilers proposed for the hospital expansion project shall be the primary heat source for the Upper Medical Campus. The existing UCHTWP boilers (Boilers 1, 3, and 4) will operate at reduced capacity after the installation of the new hospital boilers. The following measures will be implemented as BACT for the UCHTWP boilers:

1) The new hospital expansion project boilers shall be installed and operational by the end of the second quarter of calendar year 2019 and the total combined capacity of these boilers shall not exceed 118 MMBtu/hr.
2) The new hospital expansion project boilers shall be equipped with low NO_x burners rated at 30 ppmvd or less. As previously mentioned, ultra-low NO_x burners do not meet the operational requirements of the new boilers.
3) The existing UCHTWP boilers (Boilers 1, 3, and 4) shall only be used as back-up/peaking boilers and shall be limited to a natural gas usage of 530 MMscf per rolling 12-month period.

Implementation Schedule

The new hospital expansion project boilers shall be installed and operational by the end of the second quarter of calendar year 2019.The existing UCHTWP boilers (Boilers 1, 3, and 4) will operate at reduced capacity after the installation of the new hospital expansion project boilers.

The remaining BACT determinations of limiting natural gas usage, conducting manufacturer recommended maintenance, implementing good combustion practices, and only using pipeline quality natural gas shall be implemented immediately upon start-up and operation of the boilers.

Start-up/Shutdown Considerations

The UCHWTP boilers are designed to be baseload units. Because these units were not designed for frequent start-up and shut downs the units are often left online during Low Load Hours of short duration (overnight), thus reducing frequency of start-ups and shutdowns.

2.1.2 Building 303 LCHWTP Boilers

Description

The LCHWTP located in Building 303 has four natural gas-fired boilers. Boilers 3 and 4 are rated at 105 MMBtu/hr each, and Boilers 5 and 6 are rated at 50 MMBtu/hr each.

Boilers 3 and 4 have only been used during peak events or malfunctions. Boilers 3 was decommissioned in 2017 and Boiler 4 will be decommissioned by the end of 2019. A new boiler (Boiler 9) will be installed in 2019 to replace the decommissioned boilers. Boiler 9 will have an input heat capacity of 72 MMBtu/hr and will be equipped with an ultra-low NO_x burner rated at 9 ppmvd of NO_x. (Trinity Consultants, 2017a)

Boilers 5 and 6 were installed in 2016. These boilers are equipped with low NO_x burners and FGR and have a permitted NO_x limit of 9 ppmdv and 0.604 lb/hr.

Emissions Summary

The 2016 actual emissions (TPY) for Boilers 3, 4, 5 and 6 combined are as follows:

LCHWTP Boilers 2016 Actual Emissions (tpy)				
$PM_{2.5}$	**NO_x**	**SO_2**	**VOC**	**NH_3**
1.74	19.80	0.14	1.26	0.74

Control Options

NO_x is the primary pollutant emitted from natural gas-fired boilers. $PM_{2.5}$, VOCs, and SO_x are emitted at lower levels. Thus, the discussion of control options is organized into two sections. One section describes control options for NO_x emissions and the other section for $PM_{2.5}$, VOCs, and SO_x emissions.

[Pollutant - NO_x]

Available Control Technology
Available control technologies for NO_x emissions include:

- Good combustion practices
- Pre-combustion modifications (oven fire air, low excess air, air staging, etc)
- Combustion Controls
- FGR
- Low NO_x burners
- Ultra-low NO_x burners
- SCR
- SNCR

Technological Feasibility
The technical feasibility of the identified technologies is discussed in Section 2.1.1. Building 302 UCHWTP Boilers - Technical Feasibility. As described in that Section, good combustion practices, low NO_x burners, and ultra-low NO_x burners are technically feasible control options. Pre-combustion modifications and combustion controls were not evaluated as standalone control options.

Physical limitations and safety considerations make the installation of add-on controls, such as SCR and SNCR, technically infeasible at the UCHTWP in Building 303. This building does not have adequate space to accommodate add-on controls and is confined by other buildings and facilities in the area so building expansion is not possible. SCR and SNCR require storage and handling of ammonia, a hazardous chemical. Building 303 is located in a densely-packed area, adjacent to the TRAX line, the Huntsman Even Center, and the Utah Museum of Fine Arts. Storing large quantities of ammonia in an area with used by University of Utah staff, faculty, students, and the general public poses a significant health risk in the event of a leak or other unexpected event (Trinity Consultants, 2017a). Therefore, SCR and SNCR are not considered technically feasible options for these boilers.

Economic Feasibility
Boiler 4 is uncontrolled with NO_x emissions rates of 25 lb/hr (or approximately 0.24 lb/MMBtu). This boiler will be decommissioned by the end of 2019 and replaced with Boiler 9, which will be equipped with ultra-low NO_x burner (9 ppmvd or 0.011 lb/MMBtu). Therefore, an economic analysis for retrofitting or installing add-on controls to these boilers was not conducted.

Boilers 5 and 6 are currently equipped with ultra-low NO_x burners and FGR and have a permitted NO_x limit of 9 ppmvd or 0.604 lb/hr. Add-on controls or burner replacement and retrofits are not technically feasible as described above, so an economic analysis for these units was not conducted.

[Pollutant $PM_{2.5}$, VOC, and SO_2]

Available Control Technology
Available control technologies for $PM_{2.5}$, VOC, and SO_x emissions include:
- Use of pipeline quality natural gas
- Good combustion practices
- Post-combustion controls for $PM_{2.5}$ emissions, such as baghouses, cyclones, wet scrubbers, electrostatic precipitators
- Post-combustion controls for VOC emissions, such as carbon adsorption, thermal oxidizers, and catalytic oxidizers
- Post-combustion controls for SO_2 emissions, such as wet scrubbers

Technological Feasibility
The technical feasibility of the identified technologies is discussed in Section 2.1.1. Building 302 UCHWTP Boilers - Technical Feasibility. As discussed in this Section, use of pipeline quality natural gas and good combustion practices are the only technically feasible options to control $PM_{2.5}$, VOC, and SO_2 emissions from natural gas combustion.

BACT Selection

BACT consists of controls implemented in whole by December 31, 2019. The following measures will be implemented as BACT for the LCHTWP Boilers 4 and 9:
1) Boiler 4 shall be decommissioned and replaced by December 31, 2019.
2) Boiler 9, the replacement unit, shall not exceed 72 MMBtu/hr of input heat capacity.
3) The Boiler 9 burner shall be equipped with ultra-low NOx burners rated at 9 ppmvd.

Boilers 5 and 6 are currently equipped with low NO_x burners and FGR and have a permitted NO_x limit of 9 ppmvd. No additional BACT measures were identified for these units.

The U of U shall also conduct manufacturer recommended maintenance, implement good combustion practices, and only use pipeline quality natural gas on all the LCHTWP boilers.

Implementation Schedule

Replacement and decommission of Boiler 4 shall be completed by the end of 2019.

The remaining BACT determinations of conducting manufacturer recommended maintenance, implementing good combustion practices, and only using pipeline quality natural gas shall be implemented immediately.

Start-up/Shutdown Considerations

The boilers at LCHWTP are designed to be baseload units. Because these units were not designed for frequent start-up and shut downs the units are often left online during Low Load Hours of short duration (overnight), thus reducing frequency of start-ups and shutdowns.

2.1.3 Building 303 LCHWTP Cogeneration Plant

Description

The LCHWTP located in Building 303 has a natural gas-fired turbine cogeneration plant, consisting of a turbine and a WHRU duct burner. The turbine is a natural gas-fired Solar Taurus 70 T7800S (Solar's SoLoNox™) turbine rated at 7.23 MW with heat input of 72.78 MMBTU/hr. The turbine uses a lean-premixed combustion technology to optimize air/fuel ratios and is permitted for NO_x emission rates of 9 ppmdv and 2.65 lb/hr. The WHRU duct burner is rated at 85 MMBTU/hr. The duct burner is permitted for NO_x emission rates of 15 ppmdv and 8.97 lb/hr.

Emissions Summary

The 2016 actual emissions (TPY) for the cogeneration plant are as follows:

LCHWTP Cogeneration Plant 2016 Actual Emissions (tpy)				
$PM_{2.5}$	NO_x	SO_2	VOC	NH_3
9.19	18.5	0.25	5.51	1.33

Control Options

NO_x is the primary pollutant emitted from natural gas-fired turbine and duct burner. $PM_{2.5}$, VOCs, and SO_x are emitted at lower levels. Thus, the discussion of control options is organized into two sections. One section describes control options for NO_x emissions and the other section for $PM_{2.5}$, VOCs, and SO_x emissions.

[Pollutant - NO_x]

Available Control Technology
Available control technologies for NO_x emissions include:

- Good combustion practices
- Pre-combustion modifications (water/steam injection)
- SCR/SNCR
- Dry low NO_x combustors/ Low NO_x burner (turbine only)
- $SCONO_x$ (turbine only)
- FGR (WHRU only)
- Ultra-low NO_x burner (WHRU only)

Technological Feasibility

Available Controls - Turbine and WHRU Duct
Good combustion practices, such as controlling operating parameters to optimize combustion are technically feasible options for the turbine and duct burner.

Pre-combustion modifications are technically feasible, but will often result in minimal emission reductions. Additionally, these modifications will reduce burner efficiency and increase fuel demand, which can consequentially negate emissions reductions obtained by the modification (Hansen & Hanson, 2017). Therefore, these modifications will not be further considered as control options.

SCR and SNCR are both technically available technologies; however, due to the physical limitations and safety considerations discussed in the LCWHTP Boiler section, these add-on controls are not considered technically feasible for the LCWHTP.(Trinity Consultants, 2017a)

Available Controls - Turbine
Dry low NO_x combustors/Low NO_x burners use lean premixed and staged combustion to minimize NO_x formation from combustion in turbines. This technology uses staged combustion to premix a lean air to fuel mixture and a heat release strategy that minimizes combustion temperatures. The specific design of these combustors varies by manufacturer. The turbine currently in operation at the Cogeneration Plant uses $SoLowNO_x$ technology, a type of dry low NO_x combustors that can achieve NO_x emission rates of 9 ppmvd. (Trinity Consultants, 2017a)

$SCONO_x$ is a catalytic oxidation and adsorption technology that uses a single catalyst for removal of NO_x, CO, and VOC from exhaust streams. This technology has been implemented in several cogeneration turbines in other states. Control efficiencies are typically greater than 90% for NO_x, 90% for CO, and 80% for VOCs. The absorption range for $SCONO_x$ is 300° F to 700° F, with the optimal temperature of 600° F. Although this technology is available, it is not considered technically feasible due to the space limitations of the LCWHTP building. (Trinity Consultants, 2017a)

Available Controls - WHRU Duct
Ultra-low NO_x burners use a combination of low NO_x burners and FGR to minimize the

formation of NO_x. FGR is not technically feasible for the WHRU duct burner because of the space limitations in Building 303. The area where the duct burner is installed does not have sufficient space to install a straight duct long enough to obtain a proper mixing of gases (Trinity Consultants, 2017b). As previously mentioned in the LCWHTP Boiler Section 2.1.2, building expansion is not possible because the area around this building is confined by other buildings and facilities. The duct burner is currently equipped with low NO_x burners capable of limiting NO_x emissions to 15 ppmdv.

Economic Feasibility

An economic feasibility was not conducted since the technical feasible controls have already been implemented.

[Pollutant $PM_{2.5}$, VOC, and SO_2]

Available Control Technology

Available control technologies for $PM_{2.5}$, VOC, and SO_x emissions include:

- Use of pipeline quality natural gas
- Good combustion practices
- Post-combustion controls for $PM_{2.5}$ emissions, such as baghouses
- Post-combustion controls for VOC emissions, such as carbon adsorption, thermal oxidizers, and catalytic oxidizers, SCONO$_x$
- Post-combustion controls for SO_2 emissions, such as wet scrubbers

Technological Feasibility

The technical feasibility of the identified technologies is discussed in Section 2.1.1. Building 302 UCHWTP Boilers - Technical Feasibility. As discussed in this Section, use of pipeline quality natural gas and good combustion practices are the only technically feasible options to control $PM_{2.5}$, VOC, and SO_2 emissions from natural-gas combustion.

BACT Selection

BACT consists of controls implemented in whole by December 31, 2019. The turbine and duct burner are currently equipped with low NO_x burners and no additional controls were identified as technically feasible options. BACT for these units is to limit NO_x emissions to the permitted levels in DAQE-AN103540025-13 Condition II.B.2.c.

The U of U shall also conduct manufacturer recommended maintenance, implement good combustion practices, and only use pipeline quality natural gas.

Implementation Schedule

The BACT determinations of limiting hours of operation, conducting manufacturer recommended maintenance, implementing good combustion practices, and only using pipeline quality natural gas shall be implemented immediately.

Start-up/Shutdown Considerations

Start-up/shutdown emissions are anticipated to be less than or equal to emissions during normal operations. The U of U manages emissions from start-ups/shutdowns by minimizing the duration of these events. During start-up, the turbine is brought to the minimum load necessary to achieve compliance with applicable NO_x and CO limits as quickly as safe operating practices allow. During shutdown, the turbine load is reduced from the minimum load necessary to maintain compliance with applicable NO_x and CO limits to zero as quickly as safe operating practices allow.

2.1.4 Small Boilers

Description

The U of U operates 20 small boilers to meet individual building needs. These boilers range in size from 2 MMBtu/hr to 25.2 MMBtu/hr and are fueled primarily by natural gas (Trinity Consultants, 2018a). Some of these boilers have dual fuel capacity and use natural gas as primary fuel and diesel as backup fuel.

Emissions Summary

The 2016 actual emissions (TPY) for the small boilers are as follows:

Small Boilers 2016 Actual Emissions (tpy)				
$PM_{2.5}$	NO_x	SO_2	VOC	NH_3
0.70	9.16	0.05	0.50	0.29

Control Options

BACT for small sources (i.e. sources emitting <5 tpy) were evaluated in general analyses included in Appendix 1. The BACT analyses for small boilers are included in Sections 5B.0 (Combustion - Boilers, Natural Gas-Fired < 30 MMBTU/hr) and 5C.0 (Combustion - Boilers, Natural Gas-Fired < 10 MMBTU/hr).

The BACT analysis found that retrofitting or replacing boilers with low NO_x or ultra-low NO_x burners may be cost effective for boilers between 5 and 30 MMBtu/hr depending on the boiler size, age, and usage. The analyses recommend that a case-by-case evaluation be conducted to determine the economic feasibility of retrofitting or replacing boilers. The evaluation also recommends good combustion practices and the use of natural gas as primary fuel as BACT. Diesel may only be used as backup fuel. The sulfur content of any diesel or fuel oil burned shall not exceed 15 ppm by weight.

BACT Selection

BACT consists of controls implemented in whole by December 31, 2019. BACT measured for small boilers are good combustion practices and the use of natural gas as primary fuel. Diesel may only be used as backup fuel. The sulfur content of any diesel or fuel oil burned shall not exceed 15 ppm by weight.

Implementation Schedule

The BACT determination of good combustion practices, use of as primary fuel natural gas, and the use of diesel fuel not exceeding 15 ppm by weight as backup fuel shall be implemented immediately.

Start-up/Shutdown Considerations

Start-up/shutdown emissions are anticipated to be less than or equal to emissions during normal operations. The U of U manages emissions from start-ups/shutdowns by minimizing the duration of these events. There are no emission limitations for these units, so additional start-up/shutdown considerations are not necessary.

2.1.5 Diesel Emergency Generator Engines

Description

Diesel-fired emergency generators are installed at several buildings at the U of U. These engines are for emergency purposes only (except for routine testing and maintenance). Diesel fuel used in these engines meet the requirements of 40 CFR 80.510(b) (i.e. maximum sulfur content of 15 ppm for non-road fuel).

The U of U operates 61 diesel-fired emergency generator engines rated at less than or equal to 600 hp with a combined total capacity of 12,675 hp and 36 diesel-fired emergency generator engines each rated greater than 600 hp with a combined total capacity of 46,256 hp (Trinity Consultants, 2018a).

Emissions Summary

The 2016 actual emissions (TPY) for diesel emergency generator engines are as follows:

Diesel Emergency Generator Engines 2016 Actual Emissions (tpy)				
$PM_{2.5}$	NO_x	SO_2	VOC	NH_3
0.35	9.86	0.09	0.36	0.00

Control Options

BACT for small sources (i.e. sources emitting <5 tpy) were evaluated in general analyses included in Appendix 1. The BACT analyses for diesel-fired emergency generators are included in Sections 8A.0 (Engines - Diesel-Fired Emergency Generators <200 hp), Section 8B.0 (Engines - Diesel-Fired Emergency Generators 200-600 hp), and 8C.0 (Engines - Diesel-Fired Emergency Generators >600 hp).

The BACT analysis found that there were no cost effective options for controlling $PM_{2.5}$ and VOC emissions. The installation of a new emergency stationary diesel engine subject to the newest requirements for stationary emergency engines as specified in 40 CFR 60 Subpart IIII is a potential cost effective control for NO_x emissions, depending on the engine's age and size. Ultra-low sulfur diesel fuel was recommended as BACT for SO_2 control.

40 CFR 60 Subpart IIII limits emergency generators to 100 hours of operation for maintenance and testing, as specified in §60.4211(f). Many of the engines at the U of U were manufactured after 2007 and are subject to the emission standards for new non-road engines in 40 CFR 60.4202.

Required routine maintenance is specified in 40 CFR 63 Subpart ZZZZ and includes:

- Change oil and filter every 500 hours of operation or annually, whichever comes first;
- Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and
- Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

BACT Selection

The U of U conducted a general economic analysis for replacing older emergency generator engines with Tier 3 or Tier 4 engines. The following engine sizes were evaluated: 500 kW, 600 kW, 800 kW, 1,000 kW, 1,105 kW, and 2,000 kW. The analysis used a 10-year life expectancy and an interest rate of 7% to calculate cost per ton of VOC reduction. DAQ also evaluated the cost per ton of NO_x reduction based on the engine costs provided by the U of U.

The cost per ton of VOC removed ranged from $4,147,582 for the 2,000 kW engine to $6,253,292 for the 500 kW engine (Trinity Consultants, 2017c) The cost per ton of NO_x removed ranged from $54,485 for the 2,000 kW engine to $58,187 for the 500 kW engine. Based on these costs, engine replacement is not considered cost-effective option for the emergency generator engines at the U of U.

Therefore, BACT for emergency generator engines is to limit operations to 100 hours per year for testing and maintenance, use ultra-low diesel fuel, and conduct maintenance and testing as required in 40 CFR 63 Subpart ZZZZ.

Implementation Schedule

The BACT determination of limiting operations to 100 hours per year, using of ultra-low diesel fuel, and conducting maintenance and testing as required in 40 CFR 63 Subpart ZZZZ shall be implemented immediately.

Start-up/Shutdown Considerations

These engines are for emergency only and are only routinely used during routine testing and maintenance. The U of U manages emissions from start-ups/shutdowns by minimizing the duration of these events. There are no emission limitations for these units, so additional start-up/shutdown considerations are not necessary.

2.1.6 Natural Gas Emergency Generator Engines

Description

Four natural gas-fired emergency generators are installed on campus to maintain critical systems during an emergency. One engine is rated at 134 hp (100 kW) and three engines are rated at 402 hp each (300 kW). All four emergency generator engines are lean burn.

Emissions Summary

The 2016 actual emissions (TPY) for diesel emergency generator engines are as follows:

Natural Gas Emergency Generator Engines 2016 Actual Emissions (tpy)				
$PM_{2.5}$	NO_x	SO_2	VOC	NH_3
<0.01	<0.01	<0.01	0.01	0.00

Control Options

BACT for small sources (i.e. sources emitting <5 tpy) were evaluated in general analyses included in Appendix 1. The BACT analysis for natural gas-fired emergency generator engines are included in Sections 8D (Natural Gas-Fired Emergency Generators < 500 hp).

The BACT analysis found that replacing an older engine with an engine subject to the requirements of 40 CFR 60 JJJJ may be cost effective depending on the engine size. The analysis recommends that a case-by-case evaluation be conducted to determine the economic feasibility of replacing engines.

40 CFR 60 Subpart JJJJ limits emergency generators to 100 hours of operation for maintenance and testing, as specified in §60.4243(d). Required routine maintenance is specified in 40 CFR 63 Subpart ZZZZ and include:

- Change oil and filter every 500 hours of operation or annually, whichever comes first;
- Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and
- Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

Economic Feasibility

Engine replacement is not a cost-effective option given the low potential emissions from these engines (0.70 tpy of NO_x and 0.2 tpy of VOCs).

BACT Selection

BACT for the natural gas-fired emergency generator engines is to limit operations to 100 hours per year, use pipeline quality natural gas, and conduct maintenance and testing as required in 40 CFR 63 Subpart ZZZZ.

Implementation Schedule

The BACT determination of limiting operations to 100 hours per year, using pipeline quality natural gas, and conducting maintenance and testing as required in 40 CFR 63 Subpart ZZZZ shall be implemented immediately.

Start-up/Shutdown Considerations

These engines are for emergency only and are only used during routine testing and maintenance. The U of U manages emissions from start-ups/shutdowns by minimizing the duration of these events. There are no emission limitations for these units, so additional start-up/shutdown considerations are not necessary.

2.1.7 Carpentry Shop

Description

The carpentry shop on campus is a source of $PM_{2.5}$ emissions. Emissions from the carpentry shop are controlled by a baghouse. The baghouse is anticipated to achieve 99% control efficiency and a grain outlet loading of 0.016 gr/dscf.

Emissions Summary

The 2016 actual emissions (TPY) for carpentry shop are as follows:

Carpentry Shop 2016 Actual Emissions (tpy)				
$PM_{2.5}$	NO_x	SO_2	VOC	NH_3
0.14	0.00	0.00	0.00	0.00

Control Options

Baghouses typically provide control efficiencies of over 99% for $PM_{2.5}$ emissions. Other potential control options, such as wet ESP, wet scrubbers, and cyclones, have lower control efficiencies and/or are not technically feasible due to low flow rates and the type of particles emitted.

BACT for small sources (i.e. sources emitting <5 tpy) were evaluated in general analyses included in Appendix 1. The BACT analyses for baghouses are included in Section 3.0 (Baghouse Dust Collector).

The BACT analysis found that higher efficiency baghouses may be cost effective controls depending on the operation and baghouse design. The analysis recommended proper baghouse operation and maintenance, such as monitoring and maintaining the pressure drop across filter bags, cleaning the filters, and replacing the filters as needed.

BACT Selection

BACT for the carpentry shop emissions is routing all emissions through the existing baghouse prior to discharge to the atmosphere; ensuring proper operation and maintenance; and limiting operations to 1,043 hours per rolling 12-month period, as per the current AO DAQE-AN103540025-13 Condition II.B.5.a.

Upgrading baghouse efficiency is not anticipated to be a cost effective option due to the relatively low potential emissions from this unit (0.5 tpy).

Implementation Schedule

The existing controls are considered BACT for the carpentry shop. There is no implementation schedule associated with this emission unit.

Start-up/Shutdown Considerations

There are no emission limitations for these units, so additional start-up/shutdown considerations are not necessary.

2.1.8 Paint Booth and Print Plant

Description

The paint booth and print plant in Building 350 are a source of $PM_{2.5}$ and VOC emissions. Emissions from the paint booth are controlled by filter particulate system. VOC emissions from the paint booth and print plant are limited to 5 tons per rolling 12-month period.

Emissions Summary

The 2016 actual emissions (TPY) for the paint booth and print plant are as follows:

Paint Booth and Print Plant 2016 Actual Emissions (tpy)				
$PM_{2.5}$	NO_x	SO_2	VOC	NH_3
0.00	0.00	0.00	0.95	0.00

Control Options

Paint Booths
Available controls for paint booths include a particulate filter system, low VOCs paints, and add-on controls such as a catalytic incinerator.

Paint booths are equipped with an exhaust system to collect solvent fumes and exhaust the fumes through a stack to the atmosphere. Particulate filters are installed at the inlet of the exhaust systems to capture overspray from being discharged of the stack and prevent accumulation of overspray in the exhaust system, which can reduce the efficiency of the exhaust system and pose a fire hazard. A small fraction of VOCs is captured by the particulate filters as the overspray is captured, but the majority of VOCs are vented during painting operations.

Add-on controls, such as a catalytic incinerator, can be used to destroy VOCs in the effluent stream. Add-on controls are technically and economically feasible options for paint booths with high potential VOC emissions (greater than 20 tpy).

Print Plant

Available controls for the print plant includes low VOCs chemicals, good housekeeping practices, and add-on controls such as a catalytic incinerator.

Good housekeeping practices are measures implemented to reduce emissions from VOC-containing materials. The measures include tight fitting covers for open tanks, enclosing cleaning materials and wiping cloths in closed containers, reducing exposure to heat and open atmosphere.

Add-on controls, such as a catalytic incinerator, can be used to destroy VOCs in the effluent stream. Add-on controls are technically and economically feasible options for print presses with high potential VOC emissions (greater than 20 tpy).

BACT Selection

The existing controls are considered BACT for the paint booth and print press. Good housekeeping practices, routine inspections and proper maintenance of the particulate filters, and compliance with R307-351 are required as part of BACT. Additionally, the U of U has plans to decommission the print press.

Implementation Schedule

The existing controls are considered BACT for the paint shop. There is no implementation schedule associated with this emission unit.

Start-up/Shutdown Considerations

There are no emission limitations for these units, so additional start-up/shutdown considerations are not necessary.

2.1.9 Fuel Storage Tanks

Description

The U of U maintains six storage tanks for diesel fuel and jet fuel. Nine tanks are used for diesel fuel storage and have storage capacities ranging from 12,000 gallons to 35,000 gallons. One tank is used for jet fuel and has a storage capacity of 10,000 gallons. Emissions from these tanks occur when headspace vapors are displaced during filling operations (working losses) and from barometric pressure and temperature changes (breathing losses). Breathing losses from underground storage tanks are minimal because the surrounding earth insulates the tanks from barometric pressure and temperature changes.

The U of U also maintains various small fuel storage tanks on campus. These fuel tanks have capacities of less than 10,000 gallons.

Emissions Summary

The 2016 actual emissions (TPY) for underground storage tanks and fuel tanks are as follows:

Fuel Tanks 2016 Actual Emissions (tpy)				
$PM_{2.5}$	**NO_x**	**SO_2**	**VOC**	**NH_3**
0.01	0.04	0.004	0.004	0.00

The emissions labeled as “Misc. Diesel” in the emissions inventory were assumed to account for underground storage tanks and fuel storage tanks and are listed above.

Control Options

BACT for small sources (i.e. sources emitting <5 tpy) were evaluated in general analyses included in Appendix 1. The BACT analyses for underground storage tanks are included in Sections 13A.0 (Storage Tanks - Fuel Oil Storage Tanks < 30,000 gal) and 13C.0 (Storage Tanks - Underground Fuel Storage Tanks).

The BACT analysis for fuel tanks found that due to the minimal emissions associated with fuel oil storage tanks, add on controls are not technically or economically feasible. BACT for fuel oil tanks is the use of submerged fill pipes.

The BACT analysis for underground storage tanks found that a vapor return line is a cost effective option for underground storage tanks with an annual throughput of more than 250,000 gallons of gasoline. Emission controls were not found to be cost effective for tanks with an annual throughput under 250,000 gallons.

BACT Selection

The existing controls are considered BACT for the storage tanks. BACT for the fuel oil tanks is the use of submerged fill pipes.

Implementation Schedule

The existing controls are considered BACT for the storage tanks. Submerged fill pipes shall be used immediately.

Start-up/Shutdown Considerations

There are no emission limitations for these units, so additional start-up/shutdown considerations are not necessary.

2.1.10 Ethylene Oxide Sterilizer

Description

The ethylene oxide sterilizer is used to sterilize medical equipment at the University Medical Center. The sterilizer is limited to 1 tpy of ethylene oxide, as per Condition II.A.20 of the Approval Order.

Emissions Summary

The 2016 actual emissions (TPY) for ethylene oxide sterilizer are as follows:

Ethylene Oxide Sterilizer 2016 Actual Emissions (tpy)				
$PM_{2.5}$	NO_x	SO_2	VOC	NH_3
0.00	0.00	0.00	0.02	0.00

Control Options

The sterilizer is subject to NESHAP Subpart WWWWW, Hospital Ethylene Oxide Sterilizer. This subpart described management practices to minimize emissions.

The sterilizer is not subject to NESHAP O, Ethylene Oxide Emissions Standards for Sterilization Facilities, because it uses less than 1 tpy of ethylene oxide per rolling 12-month period.

Add-on control options include catalytic oxidizers and acid-water scrubbers. These controls are usually used for sterilizers that use more than 10 tpy of ethylene oxide, as per NESHAP Subpart O. Due to the minimal emissions from this sterilizer, add-on controls are not cost effective options and were not considered as part of this BACT analysis.

BACT Selection

BACT for the ethylene oxide sterilizer is good operating practices and compliance with the requirements of NESHAP Subpart WWWWW.

Implementation Schedule

The existing controls are considered BACT for the ethylene oxide sterilizer. There is no implementation schedule associated with this emission unit.

Start-up/Shutdown Considerations

There are no emission limitations for these units, so additional start-up/shutdown considerations are not necessary.

2.1.12 Ironmaking

Description

Flash ironmaking is conducted at the U of U for research purposes. The bench reactor consists of a refractory-lined vertical vessel which iron oxide concentrates will react with hot gases (hydrogen and CO) generated internally by partial combustion of natural gas and hydrogen. Ironmaking bench reactor is used twice a week and each test lasts approximately 3 hours, so emissions are negligible.

The U of U plans to decommission the ironmaking bench reactor, so a BACT analysis for this emission unit was not further analyzed.

3.0 Additional Feasible Measures and Most Stringent Measures

3.1 Extension of SIP Analysis Timeframe

As outlined in 40 CFR 51.1003(b)(2)(iii):

If the state(s) submits to the EPA a request for a Serious area attainment date extension simultaneous with the Serious area attainment plan due under paragraph (b)(1) of this section, such a plan shall meet the most stringent measure (MSM) requirements set forth at § 51.1010(b) in addition to the BACM and BACT and additional feasible measure requirements set forth at § 51.1010(a).

Thus, with the potential for an extension of the SIP regulatory attainment date from December 31, 2019 to December 31, 2024, the SIP must consider the application of both Additional Feasible Measures (AFM) and Most Stringent Measures (MSM).

3.2 Additional Feasible Measures

As defined in Subpart Z, additional feasible measure (AFM) is any control measure that otherwise meets the definition of "best available control measure" (BACM) but can only be implemented in whole or in part beginning 4 years after the date of reclassification of an area as Serious and no later than the statutory attainment date for the area. The Salt Lake Nonattainment Area was reclassified as Serious on June 9, 2017. Therefore, any viable control measures that could only be implemented in whole or in part beginning June 9, 2021 (4 years after the date of reclassification) are classified as AFM.

The subsequent sections describe additional feasible measures for each emission unit identified after a review of the available control measures described throughout this evaluation report. With the exception of the small boilers, UDAQ was unable to identify any additional control measures that were eliminated from BACT consideration due to extended construction or implementation periods.

3.3 Most Stringent Measures

As defined in Subpart Z, MSM is defined as:

… any permanent and enforceable control measure that achieves the most stringent emissions reductions in direct PM2.5 emissions and/or emissions of PM2.5 plan precursors from among those control measures which are either included in the SIP for any other NAAQS, or have been achieved in practice in any state, and that can feasibly be implemented in the relevant PM2.5 NAAQS nonattainment area.

This is further refined and clarified in 40 CFR 51.1010(b), to include the following Steps:

Step 1) The state shall identify the most stringent measures for reducing direct PM2.5 and PM2.5 plan precursors adopted into any SIP or used in practice to control emissions in any state.

Step 2) The state shall reconsider and reassess any measures previously rejected by the state during the development of any previous Moderate area or Serious area attainment plan control strategy for the area.

Step 3) The state may make a demonstration that a measure identified is not technologically or economically feasible to implement in whole or in part by 5 years after the applicable attainment date for the area, and may eliminate such whole or partial measure from further consideration.

Step 4) Except as provided in Step 3), the state shall adopt and implement all control measures identified under Steps 1) and 2) that collectively shall achieve attainment as expeditiously as practicable, but no later than 5 years after the applicable attainment date for the area.

MSM for each emission unit at the U of U are described in the subsequent sections.

3.4 UCHWTP Boilers

By the end of 2019 the usage of the UCHWTP boilers will be reduced and the new hospital expansion project boilers will the primary heat source for the Upper Medical Campus. No additional feasible measures were identified for the UCHWTP boilers.

MSM for the UCHWTP boilers is to replace or retrofit the existing boilers with low NO_x burners rated at 30 ppmvd or less, or lower if allowed by applicable building code requirements.

3.5 LCHWTP Boilers

By 2020, the uncontrolled boilers at LCHWTP will be decommissioned and only boilers meeting BACT will be in operation. No MSM/additional feasible measures were identified for the LCHTWP boilers as part of this BACT analysis.

3.6 LCHWTP Cogeneration Plan

No MSM/additional feasible measures were identified for the LCHTWP Cogeneration Plant as part of this BACT analysis.

3.7 Small Boilers

As part of additional feasible measures for small boilers, the U of U shall conduct a BACT analysis for at least three (3) of the twenty-one (21) small boilers using a representative range of boiler sizes, ages, and usages. This analysis shall evaluate the economic feasibility of retrofitting or replacing boilers with ultra-low NO_X burners and shall be finalized before January 1, 2020. Boiler replacement and retrofits that are determined to be economically and technically feasible shall be completed by May 10, 2021.

MSM for the small boilers includes the replacement or retrofit of all boiler burners with ultra-low NOx burners which have been demonstrated to be technically feasible. The U of U would be required to obtain funding approval by the Utah State Legislature for this change.

3.8 Diesel Emergency Generator Engines

As part of additional feasible measures for diesel fired emergency engines, the U of U shall conduct an economics analysis for replacement of all units which have not been certified to meet the newest Tier 3 standards for emergency engines. This economic analysis may be presented and performed on a campus wide basis and shall be finalized before January 1, 2020. Engine replacements that are determined to be economically and technically feasible shall be completed by May 10, 2021.

MSM for the emergency generator engines is the replacement of all units with new engines subject to the newest Tier 3 standards for emergency engines. The U of U would be required to obtain funding approval by the Utah State Legislature for this change.

3.9 Natural Gas Emergency Generator Engines

No MSM/additional feasible measures were identified for the natural gas-fired emergency generator engines as part of this BACT analysis.

3.10 Carpentry Shop

No MSM/additional feasible measures were identified for the carpentry shop as part of this BACT analysis.

3.11 Paint Booth and Print Plant

No MSM/additional feasible measures were identified for the paint booth and print press as part of this BACT analysis.

3.12 Underground Storage Tanks and Fuel Storage Tanks

No MSM/additional feasible measures were identified for the underground storage tanks as part of this BACT analysis.

3.13 Ethylene Oxide Sterilizer

No MSM/additional feasible measures were identified for the ethylene oxide sterilizer as part of this BACT analysis.

4.0 References

Hansen, J., & Hanson, K. (2017, June 1). Cleaver Brooks and DAQ Meeting.

Oland, C. B. (2002). *Guide to Low-Emission Boiler and Combustion Equipment Selection*. Oak Ridge National Laboratory.

Trinity Consultants. (2017a, April 28). PM2.5 Serious Nonattainment SIP BACM Analysis - The University of Utah, Salt Lake City, Utah.

Trinity Consultants. (2017b, July 21). University of Utah BACM Questions Response to the Utah Division of Air Quality.

Trinity Consultants. (2017c, July 21). University of Utah Emission Inventory and Emergency Generator BACT Control Evaluation - Draft.

Trinity Consultants. (2018a, June 13). U of U Potential Emissions - Complete Inventory 2018.

Trinity Consultants. (2018b, June 14). University of Utah Hospital Transformation BACT Reference.

THE UNIVERSITY OF UTAH

Occupational and Environmental Health and Safety Department
125 South Fort Douglas Blvd Bldg 605 SLC, UT 84113 (801)581-6590

April 28, 2017

Mr. Marty Gray
Utah Division of Air Quality
195 North 1950 West
Salt Lake City, Utah 84116

UTAH DEPARTMENT OF ENVIRONMENTAL QUALITY
APR 28 2017
DIVISION OF AIR QUALITY

RE: ***The University of Utah***
BACM/BACT Analysis – Direct $PM_{2.5}$ and $PM_{2.5}$ Precursors

Dear Mr. Gray:

The University of Utah (the University) is submitting this Best Available Control Measures/Technologies (BACM/BACT) analysis for direct particulate matter less than 2.5 microns ($PM_{2.5}$) and $PM_{2.5}$ precursors (including sulfur dioxide (SO_2), nitrogen oxide (NO_X), volatile organic compounds (VOCs), and ammonia (NH_3)) to the Utah Division of Air Quality (UDAQ), as requested in the letter dated January 23, 2017.

The University understands UDAQ is required to submit a Serious Area Attainment Control Plan as specified in 40 CFR 51, Subpart Z (Federal register (FR) Vol. 81, No. 164, August 24, 2016) due to the $PM_{2.5}$ serious nonattainment re-designation issued by the Environmental Protection Agency (EPA) on December 16, 2016. As the University is considered a major source of $PM_{2.5}$ and $PM_{2.5}$ precursors, its emission units will be included in the serious nonattainment control plan. This BACM/BACT analysis is in support of UDAQ's development of the Serious $PM_{2.5}$ Nonattainment control plan. As the University would like to continue to support UDAQ's SIP development effort, please feel free to reach out to me with any questions regarding the BACT/BACM analysis and I would appreciate the opportunity to review any draft conditions proposed for inclusion in the state implementation plan (SIP) that pertain to the University.

If you have any additional questions, please feel free to contact me at (801) 585-1617.

Sincerely,

Michael D. Brehm, P.E.
Manager, Environmental Protection

Enclosure

CC: David Quinlivan

$PM_{2.5}$ SERIOUS NONATTAINMENT SIP BACM ANALYSIS

The University of Utah > Salt Lake City, Utah

THE UNIVERSITY OF UTAH

Reviewed By:
Michael Brehm, P.E. – Environmental Protection Manager OEHS
David Quinlivan, P.E. – Associate Director Facilities Management

The University of Utah
Building 605
125 South Fort Douglas Blvd
Salt Lake City, Utah 84112

Prepared By:
Brian Mensinger – Managing Consultant
Beth Ryder – Senior Consultant
Chantelle Russell - Consultant

TRINITY CONSULTANTS
4525 Wasatch Blvd
Suite 200
Salt Lake City, UT 84124
801-272-3000

April 2017

Trinity Consultants

Environmental solutions delivered uncommonly well

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY

The Utah Division of Air Quality (UDAQ) is required to submit a Serious Area Attainment Control Plan as specified with 40 CFR 51, Subpart Z (Federal register (FR) Vol 81, No 164, August 24, 2016) in accordance with the $PM_{2.5}$ serious nonattainment re-designation issued by Environmental Protection Agency (EPA) on December 16, 2016.[1] This rule requires UDAQ to identify, adopt, and implement Best Available Control Measures or Technologies (BACM/BACT) for major sources of direct $PM_{2.5}$ and $PM_{2.5}$ precursors (Sulfur Dioxide (SO_2), Nitrogen oxide (NO_X), volatile organic compounds (VOCs), and ammonia (NH_3)).

The University of Utah (University) has the potential to emit more than 70 tons or more per year for $PM_{2.5}$ and/or $PM_{2.5}$ precursors, the University is considered a major source. DAQ has requested that each major source prepare a BACM/BACT Analysis which includes the following information:

- Detailed analysis of all applicable control measures and techniques (BACM/BACT Analysis);
- Evaluation of Most Stringent Measures (MSM);
- Evaluation of emission limits; and
- Evaluations of emissions monitoring.

The UDAQ must complete the State Implementation Plan (SIP) process by the end of July 2017 so that it can be reviewed and approved for public comment by the Air Quality Board (AQB) in September 2017 and finalized in December 2017 for submittal to the Environmental Protection Agency (EPA) by December 31, 2017.[2] As such, the University is submitting this BACM/BACT analysis in order to meet DAQ's submission deadline of April 30, 2017 as requested in the letter received January, 23, 2017.

[1] Federal Register Vol. 81, No. 164, August 24, 2016, pp. 58151

[2] 40 CFR 51.1003 Attainment Plan Submittal Requirements

2. INTRODUCTION

2.1. DESCRIPTION OF FACILITY

The University is a public higher education institution with air emissions primarily due to the operation of boilers, comforting heating equipment, and emergency generators located in Salt Lake City. The University has taken great strides to make the campus more energy efficient and has a long term commitment to sustainability. This is demonstrated, through the University's initiative to implement newer boiler technology. In a continued effort to become increasingly energy efficient, the University also continues to work on the campus buildings to make them Leadership in Energy and Environmental Design (LEED) certified.

All correspondence regarding this submission should be addressed to:

Mr. Michael Brehm
The University of Utah
Occupational and Environmental Health and Safety
125 South Fort Douglas Blvd
Salt Lake City, Utah County, Utah 84112
Phone: (801) 585-1617
Email: michael.brehm@oehs.utah.edu

2.2. PERMITTING BACKGROUND

The University is operating as a stationary source under Title V Operating Permit Number #3500063003 from the UDAQ last Revised May 20, 2015 (expiring May 20, 2020) and an approval order (AO) dated September 30, 2013 (DAQE-AN103540025-13). The University was established in 1850, and therefore has several pieces of old equipment onsite that pre-dates some federal New Source Performance Standards (NSPS) requirements. Although the University has taken great strides to make the campus more energy efficient and has a long term commitment to sustainability. This is demonstrated, through the University's initiative to implement newer boiler and heating technology on campus. In 2008, the University replaced two dual fired (natural gas and coal) boilers (Boilers #1 and #2) in Building 303 with a natural gas fired turbine with SoLoNox technology. These are two examples of major upgrades the University has completed to demonstrate their commitment to ensuring a safe and healthy environment for students, staff, and the community. The most recent installment of boiler equipment occurred in 2016 with the replacement of an old boiler (Boiler #5) with two smaller boilers (Boilers #6 and #7) in Building 303 that emitted overall less pollutants to the atmosphere. Boilers #6 and #7 started up in 2017.

Furthermore, the University will be replacing the pre-NSPS Boilers #3 and #4 in Building 303 with a single, smaller, more efficient boiler that currently meets the BACM/BACT standards. Additionally, the University intends to replace two higher emitting boilers in Building 303 with a single smaller unit with lower overall emissions.

Other permitting actions have mainly focused on ensuring compliance with federal regulations regarding emergency generation units (NESHAP ZZZZ, NSPS IIII, and NSPS JJJJJJ).

The emissions associated with the University are divided among the sources reviewed for BACT as shown in Table 2-1.

Table 2-1. Current Short-term Source Specific Emission Limit Summary

Source	Location	NO_X		VOC
Boilers 3 and 4	LCHTWP	25 lb/hr (each)	187 ppmdv (each)	NA
Boilers 5 and 6	LCHTWP	0.25 lb/hr (each)	9 ppmdv (each)	NA
Gas Turbine (Only)	LCHTWP	2.65 lb/hr	9 ppmdv	NA
Gas Turbine and Duct Burner	LCHTWP	8.97 lb/hr	15 ppmdv	NA
Carpentry Shop and Print Plant	Building 350	--	--	5 ton (12 month rolling period)
Ethylene Oxide Sterilizer	University Hospital	--	--	1 tpy

3. BEST AVAILABLE CONTROL MEASURES (BACM)

The University previously submitted a Reasonably Available Control Technology (RACT) evaluation in October 2013. The 2013 RACT analysis and the University current SIP requirements as documented in UDAQ's Moderate Non-Attainment SIP have been achieved by the University. The 2013 RACT analysis serves as a baseline for the BACM/BACT analysis documented herein. A BACM/BACT analysis has been conducted for each source addressed in Approval Order No. DAQE-AN103540025-13 and Title V permit #3500063003 in the following sections. Where appropriate, the University has addressed startup and shutdown emissions for each source as part of the BACM/BACT analysis. The University has organized the BACM/BACT analysis by emission unit group and addressed $PM_{2.5}$ and each $PM_{2.5}$ precursor in this analysis in a format that is in accordance with U.S. EPA's top-down BACT procedures.

3.1. BACM/BACT METHODOLOGY

In a memorandum dated December 1, 1987, the United States Environmental Protection Agency (U.S. EPA) stated its preference for a "top-down" BACT analysis.[3] After determining if any New Source Performance Standard (NSPS) is applicable, the first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical source or source category. If it can be shown that this level of control is technically, environmentally, or economically infeasible for the unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections. Presented below are the five basic steps of a top-down BACT review as identified by the U.S. EPA.

3.1.1. Step 1 - Identify All Control Technologies

Available control technologies are identified for each emission unit in question. The following methods are used to identify potential technologies: 1) researching the Reasonably Available Control Technology (RACT)/BACT/LAER Clearinghouse (RBLC) database, 2) surveying regulatory agencies, 3) drawing from previous engineering experience, 4) surveying air pollution control equipment vendors, and/or 5) surveying available literature.

3.1.2. Step 2 - Eliminate Technically Infeasible Options

The second step in the BACT analysis is to eliminate any technically infeasible control technologies. Each control technology for each pollutant is considered, and those that are clearly technically infeasible are eliminated. U.S. EPA states the following with regard to technical feasibility:[4]

A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review.

---

[3] U.S. EPA, Office of Air and Radiation. Memorandum from J.C. Potter to the Regional Administrators. Washington, D.C. December 1, 1987.

[4] U.S. EPA, New Source Review Workshop Manual (Draft): Prevention of Significant Deterioration and Nonattainment Area Permitting, October 1990.

3.1.3. Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Once technically infeasible options are removed from consideration, the remaining options are ranked based on their control effectiveness. If there is only one remaining option or if all of the remaining technologies could achieve equivalent control efficiencies, ranking based on control efficiency is not required.

In a retroactive BACT analysis, this step differs from the equivalent step in the NSR BACT process in that the baseline from which control effectiveness is evaluated is the current emission rate, and not some hypothetical "uncontrolled" level.

3.1.4. Step 4 - Evaluate Most Effective Controls and Document Results

Beginning with the most effective control option in the ranking, detailed economic, energy, and environmental impact evaluations are performed. If a control option is determined to be economically feasible without adverse energy or environmental impacts, it is not necessary to evaluate the remaining options with lower control effectiveness.

The economic evaluation centers on the cost effectiveness of the control option. Costs of installing and operating control technologies are estimated and annualized following the methodologies outlined in the U.S. EPA's *OAQPS Control Cost Manual* (CCM) and other industry resources.[5] Note that the analysis is not whether controls are affordable, but whether the expenditure is effective.

3.1.5. Step 5 - Select BACT

In the final step, one pollutant-specific control option is proposed as BACT for each emission unit under review based on evaluations from the previous step.

The U.S. EPA has consistently interpreted the statutory and regulatory BACT definitions as containing two core requirements that the agency believes must be met by any BACT determination, regardless of whether the "top-down" approach is used. First, the BACT analysis must include consideration of the most stringent available control technologies, i.e., those which provide the "maximum degree of emissions reduction." Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of "energy, environmental, and economic impacts."[6]

The UDAQ NOI Guide also details the requirement to achieve BACT as required in the State of Utah permitting process. The proposed BACT must be based on the most effective engineering techniques and control equipment to minimize emission of air contaminants into the outside environment from its process.

3.2. UCHTWP BOILERS

The upper campus high temperature water plant (UCHWTP), located in Building 302, has three natural gas-fired boilers, 1, 3, and 4 that are each rated at 87.5 million British thermal units per hour (MMBtu/hr) with 15% flue gas recirculation (FGR). Diesel is used as a backup fuel during periods of natural gas curtailment. The University intends to idle 50% of the UCHTWP boilers' current capacity by 2019 with new boilers in the HSC Transformation project buildings (Upper Medical Campus). The BACT review herein, however, focuses on the existing units.

---

[5] Office of Air Quality Planning and Standards (OAQPS), *EPA Air Pollution Control Cost Manual*, Sixth Edition, EPA 452-02-001 (http://www.epa.gov/ttn/catc/products.html#cccinfo), Daniel C. Mussatti & William M. Vatavuk, January 2002.

[6] Ibid.

Startup and shutdown emissions are anticipated to be less than or equal to emissions during normal operations on the boilers at the UCHTWP.

3.2.1. $PM_{2.5}$

According to EPA's AP-42, Section 1.4, since natural gas is a gaseous fuel, filterable PM emissions are typically low. Particulate matter from natural gas combustion has been estimated to be less than one micrometer in size and has filterable and condensable fractions. Particulate matter in natural gas combustion is usually larger molecular weight hydrocarbons that are not fully combusted. Increased particulate matter emissions can result from poor air/fuel mixing or maintenance problems.

UCHTWP Boilers $PM_{2.5}$ Step 1 - Identify All Control Technologies

The University has reviewed the following sources to ensure all available control technologies have been identified:

- EPA's RBLC Database for Natural Gas External Combustion Units (process type 13.31);[7]
- EPA's Air Pollution Technology Fact Sheets;
- EPA's CATC Alternative Control Techniques Document – NO_X Emissions from Utility Boilers;
- NESHAP DDDDD – Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters;
- NESHAP JJJJJJ – Industrial, Commercial, and Institutional Boilers at Area Sources;
- NSPS Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units[8]
- South Coast Air Quality Management District (SCAQMD) LAER/BACT Determinations;
- San Joaquin Valley Air Pollution Control District (SJVAPCD) BACT Clearinghouse;
- Bay Area Air Quality Management District (BAAQMD) BACT/TBACT Workbook; and
- Permits available online.

A search was conducted by querying all sources within the RBLC database in which the "Process Type Code" contained the number "13.310" (Medium Natural Gas Boilers, <100 MMBtu/hr), which covers operations associated with UCHTWP. The most closely related processes were as follows:

---

[7] Database accessed February 27, 2017.

[8] Boilers applicable to NSPS Subpart Dc do not have PM emission standards for Natural Gas Fired Boilers (40 CFR 60.43c).

Table 2 - Medium Natural Gas Boilers (<100 MMBtu) $PM_{2.5}$ Emissions[9]

Company Listing	Location	Heat Input	Controls	Emission Rate
HARRAH'S[10] Operating Company, Inc.	Clark Co, NV	24 MMBtu/hr	Operating with Manufacturer's Specifications	0.0075 lb/MMBtu
MGM MIRAGE[11]	Clark Co, NV	41.46 MMBtu/hr	Limit to the use of Natural Gas	0.0077 lb/MMBtu
MGM MIRAGE[12]	Clark Co, NV	44 MMBtu/hr	Limit to the use of Natural Gas	0.0075 lb/MMBtu

The technologies identified as possible $PM_{2.5}$ reduction technologies for Medium Size Natural Gas Boilers are shown in the table below.

Pollutant	Control Technologies
$PM_{2.5}$	Fabric Filter
	Wet Scrubber
	Dry Electrostatic Precipitator
	Cyclone

UCHTWP Boilers $PM_{2.5}$ Step 2 - Eliminate Technically Infeasible Options

A summary of the controls evaluated is in the table below based on EPA controls fact sheets. EPA does not address particulate (or fine particulate) in the controls section of AP-42 for gas-fired boilers.

---

9 The facilities were selected based on process type and purpose of equipment as well as location within similar Non-attainment areas and the application of SIP/PSD BACT.

10 RBLC Reference NV-0049, Harrah's Operating Company permit was issued in 2009.

11 RBLC Reference NV-0050, MGM Mirage permit was issued in 2009.

12 RBLC Reference NV-0050, MGM Mirage permit was issued in 2009.

Table 3 – PM Controls Evaluation for Natural Gas Combustion[13]

Technology	Typical Loading	Typical $PM_{2.5}$ Removal Efficiency	NG PM Size	NG $PM_{2.5}$ Loading	SOURCE
ESP	Not specified	97%	< 1 µm	5.7 lb/MMscf 1.9 lb/MMscf	EPA Fact Sheet EPA-452/F-03-030
Packed Bed/Tower Wet Scrubber		50 - 95%	< 1 µm	5.7 lb/MMscf 1.9 lb/MMscf	EPRI ESPs AND FINE PARTICLE COLLECTION
Spray Chamber/Tower Wet Scrubber	250 - 10,000 ppmv	Not Used	< 1 µm	5.7 lb/MMscf 1.9 lb/MMscf	EPA Fact Sheet EPA-452/F-03-015
Venturi Wet Scrubber	0.1 - 50 gr/scf	70 - 99%	< 1 µm	.7 lb/MMscf 1.9 lb/MMscf	EPA Fact Sheet EPA-452/F-03-016

The BACT analysis for $PM_{2.5}$ controls is a follows, this analysis is specific to filterable $PM_{2.5}$.

Wet Scrubber

A wet gas scrubber is an air pollution control device that removes PM and acid gases from waste streams from stationary point sources. PM and acid gases are primarily removed through the impaction, diffusion, interception and/or absorption of the pollutant onto droplets of liquid. Wet scrubbers have some advantages over ESPs and baghouses in that they are particularly useful in removing PM with the following characteristics:

- Sticky and/or hygroscopic materials;
- Combustible, corrosive or explosive materials;
- Particles that are difficult to remove in dry form;
- PM in the presence of soluble gases; and
- PM in gas stream with high moisture content.

However, considering the low concentration of $PM_{2.5}$ and the small size of particulate, a wet scrubber is considered technically infeasible for a boiler firing primarily natural gas.

Electrostatic Precipitator

An ESP is a particle control device that uses electrical forces to move the particles out of the gas stream onto collector plates. This process is accomplished by the charging of particles in the gas stream using positively or negatively charged electrodes. The particles are then collected as they are attracted to oppositely opposed electrodes. Once the particles are collected on the plates, they are removed by knocking them loose from the plates, allowing the collected layer of particles to fall down into a hopper. ESP's are used to capture coarse particles at high concentrations. Small particles at low concentrations are not effectively collected by an ESP. As

[13] PM Controls evaluation documents EPA's fact sheets for PM Controls related to natural gas combustion.

the technology is primarily for the combustion of natural gas, concentration of $PM_{2.5}$ is low and small in size. As such, ESP is considered technically infeasible for a boiler firing primarily natural gas.

Fabric Filter

A fabric filter unit (or baghouse) consists of one or more compartments containing rows of fabric bags. Particle-laden gases pass along the surface of the bags then through the fabric. Particles are retained on the upstream face of the bags and the cleaned gas stream is vented to the atmosphere. Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter. Fabric filters are used for medium and low gas flow streams with high particulate concentrations. As the boilers combust primarily natural gas, concentration of $PM_{2.5}$ is low and small in size. As such, a fabric filter is considered technically infeasible for a boiler firing primarily natural gas.

Good Combustion Practices and Use of Clean Burning Fuels

The use of good combustion practices usually include the following components: (1) proper fuel mixing in the combustion zone; (2) high temperatures and low oxygen levels in primary zone; (3) Overall excess oxygen levels high enough to complete combustion while maximizing boiler efficiency, and (4) sufficient residence time to complete combustion. Good combustion practices are accomplished through boiler design as it relates to time, temperature, and turbulence, and boiler operation as it relates to excess oxygen levels.

UCHTWP Boilers $PM_{2.5}$ Step 3-5 - Select BACT

Step 3 and 4 are not necessary since all control technologies that are not currently being used have been determined technically infeasible. No control technology is technically feasible, therefore this emission rate using good combustion practices and primarily natural gas is considered BACT.

UCHTWP Boilers $PM_{2.5}$ Most Stringent Measures

The most stringent measures would be identical to BACT as no control technology is technically feasible for these units.

3.2.2. NO_X

The NO_X that will be formed during combustion is from two major mechanisms: thermal NO_X and fuel NO_X. Since natural gas is relatively free of fuel-bound nitrogen, the contribution of this second mechanism to the formation of NO_X emissions in natural gas-fired equipment is minimal, leaving thermal NO_X as the main source of NO_X emissions. Thermal NO_X formation is a function of residence time, oxygen level, and flame temperature, and can be minimized by controlling these elements in the design of the combustion equipment.

UCHTWP Boilers NO_X Step 1 - Identify All Control Technologies

The University has reviewed the following sources to ensure all available control technologies have been identified:

- EPA's RBLC Database for Natural Gas External Combustion Units (process type 13.31);[14]
- EPA's Air Pollution Technology Fact Sheets;
- EPA's CATC Alternative Control Techniques Document – NO_X Emissions from Utility Boilers;

[14] Database accessed February 27, 2017.

- NESHAP DDDDD – Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters;
- NESHAP JJJJJJ – Industrial, Commercial, and Institutional Boilers at Area Sources;
- NSPS Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units[15]
- SCAQMD LAER/BACT Determinations;
- SJVAPCD BACT Clearinghouse;
- BAAQMD BACT/TBACT Workbook[16]; and
- Permits available online.

A search was conducted by querying all sources within the RBLC database in which the "Process Type Code" contained the number "13.310" (Medium Natural Gas Boilers, <100 MMBtu/hr), which covers operations associated with UCHTWP. The most closely related processes were as follows:

Table 4 – Medium Natural Gas Boilers (<100 MMBtu) NOx Emissions[17]

Company Listing	Location	Heat Input	Controls	Emission Rate	Concentration
HARRAH'S[18] Operating Company, Inc.	Clark Co, NV	24 MMBtu/hr	Low NOx Burner	0.0108 lb/MMBtu	9 PPM
MGM MIRAGE[19]	Clark Co, NV	41.46 MMBtu/hr	Low NOx Burner	0.011 lb/MMBtu	9 PPM
MGM MIRAGE[20]	Clark Co, NV	44 MMBtu/hr	Low NOx Burner	0.0109 lb/MMBtu	9 PPM

The technologies identified as possible NO_X reduction technologies for Medium Size Natural Gas Boilers are shown in the table below.

[15] Boilers applicable to NSPS Subpart Dc do not have NOx emission limitations for Natural Gas Fired Boilers.

[16] BACT(1) for NOx and CO (achieved using LNB+FGR+SCR and GCP) is 25 ppmvd NOx @3%O2

[17] The facilities were selected based on process type and purpose of equipment as well as location within similar Non-attainment areas and the application of SIP/PSD BACT. Up-to-date RBLC search run on April 23, 2017.

[18] RBLC Reference NV-0049, Harrah's Operating Company permit was issued in 2009.

[19] RBLC Reference NV-0050, MGM Mirage permit was issued in 2009.

[20] RBLC Reference NV-0050, MGM Mirage permit was issued in 2009.

Pollutant	Control Technologies
NO_X	Low NO_X Burners
	Ultra-Low NO_X Burners
	Flue Gas Recirculation
	Selective Catalytic Reduction
	Good Combustion Practices

UCHTWP Boilers NO_X Step 2 - Eliminate Technically Infeasible Options

To demonstrate a complete analysis, the University has evaluated the follow technologies including both replacement burners and add-on controls.

Low NOx Burners

LNB technology uses advanced burner design to reduce NO_X formation through the restriction of oxygen, flame temperature, and/or residence time. There are two general types of LNB: staged fuel and staged air burners. In a stage fuel LNB, the combustion zone is separated into two regions. The first region is a lean combustion region where a fraction of the fuel is supplied with the total quantity of combustion air. Combustion in this zone takes place at substantially lower temperatures than a standard burner. In the second combustion region, the remaining fuel is injected and combusted with left over oxygen from the first region. A staged air burner begins with full fuel but only partial combustion air, and then adds the remaining combustion air in the second combustion region. These techniques reduce the formation of thermal NO_X. This technology is listed in the RBLC search as a technically feasible control technology. BAAQMD lists typical technology for BACT for NO_X using a combination of SCR, LNB, and FGR. SCAQMD used LNB as the BACT determined control methodology for the University of California Irvine Medical Center boiler rated at 48.6 MMBtu/hr in 1999.

Ultra Low NOx Burners

ULNB technology uses internal FGR which involves recirculating the hot O_2 depleted flue gas from the heater into the combustion zone using burner design features and fuel staging to reduce NO_X. An ULNB is most commonly using an internal induced draft to reach the desired emission limitations. This technology is listed in the RBLC search as a technically feasible control technology. BAAQMD lists typical technology for BACT for NO_X using a combination of ULNB and FGR. SCAQMD used LNB plus FGR as the BACT determined control methodology for the Los Angeles County Internal Services Department boiler rated at 39 MMBtu/hr in 2004. An ULNB can achieve an emission rate of approximately 9 ppm or 0.011 pounds per million British thermal units (lb/MMBtu) when used in conjunction with FGR.

Flue Gas Recirculation

FGR is frequently used with both LNB and ULNB burners. FGR involves the recycling of post-combustion air into the air-fuel mixture to reduce the available oxygen and help cool the burner flame. External FGR requires the use of ductwork to route a portion of the flue gas in the stack back to the burner windbox; FGR can be either forced draft (where hot side fans are used) or induced draft. This technology is listed in the RBLC search as technically feasible and is paired with LNB for the BACT determined control technology. As previously discussed, both SCAQMD and BAAQMD have combined this technology with others to determine BACT. Currently, the UCHTWP boilers use this technology.

Selective Catalytic Reduction

SCR has been applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. It has been applied to large (>250 MMBtu/hr) utility and industrial boilers, process heaters, and combined cycle gas turbines. There has been limited application of SCR to other combustion devices and processes such as simple cycle gas turbines, stationary reciprocating internal combustion engines, nitric acid plants, and steel mill annealing furnaces. SCR can be applied as a stand-alone NO_X control or with other technologies such as combustion controls. The reagent reacts selectively with the flue gas NO_X within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NO_X into molecular nitrogen (N_2) and water vapor (H_2O).[21] The optimum operating temperature is dependent on the type of catalyst and the flue gas composition. Generally, the optimum temperature ranges from 480°F to 800°F.[22] In practice, SCR systems operate at efficiencies in the range of 70% to 90%.[23]

SCR is listed in the RBLC search as technically feasible. In some cases, this control technology is listed in combination with LNB and FGR. As previously mentioned, BAAQMD defines BACT as the combination of SCR, LNB, and FGR.

The ammonia "slip" associated with the SCR is a documented problem. The increased ammonia emissions (currently zero) from the implementation of this technology would offset the marginal air quality benefits the SCR option would provide from NO_X emissions reduction. Ammonia slip emissions have the potential to increase secondary $PM_{2.5}$ levels in the area more than the SCR controlled NO_X mass. Storage and handling of ammonia poses significant safety risks when applied at the University of Utah. Ammonia is toxic if swallowed or inhaled and can irritate or burn the skin, eyes, nose, or throat. It is a commonly used material that is typically handled safely and without incident. However, there are potential health and safety hazards associated with the implementation of this technology. The UCHTWP is located in a densely-packed area with other public facilities including student dormitories and the Red Butte Amphitheater, and a significant number of University staff, students, and the general public potentially in harm's way. Locating ammonia tanks in these premises poses significant health risks for students, faculty, patients, family members and the general public if a leak were to occur. The exhaust stream entering the SCR will require additional heat to meet the SCR operating temperature requirements (minimum of 480°F). This increase in exhaust temperature would require an additional combustion device, also increasing NO_X, SO_2, and $PM_{2.5}$ emissions.

Furthermore, there is a physical space issue concerning this technology. Building 302, where the UCHTWP boilers are housed, is confined by other buildings in the immediate proximity and may not provide the space required to physically install an SCR. The location of the boilers within the building also presents a space challenge when installing an SCR. That being said, the costs of installing an SCR would likely be higher than that presented in Step 4 below due to the limited amount of space under the current configuration.

Though there are obvious physical limitations, public safety concerns, and additional pollutants being emitted to use this add-on control technology, the control device is being evaluated for cost feasibility.

---

[21] Ibid.

[22] OAQPS, *EPA Air Pollution Control Cost Manual*, Sixth Edition, EPA/424/B-02-001 (http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf); January 2002

[23] OAQPS, *EPA Air Pollution Control Cost Manual*, Sixth Edition, EPA/424/B-02-001 (http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf); January 2002

Good Combustion Practices

Good combustion practices were previously addressed in the $PM_{2.5}$ control device evaluation for the UCHTWP boilers above.

UCHTWP Boilers NO_X Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Based on an RBLC search the following technologies are currently being used for boilers between 25 MMBtu/hr and 100 MMBtu/hr. These are ranked based on which technology can achieve the lowest emission rate. Note, an ULNB has not been proven with an SCR based on RBLC review.

1. SCR = 9 ppm or 0.011 lb/MMBtu[24]
2. ULNB = 9 ppm or 0.011 lb/MMBtu
3. LNB = 30 ppm or 0.036 lb/MMBtu
4. FGR = 42ppm or 0.05 lb/MMBtu

UCHTWP Boilers NO_X Step 4 - Evaluate Most Effective Controls and Document Results

The UCHTWP boilers are currently using 15% FGR and achieve an emission rate of 0.05 lb/MMBtu. To achieve an emission rate of 9 ppm, an SCR may be installed on each boiler. Assuming 70% control efficiency for the SCR, it would cost $149,046/ton of NO_X removed.[25] Calculations are shown in Appendix A and are based on generally provided capital costs from EPA's Air Pollution Control Cost Manual. The cost per ton of NO_X removed is beyond acceptable cost control effectiveness levels and therefore, the University has determined that this technology is economically infeasible for these units.

The University also reviewed replacing the current burner with an UNLB with an emission rate of 9 ppm NO_X or less. It would cost $109,755/ton of NO_x removed to achieve the 9 ppm emission rate. The cost per ton of NO_X removed is beyond acceptable cost control effectiveness levels and therefore, the University is considering this burner technology economically infeasible for these units. Detailed cost calculations for this control technology for the UCHTWP are provided in Appendix A. Installation of a lower efficiency burner, i.e. LNB technology, is not expected to decrease the capital investment substantially. Therefore, the University has assumed replacing the current burner with a LNB is also economically infeasible.

UCHTWP Boilers NO_X Step 5 - Select BACT

The University has selected the currently installed control technology as BACT for the UCHTWP boilers. The boilers have an emission rate of 0.05 lb/MMBtu using 15% FGR. As previously discussed, the University intends to idle 50% of the current capacity 2019 with new boilers in the Upper Medical Campus, in the University's continued effort to become more energy efficient.

---

[24] Several sources listed within RBLC with an emission rate of 9 ppm. Each of these technology combinations have been shown to meet this level of control

[25] An efficiency of 70% was assumed, given that SCR can generally operate between 70% and 90% control efficiency. The University has not obtained a vendor guarantee for this level of control for a unit with such a low concentration exhaust stream and would require consultation with a vendor prior to installation of this equipment.

Table 3-5. BACT Summary for UCHTWP Boilers

Control Technologies	Controlled Emission Rate (lb/MMBtu)	Technically Feasible ?	Economic Feasibility ($/ton removal)	BACT
SCR	0.011	Yes	$149,046	
ULNB	0.011	Yes	$109,755	
LNB + FGR	0.011	Yes	--[a]	
LNB	0.036	Yes	$109,755[b]	
FGR (Current Technology)	0.05	Yes	--[c]	Yes
Good Combustion Practice	N/A	Yes		Yes

a. LNB + FGR was not considered for economic feasibility because the ULNB alone can achieve the desired emission rate.
b. Economic feasibility was not specifically determined for this control technology, but is expected to be reasonably close to the cost of an ULNB replacement.
c. This is the current technology used on the system, economic feasibility is not required.

UCHTWP Boilers NO_X Most Stringent Measures

MSM is installation of ULNB to achieve an emission rate of 0.011 lbs/MMBtu. This will be a substantial economic investment for the University.

3.2.3. SO_2

SO_2 emissions associated with the boilers are due to natural gas and diesel combustion. Emissions associated with all boilers are less than 1 tpy. Therefore, the University is proposing good combustion practices and use of natural gas (with diesel as a backup fuel) as BACT.[26]

A search was conducted by querying all sources within the RBLC database in which the "Process Type Code" contained the number "13.310" (Medium Natural Gas Boilers, <100 MMBtu/hr), which covers operations associated with UCHTWP. The most closely related processes were as follows:

[26] BAAQMD BACT/TBACT Workbook - BACT(2) for SO2 and PM10 is the use of low sulfur fuel with < 0.05 wt% S

Table 6 – Medium Natural Gas Boilers (<100 MMBtu) SO_2 Emissions[27]

Company Listing	Location	Heat Input	Controls	Emission Rate
HARRAH'S[28] Operating Company, Inc.	Clark Co, NV	24 MMBtu/hr	Fuel is limited to Natural Gas	0.0006 lb/MMBtu
MGM MIRAGE[29]	Clark Co, NV	41.46 MMBtu/hr	Fuel is limited to Natural Gas	0.0007 lb/MMBtu
MGM MIRAGE[30]	Clark Co, NV	44 MMBtu/hr	Fuel is limited to Natural Gas	0.0007 lb/MMBtu

The technologies identified as possible SO_2 reduction technologies for Medium Size Natural Gas Boilers are natural gas and good combustion practices.

UCHTWP Boilers SO_2 Step 1 - Identify All Control Technologies

There are two primary mechanisms to reduce SO_2 emissions from combustion sources which are: (1) reduce the amount of sulfur in the fuel, and (2) remove the sulfur from the exhaust gases with post-combustion control device such as flue gas desulfurization utilizing wet scrubbers or dry scrubbers.

The University will be using pipeline-quality natural gas as the primary fuel which has a low sulfur content. The use of a fuel containing low sulfur content is considered a control technology.

Two main types of SO_2 post-combustion control technologies, wet and dry scrubbing, were identified to reduce SO_2 in the exhaust gas.

UCHTWP Boilers SO_2 Step 2 - Eliminate Technically Infeasible Options

The requirement for low-sulfur natural gas is a control technique that has been achieved in practice and is technically feasible and cost-effective and will be further considered for BACT. Post-combustion devices such as wet or dry scrubbers are typically installed on coal-fired power plants that burn fuels with much higher sulfur contents. The SO_2 concentrations in the natural gas combustion exhaust gases from the boilers are too low for scrubbing technologies to work effectively or to be technically feasible and cost effective. These control technologies require much higher sulfur concentrations in the exhaust gases to be feasible as a control technology. Thus, post-combustion SO_2 control devices, such as wet and dry scrubbing have not been achieved in practice on natural gas boilers. Since these controls are not technically feasible, they have been eliminated from further consideration for the boilers.

---

[27] The facilities were selected based on process type and purpose of equipment as well as location within similar Non-attainment areas and the application of SIP/PSD BACT. Up-to-date RBLC search run on April 23, 2017.

[28] RBLC Reference NV-0049, Harrah's Operating Company permit was issued in 2009.

[29] RBLC Reference NV-0050, MGM Mirage permit was issued in 2009.

[30] RBLC Reference NV-0050, MGM Mirage permit was issued in 2009.

UCHTWP Boilers SO_2 Step 3 - 5 - Select BACT

The use of pipeline-quality natural gas as the primary fuel is the only feasible SO_2 control technology for the boilers to control SO_2. There is no adverse energy, environmental or cost impact associated with the use of this control technology. Thus, no further analysis is required under EPA's top-down BACT approach. SO_2 emissions associated with the boilers are due to fuel combustion. Emissions associated with this process are less than 1 tpy. Therefore, the University is proposing good combustion practices and use pipeline-quality natural gas as the primary fuel is considered BACT.

UCHTWP Boilers SO_2 Most Stringent Measures

MSM is equivalent to BACT in this instance since no add-on control technologies are available for these units.

3.2.4. VOC

UCHTWP Boilers VOC Step 1 - Identify All Control Technologies

The University has reviewed the following sources to ensure all available control technologies have been identified:

- EPA's RBLC Database for Natural Gas External Combustion Units (process type 13.31);31
- EPA's Air Pollution Technology Fact Sheets;
- EPA's CATC Alternative Control Techniques Document – NOX Emissions from Utility Boilers;
- NESHAP DDDDD – Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters;
- NESHAP JJJJJJ – Industrial, Commercial, and Institutional Boilers at Area Sources;
- SCAQMD LAER/BACT Determinations;
- SJVAPCD BACT Clearinghouse;
- BAAQMD BACT/TBACT Workbook[32]; and
- Permits available online.

A search was conducted by querying all sources within the RBLC database in which the "Process Type Code" contained the number "13.310" (Medium Natural Gas Boilers, <100 MMBtu/hr), which covers operations associated with UCHTWP. The most closely related processes were as follows:

[31] Database accessed February 27, 2017.

[32] BAAQMD BACT/TBACT Workbook - BACT(2) for POC is GCP

Table 7 – Medium Natural Gas Boilers (<100 MMBtu) VOCs Emissions[33]

Company Listing	Location	Heat Input	Controls	Emission Rate
HARRAH'S[34] Operating Company, Inc.	Clark Co, NV	24 MMBtu/hr	Operating according to manufacturer's specifications	0.0054 lb/MMBtu
MGM MIRAGE[35]	Clark Co, NV	41.46 MMBtu/hr	Limiting to Natural Gas and Good Combustion Practices	0.0024 lb/MMBtu
MGM MIRAGE[36]	Clark Co, NV	44 MMBtu/hr	Limiting to Natural Gas and Good Combustion Practices	0.0055 lb/MMBtu

The technologies identified as possible VOC reduction technologies for Medium Size Natural Gas Boilers are shown in the table below.

Pollutant	Control Technologies
VOCs	Thermal Oxidizer/Afterburner
	Regenerative Thermal Oxidizer (RTO)
	Catalytic Oxidation
	Good Combustion Practices

UCHTWP Boilers VOC Step 2 - Eliminate Technically Infeasible Options

Simple Thermal Oxidizer or Afterburner (TO)

In a simple TO or afterburner, the flue gas exiting the boiler is reheated in the presence of sufficient oxygen to oxidize the VOC present in the flue gas. A typical TO is a flare and is not equipped with any heat recovery device. A TO will require additional fuel to heat the gas stream starting from 280°F to at least 1,600°F and which will generate additional emissions. Additionally, a TO is no different from the combustion chamber of the boiler. Therefore, there would be little expected reduction in VOC with an increase in other combustion pollutants for the required heating of the exhaust stream. Therefore, the TO is not considered further.

---

[33] The facilities were selected based on process type and purpose of equipment as well as location within similar Non-attainment areas and the application of SIP/PSD BACT. Up-to-date RBLC search run on April 23, 2017.

[34] RBLC Reference NV-0049, Harrah's Operating Company permit was issued in 2009.

[35] RBLC Reference NV-0050, MGM Mirage permit was issued in 2009.

[36] RBLC Reference NV-0050, MGM Mirage permit was issued in 2009.

Regenerative Thermal Oxidizer (RTO)

A RTO is equipped with ceramic heat recovery media (stoneware) that has large surface area for heat transfer and can be stable to 2,300°F. Operating temperatures of the RTO system typically range from 1,500°F to 1,800°F with a retention time of approximately one second. The combustion chamber of the RTO is surrounded by multiple integral heat recovery chambers, each of which sequentially switches back and forth from being a preheater to a heat recovery chamber. In this fashion, energy is absorbed from the gas exhausted from the unit and stored in the heat exchange media to preheat the next cycle of incoming gas. An RTO will require additional fuel to heat the gas stream from 280°F to at least 1,500°F and which will generate additional emissions; therefore, the RTO is not considered further.

Catalytic Oxidation

Catalytic oxidation allows complete oxidation to take place at a faster rate and a lower temperature than is possible with thermal oxidation. Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency. In a typical catalytic oxidizer, the gas stream is passed through a flame area and then through a catalyst bed at a velocity in the range of 10 to 30 feet per second (fps). Catalytic oxidizers typically operate at a narrow temperature range of approximately 600°F to 1100°F. A catalytic oxidizer will require additional fuel to heat the gas stream from 280°F to at least 600°F and which will generate additional emissions; therefore, the catalytic oxidation is not considered further. This is listed in RBLC for a single source with higher emission rates than others using good operating practices.

Good Combustion Practices and Use of Clean Burning Fuels

Good combustion practices for VOCs include adequate fuel residence times, proper fuel-air mixing, and temperature control. As it is imperative for process controls, the University will maintain combustion optimal to their process. Most results in RBLC determined that this was sufficient controls for VOC. Additionally, BAAQMD and SCAQMD did not provide BACT determinations for VOC.

UCHTWP Boilers VOC Step 3-5 - Select BACT

Step 3 and 4 are not necessary since all control technologies not currently being used have been determined technically infeasible or current technologies have lower emission rates. BACT for the boilers is good combustion practices and the use of clean burning fuel.

UCHTWP Boilers VOC Most Stringent Measures

MSM is equivalent to BACT in this instance.

3.2.5. Ammonia

The University found ammonia emission factors for uncontrolled boilers on EPA's WebFIRE database.[37] The emission factors cited within this document are from the 1994 version of EPA's AP-42 Chapter 1.4. In 1998, this chapter was updated and ammonia emissions were removed from the list of emission factors associated with external combustion sources fueled by natural gas. As such, the University assumes there are minimal ammonia emissions associated with the boilers and have not considered them further for BACT.

---

[37] Database accessed April 12, 2017.

3.3. LCHTWP BOILERS

The lower campus high temperature water plant (LCHTWP) provides the heating and cooling necessary for the lower (western) portion of campus and is located in Building 303. The LCHWTP has four natural gas-fired boilers and a cogeneration unit which consists of a turbine and a waste heat recovery unit.

The University has taken great strides to make the campus more energy efficient and has a long term commitment to sustainability. This is demonstrated, through the University's initiative to implement newer boiler technology, such as that planned for the UCHTWP boilers, and the new 6.5 megawatt (MW) combined heat and power (CHP) system installed in 2008. In a continued effort to become increasingly energy efficient, the University also continues to work on the campus buildings to make them LEED certified. The University currently exceeds State of Utah energy standards for construction, requiring 12% more energy cost savings over what is required by the State and code (32% vs 20%).

This section focuses on the boilers installed: two units rated at 105 MMBtu/hr each (Units 3 and 4) and two units rated at 50 MMBtu/hr each (Units 6 and 7). Table 3-8 below summarizes the operating characteristics and replacement schedule for each boiler.

Table 3-8 Operating Characteristics and Replacement Schedule

Boiler Number	Input Capacity (MMBtu/hr)	Installed/Operating Characteristics	Replacement Schedule
Unit 3	105	- Only used at peak demand or during a malfunction	- To be decommissioned by the end of 2018 - Replaced with a high efficiency unit (Unit #9) by December 31, 2018
Unit 4	105	- Only used at peak demand or during a malfunction	- To be decommissioned in 2018 - Will be removed
Unit 6	50	- Utilize LNB + FGR - 9 ppm	- Installed in 2016
Unit 7	50	- Utilize LNB + FGR - 9 ppm	- Installed in 2016

As part of the 2013 moderate non-attainment SIP development, the University committed to decommissioning Units 3 and 4 in 2019, respectively. In place of the units the University will install a single 75 MMBtu/hr high efficiency natural gas boiler. The University plans to meet the agreed upon deadlines for decommissioning and will have Units 3 and 4 will be decommissioned and replaced by December 31, 2018. In accordance with the $PM_{2.5}$ Moderate SIP, the BACT review presented below applies to the 75 MMBtu/hr replacement high efficiency boiler for Unit 3, as well as Units 6 and 7. The implementation of newer boiler technologies demonstrate the University's continued effort to become increasingly energy efficient, amongst other strides the University has taken and is taking as discussed in the UCHTWP boiler section, Section 3.2.

Startup and shutdown emissions are anticipated to be less than or equal to emissions during normal operations on the boilers at the LCHTWP.

3.3.1. $PM_{2.5}$

According to EPA's AP-42, Section 1.4, since natural gas is a gaseous fuel, filterable PM emissions are typically low. Particulate matter from natural gas combustion has been estimated to be less than one micrometer in size and has filterable and condensable fractions. Particulate matter in natural gas combustion is usually larger molecular weight hydrocarbons that are not fully combusted. Increased particulate matter emissions can result from poor air/fuel mixing or maintenance problems.

LCHTWP Boilers $PM_{2.5}$ Step 1 - Identify All Control Technologies

The University has reviewed the following sources to ensure all available control technologies have been identified:

- EPA's RBLC Database for Natural Gas External Combustion Units (process type 13.31);[38]
- EPA's Air Pollution Technology Fact Sheets;
- EPA's CATC Alternative Control Techniques Document – NO_X Emissions from Utility Boilers;
- NESHAP DDDDD – Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters;
- NESHAP JJJJJJ – Industrial, Commercial, and Institutional Boilers at Area Sources;
- SCAQMD LAER/BACT Determinations;
- SJVAPCD BACT Clearinghouse;
- BAAQMD BACT/TBACT Workbook; and
- Permits available online.

To demonstrate a complete analysis, the University has evaluated the following for $PM_{2.5}$.

A search was conducted by querying all sources within the RBLC database in which the "Process Type Code" contained the number "13.310" (Medium Natural Gas Boilers, <100 MMBtu/hr), which covers operations associated with UCHTWP. Similar to the LCHTWP had similar sources in the RBLC search as the LCHTWP, therefore it is not repeated from above. The same results for $PM_{2.5}$ can be found in Table 2 - Medium Natural Gas Boilers (<100 MMBtu) $PM_{2.5}$ Emissions Table 2.

The technologies identified as possible $PM_{2.5}$ reduction technologies for Medium Size Natural Gas Boilers are shown in the table below.

[38] Database accessed February 27, 2017.

Pollutant	Control Technologies
$PM_{2.5}$	Fabric Filter
	Wet Scrubber
	Electrostatic Precipitator
	Cyclone

LCHTWP Boilers $PM_{2.5}$ Step 2 - Eliminate Technically Infeasible Options

Wet Scrubber

A wet gas scrubber is an air pollution control device that removes PM and acid gases from waste streams from stationary point sources. PM and acid gases are primarily removed through the impaction, diffusion, interception and/or absorption of the pollutant onto droplets of liquid. Wet scrubbers have some advantages over ESPs and baghouses in that they are particularly useful in removing PM with the following characteristics:

- Sticky and/or hygroscopic materials;
- Combustible, corrosive or explosive materials;
- Particles that are difficult to remove in dry form;
- PM in the presence of soluble gases; and
- PM in gas stream with high moisture content.

However, considering the low concentration of $PM_{2.5}$ and the small size of particulate, a wet scrubber is considered technically infeasible for a boiler firing natural gas.

Electrostatic Precipitator

An ESP is a particle control device that uses electrical forces to move the particles out of the gas stream onto collector plates. This process is accomplished by the charging of particles in the gas stream using positively or negatively charged electrodes. The particles are then collected as they are attracted to oppositely opposed electrodes. Once the particles are collected on the plates, they are removed by knocking them loose from the plates, allowing the collected layer of particles to fall down into a hopper. ESP's are used to capture coarse particles at high concentrations. Small particles at low concentrations are not effectively collected by an ESP. As the technology is for the combustion of natural gas, concentration of $PM_{2.5}$ is low and small in size. As such, ESP is considered technically infeasible for a boiler firing natural gas.

Fabric Filter

A fabric filter unit (or baghouse) consists of one or more compartments containing rows of fabric bags. Particle-laden gases pass along the surface of the bags then through the fabric. Particles are retained on the upstream face of the bags and the cleaned gas stream is vented to the atmosphere. Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter. Fabric filters are used for medium and low gas flow streams with high particulate concentrations. As the boilers combust natural gas, concentration of $PM_{2.5}$ is low and small in size. As such, a fabric filter is considered technically infeasible for a boiler firing natural gas.

Good Combustion Practices and Use of Clean Burning Fuels

The use of good combustion practices usually include the following components: (1) proper fuel mixing in the combustion zone; (2) high temperatures and low oxygen levels in primary zone; (3) Overall excess oxygen levels high enough to complete combustion while maximizing boiler efficiency, and (4) sufficient residence time to complete combustion. Good combustion practices are accomplished through boiler design as it relates to time, temperature, and turbulence, and boiler operation as it related to excess oxygen levels.

LCHTWP Boilers $PM_{2.5}$ Step 3-5 - Select BACT

Step 3 and 4 are not necessary since all control technologies that are not currently being used have been determined technically infeasible. No control technology is technically feasible, therefore this emission rate using good combustion practices and natural gas is considered BACT.

LCHTWP Boilers $PM_{2.5}$ Most Stringent Measures

The most stringent measures would be identical to BACT as no control technology is technically feasible for these units.

3.3.2. NO_X

The NO_X that will be formed during combustion is from two major mechanisms: thermal NO_X and fuel NO_X. Since natural gas is relatively free of fuel-bound nitrogen, the contribution of this second mechanism to the formation of NO_X emissions in natural gas-fired equipment is minimal, leaving thermal NO_X as the main source of NO_X emissions. Thermal NO_X formation is a function of residence time, oxygen level, and flame temperature, and can be minimized by controlling these elements in the design of the combustion equipment.

LCHTWP Boilers NO_X Step 1 - Identify All Control Technologies

The University has reviewed the following sources to ensure all available control technologies have been identified:

- EPA's RBLC Database for Natural Gas External Combustion Units (process type 13.31);[39]
- EPA's Air Pollution Technology Fact Sheets;
- EPA's CATC Alternative Control Techniques Document – NO_X Emissions from Utility Boilers;
- NESHAP DDDDD – Major Sources: Industrial, Commercial, and Institutional Boilers and Process
- Heaters;
- NESHAP JJJJJJ – Industrial, Commercial, and Institutional Boilers at Area Sources;
- SCAQMD LAER/BACT Determinations;
- SJVAPCD BACT Clearinghouse;
- BAAQMD BACT/TBACT Workbook; and
- Permits available online.

A search was conducted by querying all sources within the RBLC database in which the "Process Type Code" contained the number "13.310" (Medium Natural Gas Boilers, <100 MMBtu/hr), which covers operations associated with UCHTWP. Similar to the LCHTWP had similar sources in the RBLC search as the LCHTWP, therefore it is not repeated from above.

The technologies identified as possible NO_X reduction technologies for Medium Size Natural Gas Boilers are shown in the table below.

---

[39] Database accessed February 27, 2017.

Pollutant	Control Technologies
NO_X	Low NO_X Burners
	Ultra-Low NO_X Burners
	Flue Gas Recirculation
	Selective Catalytic Reduction
	Good Combustion Practices

LCHTWP Boilers NO_X Step 2 - Eliminate Technically Infeasible Options

To demonstrate a complete analysis, the University has evaluated the follow technologies including both replacement burners and add-on controls.

Low NOx Burners

LNB technology uses advanced burner design to reduce NO_X formation through the restriction of oxygen, flame temperature, and/or residence time. There are two general types of LNB: staged fuel and staged air burners. In a stage fuel LNB, the combustion zone is separated into two regions. The first region is a lean combustion region where a fraction of the fuel is supplied with the total quantity of combustion air. Combustion in this zone takes place at substantially lower temperatures than a standard burner. In the second combustion region, the remaining fuel is injected and combusted with left over oxygen from the first region. A staged air burner begins with full fuel but only partial combustion air, and then adds the remaining combustion air in the second combustion region. These techniques reduce the formation of thermal NO_X. This technology is listed in the RBLC search as a technically feasible control technology. BAAQMD lists typical technology for BACT for NO_X using a combination of SCR, LNB, and FGR. SCAQMD used LNB as the BACT determined control methodology for the University of California Irvine Medical Center boiler rated at 48.6 MMBtu/hr in 1999.

Ultra Low NOx Burners

ULNB technology uses internal FGR which involves recirculating the hot O_2 depleted flue gas from the heater into the combustion zone using burner design features and fuel staging to reduce NO_X. An ULNB is most commonly using an internal induced draft to reach the desired emission limitations. This technology is listed in the RBLC search as a technically feasible control technology. BAAQMD lists typical technology for BACT for NO_X using a combination of ULNB and FGR. SCAQMD used LNB plus FGR as the BACT determined control methodology for the Los Angeles County Internal Services Department boiler rated at 39 MMBtu/hr in 2004. An ULNB can achieve an emission rate of approximately 9 ppm or 0.011 lb/MMBtu when used in conjunction with FGR. Unit 9, which will be installed in place of Units 3 and 4 in 2018 will utilize ULNB technology.

Flue Gas Recirculation

FGR is frequently used with both LNB and ULNB burners. FGR involves the recycling of post-combustion air into the air-fuel mixture to reduce the available oxygen and help cool the burner flame. External FGR requires the use of ductwork to route a portion of the flue gas in the stack back to the burner windbox; FGR can be either forced draft (where hot side fans are used) or induced draft. This technology is listed in the RBLC search as technically feasible and is paired with LNB for the BACT determined control technology. As previously discussed, both SCAQMD and BAAQMD have combined this technology with others to determine BACT. Currently, Units 6 and 7 utilize use this technology.

Selective Catalytic Reduction

SCR has been applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. It has been applied to large (>250 MMBtu/hr) utility and industrial boilers, process heaters, and combined cycle gas turbines. There has been limited application of SCR to other combustion devices and processes such as simple cycle gas turbines, stationary reciprocating internal combustion engines, nitric acid plants, and steel mill annealing furnaces. SCR can be applied as a stand-alone NOX control or with other technologies such as combustion controls. The reagent reacts selectively with the flue gas NOX within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOX into molecular nitrogen (N2) and water vapor (H_2O).[40] The optimum operating temperature is dependent on the type of catalyst and the flue gas composition. Generally, the optimum temperature ranges from 480°F to 800°F.[41] In practice, SCR systems operate at efficiencies in the range of 70% to 90%.[42]

SCR is listed in the RBLC search as technically feasible. In some cases, this control technology is listed in combination with LNB and FGR. As previously mentioned, BAAQMD defines BACT as the combination of SCR, LNB, and FGR.

The ammonia "slip" associated with the SCR is a documented problem. The increased ammonia emissions (currently zero) from the implementation of this technology would offset the marginal air quality benefits the SCR option would provide from NO_X emissions reduction. Ammonia slip emissions have the potential to increase secondary $PM_{2.5}$ levels in the area more than the SCR controlled NO_X mass. Storage and handling of ammonia poses significant safety risks when applied at the University of Utah. Ammonia is toxic if swallowed or inhaled and can irritate or burn the skin, eyes, nose, or throat, it is a commonly used material that is typically handled safely and without incident. However, there are potential health and safety hazards associated with the implementation of this technology. The LCHTWP is located in a densely-packed area with other public facilities and a significant number of University staff, students, and the general public potentially in harm's way. Locating ammonia tanks in these premises poses significant health risks for students, faculty, patients, family members and the general public if a leak were to occur. The exhaust stream entering the SCR will require additional heat to meet the SCR operating temperature requirements (minimum of 480°F). This increase in exhaust temperature would require an additional combustion device, also increasing NO_X, SO_2, and $PM_{2.5}$ emissions.

Furthermore, there is a physical space issue concerning this technology. Building 303, where the LCHTWP boilers are housed, is confined by other buildings in the immediate proximity and currently does not provide the space required to physically install an SCR. The location of the boilers within the building also presents a space challenge when installing an SCR. The physical space restriction within Building 303 is more confined than the physical space in Building 302 as discussed in Section 3.2.2. Therefore, the SCR is considered technically infeasible for the boilers located in Building 303 due to physical limitations, public safety concerns, and additional pollutants being emitted to use this add-on control technology.

---

[40] Ibid.

[41] OAQPS, *EPA Air Pollution Control Cost Manual*, Sixth Edition, EPA/424/B-02-001 (http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf); January 2002

[42] OAQPS, *EPA Air Pollution Control Cost Manual*, Sixth Edition, EPA/424/B-02-001 (http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf); January 2002

Good Combustion Practices

Good combustion practices were previously addressed in the $PM_{2.5}$ control device evaluation for the LCHTWP boilers above.

LCHTWP Boilers NO_X Step 3-5 - Select BACT

Based on an RBLC search the following technologies are currently being used for boilers between 25 MMBtu/hr and 100 MMBtu/hr. These are ranked based on which technology can achieve the lowest emission rate. Note, an ULNB has not been proven with an SCR based on RBLC review.

1. ULNB or LNB + FGR = 9 ppm or 0.011 lb/MMBtu
2. LNB = 30 ppm or 0.036 lb/MMBtu
3. FGR = 187 ppm or 0.23 lb/MMBtu

Units 6 and 7 currently utilize LNB and FGR and have a permitted NO_x emission rate of 9 ppm (0.25 lb/hr), each.[43] Unit 9, which will replace existing Units 3 and 4 in 2018, will utilize ULNB technology and achieve an emission rate of 9 ppm. That being said, while other control technologies are available, all three (3) of these units will meet BACT with the control technologies that are currently employed or will be employed (in the case of Units 6 and 7, and Unit 9, respectively) and, thus, further evaluation is not needed. Consequently, the University has concluded BACT for Units 6 and 7 is LNB and FGR and BACT for Unit 9 is an ULNB.

LCHTWP Boilers NO_X Most Stringent Measures

MSM is identical to BACT in this instance.

3.3.3. SO_2

The top-down BACT analysis for SO_2 emissions for the LCHTWP boilers is presented below. The technologies identified as possible SO_2 reduction technologies for Medium Size Natural Gas Boilers are natural gas and good combustion practices as identified in Table 6 – Medium Natural Gas Boilers (<100 MMBtu) SO_2 Emissions.

SO_2 emissions associated with the boilers are due to natural gas combustion. Emissions associated with all boilers are less than 2 tpy. Therefore, the University is proposing good combustion practices and use of natural gas as BACT.

LCHTWP Boilers SO_2 Step 1 - Identify All Control Technologies

There are two primary mechanisms to reduce SO_2 emissions from combustion sources which are: (1) reduce the amount of sulfur in the fuel, and (2) remove the sulfur from the exhaust gases with post-combustion control device such as flue gas desulfurization utilizing wet scrubbers or dry scrubbers.

The University will be using pipeline-quality natural gas which has a low sulfur content. The use of a fuel containing low sulfur content is considered a control technology.

Two main types of SO_2 post-combustion control technologies, wet and dry scrubbing, were identified to reduce SO_2 in the exhaust gas.

---

[43] AO AN103540025-13, Permit Condition II.B.2.c

LCHTWP Boilers SO_2 Step 2 - Eliminate Technically Infeasible Options

The requirement for low-sulfur natural gas is a control technique that has been achieved in practice and is technically feasible and cost-effective and will be further considered for BACT. Post-combustion devices such as wet or dry scrubbers are typically installed on coal-fired power plants that burn fuels with much higher sulfur contents. The SO_2 concentrations in the natural gas combustion exhaust gases from the boilers are too low for scrubbing technologies to work effectively or to be technically feasible and cost effective. These control technologies require much higher sulfur concentrations in the exhaust gases to be feasible as a control technology. Thus, post-combustion SO_2 control devices, such as wet and dry scrubbing have not been achieved in practice on natural gas boilers. Since these controls are not technically feasible, they have been eliminated from further consideration for the boilers.

LCHTWP Boilers SO_2 Step 3-5 - Select BACT

The use of pipeline-quality natural gas is the only feasible SO_2 control technology for the boilers to control SO_2. There is no adverse energy, environmental or cost impact associated with the use of these control technologies. Thus, no further analysis is required under EPA's top-down BACT approach. SO_2 emissions associated with the boilers are due to natural gas combustion. Emissions associated with this process are less than 2 tpy. Therefore, the University is proposing good combustion practices and use pipeline-quality natural gas as the primary fuel is considered BACT.

LCHTWP Boilers SO_2 Most Stringent Measures

MSM is equivalent to BACT in this instance since no add-on control technologies are available for these units.

3.3.4. VOC

LCHTWP Boilers VOC Step 1 - Identify All Control Technologies

The University has reviewed the following sources to ensure all available control technologies have been identified:

- EPA's RBLC Database for Natural Gas External Combustion Units (process type 13.31);[44]
- EPA's Air Pollution Technology Fact Sheets;
- EPA's CATC Alternative Control Techniques Document – NOX Emissions from Utility Boilers;
- NESHAP DDDDD – Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters;
- NESHAP JJJJJJ – Industrial, Commercial, and Institutional Boilers at Area Sources;
- SCAQMD LAER/BACT Determinations;
- SJVAPCD BACT Clearinghouse;
- BAAQMD BACT/TBACT Workbook; and
- Permits available online.

To demonstrate a complete analysis, the University has evaluated the follow technologies for VOCs.

A search was conducted by querying all sources within the RBLC database in which the "Process Type Code" contained the number "13.310" (Medium Natural Gas Boilers, <100 MMBtu/hr), which covers operations associated with UCHTWP. Similar to the LCHTWP had similar sources in the RBLC search as the LCHTWP,

---

[44] Database accessed February 27, 2017.

therefore it is not repeated from above. The same results for VOC can be found in Table 7 – Medium Natural Gas Boilers (<100 MMBtu) VOCs Emissions.

The technologies identified as possible VOC reduction technologies for Medium Size Natural Gas Boilers are shown in the table below.

Pollutant	Control Technologies
VOCs	Thermal Oxidizer/Afterburner
	Regenerative Thermal Oxidizer (RTO)
	Catalytic Oxidation
	Good Combustion Practices

LCHTWP Boilers VOC Step 2 - Eliminate Technically Infeasible Options

Simple Thermal Oxidizer or Afterburner

In a simple TO or afterburner, the flue gas exiting the boiler is reheated in the presence of sufficient oxygen to oxidize the VOC present in the flue gas. A typical TO is a flare and is not equipped with any heat recovery device. A TO will require additional fuel to heat the gas stream starting from 280°F to at least 1,600°F and which will generate additional emissions. Additionally, a TO is no different from the combustion chamber of the boiler. Therefore, there would be little expected reduction in VOC with an increase in other combustion pollutants for the required heating of the exhaust stream. Therefore, the TO is not considered further.

Regenerative Thermal Oxidizer

A RTO is equipped with ceramic heat recovery media (stoneware) that has large surface area for heat transfer and can be stable to 2,300°F. Operating temperatures of the RTO system typically range from 1,500°F to 1,800°F with a retention time of approximately one second. The combustion chamber of the RTO is surrounded by multiple integral heat recovery chambers, each of which sequentially switches back and forth from being a preheater to a heat recovery chamber. In this fashion, energy is absorbed from the gas exhausted from the unit and stored in the heat exchange media to preheat the next cycle of incoming gas. An RTO will require additional fuel to heat the gas stream from 280°F to at least 1,500°F and which will generate additional emissions; therefore, the RTO is not considered further.

Catalytic Oxidation

Catalytic oxidation allows complete oxidation to take place at a faster rate and a lower temperature than is possible with thermal oxidation. Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency. In a typical catalytic oxidizer, the gas stream is passed through a flame area and then through a catalyst bed at a velocity in the range of 10 to 30 feet per second (fps). Catalytic oxidizers typically operate at a narrow temperature range of approximately 600°F to 1100°F. A catalytic oxidizer will require additional fuel to heat the gas stream from 280°F to at least 600°F and which will generate additional emissions; therefore, the catalytic oxidation is not considered further. This is listed in RBLC for a single source with higher emission rates than others using good operating practices.

Good Combustion Practices and Use of Clean Burning Fuels

Good combustion practices for VOCs include adequate fuel residence times, proper fuel-air mixing, and temperature control. As it is imperative for process controls, the University will maintain combustion optimal to their process. Most results in RBLC determined that this was sufficient controls for VOC. Additionally, BAAQMD and SCAQMD did not provide BACT determinations for VOC.

LCHTWP Boilers VOC Step 3-5 - Select BACT

Step 3 and 4 are not necessary since all control technologies not currently being used have been determined technically infeasible or current technologies have lower emission rates. BACT for the boilers is good combustion practices and the use of clean burning fuel.

LCHTWP Boilers VOC Most Stringent Measures

MSM is equivalent to BACT in this instance since no add-on control technologies are available for these units.

3.3.5. Ammonia

The University found ammonia emission factors for uncontrolled boilers on EPA's WebFIRE database.[45] The emission factors cited within this document are from the 1994 version of EPA's AP-42 Chapter 1.4. In 1998, this chapter was updated and ammonia emissions were removed from the list of emission factors associated with external combustion sources fueled by natural gas. As such, the University assumes there are minimal ammonia emissions associated with the boilers and have not considered them further for BACT.

3.4. LCHTWP TURBINE WITH WASTE HEAT RECOVERY UNIT

The University has a natural gas-fired turbine cogeneration plant which includes both a turbine and waste heat recovery unit (WHRU) with duct burner. This combination is also known as a combined cycle turbine. The turbine model is a Solar Taurus 70 T7800S equipped with Solar's SoLoNOx™ technology. The SoLoNOx™ technology uses lean-premixed combustion technology to ensure uniform air/fuel mixture, thus reducing formation of regulated pollutants. The unit is rated to 7.23 megawatts (MW) and de-rated to 6.5 MW based on altitude. The turbine has a heat input of 72.78 MMBtu/hr. The recycled waste heat from the gas turbine is sent to a Rentech waste heat recovery boiler. The supplemental duct burner is rated at 85 MMBtu/hr.

The WHRU is a part of the combined cycle turbine system. The WHRU cannot operate without the turbine. For general practice the WHRU and turbine operate together and therefore have been evaluated as one unit. This unit is subject to the requirements of NSPS Subpart KKKK.

The following sections detail potential controls and operating conditions necessary to achieve the required emissions for each pollutant. The review will detail controls as they apply to normal operations. Startup and shutdown operations manage emission rates by minimizing the duration of startup and shutdown. Therefore, the University of Utah during a startup will bring the turbine to the minimum load necessary to achieve compliance with the applicable NO_X and CO emission limits as quickly as possible, consistent with the equipment manufacturers' recommendations and safe operating practices. During a shutdown, once the turbine reaches a load that is below the minimum load necessary to maintain compliance with the applicable NO_X and CO emission

[45] Database accessed April 12, 2017.

limits, reduce the turbine load to zero as quickly as possible, consistent with the equipment manufacturers' recommendations and safe operating practices.

Startup and shutdown emissions are anticipated to be less than or equal to emissions during normal operations on the turbine and waste heat recover unit (WHRU) at the LCHTWP.

3.4.1. $PM_{2.5}$

According to EPA's AP-42, Section 1.4, since natural gas is a gaseous fuel, filterable PM emissions are typically low. Particulate matter from natural gas combustion has been estimated to be less than one micrometer in size and has filterable and condensable fractions. Particulate matter in natural gas combustion is usually larger molecular weight hydrocarbons that are not fully combusted. Increased particulate matter emissions can result from poor air/fuel mixing or maintenance problems. This section specifically addresses the filterable portion of $PM_{2.5}$, as the precursors are addressed as individual pollutants (NO_X, SO_2, VOCs, NH_3).

Turbine $PM_{2.5}$ Step 1 - Identify All Control Technologies

Potential control technologies were identified through the review of the following:

- SCAQMD LAER/BACT Determinations;
- BAAQMD BACT/TBACT Workbook;
- SJVAPCD BACT Clearinghouse;
- California Environmental Protection Agency (CEPA);
- EPA's RBLC Database for Combined Cycle Turbines (16.210);[46]
- NSPS KKKK – Standards of Performance for Stationary Combustion Turbines; and
- TCEQ BACT Requirements.

A search was conducted by querying all sources within the RBLC database in which the "Process Type Code" contained the number "16.210" (Small Combustion Turbine, Combined Cycle and Cogeneration < 25 Mega Watt (MW)), which covers operations associated with UCHTWP. Those with $PM_{2.5}$ limits and most closely related processes were as follows:

Table 9 – $PM_{2.5}$ Turbine Controls and Emission Rates from RBLC[47]

Facility Name	State	Permit Issu:	Throughput	Control Method	Emission Limit	Averaging Time	Case-by-Case
MEDICAL AREA TOTAL ENERGY PLANT	MA	07/01/2016	203.4 MMBtu/hr		0.02 LB/MMBT	1 hour block avg/Exlcuding SS,	BACT-PSD
WOODBRIDGE ENERGY CENTER	NJ	07/25/2012	40,297.60 MMcubic ft/yr	*Use of natural gas, a clean burning fuel*	12.1 LB/H	Avg of three tests	OTHER CASE-BY-CASE
WOODBRIDGE ENERGY CENTER	NJ	07/25/2012	40,297.60 MMcubic ft/yr	Good combustion practices and use of natural gas	19.1 LB/H	Avg of three tests	OTHER CASE-BY-CASE
HESS NEWARK ENERGY CENTER	NJ	11/01/2012	39,463 MMcubic ft/yr	Use of natural gas a clean burning fuel	11 LB/H	Avg of three tests	N/A
HESS NEWARK ENERGY CENTER	NJ	11/01/2012	39,463 MMcubic ft/yr	Use of natural gas a clean burning fuel	13.2 LB/H	Avg of three tests	N/A
CORNELL COMBINED HEAT & POWER PROJECT	NY	03/12/2008	155 MMBtu/hr	Sulfur in gas assumed max 1.2 g/100 scf Work Practice to minimize NH_3 Slip.	3.9 LB/H	Above 0'F, 1 hour avg.	BACT-PSD
CORNELL COMBINED HEAT & POWER PROJECT	NY	03/12/2008	155 MMBtu/hr	Ultra low sulfur in diesel at 15 ppm. Work Practice to minimize NH_3 Slip.	6.3 LB/H	Above 0'F, 1 hour avg.	BACT-PSD
CORNELL COMBINED HEAT & POWER PROJECT	NY	03/12/2008	155 MMBtu/hr	Sulfur in gas assumed max 1.2 g/100 scf Work Practice to minimize NH_3 Slip.	6.7 LB/H	Above/below, 1 hour avg.	BACT-PSD
CORNELL COMBINED HEAT & POWER PROJECT	NY	03/12/2008	155 MMBtu/hr	Ultra low sulfur in diesel at 15 ppm. Work Practice to minimize NH_3 Slip.	8.3 LB/H	Above 0'F, 1 hour avg.	BACT-PSD
WA PARISH ELECTRIC GENERATING STATION -[	TX	12/19/2012	80 MW	Good combustion and use of natural gas	16.58 LB/H	1 Hour	BACT-PSD

[46] Database accessed March 13, 2017.

[47] Up-to-date RBLC search run on April 23, 2017.

The technologies identified as possible $PM_{2.5}$ reduction technologies for small combustion, combined cycle and cogeneration turbines are shown in the table below.

Pollutant	Control Technologies
$PM_{2.5}$	Fabric Filter (Baghouse)
	Natural Gas Usage and Good Combustion Practices

Turbine $PM_{2.5}$ Step 2 - Eliminate Technically Infeasible Options

Fabric Filter

A fabric filter unit (or baghouse) consists of one or more compartments containing rows of fabric bags. Particle-laden gases pass along the surface of the bags then through the fabric. Particles are retained on the upstream face of the bags and the cleaned gas stream is vented to the atmosphere. Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter. Fabric filters are used for medium and low gas flow streams with high particulate concentrations. The turbine and duct burner associated with the WHRU combust natural gas, resulting in low concentration of $PM_{2.5}$. With such low concentrations a fabric filter would not be effective and therefore is considered technically infeasible for a turbine and WHRU duct burner firing natural gas.

Natural Gas Usage and Good Combustion Practices

Natural gas usage and good combustion practices are listed in the SJVAPCD BACT Clearinghouse, BAAQMD BACT/TBACT Workbook, and RBLC as the appropriate control technology for $PM_{2.5}$. Emissions associated with $PM_{2.5}$ for the turbine and WHRU duct burner are low in concentration due to the use of natural gas fuel in comparison to other available fuel types. Increased particulate matter emissions can result from poor air/fuel mixing or maintenance problems. The turbine is equipped with the SoLowNOx™ technology allowing proper air/fuel mixing. The turbine and WHRU duct burner are natural gas fired and regularly maintained in accordance with manufacturer recommendations to ensure good combustion practices are maintained.

Turbine $PM_{2.5}$ Step 3-5 - Select BACT

Step 3 and 4 are not necessary since the University is using the best available control technology recommended in state-by-state nonattainment area SIPs and the RBLC. The turbine and WHRU duct burner will continue to use natural gas fuel and good combustion practices as BACT.

Turbine $PM_{2.5}$ Most Stringent Measures

The most stringent measures would be identical to BACT as no control technology is technically feasible for these units.

3.4.2. NO_X

The NO_X that will be formed during combustion by two major mechanisms: thermal NO_X and fuel NO_X. Since natural gas is relatively free of fuel-bound nitrogen, the contribution of this second mechanism to the formation of NO_X emissions in natural gas-fired equipment is minimal and thermal NO_X is the chief source of NO_X emissions. Thermal NO_X formation is a function of residence time, oxygen level, and flame temperature, and can be minimized by controlling these elements in the design of the combustion equipment.

The turbine is permitted for an emission rate of 9 ppm NO_X at 15% O_2 and 2.65 pounds per hour (lbs/hr).[48] The combined turbine and WHRU duct burner is permitted for an emission rate of 15 ppm NO_X at 15% O_2 and 18.97 lb/hr.[49]

Turbine NO_X Step 1 - Identify All Control Technologies

Potential control technologies were identified through the review of the following:

- SCAQMD LAER/BACT Determinations;
- BAAQMD BACT/TBACT Workbook;
- SJVAPCD BACT Clearinghouse;
- CEPA;
- EPA's RBLC Database for Combined Cycle Turbines (16.210);[50]
- EPA Alternative Control Techniques Document – NO_X Emissions from Stationary Gas Turbines;
- NSPS KKKK – Standards of Performance for Stationary Combustion Turbines; and
- TCEQ BACT Requirements.

To demonstrate a complete analysis the University of Utah has evaluated the following technologies for NO_X.

A search was conducted by querying all sources within the RBLC database in which the "Process Type Code" contained the number "16.210" (Small Combustion Turbine, Combined Cycle and Cogeneration < 25 Mega Watt (MW)), which covers operations associated with UCHTWP. The most closely related processes were as follows:

Table 10 – NO_X Turbine Controls and Emission Rates from RBLC[51]

Facility Name	State	Permit Issua	Throughput	Control Method	Emission Limit	Averaging Time	Case-by-Case
MEDICAL AREA TOTAL ENERGY PLANT	MA	7/1/2016	203.4 MMBtu/hr	Dry Low NOx Combustor and SCR	2 PPMVD@15% O_2	1 HR BLOCK AVG/EXCLUDING SS, NG FIRING	OTHER CASE-BY
GEISINGER MED CTR/DANVILLE	PA	6/18/2010	55.62 MMBtu/hr	SoLoNOx combustor	15 PPMVD@15% O_2	IN SOLONOX MODE	OTHER CASE-BY
DEER CREEK STATION	SD	6/29/2010	300 Megawatts	SCR	25.8 lb/hr	3-HOUR, EXCLUDES SSM	BACT-PSD
ENDICOTT PRODUCTION FACILITY, LIBERTY DEVELOPMENT PROJECT	AK	6/15/2009	7.5 KW	Dry Low NOx Combustors	25 PPMVD@15% O_2	WHEN AMBIENT TEMPERATURE => 10 DEG-F	BACT-PSD
AUBURNDALE CITRUS FACILITY	FL	6/12/2008	62.7 MMBtu/hr	Dry Low NOx Burner	25 PPMVD	HR AVG/CORRECTED TO 25% O2	BACT-PSD
AUBURNDALE CITRUS FACILITY	FL	6/12/2008	62.7 MMBtu/hr	Dry Low NOx Burner	25 PPMVD	HR AVG/CORRECTED TO 25% O2	BACT-PSD
LEESBURG CITRUS FACILITY	FL	6/2/2008	62.7 MMBtu/hr	Dry Low NOx Burner	25 PPMVD	HR AV/CORRECTED TO 25% O2	BACT-PSD
WESTLAKE FACILITY	LA	7/12/2016	159.46 MMBtu/hr	Dry low NOx combustor (SoLoNOx)	14.25 lb/hr	HOURLY MAXIMUM	BACT-PSD
WOODBRIDGE ENERGY CENTER	NJ	5/2012	40298 mmcubic ft/yr	DLN combustion system with SCR on e	2 PPMVD	3-HR ROLLING AVE BASED ON 1-HR BLOCK	LAER
WOODBRIDGE ENERGY CENTER	NJ	5/2012	40298 mmcubic ft/yr	Low NOx burners and Selective Cataly	19.8 lb/hr	AVERAGE OF THREE 1- HOUR TESTS	LAER
HESS NEWARK ENERGY CENTER	NJ	11/1/2012	39463 MMCubic ft/yr	SCR System and use of natural gas	0.75 lb/hr	AVERAGE OF THREE TESTS	LAER
WA PARISH ELECTRIC GENERATING STATION -DEMONSTRATION PROJECT	TX	12/19/2012	80 MW	Dry Low NOx combusters on the turbine and SCR	2 PPMVD	3-HR ROLLING AVG, AT 15% OXYGEN	LAER
UTILITY PLANT	TX	12/2/2014	49 MW	SCR	2 PPMVD	@15% O2, 24-HR ROLLING AVERAGE	BACT-PSD
W. A. PARISH ELECTRIC GENERATING STATION	TX	12/21/2012	80 MW	SCR	2 PPMVD@15% O_2	3-HR AVERAGE	LAER

The technologies identified as possible NO_X reduction technologies for small combustion, combined cycle and cogeneration turbines are shown in the table below.

---

[48] Title V Operating Permit #3500063003 Condition II.B.8.a.

[49] ibid.

[50] Database accessed March 13, 2017.

[51] Up-to-date RBLC search run on April 23, 2017.

Pollutant	Control Technologies
NO_X	Dry Low NO_X Combustors/Low NO_X Burner Selective Catalytic Reduction (SCR) EMx (formerly SCONOx) System Water/Steam Injection Natural Gas Usage and Good Combustion Practices

Control technologies included in this table are those that have been shown in practice for use in one of the previously listed databases.

Turbine NO_X Step 2 - Eliminate Technically Infeasible Options

Dry Low NO_X Combustors/Low NO_X Burner (Turbine Only)

Although dry low NO_X (DLN) combustors designed by different manufacturers may vary, they all employ the strategies of fuel and air pre-mixing and staged combustion to minimize NO_X formation in combustion turbines. The combustors burn a lean, pre-mixed fuel and air mixture to avoid localized high temperature regions. A lean air-to-fuel ratio approaching the lean flammability limit is maintained, and the excess air acts as a heat sink to lower combustion temperatures, which lowers thermal NOx formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment. Other techniques, such as variable geometry, fuel staging, or combustion staging, are also incorporated in DLN combustor design. The turbine currently includes this control technology, also known as the SoLowNOx™ technology.

Ultra-Low NO_X Burner (WHRU Only)

ULNB technology combines internal flue gas recirculation (FGR), a low NO_X burner and advanced engineering principle to further optimize oxygen concentrations, flame temperature, and/or residence time which involves recirculating the hot O_2 depleted flue gas from the heater into the combustion zone using burner design features and fuel staging to reduce NO_X. Since ULNB technology utilizes FGR technology the implementation of an ULNB is not technically feasible since the implementation of FGR technology is not technically feasible. Additionally, based on an inquiry with the duct burner manufacturer, the duct burner has NO_X emission guarantee for 0.08 lbs/MMBtu High Heat Value (HHV) (equivalent to 66 ppm). The duct burner manufacturer does not have a burner that can offer lower emissions.

Selective Catalytic Reduction

SCR refers to the process in which NO_X is reduced by ammonia over a heterogeneous catalyst in the presence of oxygen. The process is termed selective because the ammonia preferentially reacts with NO_X rather than oxygen, although the oxygen enhances the reaction and is a necessary component of the process. The overall reactions can be written:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O \qquad \text{(Equation 1)}$$
$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O \qquad \text{(Equation 2)}$$

SCR can be applied as a stand-alone NO_X control or with other technologies such as combustion controls. The SCR process requires a reactor, a catalyst, and an ammonia storage and injection system. The effectiveness of an SCR system is dependent on a variety of factors, including the inlet NO_X concentration, the exhaust temperature, the ammonia injection rate, and the type of catalyst. According to EPA, the optimum temperature range over which SCR is effective is dependent on the type of catalyst and the flue gas composition. In general, the optimum temperature range is between 480 and 800°F.[52] SCR units typically achieve 70 - 90% NO_X reduction.[53] However, if the upstream NO_X concentration is already low, as is the case with these units, it is difficult to achieve these control efficiencies.

The ammonia "slip" associated with the SCR is a documented problem. The increased ammonia emissions (currently zero) from the implementation of this technology would offset the marginal air quality benefits the SCR option would provide from NO_X emissions reduction. Ammonia slip emissions have the potential to increase secondary $PM_{2.5}$ levels in the area more than the SCR controlled NO_X mass. Storage and handling of ammonia poses significant safety risks when applied at the University. Ammonia is toxic if swallowed or inhaled and can irritate or burn the skin, eyes, nose, or throat, it is a commonly used material that is typically handled safely and without incident. However, there are potential health and safety hazards associated with the implementation of this technology. The LCHTWP (Bldg 303) is located in a densely-packed area, adjacent to the TRAX line, the Huntsman Event Center, The Utah Museum of Fine Arts, and other public facilities, with a significant number of University staff, students, and the general public potentially in harm's way. Locating ammonia tanks in these premises poses significant health risks for students, faculty, patients, family members, and the general public if a leak were to occur.

The exhaust stream entering the SCR will require additional heat to meet the SCR operating temperature requirements (minimum of 480°F). This increase in exhaust temperature would require an additional combustion device, also increasing NO_X, SO_2, and $PM_{2.5}$ emissions.

Furthermore, there is a physical space issue concerning this technology and the current location. Building 303, where the LCHTWP boilers and the turbine are housed, is confined by other buildings in the immediate proximity and currently does not provide the space required to physically install an SCR. The location of the turbine within the building also presents a space challenge when installing an SCR. The physical space restriction within Building 303 is more confined than the physical space in Building 302 as discussed in Section 3.2.2. Therefore, the SCR is considered technically infeasible for the turbine and WHRU located in building 303 due to physical limitations, public safety concerns, and additional pollutants being emitted to use this add-on control technology.

SCONOx (EMx)

SCONOx is a catalytic oxidation and absorption technology that uses a single catalyst for the removal of NO_X, CO, and VOC. This technology has been used since the late 1990s and is proven for use on combined cycle turbines, lean burn reciprocating engines, diesel vehicles, and refineries. This technology has several advantages over an SCR including:

---

[52] L.M. Campdell, D.K. Stone, and G.S. Shareef, *Sourcebook: NO_x Control Technology Data*, EPA/600/S2-91/029, 1991.
[53] OAQPS, *EPA Air Pollution Control Cost Manual*, Sixth Edition, EPA/424/B-02-001 (http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf); January 2002

- Provides control for several pollutants - lowering overall reported emissions of NO_X, CO, VOC, and PM;
- No use of ammonia;
- Requires lower exhaust temperatures; and
- Available on a range of emission unit sizes – installed on units as small as 1 MW.

Estimates of control system efficiency vary. However, EMx Design information indicates testing showing emission reduction as much as 99.5%.[54] Commercially quoted NOx emission rates for the SCONOx system range from 2.0 ppm on a 3-hour average basis, representing a 78% reduction, to 1.0 ppm with no averaging period specified (96% reduction).

The control technology has specific requirements for use, and may be added as a retrofit technology or may require a new turbine to install the technology. Based on physical space constraints as discussed in the SCR section, the University has deemed this control technically infeasible as well.

Water/Steam Injection

Combustion control using water or steam lowers combustion temperatures, which reduces thermal NO_X formation. Water or steam, treated to quality levels comparable to boiler feedwater, is injected into the combustor and acts as a heat sink to lower flame temperatures. This control technique is available for all new turbine models and can be retrofitted to most existing installations. Although uncontrolled emission levels vary widely, the range of achievable controlled emission levels using water or steam injection is relatively small. Controlled NO_X emission levels range from 25 to 42 ppmv for natural gas fuel.[55]

Good Combustion Practices

Good combustion practices involve controlling the operating parameters of the combustors for temperature and turbulence, excess oxygen levels, and air/fuel mixing to ensure continual operation as close to optimum (i.e., minimum emission) conditions as possible.

Turbine NO_X Step 3 - Rank Remaining Control Technologies by Control Effectiveness

SoLowNOx technology (DLN combustor), water/steam injection, and good combustion practices are all considered technically feasible. The turbine currently has the SoLowNOx technology installed and achieves an emission rate of 9 ppm. The water/steam inject states it is only able to achieve emission levels as low as 25 ppm. As such, the water/steam injection is removed from further consideration. The remaining technologies are ranked based on their lowest achievable emission rate:

1. SoLowNOx technology™ – 9 ppm for Turbine alone[56]
2. Good Combustion Practices

For the WHRU, based on inquiry with the duct burner manufacturer, the current burner is the best available NO_X guarantee for the application that is available.

---

[54] Reduction shown in PowerPoint presentation sent to Beth Ryder, trinity Consultants from Josh Gillespie, EmeraChem LLC.

[55] Alternative Control Techniques Document— NOx Emissions from Stationary Gas Turbines

[56] Title V Operating Permit #3500063003 Condition II.B.8.a.

Turbine NO_X Step 4 - Evaluate Most Effective Controls and Document Results

The turbine is currently equipped with SoLowNOx technology for combustion control on the turbine and the WHRU duct burner is using good combustion practices. These are the most effective controls available for the unit.

Turbine NO_X Step 5 - Select BACT

Based on the analysis performed, the use of SoLowNOx™ currently installed control technology as BACT. The turbine uses the SoLowNOx technology and the duct burner good combustion practices. Emission limits will remain at 9 ppmdv NO_X (2.65 lb/hr) for the turbine and 15 ppm NO_X (8.97 lb/hr) for the turbine and WHRU combined.

Turbine NO_X Most Stringent Measures

The most stringent measures would be identical to BACT.

3.4.3. SO_2

SO_2 emissions associated with the turbine and WHRU duct burner are due to natural gas combustion. Emissions are less than 1 tpy. Therefore, the University is proposing good combustion practices and use of natural gas as BACT.

To demonstrate a complete analysis, the University of Utah has evaluated the following technologies for SO_2.

A search was conducted by querying all sources within the RBLC database in which the "Process Type Code" contained the number "16.210" (Small Combustion Turbine, Combined Cycle and Cogeneration < 25 Mega Watt (MW)), which covers operations associated with UCHTWP. The sources with SO_2 limits and most closely related processes were as follows:

Table 11 - SO_2 Turbine Controls and Emission Rates from RBLC[57]

Facility Name	State	Permit Issu:	Throughput	Control Method	Emission Limit	Averaging Time	Case-by-Case
MEDICAL AREA TOTAL ENERGY PLANT	MA	07/01/2016	203.4 MMBtu/hr	clean fuels - using natural gas as primary fuel and ultra low sulfur diesel as backup.	0.6 PPMVD@	1 hour block avg/Exlcuding SS,	OTHER CASE-BY-CASE
WOODBRIDGE ENERGY CENTER	NJ	07/25/2012	40,297.60 MMcubic ft/yr	Use of only natural gas a clean burning fuel	4.1 lb/hr	Avg of three tests	OTHER CASE-BY-CASE
WOODBRIDGE ENERGY CENTER	NJ	07/25/2012	40,297.60 MMcubic ft/yr	Good Combustion Practices and Use of Natural gas,a clean burning fuel.	4.9 lb/hr	Avg of three tests	OTHER CASE-BY-CASE
HESS NEWARK ENERGY CENTER	NJ	11/01/2012	39,463 MMcubic ft/yr	Use of natural gas, a clean low sulfur fuel	2.5 lb/hr	Avg of three tests	N/A
HESS NEWARK ENERGY CENTER	NJ	11/01/2012	39,463 MMcubic ft/yr	Use of natural gas a clean low sulfur fuel	2.8 lb/hr	Avg of three tests	N/A

Turbine SO_2 Step 1 - Identify All Control Technologies

There are two primary mechanisms to reduce SO_2 emissions from combustion sources which are: (1) reduce the amount of sulfur in the fuel, and (2) remove the sulfur from the exhaust gases with post-combustion control device such as flue gas desulfurization utilizing wet scrubbers or dry scrubbers.

The University will be using pipeline-quality natural gas as the primary fuel which has a low sulfur content. The use of a fuel containing low sulfur content is considered a control technology.

[57] Up-to-date RBLC search run on April 23, 2017.

Two main types of SO_2 post-combustion control technologies, wet and dry scrubbing, were identified to reduce SO_2 in the exhaust gas.

Turbine SO_2 Step 2 - Eliminate Technically Infeasible Options

The requirement for low-sulfur natural gas is a control technique that has been achieved in practice. This technology is technically feasible and cost-effective and will be further considered for BACT. Post-combustion devices such as wet or dry scrubbers are typically installed on coal-fired power plants that burn fuels with much higher sulfur contents. The SO_2 concentrations in the natural gas combustion exhaust gases from the turbine and WHRU duct burner are too low for scrubbing technologies to work effectively or to be technically feasible and cost effective. These control technologies require much higher sulfur concentrations in the exhaust gases to be feasible as a control technology. Thus, post-combustion SO_2 control devices, such as wet and dry scrubbing have not been achieved in practice on natural gas combustion. Since these controls are not technically feasible, they have been eliminated from further consideration for the turbine and WHRU duct burner.

Turbine SO_2 Step 3-5 - Select BACT

The use of pipeline-quality natural gas is the only feasible and cost effective SO2 control technology for the turbine and WHRU duct burner. There is no adverse energy, environmental or cost impact associated with the use of this control technologies. The University will continue to use natural gas which contains 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 Thus, no further analysis is required under EPA's top-down BACT approach.

Turbine SO_2 Most Stringent Measures

MSM is equivalent to BACT because no add-on SO_2 control technologies are available for these units.

3.4.4. VOC

Turbine VOC Step 1 - Identify All Control Technologies

The University has reviewed the following sources to ensure all available control technologies have been identified:

- EPA's RBLC Database for Natural Gas External Combustion Units (process type 13.31);[58]
- EPA's Air Pollution Technology Fact Sheets;
- SCAQMD LAER/BACT Determinations;
- SJVAPCD BACT Clearinghouse;
- BAAQMD BACT/TBACT Workbook; and
- Permits available online.

To demonstrate a complete analysis, the University of Utah has evaluated the following technologies for VOCs.

A search was conducted by querying all sources within the RBLC database in which the "Process Type Code" contained the number "16.210" (Small Combustion Turbine, Combined Cycle and Cogeneration < 25 Mega Watt (MW)), which covers operations associated with UCHTWP. The sources with VOC limits and most closely related processes were as follows:

---

[58] Database accessed February 27, 2017.

Table 12 - VOC Turbine Controls and Emission Rates from RBLC[59]

Facility Name	State	Permit Issuan	Throughput	Control Method	Emission Limit	Averaging Time	Case-by-Case
MEDICAL AREA TOTAL ENERGY PLAN	MA	7/1/2016	203.4 MMBtu/hr	Oxidation Catalyst	1.7 PPMVD @ 15% O_2	1 hour block average/excluding SS	OTHER CASE-BY-CASE
GEISINGER MED CTR/DANVILLE	PA	6/18/2010	55.62 MMBtu/hr	Natural gas	0.6 lb/hr	In SoLoNO$_X$ Mode	OTHER CASE-BY-CASE
WESTLAKE FACILITY	LA	7/12/2016	159.46 MM Btu/hr	Good combustion practices, including good equipment design, use of gaseous fuels	1.64 lb/hr	Hourly Maximum	BACT-PSD
WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	40,297.60 mmcubic ft/yr	Oxidation Catalyst and Good Combustion Practices and use of clean fuel (Natural gas)	2 PPMVD	3- hour rolling avg, based on 1-hr b	LAER
WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	40,297.60 mmcubic ft/yr	Oxidation catalyst and Good Combustion Practices, use of natural gas a clean burning fuel	2.9 lb/hr	Avg fo 3 test runs	LAER
HESS NEWARK ENERGY CENTER	NJ	11/1/2012	39,463 mmcubic ft/yr	Oxidation catalyst	1 PPMVD	3- hour rolling avg, based on 1-hr b	LAER
HESS NEWARK ENERGY CENTER	NJ	11/1/2012	39,463 MMCubic ft/yr	Oxidation Catalyst and Good Combustion Practices and use of natural gas a clean burning fuel	2.9 lb/hr	Avg fo 3 test runs	LAER
WA PARISH ELECTRIC GENERATING S	TX	12/19/2012	80 MW	Oxidation catalyst	2 PPMVD	Initial stack test	LAER
UTILITY PLANT	TX	12/2/2014	49 MW	Oxidation catalyst	4 PPMVD	@15% O2, 24-hour rolling avg	BACT-PSD
W. A. PARISH ELECTRIC GENERATINC	TX	12/21/2012	80 MW	Oxidation catalyst	2 PPMVD @ 15% O_2		LAER

The technologies identified as possible VOC reduction technologies for small combustion, combined cycle and cogeneration turbines are shown in the table below.

Pollutant	Control Technologies
VOCs	Catalytic Oxidation
	Thermal Oxidation
	Good Combustion Practices

Turbine VOC Step 2 - Eliminate Technically Infeasible Options

Catalytic Oxidation

Catalytic oxidation allows complete oxidation to take place at a faster rate and a lower temperature than is possible with thermal oxidation. Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency. In a typical catalytic oxidizer, the gas stream is passed through a flame area and then through a catalyst bed at a velocity in the range of 10 to 30 feet per second (fps). Catalytic oxidizers typically operate at a narrow temperature range of approximately 600°F to 1100°F. A catalytic oxidizer will require additional fuel to heat the gas stream at least 600°F and which will generate additional emissions; therefore, the catalytic oxidation is not being considered further.

Simple Thermal Oxidizer or Afterburner

In a simple TO or afterburner, the flue gas exiting the turbine and WHRU duct burner is reheated in the presence of sufficient oxygen to oxidize the VOC present in the flue gas. A typical TO is a flare and is not equipped with any

[59] Up-to-date RBLC search run on April 23, 2017.

heat recovery device. A TO will require additional fuel to heat the gas stream starting from 280°F to at least 1,600°F and which will generate additional emissions. Therefore, there would be little expected reduction in VOC with an increase in other combustion pollutants for the required heating of the exhaust stream. Therefore, the TO is not being considered further.

Good Combustion Practices

Good combustion practices refer to the operation of engines at high combustion efficiency which reduces the products of incomplete combustion. The turbine installed has been designed to achieve maximum combustion efficiency. The University follows all instructions given in the operation and maintenance manuals that detail the required methods to achieve the highest levels of combustion efficiency.

Turbine VOC Step 3 through 5 - Select BACT

Since other add on control technologies require additional combustion units and therefore pollutant emissions, good combustion practices is the control for VOC emissions on a natural gas turbine and WHRU duct burner.

Turbine VOC Most Stringent Measures

MSM is equivalent to BACT.

3.4.5. Ammonia

The University found ammonia emission factors for uncontrolled boilers on EPA's WebFIRE database.[60] The emission factors cited within this document are from the 1994 version of EPA's AP-42 Chapter 1.4. In 1998, this chapter was updated and ammonia emissions were removed from the list of emission factors associated with external combustion sources fueled by natural gas. As such, the University assumes there are minimal ammonia emissions associated with the boilers and have not considered them further for BACT.

3.5. ADDITIONAL SMALL BOILERS

The University operates several other boilers around campus to support individual building needs. All boilers combust natural gas. Diesel is used as a backup fuel in some of the boilers during times of natural gas curtailment. A complete list of these boilers is contained in in the Table 3-13. The University plans to replace 587 boilers by December 31, 2018. This analysis evaluates the additional small boilers taking this replacement into consideration.

---

[60] Database accessed April 12, 2017.

Table 3-13. Additional Small Boilers at the University

Location				Fuel Type	
Building Number	Building Name	Operating Scenario	Capacity (MMBtu/hr)	Primary	Backup
32	Rice-Eccles Stadium	Primary	3	Natural Gas	-
32	Rice-Eccles Stadium	Primary	3	Natural Gas	-
32	Rice-Eccles Stadium	Primary	1	Natural Gas	-
33	Clark Football Center	Primary	5.25	Natural Gas	-
151	Sorenson Biotechnology Bldg. - USTAR	Backup	20.67	Natural Gas	-
521/525/526	University Hospital	Backup	10.5	Natural Gas	Fuel Oil
521/525/526	University Hospital	Backup	10.5	Natural Gas	Fuel Oil
521/525/526	University Hospital	Out-of-Service	13.5	Natural Gas	Fuel Oil
523	Moran Eye Center	Backup	8.165	Natural Gas	-
523	Moran Eye Center	Backup	25.2	Natural Gas	Diesel
523	Moran Eye Center	Backup	25.2	Natural Gas	Diesel
555	Hunstman Cancer Institute	Primary	16.8	Natural Gas	Diesel
555	Hunstman Cancer Institute	Primary	16.8	Natural Gas	Diesel
555	Hunstman Cancer Institute	Backup	5	Natural Gas	Diesel
555	Hunstman Cancer Institute	Backup	5	Natural Gas	Diesel
556	Huntsman Cancer Hospital	Backup	6	Natural Gas	Fuel Oil
556	Huntsman Cancer Hospital	Backup	6	Natural Gas	Fuel Oil
565	Emma-Eccles-Jone Medical Research Center	Backup	19	Natural Gas	-
853	Health Profession Education	Primary	2	Natural Gas	-
853	Health Profession Education	Primary	2	Natural Gas	-
581	School of Pharmacy Building	Backup	17	Natural Gas	-
587	CMC	Primary	13.5	Natural Gas	-
587	CMC	Primary	13.5	Natural Gas	-
865	Williams Building	Regular Use	10	Natural Gas	-

Startup and shutdown emissions are anticipated to be less than or equal to emissions during normal operations on the additional small boilers.

3.5.1. $PM_{2.5}$

According to EPA's AP-42, Section 1.4, since natural gas is a gaseous fuel, filterable PM emissions are typically low. Particulate matter from natural gas combustion has been estimated to be less than one micrometer in size and has filterable and condensable fractions. Particulate matter in natural gas combustion is usually larger molecular weight hydrocarbons that are not fully combusted. Increased particulate matter emissions can result from poor air/fuel mixing or maintenance problems.

Additional Boilers $PM_{2.5}$ Step 1 - Identify All Control Technologies

The University has reviewed the following sources to ensure all available control technologies have been identified:

- EPA's RBLC Database for Natural Gas External Combustion Units (process type 13.31);[61]
- EPA's Air Pollution Technology Fact Sheets;
- EPA's CATC Alternative Control Techniques Document – NOX Emissions from Utility Boilers;
- NESHAP DDDDD – Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters;
- NESHAP JJJJJJ – Industrial, Commercial, and Institutional Boilers at Area Sources;
- SCAQMD LAER/BACT Determinations;
- SJVAPCD BACT Clearinghouse;
- BAAQMD BACT/TBACT Workbook; and
- Permits available online.

To demonstrate a complete analysis, the University has evaluated the follow for $PM_{2.5}$.

A search was conducted by querying all sources within the RBLC database in which the "Process Type Code" contained the number "13.310" (Medium Natural Gas Boilers, <100 MMBtu/hr), which covers operations associated with UCHTWP. Additionally small boiler sources are listed in the RBLC search; therefore it is not repeated from above. The same results for $PM_{2.5}$ can be found in Table 2.

The technologies identified as possible $PM_{2.5}$ reduction technologies for additional Natural Gas Boilers are shown in the table below.

[61] Database accessed February 27, 2017.

Pollutant	Control Technologies
$PM_{2.5}$	Fabric Filter (Dust Collector) Wet Scrubber Dry Electrostatic Precipitator (ESP) Cyclone

Additional Boilers $PM_{2.5}$ Step 2 - Eliminate Technically Infeasible Options

Wet Scrubber

A wet gas scrubber is an air pollution control device that removes PM and acid gases from waste streams from stationary point sources. PM and acid gases are primarily removed through the impaction, diffusion, interception and/or absorption of the pollutant onto droplets of liquid. Wet scrubbers have some advantages over ESPs and baghouses in that they are particularly useful in removing PM with the following characteristics:

- Sticky and/or hygroscopic materials;
- Combustible, corrosive or explosive materials;
- Particles that are difficult to remove in dry form;
- PM in the presence of soluble gases; and
- PM in gas stream with high moisture content.

However, considering the low concentration of $PM_{2.5}$ and the small size of particulate, a wet scrubber is considered technically infeasible for a boiler firing primarily natural gas.

ESP

An ESP is a particle control device that uses electrical forces to move the particles out of the gas stream onto collector plates. This process is accomplished by the charging of particles in the gas stream using positively or negatively charged electrodes. The particles are then collected as they are attracted to oppositely opposed electrodes. Once the particles are collected on the plates, they are removed by knocking them loose from the plates, allowing the collected layer of particles to fall down into a hopper. ESP's are used to capture coarse particles at high concentrations. Small particles at low concentrations are not effectively collected by an ESP. As the technology is primarily for the combustion of natural gas, concentration of $PM_{2.5}$ is low and small in size. As such, ESP is considered technically infeasible for a boiler firing primarily natural gas.

Fabric Filter

A fabric filter unit (or baghouse) consists of one or more compartments containing rows of fabric bags. Particle-laden gases pass along the surface of the bags then through the fabric. Particles are retained on the upstream face of the bags and the cleaned gas stream is vented to the atmosphere. Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter. Fabric filters are used for medium and low gas flow streams with high particulate concentrations. As the boilers combust primarily natural gas, concentration of $PM_{2.5}$ is low and small in size. As such, a fabric filter is considered technically infeasible for a boiler firing primarily natural gas.

Good Combustion Practices and Use of Clean Burning Fuels

The use of good combustion practices usually include the following components: (1) proper fuel mixing in the combustion zone; (2) high temperatures and low oxygen levels in primary zone; (3) Overall excess oxygen levels high enough to complete combustion while maximizing boiler efficiency, and (4) sufficient residence time to complete combustion. Good combustion practices are accomplished through boiler design as it relates to time, temperature, and turbulence, and boiler operation as it related to excess oxygen levels.

Additional Boilers $PM_{2.5}$ Step 3 - 5 - Select BACT

Step 3 and 4 are not necessary since all control technologies not currently being used have been determined technically infeasible.

No control technology is technically feasible, therefore this emission rate using good combustion practices and primarily natural gas is considered BACT.

Additional Boilers $PM_{2.5}$ Most Stringent Measures

The most stringent measures would be identical to BACT as no control technology is technically feasible for these units.

3.5.2. NO_X

The NO_X that will be formed during combustion is from two major mechanisms: thermal NO_X and fuel NO_X. Since natural gas is relatively free of fuel-bound nitrogen, the contribution of this second mechanism to the formation of NO_X emissions in natural gas-fired equipment is minimal, leaving thermal NO_X as the main source of NO_X emissions. Thermal NO_X formation is a function of residence time, oxygen level, and flame temperature, and can be minimized by controlling these elements in the design of the combustion equipment.

Additional Boilers NO_X Step 1 - Identify All Control Technologies

The University has reviewed the following sources to ensure all available control technologies have been identified:

- EPA's RBLC Database for Natural Gas External Combustion Units (process type 13.31);[62]
- EPA's Air Pollution Technology Fact Sheets;
- EPA's CATC Alternative Control Techniques Document – NO_X Emissions from Utility Boilers;
- NESHAP DDDDD – Major Sources: Industrial, Commercial, and Institutional Boilers and Process
- Heaters;
- NESHAP JJJJJJ – Industrial, Commercial, and Institutional Boilers at Area Sources;
- SCAQMD LAER/BACT Determinations;
- SJVAPCD BACT Clearinghouse;[63]
- BAAQMD BACT/TBACT Workbook; and
- Permits available online.

---

[62] Database accessed February 27, 2017.

[63] SJVAPCD BACT Clearinghouse Boiler: < or = 20.0 MMBtu/hr, Natural Gas or Propane Fired *RESCINDED* http://www.valleyair.org/busind/pto/bact/chapter1.pdf

A search was conducted by querying all sources within the RBLC database in which the "Process Type Code" contained the number "13.310" (Medium Natural Gas Boilers ,<100 MMBtu/hr), which covers operations associated with UCHTWP. Additional small boilers are considered in the RBLC search; therefore it is not repeated from above. The same results for NO_X can be found in Table 4 – Medium Natural Gas Boilers (<100 MMBtu) NOx Emissions.

To demonstrate a complete analysis, the University has evaluated the follow technologies including both replacement burners and add-on controls.[64]

Pollutant	Control Technologies
NO_X	Low NO_X Burners
	Ultra-Low NO_X Burners
	Flue Gas Recirculation
	Good Combustion Practices

Additional Boilers NO_X Step 2 - Eliminate Technically Infeasible Options

Low NO_X Burners

LNB technology uses advanced burner design to reduce NO_X formation through the restriction of oxygen, flame temperature, and/or residence time. There are two general types of LNB: staged fuel and staged air burners. In a stage fuel LNB, the combustion zone is separated into two regions. The first region is a lean combustion region where a fraction of the fuel is supplied with the total quantity of combustion air. Combustion in this zone takes place at substantially lower temperatures than a standard burner. In the second combustion region, the remaining fuel is injected and combusted with left over oxygen from the first region. A staged air burner begins with full fuel but only partial combustion air, and then adds the remaining combustion air in the second combustion region. These techniques reduce the formation of thermal NO_X. This technology is listed in the RBLC search as a technically feasible control technology. BAAQMD lists typical technology for BACT for NO_X using a combination of SCR, LNB, and FGR. SCAQMD used LNB as the BACT determined control methodology for the University of California Irvine Medical Center boiler rated at 48.6 MMBtu/hr in 1999.

Ultra Low NO_X Burners

ULNB technology uses internal FGR which involves recirculating the hot 02 depleted flue gas from the heater into the combustion zone using burner design features and fuel staging to reduce NO_X. An ULNB is most commonly using an internal induced draft to reach the desired emission limitations. Due to this induced draft, a ULNB cannot handle a quick change in load to achieve the desired operational flexibility necessary for the varied products in the paper machine. This technology is listed in the RBLC search as a technically feasible control technology. BAAQMD lists typical technology for BACT for NOX using a combination of ULNB and FGR. SCAQMD used LNB plus FGR as the BACT determined control methodology for the Los Angeles County Internal Services Department boiler rated at 39 MMBtu/hr in 2004. An ULNB can achieve an emission rate of approximately 9

[64] Note, during review of available control technology through RBLC and other databases, an SCR was not listed for any source less than 26 MMBtu/hr. Therefore, this control technology was not evaluated for use on the boilers in this section.

ppm or 0.011 lb/MMBtu when used in conjunction with FGR. Though this burner type risks loss in product due to the increased time to change between load rates, it is being considered for economic feasibility.

Flue Gas Recirculation

FGR is frequently used with both LNB and ULNB burners. FGR involves the recycling of post-combustion air into the air-fuel mixture to reduce the available oxygen and help cool the burner flame. External FGR requires the use of ductwork to route a portion of the flue gas in the stack back to the burner windbox; FGR can be either forced draft (where hot side fans are used) or induced draft. This technology is listed in the RBLC search as technically feasible and is paired with LNB for the BACT determined control technology. As previously discussed, both SCAQMD and BAAQMD have combined this technology with others to determine BACT.

Good Combustion Practices

The use of good combustion practices usually include the following components: (1) proper fuel mixing in the combustion zone; (2) high temperatures and low oxygen levels in primary zone; (3) Overall excess oxygen levels high enough to complete combustion while maximizing boiler efficiency, and (4) sufficient residence time to complete combustion. Good combustion practices are accomplished through boiler design as it relates to time, temperature, and turbulence, and boiler operation as it related to excess oxygen levels.

Additional Boilers NO_X Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Based on an RBLC search the following technologies are currently being used for boilers between 1 MMBtu/hr and 26 MMBtu/hr. These are ranked based on which technology can achieve the lowest emission rate.

1. ULNB = 9 ppm or 0.011 lb/MMBtu
2. LNB = 30 ppm or 0.036 lb/MMBtu
3. Good Combustion Practices

Additional Boilers NO_X Step 4 - Evaluate Most Effective Controls and Document Results

The Moran Eye Center boilers (25.2 MMBtu/hr, each) are rated for 15 ppm NO_X. All other boilers are assumed to have an emission rate equivalent to AP-42 emission factors at 100 pounds per million standard cubic feet (lb/MMscf), While ULNB and LNB are available for units of this size, the University has determined that it would be economically infeasible to replace each burner on units of this size. Considering that the University showed that the cost to replace the burner on the much larger UCHTWP boilers in Section 3.2.2 was economically infeasible, the burners of much smaller capacity also come to that conclusion.

Additional Boilers NO_X Step 5 - Select BACT

BACT for these boilers is good combustion and operating practices. The boilers located in building 587 will be replaced with boilers that meet 9 ppm NO_X emission limit during the summer of 2017.

Additional Boilers NO_X Most Stringent Measures

MSM is equivalent to BACT.

3.5.3. SO_2

The top-down BACT analysis for SO_2 emissions for the additional small boilers is presented below. The technologies identified as possible SO_2 reduction technologies for Medium Size Natural Gas Boilers are natural gas and good combustion practices as identified in Table 6 – Medium Natural Gas Boilers (<100 MMBtu) SO_2 Emissions.

SO_2 emissions associated with the boilers are due to natural gas combustion.

Additional Boilers SO_2 Step 1 - Identify All Control Technologies

There are two primary mechanisms to reduce SO_2 emissions from combustion sources which are: (1) reduce the amount of sulfur in the fuel, and (2) remove the sulfur from the exhaust gases with post-combustion control device such as flue gas desulfurization utilizing wet scrubbers or dry scrubbers.

The University will be using pipeline-quality natural gas as the primary fuel which has a low sulfur content. The use of a fuel containing low sulfur content is considered a control technology.

Two main types of SO_2 post-combustion control technologies, wet and dry scrubbing, were identified to reduce SO_2 in the exhaust gas.

Additional Boilers SO_2 Step 2 - Eliminate Technically Infeasible Options

The requirement for low-sulfur natural gas is a control technique that has been achieved in practice and is technically feasible and cost-effective and will be further considered for BACT. Post-combustion devices such as wet or dry scrubbers are typically installed on coal-fired power plants that burn fuels with much higher sulfur contents. The SO_2 concentrations in the natural gas combustion exhaust gases from the boilers are too low for scrubbing technologies to work effectively or to be technically feasible and cost effective. These control technologies require much higher sulfur concentrations in the exhaust gases to be feasible as a control technology. Thus, post-combustion SO_2 control devices, such as wet and dry scrubbing have not been achieved in practice on natural gas boilers. Since these controls are not technically feasible, they have been eliminated from further consideration for the boilers.

Additional Boilers SO_2 Step 3-5 - Select BACT

The use of pipeline-quality natural gas as the primary fuel is the only feasible SO_2 control technology for the boilers to control SO_2. There is no adverse energy, environmental or cost impact associated with the use of these control technologies. Thus, no further analysis is required under EPA's top-down BACT approach. SO_2 emissions associated with the boilers are due to fuel combustion. Therefore, the University is proposing good combustion practices and use pipeline-quality natural gas as the primary fuel is considered BACT.

Additional Boilers SO_2 Most Stringent Measures

MSM is equivalent to BACT in this instance since no add-on control technologies are available for these units.

3.5.4. VOC

Additional Boilers VOC Step 1 - Identify All Control Technologies

The University has reviewed the following sources to ensure all available control technologies have been identified:

- EPA's RBLC Database for Natural Gas External Combustion Units (process type 13.31);65
- EPA's Air Pollution Technology Fact Sheets;
- EPA's CATC Alternative Control Techniques Document – NOX Emissions from Utility Boilers;
- NESHAP DDDDD – Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters;

[65] Database accessed February 27, 2017.

- NESHAP JJJJJJ – Industrial, Commercial, and Institutional Boilers at Area Sources;
- SCAQMD LAER/BACT Determinations;
- SJVAPCD BACT Clearinghouse;
- BAAQMD BACT/TBACT Workbook; and
- Permits available online.

To demonstrate a complete analysis, the University has evaluated the follow technologies for VOCs.

A search was conducted by querying all sources within the RBLC database in which the "Process Type Code" contained the number "13.310" (Medium Natural Gas Boilers ,<100 MMBTu/hr), which covers operations associated with UCHTWP. Additional small boilers are considered in the RBLC search; therefore it is not repeated from above. The same results for VOC can be found in Table 7 – Medium Natural Gas Boilers (<100 MMBtu) VOCs Emissions

To demonstrate a complete analysis, the University has evaluated the follow technologies including add-on controls and good combustion practices.

Pollutant	Control Technologies
VOCs	Thermal Oxidizer/Afterburner
	Regenerative Thermal Oxidizer
	Catalytic Oxidation
	Good Combustion Practices

Additional Boilers VOC Step 2 - Eliminate Technically Infeasible Options

Simple Thermal Oxidizer or Afterburner

In a simple TO or afterburner, the flue gas exiting the boiler is reheated in the presence of sufficient oxygen to oxidize the VOC present in the flue gas. A typical TO is a flare and is not equipped with any heat recovery device. A TO will require additional fuel to heat the gas stream starting from 280°F to at least 1,600°F and which will generate additional emissions. Additionally, a TO is no different from the combustion chamber of the boiler. Therefore, there would be little expected reduction in VOC with an increase in other combustion pollutants for the required heating of the exhaust stream. Therefore, the TO is considered technically infeasible.

Regenerative Thermal Oxidizer

A RTO is equipped with ceramic heat recovery media (stoneware) that has large surface area for heat transfer and can be stable to 2,300°F. Operating temperatures of the RTO system typically range from 1,500°F to 1,800°F with a retention time of approximately one second. The combustion chamber of the RTO is surrounded by multiple integral heat recovery chambers, each of which sequentially switches back and forth from being a preheater to a heat recovery chamber. In this fashion, energy is absorbed from the gas exhausted from the unit and stored in the heat exchange media to preheat the next cycle of incoming gas. An RTO will require additional fuel to heat the gas stream from 280°F to at least 1,500°F and which will generate additional emissions; therefore, the RTO is considered technically infeasible.

Catalytic Oxidation

Catalytic oxidation allows complete oxidation to take place at a faster rate and a lower temperature than is possible with thermal oxidation. Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency. In a typical catalytic oxidizer, the gas stream is passed through a flame area and then through a catalyst bed at a velocity in the range of 10 to 30 feet per second (fps). Catalytic oxidizers typically operate at a narrow temperature range of approximately 600°F to 1100°F. A catalytic oxidizer will require additional fuel to heat the gas stream from 280°F to at least 600°F and which will generate additional emissions; therefore, the catalytic oxidation is considered technically infeasible. This is listed in RBLC for a single source with higher emission rates than others using good operating practices.

Good Combustion Practices and Use of Clean Burning Fuels

Good combustion practices for VOCs include adequate fuel residence times, proper fuel-air mixing, and temperature control. As it is imperative for process controls, the University will maintain combustion optimal to their process. Most results in RBLC determined that this was sufficient controls for VOC. Additionally, BAAQMD and SCAQMD did not provide BACT determinations for VOC.

Additional Boilers VOC Step 3-5 - Select BACT

Step 3 and 4 are not necessary since all control technologies not currently being used have been determined technically infeasible. BACT for the boilers is good combustion practices and the use of clean burning fuel.

Additional Boilers VOC Most Stringent Measures

MSM is equivalent to BACT in this instance since no add-on control technologies are available for these units.

3.5.5. Ammonia

The University found ammonia emission factors for uncontrolled boilers on EPA's WebFIRE database.[66] The emission factors cited within this document are from the 1994 version of EPA's AP-42 Chapter 1.4. In 1998, this chapter was updated and ammonia emissions were removed from the list of emission factors associated with external combustion sources fueled by natural gas. As such, the University assumes there are minimal ammonia emissions associated with the boilers and have not considered them further for BACT.

3.6. DIESEL EMERGENCY GENERATORS

Diesel-fired engines are classified as compression ignition (CI) internal combustion engines (ICE). The primary pollutants in the exhaust gases include NO_X, VOC, SO_2, and $PM_{2.5}$. The diesel-fired engines installed at the University of Utah (the University) are for emergency use only (except for readiness testing) and will use diesel fuel meeting the requirements of 40 CFR §80.510(b) for non-road diesel fuel (i.e., a maximum sulfur content of 15 ppm and either a minimum cetane index of 40 or a maximum aromatic content of 35 percent by volume).

The University has multiple diesel-fired emergency generators permitted in Approval Orders (AO AN103540024-13 and AO AN103540025-13), as well as Title V Permit No. 3500063003.

---

[66] Database accessed April 12, 2017.

The University has small diesel-fired emergency generator engines that are each rated less than 600 hp and having a combined total capacity of up to 9,835 hp.

The University also has large diesel-fired emergency generator engines that are each rated greater than 600 Hp and having a combined total capacity of up to 47,250 hp.

EPA's RBLC was queried to identify controls for other similar-sized emergency generator engines. The RBLC shows that most diesel-fired emergency generator engines have BACT emission limits or permitted emission limits under other regulatory programs at or above the recently promulgated NSPS Subpart IIII emissions standards.

Presented below are the five steps of the top-down BACT review for diesel-fired emergency generator engines.

3.6.1. $PM_{2.5}$, NO_x, SO_2 and VOC

Diesel Emergency Generators Step 1 - Identify All Control Technologies

The following sources were reviewed to identify available control technologies:

- EPA's RBLC Database for Diesel Generators (process type 17.110 Large Internal Combustion Engines [>500 Hp] – Fuel Oil);[67]
- EPA's Air Pollution Technology Fact Sheets; and
- South Coast Air Quality Management District Example Permits.

Available control technologies for diesel-fired emergency generator engines include the following:

- Limited Hours of Operation
- Good Combustion Practices
- Use of a Tier Certified Engine
- Engine Design
- Diesel Particulate Filter
- Ultra Low Sulfur Fuel
- Diesel Oxidation Catalyst
- Selective Catalyst Reduction (SCR)

The following step evaluates the technical feasibility of each of these options.

Diesel Emergency Generators Step 2 - Eliminate Technically Infeasible Options

Limited Hours of Operation

One of the apparent opportunities to control the emissions of all pollutants released from emergency generator engines is to limit the hours of operation for the equipment. Due to the designation of these equipment as emergency equipment, only 100 hours of operation for maintenance and testing are permitted per NSPS Subpart

[67] Database accessed March 3, 2017.

IIII.[68] The University complies with NSPS Subpart IIII requirements and minimizes operation time for emergency generator engines to maintenance and testing[69].

Good Combustion Practices

Good combustion practices refer to the operation of engines at high combustion efficiency, which reduces the products of incomplete combustion. The emergency generator engines are designed to achieve maximum combustion efficiency. The manufacturer has provided operation and maintenance manuals that detail the required methods to achieve the highest levels of combustion efficiency. The University operates and maintains all diesel-fired engines in accordance with the manufacture provided instructions and best industry practices[70].

Use of an Appropriate Tier Certified Engines

EPA noted that non-road engines were a significant source of emissions and began adopting emission standards for these emission units in 1994. Today engines are required to meet certain emission limits, or tier ratings, based on the size and model year. Emission standards for these engines have progressively gotten more stringent over time and are an indicator of good combustion design. The University has installed non-road engines with a Tier rating available at the time of purchase. Since most of the engines were purchased on or after 2007[71], the existing non-road engines are either Tier 2 or 3 certified. However, the University maintains and operates four (4) diesel-fired emergency generator engines that have a capacity greater than 600 hp (as well as various smaller units) that were installed prior to the implementation of EPA's Tier system. An analysis pertaining to necessary control measures for these four (4) larger engines is contained in the discussion regarding most stringent measures (MSM) for diesel-fired emergency generator engines.

Diesel Particulate Filters

This simple technology is placed in the exhaust pathway to prevent the release of particulate and may be coated with a catalyst to further capture hydrocarbon emissions.

According to EPA's Response to Public Comments on Notice of Reconsideration of NESHAP for RICE and NSPS for Stationary ICE, "Diesel particulate filters are also proven, commercially available technology for retrofit applications to stationary engines...and are capable of reducing diesel PM by 90 percent or more."[72] Additionally the CA ARB was able to determine that this technology was technically feasible for emergency and prime engines through obtaining several vendor quotes.[73]

However EPA remained concerned with the installation of a catalyzed particulate filter, citing technical issues including the fact that many older engines are not electronically controlled, PM emissions are often too high for

---

68 40 CFR 60.4211(f)(2)

69 Per Condition II.B.25.d of the Title V permit (3500063003)

70 Per Condition II.B.25.b of the Title V permit (3500063003)

71 Per Condition II.B.25.a of the Title V permit (3500063003)

72 Response to Public Comments on Notice of Reconsideration of National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines and New Source Performance Standards for Stationary Internal Combustion Engines, EPA Docket EPA-HQ-OAR-2008-0708, June 16, 2014

73 Response to Public Comments on Notice of Reconsideration of National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines and New Source Performance Standards for Stationary Internal Combustion Engines, EPA Docket EPA-HQ-OAR-2008-0708, June 16, 2014

efficient operation and, in some cases, engine exhaust temperatures are not high enough for filter substrate regeneration.[74]

While a catalytic diesel particulate filter is not considered to be technically feasible, consideration of a simple particulate filter will be evaluated.

Ultra Low Sulfur Diesel

Ultra low sulfur diesel contains less than 0.0015 % sulfur by weight. The reduced sulfur content reduces the potential for SO_2 emissions. Additionally the low sulfur content results in a lower potential for aggregation of sulfur containing compounds and thus reduces $PM_{2.5}$ emissions. The University uses ultra-low sulfur diesel fuel for the diesel-fired emergency engines on-site[75].

Diesel Oxidation Catalyst

A diesel oxidation catalyst (DOC) utilizes a catalyst such as platinum or palladium to further oxidize the engine's exhaust, which includes hydrocarbons (HC), (e.g., VOC), to carbon dioxide (CO_2) and water. Use of a diesel oxidation catalyst can result in approximately 90 percent reduction in HC/VOC emissions.[76] In addition to controlling HC/VOC, a DOC also has the potential to reduce PM emissions by 30 percent (based on the concentration of soluble organics) and CO emissions by 50 percent if low sulfur diesel fuel is used.[77]

The use of a diesel oxidation catalyst reduces the effective power output of RICE and results in a solid waste stream. However, for the purposes of identifying technical feasibility, no formal consideration of these adverse energy and environmental impacts is presented. A diesel oxidation catalyst is considered technically feasible and is further considered for BACT.

Selective Catalytic Reduction

Selective catalytic reduction (SCR) systems introduce a liquid reducing agent such as ammonia or urea into the flue gas stream prior to a catalyst. The catalyst reduces the temperature needed to initiate the reaction between the reducing agent and NO_x to form nitrogen and water.

For SCR systems to function effectively, exhaust temperatures must be high enough (200°C to 500°C) to enable catalyst activation. For this reason, SCR control efficiencies are expected to be relatively low during the first 20 to 30 minutes after engine start up, especially during maintenance and testing. There are also complications controlling the excess ammonia (ammonia slip) from SCR use. Since SCR is anticipated to have a relatively low combustion efficiency during maintenance and testing, SCR is not considered technically feasible for emergency units.

---

[74] Response to Public Comments on Notice of Reconsideration of National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines and New Source Performance Standards for Stationary Internal Combustion Engines, EPA Docket EPA-HQ-OAR-2008-0708, June 16, 2014

[75] Per Condition II.B.25.c of the Title V permit (3500063003)

[76] U.S. EPA, *Alternative Control Techniques Document: Stationary Diesel Engines*, March 5, 2010, p. 41. (https://www.epa.gov/sites/production/files/2014-02/documents/3_2010_diesel_eng_alternativecontrol.pdf)

[77] Response to Public Comments on Notice of Reconsideration of National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines and New Source Performance Standards for Stationary Internal Combustion Engines, EPA Docket EPA-HQ-OAR-2008-0708, June 16, 2014

Diesel Emergency Generators Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Effective control technologies for diesel engines include limited hours of operation, good combustion practices, use of tier certified engines, use of high efficiency engines, diesel particulate filters, ultra-low sulfur diesel, and diesel oxidation catalysts. All control technologies considered effective are currently implemented with the exception of diesel particulate filters and diesel oxidation catalysts. Both technologies result in significant emission reductions and are further evaluated to determine the economic feasibility of implementation.

Diesel Emergency Generators Step 4 - Evaluate Most Effective Controls and Document Results

When reviewing the implementation and costs associated with installing diesel oxidation catalyst controls for an emergency-use or intermittent-use engines, the University found that "[b]ecause these engines are typically used only a few number of hours per year...[s]uch engines rarely if ever use the [diesel oxidation catalyst] type of emission controls."[78] Additionally, in its 2010 MACT/GACT evaluation for engines, EPA concluded for emergency engines: "Because these engines are typically used only a few number of hours per year [(27 hours per year per NFPA codes)], the costs of emission control are not warranted when compared to the emission reductions that would be achieved."[79] Based on EPA's assessment and the fact that the RBLC contains no records of diesel oxidation catalyst installation on emergency-use or non-road engines, installation of a diesel oxidation catalyst is eliminated from consideration as BACT.

EPA gathered cost estimates for installing a diesel particulate filter when reviewing NESHAP ZZZZ and NSPS IIII and JJJJ, and determined the costs to be excessive.[80] EPA determined that the cost per ton of PM reduced from engines between 300 and 600 HP was close to $260,000 and more than $700,000 for engines above 750 HP when installed at the time of manufacturing.[81] EPA concluded that the installation of a diesel particulate filter was only required for the operation of non-emergency engines as documented in NESHAP Subpart ZZZZ, therefore this technology is not further considered.[82]

Diesel Emergency Generators Step 5 - Select BACT

The diesel-fired emergency generator engines are well designed, efficient, reliable, and operated using good combustion practices[83]. The diesel-fired engines installed after the implementation of the EPA's Tier system meet the required Tier rating in 40 CFR 89 based on available inventory at the time of purchase. Additionally, the emergency generator engines will be operated and maintained in accordance with good combustion

---

[78] U.S. EPA, Memorandum: *Response to Public Comments on Proposed National Emission Standards for Hazardous Air Pollutants for Existing Stationary Reciprocating Internal Combustion Engines Located at Area Sources of Hazardous Air Pollutant Emissions or Have a Site Rating Less Than or Equal to 500 Brake HP Located at Major Sources of Hazardous Air Pollutant Emissions*, August 10, 2010, p. 172-173. (EPA-HQ-OAR-2008-0708)

[79] Ibid.

[80] Response to Public Comments on Notice of Reconsideration of National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines and New Source Performance Standards for Stationary Internal Combustion Engines, EPA Docket EPA-HQ-OAR-2008-0708, June 16, 2014

[81] Memorandum from Tanya Parise, Alpha-Gamma Technologies to Jaime Pagán, EPA. Cost per Ton for NSPS for Stationary CI ICE. EPA-HQ-OAR-2005-0029-0276. May 12, 2006.

[82] 40 CFR 63.6625(g)

[83] Per Condition II.B.25.b of the Title V permit (3500063003)

practices and combust only ultra-low sulfur diesel.[84] The hours of operation are restricted to 100 hours for maintenance and testing per year in accordance with 40 CFR 60, Subpart IIII[85]. As a result, the diesel-fired emergency generator engines meet BACT.

Diesel Emergency Generators Most Stringent Measures

The MSM for the diesel-fired emergency generators would be equivalent to BACT as specified above.[86]

3.7. NATURAL GAS EMERGENCY GENERATORS

The University utilizes four (4) natural gas-fired emergency generators on campus to maintain critical systems during an emergency. Specific information pertaining to the natural gas-fired emergency generators and their respective building locations are summarized in the table below.

Building Number	Engine Capacity (hp)
Building 64	134
Building 67	402
Building 350	402
Building 685	402

3.7.1. $PM_{2.5}$, NO_x, SO_2 and VOC

Natural Gas Non-Road Engines Step 1 - Identify All Control Technologies

The following sources were reviewed to identify available control technologies:

- South Coast Air Quality Management District;
- Bay Area Quality Management District;
- San Joaquin Valley Air Pollution Control District;
- Texas Commission on Environmental Quality BACT Requirements;
- EPA's RBLC Database for Natural Gas Generators (process type 17.230 Small Internal Combustion Engines [<500 Hp] – Natural Gas);[87] and
- EPA's Air Pollution Technology Fact Sheets.

Available control technologies for natural gas-fired emergency generator engines includes the following:

- Limited Hours of Operation

---

84 Per Condition II.B.25.c of the Title V permit (3500063003)

85 Per Condition II.B.25.d of the Title V permit (3500063003)

86 Approval to replace emergency generators or any combustion equipment requires funding approval by the Utah State Legislature.

87 Database accessed April 13, 2017.

- Routine Maintenance
- Good Combustion Practices
- Use of Natural Gas
- Lean Burn Technology
- Selective Catalyst Reduction (SCR)

The following step evaluates the technical feasibility of each of these options.

Natural Gas Non-Road Engines Step 2 - Eliminate Technically Infeasible Options

Limited Hours of Operation

One of the apparent opportunities to control the emissions of all pollutants released from natural gas-fired emergency generator engines is to limit the hours of operation for the equipment. Under NSPS Subpart JJJJ and RICE NESHAP[88], only 100 hours of operation for maintenance and testing are allowed for generators designated as emergency. The University will comply with the federal requirements and minimize operation time for emergency generators to maintenance and testing.

Routine Maintenance

Routine maintenance ensures the engines are working properly and as efficiently as possible, which, in turn, helps reduce emissions. For spark ignition internal combustion engines, such as those utilized by the University, RICE NESHAP[89] requires sources to:

- Change oil and filters every 500 hours of operation or annually, whichever comes first;
- Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and
- Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

The University will comply with the routine maintenance specified in RICE NESHAP and summarized herein.

Good Combustion Practices

Good combustion practices refer to the operation of engines at high combustion efficiency, which reduces the products of incomplete combustion. The natural gas-fired emergency generator engines installed at the University are designed to achieve maximum combustion efficiency. The manufacturer has provided operation and maintenance manuals that detail the required methods to achieve the highest levels of combustion efficiency for each unit. The University operates and maintains these generator engines in accordance with the manufacture provided instructions and best industry practices.

Use of Natural Gas

Natural gas is the cleanest fossil fuel and is a highly efficient form of energy. It is composed mainly of methane and its combustion results in less particulate matter, NO_x, and SO_2 in comparison to other fossil fuels. The University uses natural gas for these four (4) emergency engines on-site.

---

[88] 40 CFR 60.4243(d)(2) and 40 CFR 63.6640(f), respectively

[89] 40 CFR 63.6603(a)

Lean Burn Technology

With lean burn combustion technology excess air is introduced into the engine along with the fuel. In lean burn engines the air:fuel ratio may be as lean as 65:1 by mass. Excess air, in turn, reduces the temperature of the combustion process and combusts more of the fuel which ultimately results in fewer hydrocarbons being emitted. The four (4) natural gas-fired emergency generator engines at the University utilize lean burn technology.

Selective Catalytic Reduction

SCR systems introduce a liquid reducing agent such as ammonia or urea into the flue gas stream prior to a catalyst. The catalyst then reduces the temperature needed to initiate the reaction between the reducing agent and NO_x to form nitrogen and water.

For SCR systems to function effectively, exhaust temperatures must be high enough (200°C to 500°C) to enable catalyst activation. For this reason, SCR control efficiencies are expected to be relatively low during the first 20 to 30 minutes after engine start up, especially during maintenance and testing. There are also complications controlling the excess ammonia (ammonia slip) from SCR use. Since SCR is anticipated to have a relatively low combustion efficiency during maintenance and testing due to short periods of operation and frequent starts/stops, implementing a SCR technology for emergency units is challenging, if not infeasible.

Natural Gas Non-Road Engines Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Effective control technologies for natural gas-fired engines include the limited hours of operation, routine maintenance, good combustion practices, use of natural gas, and lean burn technology. All control technologies considered effective are currently implemented or will be implemented at the University, with the exception of SCR technology, which is evaluated further in Step 4 below to determine the economic feasibility of implementation.

Natural Gas Non-Road Engines Step 4 - Evaluate Most Effective Controls and Document Results

In the 2010 MACT/GACT evaluation for engines, EPA concluded for emergency engines: "Because these engines are typically used only a few number of hours per year [(27 hours per year per NFPA codes)], the costs of emission control are not warranted when compared to the emission reductions that would be achieved."[90] Based on EPA's assessment and the fact that the RBLC contains no records of SCR installation on emergency-use or non-road engines, installation of a SCR system is eliminated from consideration as BACT.

Natural Gas Non-Road Engines Step 5 - Select BACT

The University natural gas-fired emergency generator engines will be operated and maintained in accordance with good combustion practices, which will include routine maintenance being performed on the units in accordance with the RICE NESHAP requirements, combust only natural gas, and utilize lean burn technology. The hours of operation will be limited to 100 hours for maintenance and testing per year in accordance with NSPS Subpart JJJJ and RICE NESHAP. As a result, the University engines will meet BACT.

---

[90] Ibid.

Natural Gas Non-Road Engines Most Stringent Measures

MSM would be the same as the BACT requirements specified above for natural gas-fired emergency generator engines.

3.8. VOC FUGITIVES

Fugitive VOC emissions result from the printing plant, spray paint booth and parts washers at the University. The paint booth and printing plant cumulatively these sources are limited to 5 tpy of VOC emissions.[91]

3.8.1. VOC

VOC Fugitives Step 1 - Identify All Control Technologies

The University reviewed EPA's Alternative Control Technology Paper "Control Techniques for Volatile Organic Compound Emissions from Stationary Sources" published in December of 1992 to determine appropriate control technologies. The University has also included additional control technologies specific to painting and degreasing operations cited in the TCEQ BACT Guidelines and the BAAQMD BACT/TBACT Workbook. VOC emissions can be reduced via three approaches: alternative chemical properties, good housekeeping practices and add on control technologies.

VOC Fugitives Step 2 - Eliminate Technically Infeasible Options

Alternative Chemical Properties

Alternative chemical properties prevent VOC emissions through a reduced potential for the material to evaporate. One common method is to use alternative materials with chemical properties that are less likely to result in VOC emissions. Chemical properties that are likely to result in low VOC emissions include materials with a low VOC content and low vapor pressure.

Good Housekeeping Practices

Good housekeeping measures ensure that VOC containing materials are not permitted to evaporate unnecessarily or used in excess of process requirements. Examples of good housekeeping practices include covering containers containing VOC material, enclosing waste material with VOC containing material, diminishing exposure to heat and open atmosphere as much as the process allows.

Add on Controls

Add on controls would be accomplished through the use of control techniques that oxidize, combust or otherwise change VOC emissions produced from a process into less harmful pollutants or a less harmful form of the pollutant. Any control system that destroys VOC emissions from a process has two fundamental components. The first is the containment or capture system, which is a single device or group of devices whose function is to collect the pollutant vapors and direct them into a duct leading to a control device. The second component is the control device, which reduces the quantity of the pollutant emitted to the atmosphere.[92]

---

[91] Condition II.B.4 of AO AN103540025-13.

[92] EPA's Alternative Control Technology Paper "Control Techniques for Volatile Organic Compound Emissions from Stationary Sources" published in December of 1992.

The fugitive sources described in this section are small sources with minor emissions per source located throughout the University. Creating a capture system that spans this much area is technically infeasible therefore no destruction control techniques have been further evaluated.

VOC Fugitives Step 3 - 5 - Select BACT

Alternative chemical properties (1st) and good housekeeping practices (2nd) are both technically feasible. These control technologies are used in conjunction with one another to ensure practically low VOC emissions. The highest ranked control measures are currently being implemented; therefore, no economic, energy, or environmental analysis was conducted. The University proposes these two activities as BACT as described below.

Print Plant and Paint Booth

When possible, the University utilizes low VOC inks, fountain solutions, cleaners, solvents and water based paints. Further, combined emissions of VOC from the Building 350 Paint Booth and Print Plant are limited to 5.0 tons per rolling 12-month period per Condition II.B.9.a of the Title V Operating Permit (Permit Number 3500063003). The print plant is not subject to Utah Administrative Code (UAC) Rule R-307-351, Graphic Arts, however, the University implements the work practice standards detailed in R307-351-7, as applicable, to help minimize fugitive VOC emissions from these sources. These work practice standards include: 1) utilizing fitting covers for open tanks; and 2) keeping cleaning materials, used shop towels, and solvent wiping cloths in closed containers.

Parts Washer

When possible, the University utilizes low VOC solvents and degreasers. Additionally, the parts washers throughout the University are subject to UAC Rule R307-335, Degreasing and Solvent Cleaning Operations. This regulation requires the University to meet several good housekeeping related requirements as detailed in Condition II.B.2.a of the Title V Operating Permit (Permit Number 3500063003).

VOC Fugitives Most Stringent Measures

MSM is the same as BACT for these sources.

3.9. PM FUGITVES

The following sources of fugitive PM are grouped into two groups for BACT analysis. These sources have similar control techniques, but have been evaluated separately for completeness purposes. The sources with $PM_{2.5}$ fugitives are as follows:

Carpentry Shop

Fugitive PM emissions result from the carpentry shop at the University. This source produces less than 0.5 ton per year of PM emissions.[93]

Paint Booth

A review of previous BACT analyses, the California Air Resources Board, EPA's RACT/BACT/LAER (RBLC) Clearinghouse, and other state databases was performed to identify possible $PM_{2.5}$ control technologies that are

[93] 2014 Emission Inventory

available on the market and have been proven in practice in the coating industries with similar requirements for surface coating and stripping/depainting operations.

3.9.1. $PM_{2.5}$

The University has reviewed the following sources to ensure all available control technologies have been identified:

- EPA's RBLC Database for Other Fugitive Dust Sources (process type 99.190);[94] and
- EPA's Air Pollution Technology Fact Sheets.

PM Fugitives Step 1 - Identify All Control Technologies

Control technologies include:

- Baghouse/Fabric Filter
- Wet Electrostatic Precipitator (ESP)
- Wet Scrubber
- High-Efficiency Cyclone
- Good Operating Practices

PM Fugitives Step 2 - Eliminate Technically Infeasible Options

Carpentry Shop

Baghouse

Baghouses remove particulates by collecting particulates on the filter bag as the exhaust stream passes through the baghouse. Baghouses typically cannot withstand high exhaust temperatures (greater than 500 °F). Fabric filters have been considered effective for medium and low gas flow streams with high particulate concentrations. Baghouses have been shown to obtain a particulate collection efficiency up to 99.5% for PM_{10}, and up to 99% capture for $PM_{2.5}$. A baghouse is currently used to control particulate emissions from the Carpentry Shop.

Wet ESP

As part of this analysis, the possibility of using a Wet Electrostatic Precipitator (ESP) was also reviewed. Wet ESP technology removes particulates by electrically charging the particles and collecting the charged particles on plates. The collected particulate is washed off the plates and collected in hoppers at the bottom of the ESP. High efficiency ESPs have been shown to achieve control of particulates up to 99.5% for PM_{10}, and up to 95% capture for $PM_{2.5}$. Due to the molecular structure of the wood particles generated from the carpentry activities it is difficult to induce the electrical charge required to capture particulate matter composed of this material. Without the ability to create an electrical charge this control technology is not technically feasible.

Wet Scrubber

Wet gas scrubber (WGS) technology was also evaluated for use as a particulate control technology for the proposed gas stream. A WGS reduces particulate emissions by mixing flue gas with scrubber liquid to remove

[94] Accessed March 3, 2017.

particulate. The purge stream containing the collected particulate exits the bottom of the WGS to be further treated as wastewater. High efficiency wet scrubbers have been shown to achieve 99% capture for PM_{10}, but only up to 90% capture for $PM_{2.5}$. This type of control may be feasible for use with the proposed gas stream. However, the baghouse currently in use with the carpentry operations provides better control efficiency than a wet scrubber for control of $PM_{2.5}$.

Cyclone

Cyclones use centrifugal force and inertia to remove particles from a gas stream. The inertia of the particles resists the change in direction of the gas and they move outward under the influence of centrifugal force until they strike the walls of the cyclone. At this point, the particles are caught in a thin laminar layer of air next to the cyclone wall and are carried downward by gravity where they are collected in hoppers. Cyclones are capable of removing in excess of 90 percent of the larger diameter (> 30 μm) PM. However, their efficiency decreases with smaller particles. The baghouse currently in use with the carpentry operations provides better control efficiency than a cyclone for control of $PM_{2.5}$.

Paint Booth

As there is a minimal amount of particulate emissions from the paint booth, the University has considered the following:

Wet ESP

ESP's were not identified in the literature or databases as a means of controlling PM from spray booth operations. Thus, this control technology was eliminated from further consideration.

Wet Scrubber

For a wet scrubber the solubility of the material being collected needs to be considered. Since the particulate to be controlled is not readily soluble in water, this technology was eliminated from further consideration.

Good Operating Practices

Good operating Practices include any overspray (particulate) is controlled in a paint booth, through application, and/or exhausted through filter media. Filter media is currently in place on the ventilation and capture system of the paint booth.

High Transfer Efficiency Application Techniques

The coatings are applied using high-volume, low-pressure (HVLP) spray nozzle gun used within the booth. Therefore, minimal particulate emissions escaping from the process.

PM Fugitives Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The control technologies under consideration are ranked as follows in order of most effective to least effective for control of $PM_{2.5}$:

Carpentry Shop

Pollutant	Control Technologies	Approximate Control Efficiency
$PM_{2.5}$	Baghouse (Dust collector)	99% - 99.5%
	Wet scrubber	90%-99%
	Cyclone	20%-70%

Paint Booth

Pollutant	Control Technologies	Approximate Control Efficiency
$PM_{2.5}$	Good Operating Practices	Intrinsic
	High transfer efficiency application techniques	Intrinsic

PM Fugitives Step 4 - Evaluate Most Effective Controls and Document Results

Carpentry Shop

While wet scrubber and cyclone controls are technically feasible control options, the control efficiency for these technologies are ranked less than the baghouse currently installed for the process. As a result, no detailed economic, energy, and environmental impact evaluations were conducted for the Carpentry Shop.

Paint Booth

Since available control technology is currently being implemented, no detailed economic, energy, and environmental impact evaluations were conducted.

PM Fugitives Step 5 - Select BACT

Carpentry Shop

BACT for $PM_{2.5}$ emissions is the existing baghouse that has an estimated control efficiency of 99% and a grain outlet loading of 0.16 gr/dscf. Additionally, the dust collector is limited in hours and may only be used for 1043 hours per rolling 12-month period.[95]

Paint Booth

As the University is currently implementing BACT through the use of a filter particulate capture system, the following good operating practices are being implemented as specified in Title V condition II.B.11.a.1. Specifically, the spray booth particulate capture system is inspected before each use to verify that it is functioning properly which include but are not limited to the following:

---

[95] Title V Operating Permit #3500063003 Condition II.B.12.b

a. Inspection for holes in the particulate filters.
b. Inspection of the particulate filters to determine proper installation within the support rack.
c. Inspection of the exhaust fan to ensure that it is operating

Most Stringent Measures

MSM is the same technology as BACT in this case.

3.10. INSIGNIFICANT ACTIVITIES

The following unit types have small emission rates that the University is considering negligible for emission control. These sources emit VOCs and PM and are fugitive in nature. An analysis for these units would be similar or identical to the analysis provided in the VOC Fugitives and PM Fugitive Sections. Since emissions from these sources are minor and fugitive, the University has not considered control technologies beyond best operating practices for these units.

3.10.1. Ethylene Oxide Sterilizer

The ethylene oxide sterilizer is used at the University Medical Center for the sterilization of medical equipment. Per Title V Operating Permit #3500063003 Condition II.A.32, the sterilization unit uses less than 1 tpy of ethylene oxide. Ethylene oxide is a VOC emissions, therefore due to permit conditions, the University can emit a maximum of1 tpy of VOC from this process.

Additionally, the sterilizer is subject to NESHAP WWWWW, Hospital Ethylene Oxide Sterilizers.[96] Therefore the sterilizer will "...run full loads of items having a common aeration time, except under medically necessary circumstances."[97] Furthermore, the University is not subject to NESHAP O, Ethylene Oxide Emissions Standards for Sterilization Facilities, because they do not use more than 1 tpy of ethylene oxide within 12 consecutive months and they are a hospital. The University has low enough emissions that NESHAP O does not apply and complies with the management practice requirements of NESHAP WWWWW to ensure the sterilizer is used as efficiently as possible while meeting medical requirements.

3.10.2. Underground Storage Tanks

The university maintains four underground storage tanks - two diesel tanks with a capacity of 20,000 gallons, one diesel tank with a capacity of 30,000 gallons, and one jet fuel tank with a capacity of 12,000 gallons. Emissions from fixed roof storage tanks result from displacement of headspace vapor during filling operations (working losses) and from diurnal temperature and heating variations (breathing losses).[98] Losses due to changes in temperature or barometric pressure are minimal for underground tanks because the surrounding earth limits the diurnal temperature change and changes in the barometric pressure would result in only small losses.[99]. The University has considered emissions from these underground storage tanks negligible.

---

[96] Title V Operating Permit #3500063003 Condition II.B.27.a

[97] 40 CFR 63.10390

[98] EPA, Emission Factor Documentation for AP-42 Section 7.1 Organic Liquid Storage Tanks, September 2006.

[99] Ibid.

3.10.3. Small Fuel Storage Tanks

Various small fuel storage tanks are located throughout the University and have no federal applicable requirements. All tanks have a capacity of 10,000 gallons or less. Due to the small size and infrequent use, the University has considered emissions from these storage tanks negligible.

3.10.4. Ironmaking

The flash ironmaking conducted at the University is solely for research purposes and is performed on an infrequent basis. The bench reactor consists of a refractory-lined vertical vessel in which iron oxide concentrates will react with hot reducing gases (hydrogen and carbon monoxide) generated internally by the partial combustion of natural gas or hydrogen. The solid product particles (iron (Fe) with varying amounts of iron oxides (FeO and Fe_3O_4)) will fall to the bottom of the vessel into a quench chamber. Nitrogen will be injected into the quench chamber to lower the temperature of the solid product and offgas to approximately 400 °C. The resulting offgas will contain nitrogen, hydrogen, water vapor, carbon monoxide, carbon dioxide, and a small amount of reduced iron dust. Flammable gases will be completely burned in an afterburner chamber before being released to the atmosphere through a flare stack. Flammable gases will be completely burned in an afterburner chamber before being released to the atmosphere through a flare stack. The flare has a heat input of 3.78 MMBtu/hr which is less than the source category exemptions listed in UAC Rule R307-401-10. Dust particles will be oxidized to hematite (Fe_2O_3).

It's expected the dust particles after going through the flare stack will be greater than 20 microns. Additionally, the experiments will generally occur twice a week and last approximately 3 hours per test. Consequently, $PM_{2.5}$, NO_X, SO_2, and VOC emissions from this activity are assumed to be negligible.

4.1. EMISSION SUMMARY

The following table provides emission limits during normal operation and startup, shutdown and maintenance settings. Refer to Table 4-1

Table 4-1 Facility-Wide Impact of Emission Units

Operating Scenario	Pollutant				
	$PM_{2.5}$[100]	NO_x	SO_2	VOC	NH_3[101]
Normal Operation	19.29	100.05	3.85	14.07	'--

[100] The $PM_{2.5}$ limits in the University of Utah's current Approval Order (DAQE-AN103540025-13) only represent the filterable portion of $PM_{2.5}$ and does not account for the condensable fraction. An increase in $PM_{2.5}$ emissions limit is required to ensure both have been accounted for in the total.

[101] The University currently does not have an NH_3 limit in its Approval Order (DAQE-AN103540025-13).

5. MONITORING CONDITIONS

Table 5-1 below is a summary of monitoring conditions for the site, both existing and proposed.

Table 5-1 Summary of Monitoring Conditions

Monitoring Condition	Frequency	Source(s) Covered	Permit Condition
Good air pollution control practices during startup, shutdown, and malfunction	As necessary	Source-wide	#3500063003 Condition II.B.1.c.1
Fuel use and fuel type records	When in operation	Source-wide	#3500063003 Condition II.B.1.e.1
Emergency generator use: dates of use, reason, duration	When in operation	Source-wide	#3500063003 Condition II.B.1.f.1
Natural gas consumption in boilers > or = 5.0 MMBtu/hr	Monthly Calculation by the 25th day of the month	Source-wide	#3500063003 Condition II.B.1.g.1
Fuel use in boiler: dates of use, reason, duration	As necessary when a boiler combusts fuel other than natural gas	Source-wide	#3500063003 Condition II.B.1.h.1
Visual observation of conditions of parts washers - covers in place, adequate solvent drainage, condition of storage tanks and containers, posted procedures, etc.	Monthly	Miscellaneous Parts Washers	#3500063003 Condition II.B.2.a.1
Fuel usage/type	Unspecified	Bldg 32 West Boiler	#3500063003 Condition II.B.3.a.1
Monitoring per 40 CFR 60 Subpart A	Daily	Bldg 32 West Boiler	#3500063003 Condition II.B.3.b.1
Monitoring per 40 CFR 60.48c(g) - Fuel usage for each fuel	Monthly report fuel on a daily basis	Bldg 32 West Boiler	#3500063003 Condition II.B.3.c.1
Fuel usage/type	Unspecified	Bldg 33 Boiler	#3500063003 Condition II.B.4.a.1
Generator use: dates used, duration, reason	As necessary when operated	Bldg 151 3 Diesel-fired 1,175 hp emergency generators	#3500063003 Condition II.B.5.a.1
Monitoring per 40 CFR 60.48c(g) - Fuel usage for each fuel	Monthly report fuel on a daily basis	Bldg 151 Boiler	#3500063003 Condition II.B.5.b.1

Monitoring Condition	Frequency	Source(s) Covered	Permit Condition
Fuel usage	Daily	Bldg 151 Boiler	#3500063003 Condition II.B.5.d.1
Fuel usage Visual emission survey	Daily when burning natural gas Semiannually if burning fuel oil, Method 9 within 24 hours if VE are observed	Bldg 302 Boiler	#3500063003 Condition II.B.6.a.1
Fuel usage – type, amount	Monthly	Bldg 302 Boiler	#3500063003 Condition II.B.6.b.1
Stack Testing	Every 3 years	Bldg 303 Boilers 3 & 4, 6 & 7	#3500063003 Condition II.B.7.a.1
Fuel usage	Not specified	Bldg 303 Boilers 3 & 4, 6 & 7	#3500063003 Condition II.B.7.b.1
Fuel usage – type, amount	Monthly	Bldg 303 Boilers 6 & 7	#3500063003 Condition II.B.7.c.1
Monitoring per 40 CFR 60 Subpart A – Fuel Usage	Daily	Bldg 303 Boilers 6 & 7	#3500063003 Condition II.B.7.d.1
Stack Test	Annually between December 1 and February 29	Water Plant Cogen Unit and WHRU Duct Burner	#3500063003 Condition II.B.8.a.1
Fuel Usage – type, amount	Not specified	Water Plant Cogen Unit and WHRU Duct Burner	#3500063003 Condition II.B.8.b.1
Sulfur Content of gas burned	Not specified	Water Plant Cogen Unit and WHRU Duct Burner	#3500063003 Condition II.B.8.c.1
Monitoring per 40 CFR 60 Subpart A	Daily	Water Plant Cogen Unit and WHRU Duct Burner	#3500063003 Condition II.B.8.d.1
VOC/HAP Emissions on 12-month rolling total	By the 20th of each month	Bldg 350 Paint Booth and Print Shop	#3500063003 Condition II.B.9.a.1
Inspection of waste containers	Daily	Print Plant	#3500063003 Condition II.B.10.a.1
Inspection of VOC solvent containers	Daily	Print Plant	#3500063003 Condition II.B.10.b.1

Monitoring Condition	Frequency	Source(s) Covered	Permit Condition
Visible emissions Method 9	Annually	Bldg 350 Carpentry Shop Dust Collector	#3500063003 Condition II.B.12.a.1
Hours of operation	Rolling 12-month total determined monthly by the 20th	Bldg 350 Carpentry Shop Dust Collector	#3500063003 Condition II.B.12.b.1
Fuel type verification when natural gas is being combusted Opacity survey when fuel oil is combusted	As necessary Semiannually if burning fuel oil, Method 9 within 24 hours if VE are observed	Bldg 521/525/526 Hosptial Boilers	#3500063003 Condition II.B.13.a.1
Fuel use type	As necessary	Bldg 532 Hospital Boilers	#3500063003 Condition II.B.14.a.1
Monitoring per 40 CFR 60.48c(g) – Fuel usage for each fuel	Monthly report fuel on a daily basis	Bldg 532 Hospital Boilers	#3500063003 Condition II.B.14.b.1
Monitoring per 40 CFR 60 Subpart A – fuel type, amount, supplier certifications for fuel oil	As necessary	Bldg 532 Hospital Boilers	#3500063003 Condition II.B.14.c.1
Fuel use type	As necessary	Bldg 523 Eye Center Boiler	#3500063003 Condition II.B.15.a.1
Fuel type verification when natural gas is being combusted Opacity Method 9 when fuel oil is combusted more than 12 hours	As necessary Daily	Bldg 555 Huntsman Cancer Inst. Boiler	#3500063003 Condition II.B.16.a.1
Monitoring per 40 CFR 60.48c(g) – Fuel usage for each fuel	Monthly report fuel on a daily basis	Bldg 555 Huntsman Cancer Inst. 16.8 MMBtu/hr NSPS Boilers	#3500063003 Condition II.B.16.c.1
Fuel type verification when natural gas is being combusted Opacity Method 9 when fuel oil is combusted more than 12 hours	As necessary Daily	Bldg 556 Huntsman Cancer Inst. Boilers	#3500063003 Condition II.B.17.a.1
Fuel use type	As necessary	Bldg 565 E-E-J Medical Research Center Boiler	#3500063003 Condition II.B.18.a.1

Monitoring Condition	Frequency	Source(s) Covered	Permit Condition
Monitoring per 40 CFR 60.48c(g) – Fuel usage for each fuel	Monthly report fuel on a daily basis	Bldg 565 E-E-J Medical Research Center Boiler	#3500063003 Condition II.B.18.c.1
Fuel type usage	As necessary	Bldg 853 Health Profession Education	#3500063003 Condition II.B.19.a.1
Monitoring per 40 CFR 60.48c(g) – Fuel usage for each fuel	Monthly report fuel on a daily basis	Bldg 581 School of Pharmacy	#3500063003 Condition II.B.20.a.1
Monitoring per 40 CFR 60 Subpart A [102]	Daily	Bldg 581 School of Pharmacy	#3500063003 Condition II.B.20.b.1
Fuel use type	As necessary	Bldg 865 Boiler	#3500063003 Condition II.B.21.a.1
Fuel use type	As necessary	Bldg 587 Boiler	#3500063003 Condition II.B.22.a.1
Monitoring per 40 CFR 60 Subpart A [103]	Daily	Bldg 587 Boiler	#3500063003 Condition II.B.22.b.1
Monitoring per 40 CFR 60.48c(g) – Fuel usage for each fuel	Monthly report fuel on a daily basis	Bldg 587 Boiler	#3500063003 Condition II.B.22.c.1
Method 9	Annually	Small Diesel Fired Engines	#3500063003 Condition II.B.23.a.1
Method 9	Annually	Large Diesel Fired Engines	#3500063003 Condition II.B.24.a.1
Monitor generator usage (type – testing, maintenance & emergency use), hours of operation, reason for operation,	Each time a generator is operated	Bldg 85, 168 Hp Bldg 526, 1475 Hp Bldg 526 1475 Hp	#3500063003 Condition II.B.25.a.1
Engine certifications Operation & maintenance consistent with manufacturer recommendations	Must have always Every time units operate	See List Below	#3500063003 Condition II.B.25.a.1 Condition II.B.25.b.1
Sulfur content of diesel fuel	Each time generator fuel tank is filled	Bldg 85, 168 Hp Bldg 526 1475 Hp Bldg 526 1475 Hp See List Below	#3500063003 Condition II.B.25.c.1
Monitor generator usage (type – testing, maintenance & emergency use), hours of operation, reason for operation,	Every time a unit operates (records kept monthly)	Bldg 85, 168 Hp Bldg 526 1475 Hp Bldg 526 1475 Hp See List Below	#3500063003 Condition II.B.25.d.1

Monitoring Condition	Frequency	Source(s) Covered	Permit Condition
Fuel use	Every time a unit operates	Natural Gas Fired Emergency Generators	#3500063003 Condition II.B.26.a.1

Per 40 CFR 60.48c(g)(1) "the owner or operator of each affected facility shall record and maintain records of the amount of fuel each day."

[102] Per 40 CFR 60.Subpart Dc – the only monitoring requirement for natural gas is found in 40 CFR 60.48c(g), and consist of daily fuel use monitoring.

[103] Per 40 CFR 60.Subpart Dc – the only monitoring requirement for natural gas is found in 40 CFR 60.48c(g), and consist of daily fuel use monitoring.

6. PROPOSED SIP CONDITIONS

Include a brief list of conditions that the source anticipates will be necessary for the SIP.

i. Emissions to the atmosphere from the listed emission points in Building 303 shall not exceed the following concentrations:

EMISSION POINT	POLLUTANT	ppmdv (3% O_2 dry)	
A. Boilers #3	NO_x	187	(Replace with new boiler at 9 PPM by December 31, 2018).
B. Boilers #4	NO_x	187	Decommission in 2018.
C. Boilers #6	NO_x	9	
C. Boilers #7	NO_x	9	
D. Turbine	NO_x	9	
E. Turbine and WHRU Duct burner	NO_x	15	

ii. Stack testing to show compliance with the emissions limitations of Condition i above shall be performed as specified below:

EMISSION POINT	POLLUTANT	INITIAL TEST	TEST FREQUENCY
A. Boilers #9	NO_x	2019	every 3
B. Boilers #3 & #4	NO_x	*	every 3
C. Boilers #6	NO_x	*	every 3
D Boilers #7	NO_x	*	every 3
E. Turbine	NO_x	*	every year
F. Turbine and WHRU Duct Burner	NO_x	*	every year

* Initial test already performed

APPENDIX A: COST ANALYSIS

BACT CONTROL COST EVALUATION

Technology:	Selective Catalytic Reduction (SCR)
Application:	UCHTWP Natural Gas Fired Boiler
Pollutants:	Oxides of Nitrogen (NOx)

Selective Catalytic Reduction (SCR)

Key Assumptions	Each UCHTWP Boiler	Notes
Process Information		
Uncontrolled Emissions (tpy)	4.85	
Heat Input (MMBtu/hr)	87.50	
Control Efficiency (%)	70%	- 70% efficiency assumed due to low concentration in exhaust
Catalyst Volume (ft^3)	487	
SCR Height (ft)	17	
Ammonia Reagent (lb/hr)	10 20	
Electrical Consumption (kWh/year)	429,240	
Gas Consumption (MMBtu/year)	7,665	
Water Consumption (Mgal/year)	0	
Utility Costs		
Electricity ($/kWh)	$ 0.089	Average Utah prices
Natural Gas ($/MMBtu)	$ 2.83	Average U S. Prices (Jan 2017)
Water ($/Mgal)	$ 33.45	Sandy Utah (2" Meter, July 2016)
Ammonia Reagent ($/lb)	$ 0.48	
Labor Costs		
Operator ($/hour)	$ 15.00	
Supervisor ($/hour)	$ 20 00	
Maintenance ($/hour)	$ 20.00	
Economic Factors		
Dollar Inflation (2002 to 2017)	1.3416	U S Consumer Price Index
Equipment Life Expectancy (Years)	10	
Interest Rate (%)	7%	Current Avg SBA Loan Rate
Capital Recovery Factor (CRF)	0.1424	

DIRECT COSTS

Capital Cost	Each UCHTWP Boiler	Notes
Purchased Equipment Costs		
Total Equipment Cost[1]	880,422	A
Instrumentation	88,042	0 10 × A
Sales Tax	52,825	0 06 × A
Freight	44,021	0.05 × A
Total Purchased Equipment Costs	*1,065,311*	*B = 1.18 × A*
Direct Installation Costs [2]		
Foundations and Supports	85,225	0.08 × B
Handling and Erection	149,143	0 14 × B
Electrical	42,612	0.04 × B
Piping	21,306	0.02 × B
Insulation	10,653	0.01 × B
Painting	10,653	0.01 × B
Site Preparation & Buildings	-	No estimate / Site specific
Additional duct work	-	No estimate / Site specific
Total Direct Installation Costs	*319,593*	*C = 0.30 × B*
Indirect Installation Costs [2]		
Engineering	106,531	0 10 × B
Construction and Field Expense	53,266	0.05 × B
Contractor Fees	106,531	0.10 × B
Start-up	21,306	0.02 × B
Performance Test	10,653	0.01 × B
Process Contingencies	31,959	0.03 × B
Total Indirect Installation Costs	*330,246*	*D = 0 31 × B*
Total Capital Investment ($)	**1,715,150**	**TCI = B + C + D**

ANNUAL COSTS

Operating Cost	Each UCHTWP Boiler	Notes
Direct Annual Costs[3]		
Operating Labor (0.5 hr, per 8-hr shift)	8,213	E
Supervisory Labor (15% operating labor)	1,232	F = 0.15 × E
Maintenance Labor (0.5 hr, per 8-hr shift)	10,950	G
Maintenance Materials	8,576	H = 0.005 x TCI
Electricity	38,202	I
Natural Gas	21,692	J
Water	0	K
Reagent	42,443	L
Catalyst Replacement (Cost x CRF for 3 yrs)	44,577	M
Total Direct Annual Costs	*175,885*	*DAC = E +F+ G+ H+ I+ J +K+L+M*
Indirect Annual Costs[3]		
Overhead	17,382	N = 0.60 × (E + F + G + H)
Administrative Charges	34,303	O = 0.02 × TCI
Property Tax	17,151	P = 0.01 × TCI
Insurance	17,151	Q = 0.01 × TCI
Capital Recovery[4]	244,199	R
Total Indirect Annual Costs	*330,187*	*IDAC = N+O+P+Q+R*
Total Annual Cost ($)	**506,072**	*TAC = DAC + IDAC*
Pollutant Removed (tpy)	3.40	
Cost per ton of Pollutant Removed ($)	**149,064**	*$/ton = TAC / Pollutant Removed*
New Emission Rate (tpy)	1.46	
New Emission Factor (lb/MMBtu)	0.004	

1. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (7th Edition)*, May 2016, Section 4.2, Chapter 2 (Selective Catalytic Reduction), Tab
2. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)*, January 2002, Section 3.2, Chapter 2, Table 2 8 (assume same as cata
3. U.S EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)*, January 2002, Section 3.2, Chapter 2, Table 2.10 (assume same as cat
4. Capital Recovery factor calculated based on Equation 2.8a (Section 1, Chapter 2, page 2-21) and Table 1.13 (Section 2, Chapter 1, page 1-52) of U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual (6th Edition), January 2002.

BACT CONTROL COST EVALUATION

Technology:	Ultra Low NO_X Burner
Application:	Natural Gas Fired Boiler
Pollutants:	Oxides of Nitrogen (NOx)

Ultra Low NOX Burner

Key Assumptions	Each UCHTWP Boiler	Notes
Process Information		
Uncontrolled Emissions (tpy)	4.85	
Heat Input (MMBtu/hr)	87.50	
Controlled Emissions (tpy)	3.20	
Utility Costs		
Labor Costs		
Operator ($/hour)	$ 15.00	
Supervisor ($/hour)	$ 20.00	
Maintenance ($/hour)	$ 20.00	
Economic Factors		
Dollar Inflation (2002 to 2017)	1.3416	U.S. Consumer Price Index
Equipment Life Expectancy (Years)	10	
Interest Rate (%)	7.00%	Current Avg SBA Loan Rate
Capital Recovery Factor (CRF)	0.1424	

DIRECT COSTS

Capital Cost	Each UCHTWP Boiler	Notes
Purchased Equipment Costs		
Total Equipment Cost[1]	400,000	A
Instrumentation	40,000	0.10 × A
Sales Tax	24,000	0.06 × A
Freight	20,000	0.05 × A
Total Purchased Equipment Costs	*484,000*	*B = 1.18 × A*
Direct Installation Costs [2]		
Foundations and Supports	38,720	0.08 × B
Handling and Erection	67,760	0.14 × B
Electrical	19,360	0.04 × B
Piping	9,680	0.02 × B
Insulation	4,840	0.01 × B
Painting	4,840	0.01 × B
Site Preparation & Buildings	-	No estimate / Site specific
Additional duct work	-	No estimate / Site specific
Total Direct Installation Costs	*145,200*	*C = 0.30 × B*
Indirect Installation Costs [2]		
Engineering	48,400	0.10 × B
Construction and Field Expense	24,200	0.05 × B
Contractor Fees	48,400	0.10 × B
Start-up	9,680	0.02 × B
Performance Test	4,840	0.01 × B
Process Contingencies	14,520	0.03 × B
Total Indirect Installation Costs	*150,040*	*D = 0.31 × B*
Total Capital Investment ($)	**779,240**	**TCI = B + C + D**

ANNUAL COSTS

Operating Cost	Each UCHTWP Boiler	Notes
Direct Annual Costs [3]		
Operating Labor (0.5 hr, per 8-hr shift)	8,213	E
Supervisory Labor (15% operating labor)	1,232	F = 0.15 × E
Maintenance Labor (0.5 hr, per 8-hr shift)	10,950	G
Maintenance Materials	3,896	H = 0.005 x TCI
Total Direct Annual Costs	*24,291*	*DAC = E +F+ G+ H+ J*
Indirect Annual Costs [3]		
Overhead	14,574	N = 0.60 × (E + F + G + H)
Administrative Charges	15,585	O = 0 02 × TCI
Property Tax	7,792	P = 0 01 × TCI
Insurance	7,792	Q = 0 01 × TCI
Capital Recovery[4]	110,946	R
Total Indirect Annual Costs	*156,690*	*IDAC = N+O+P+Q+R*
Total Annual Cost ($)	**180,981**	*TAC = DAC + IDAC*
Pollutant Removed (tpy)	1.65	
Cost per ton of Pollutant Removed ($)	**109,755**	*$/ton = TAC / Pollutant Removed*

1. Allan Woodbury with North Associate, Inc. provided estimate.

2. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)*, January 2002, Section 3.2, Chapter 2, Table 2.8 (assume same as catalytic incineration)

3. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)*, January 2002, Section 3.2, Chapter 2, Table 2 10 (assume same as catalytic incineration)

4. Capital Recovery factor calculated based on Equation 2.8a (Section 1, Chapter 2, page 2-21) and Table 1.13 (Section 2, Chapter 1, page 1-52) of U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual (6th Edition), January 2002.

5. It is assumed that the cost and consumption of natural gas will not be influenced by the purchase of a new unit.

University of Utah
BACM Questions Response to the Utah Division of Air Quality

July 21, 2017

Prepared by: Trinity Consultants, Inc.

For/Reviewed by: Michael D. Brehm, P.E.

David Quinlivan, P.E.

Catherine,

Responses to your questions regarding the University of Utah's (University's) Best Available Control Measures (BACM) report are detailed in the text below and/or attachments. The questions are based on your email on July 14, 2017, plus follow up phone call on the same day between the University and the Utah Division of Air Quality (UDAQ). Questions are identified below in *italics* with the University's response listed in plain text. Please do not hesitate to reach out if you have any follow up questions or concerns.

1. *Please breakout your potential to emit (PTE) by category (same categories as used in the BACM analysis works). PTE for current AO.*

Attachment No. 1 contains the University's potential to emit (PTE) calculations. These calculations have been developed based on emission guarantees from vendors, U.S. Environmental Protection Agency (EPA) emission factors (i.e., AP-42) or non-road engine tier ratings. These emission calculations represent the allowable emissions established with the University's site-wide emissions limitations in its approval order (AO) DAQE-AN103540025-13. These emission estimates are based on natural gas usage representative of our University Operation's needs, consistent with the University's site-wide natural gas consumption limitation in the University's AO. Although the emissions inventory is representative of major emission sources, some of the minor sources have not been included at this time.

2. *Please provide additional details on the HSC Transformation Project Building. Will a new boiler be installed as part of this project? Please explain any new equipment and emission changes as part of this project. I need to project your future emissions, so I need to know about upcoming projects that may impact your emissions.*

University of Utah will develop response.

3. *You mentioned that Boiler #9 will replace Boiler 3 in Lower Campus. Please provide details on the new boilers, including emission changes and construction schedule.*

University will develop response.

4. *The cost analysis for the three 87.5 million British thermal units per hour (MMBtu/hr) boilers is based on uncontrolled emissions of 4.85 tons per year (tpy). Could you explain how this value was estimated? BACT should be conducted based on PTE of the equipment.*

The University's approval order establishes a natural gas consumption limit in standard cubic foot (scf) for all natural gas fired boilers, DAQE-AN103540025-13, Condition II.B.1.c. This consumption limit is lower than the combined continuous capacity of all natural gas fueled boilers greater than 5 MMBtu/hr. Therefore, potential emissions for each of the boilers greater than 5 MMBtu/hr is limited by natural gas usage as opposed to heat input capacity. Potential emissions for each boiler are determined based on potential natural gas usage representative of the University's Operations in (see Attachment No.1).

The three 87.5 MMBtu/hr boilers are collectively referred to as the UCHTWP Boilers. Utilizing AP-42 emission factors and guarantees from vendors, natural gas higher heating values, and potential natural gas usage; total emissions for the UCHTWP boilers sum to 14.55 tpy. Dividing the emissions evenly amongst the three boilers provides uncontrolled emissions of 4.85 tpy per boiler.

Sample calculations are provided below:

"Emission Factor" ("lb" /"MMBtu")"x" "Natural Gas Higher Heating Value" ("MMBtu" /"MMscf")"x"

"Potential Natural Gas Usage for UCHTWP Boilers" ("MMscf" /"yr") ÷3=4.85 tpy

5. *We need more information to support the BACT determination for the small boilers. Please provide a cost analysis for retrofitting and/or replacing the small boilers.*

The University is in the process of securing an engineering company to perform an analysis to determine what equipment/controls are technically feasible and will provide a cost estimate for controls and installation. An analysis will be provided to UDAQ with a later time response.

6. *We need more information to support the BACT determination for the diesel emergency generators. Please provide a cost analysis for replacing the older diesel emergency generators with new Tier 3 or Tier 4 certified engines.*

Attachment No. 2 includes an economic feasibility analysis for replacing the largest and oldest generators in the University's inventory. The cost estimates are for replacement engines and Tier 3 or Tier 4 emissions thresholds were used to determine the cost per ton of pollutant removed.

7. *Please provide a copy of the cost estimate from the manufacturer for the ULNB cost analysis. Your analysis assumes the same cost for ULNB and LNB. Please provide manufacturer documentation to support this assumption.*

The University is in the process of securing an engineering company to perform an analysis to determine what equipment/controls are technically feasible and will provide a cost estimate for controls and installation. An analysis will be provided to UDAQ with a later time response.

8. *You provided a discussion for selective catalytic reduction (SCR) but not selective non-catalytic reduction (SNCR). Please provide a statement describing the technical feasibility of SNCR.*

Step 1 of the 5-step BACM analysis identifies all control technologies. A large number of resources were used to identify control techniques currently implemented as BACT. See Step 1 for each set of equipment and a complete listing of applicable resources sources researched. The review was completed for $PM_{2.5}$ and each precursor that may be emitted by sources at the University of Utah. Based on the review of all sources, selective non-catalytic (SNCR) was not included as an identified technology because similar sources of a similar size were not implementing SNCR. Control technologies with higher efficiency systems were identified in the original analysis, as SNCR provides minimal NO_X reductions in the 30 to 50% range.

Selective Non-Catalytic Reduction

SNCR is typically applied to combustion units ranging from 50 to 6,000 MMBtu/hr and can achieve NO_X reduction levels ranging from 30% to 50%. However, the SCNR is less effective in instances where NO_X concentration is minimal in the exhaust gas stream.

NO_X concentration levels required for an effective SNCR are 200-400 parts per million (ppm). Similarly to an SCR, SNCR also has ammonia slip emissions due to unreacted ammonia from the incomplete reaction of the NO_X and the reagent. Ammonia slip associated with the SNCR is a documented problem. The increased ammonia emissions (which are currently zero) from the implementation of this technology would offset the marginal air quality benefits the SNCR option would provide from NO_X emissions reduction. Ammonia slip emissions have the potential to increase secondary $PM_{2.5}$ levels in the area as ammonia is a precursor for the formation of secondary $PM_{2.5}$.

Additionally, storage and handling of ammonia poses significant safety risks when applied at the University of Utah. Ammonia is toxic if swallowed or inhaled and can irritate or burn the skin, eyes, nose, or throat. It is a commonly used material that is typically handled safely and without incident. However, there are potential health and safety hazards associated with the implementation of this technology. Boilers throughout the university are located in areas where students, faculty, patients, family members and the general public may be exposed if an ammonia leak were to occur.

SNCR technology chemically reduces the NO_X molecule to N_2 and H_2O. Urea or ammonia is used as a reducing agent which is injected into the flue gas stream. Heat from the boiler provides sufficient energy for the chemical reaction to occur. Design and operational factors affecting the reduction of NO_X utilizing an SNCR system are as follows.

- Temperature range for the reaction;
- Residence time available in the necessary temperature range;
- Degree of mixing (reagent and combustion gases)
- NO_X concentration level in the flue gas
- Molar ratio of reagent to NO_X concentration; and
- Ammonia slip.

Technical Feasibility - Boilers

SNCR is difficult to apply to package boilers where flue gas temperatures range from approximately 1,600 to 1,900 °F. In these boilers, the 1,600 to 1,900 °F temperature range is present in the convective passes in which the residence time would be too short for SNCR to be an effective control. Flue gas temperature is impacted by boiler load making the optimum design and operation of an SNCR more difficult if this device were to be installed. A potential for ammonia slip also makes this control infeasible.

Technical Feasibility - Turbine

SNCR is technically infeasible for the turbine because currently $SCONO_X$ (EM_X) technology is utilized. EM_X is achieving a 9 parts per million by dry volume (ppmdv) NO_X outlet concentration for the turbine and a 15 ppm

NO_X outlet concentration for the turbine and waste heat recovery unit. As discussed above, SNCR achieves a 30-50% reduction in NO_X emissions if the flue gas concentration is 200-400 ppm. Because the exhaust concentration is much lower, SNCR would not be effective. Ammonia slip issues also make this infeasible.

Technical Feasibility – Additional Small Boilers

SNCR is difficult to apply to package boilers where flue gas temperatures range from approximately 1,600 to 1,900 °F. In these boilers, the 1,600 to 1,900 °F temperature range is present in the convective passes in which the residence time would be too short for SNCR to be an effective control. Flue gas temperature is impacted by boiler load making the optimum design and operation of an SNCR more difficult if this device were to be installed. A potential for ammonia slip also makes this control infeasible.

Technical Feasibility – Engines

Diesel and natural gas fired emergency generators are limited to 100 hours of operation for maintenance and testing. SNCR is infeasible for these engines due to low exhaust temperature, especially during maintenance and testing, and safety concerns associated with ammonia slip.

Please confirm whether Boilers 1 and 3 have been upgraded with O_2 trims.

University to prepare a response.

9. *Please provide additional details of why flue gas recirculation (FGR) is not technically feasible for the Duct burner.*

The University had a third party contractor specializing in commercial and industrial combustion equipment evaluate the feasibility of installing FGR on the existing duct burner. Based on this analysis, flue gas recirculation is not feasible because there is not adequate space in the building to install the equipment necessary for FGR. Building expansion is also prohibitive due to the location of the duct burner and the buildings location relative to the surrounding area. Currently with the space available there is not sufficient straight duct for to obtain proper mixing of gases for FGR which would provide a lower emissions guarantee for the duct burner. Implementation of an FGR system requires a larger duct which would have the possibility to result in de-rated capacity of the unit.

The University appreciates working with UDAQ in the development of the $PM_{2.5}$ Serious Non-attainment State Implementation Plan (SIP). We will continue to provide information as it is obtained.

If you have any questions, please do not hesitate to contact me at (801) 585-1617.

MEMORANDUM

To: Catherine Wyffels
From: Brian Mensinger, Trinity Consultants, Inc.; Michael Brehm, University of Utah
Date: June 15, 2018
RE: Campus Transformation at University Hospital BACT Analysis

In support of the Utah Division of Air Quality's (UDAQ's) efforts to prepare and submit a Technical Support Document (TSD) specific to the University of Utah (University) for the particulate matter less than 2.5 microns in diameter ($PM_{2.5}$) Serious Nonattainment State Implementation Plan (SIP), the University is submitting a Best Available Control Technology (BACT) analysis specific to the campus transformation of the University's Hospital. This BACT analysis is being submitted in advance of the Notice of Intent (NOI) air quality application being prepared for the University's Hospital transformation project to document the TSD and SIP Part H limits consistent with the University's plans.

CAMPUS TRANSFORMATION AT UNIVERSITY HOSPITAL

The campus transformation includes the reduction of the heat load provided by the Upper Campus High Temperature Water Plant (UCHTWP) and installation of new boilers within hospital buildings. The University anticipates that the reduction in heat load will be equivalent to 164,000 MMbtu/yr. Per our discussions, this change will occur after the second quarter of calendar year 2019. After the time of this transition the UCHWTP boilers will be limited to a natural gas usage of 530 MMscf per calendar year as documented in the SIP Part H conditions for the University. Upon completion of the campus transformation the three (3) 87.5 MMbtu/hr boilers in the UCHTWP will continue to serve the upper campus heating needs and provide a back-up source of heat for the hospital.

During Phase I of the transformation occurring at the hospital, ten hot water boilers with a combined heat rating of 96 MMBtu/hr will be installed, with capacities ranging from 5 to 12 MMBtu/hr. The University also proposes to install steam boilers with a total capacity of 4 MMbtu/hr. These boilers are available to provide steam for autoclaves, humidification, backup hot domestic water, and other hospital equipment necessary to provide for heating sources and essential accessories.[1] According to current University planning, Phase I is scheduled to be completed and operational in late 2018.

During Phase II of the transformation occurring at the hospital, an 8.84 MMBtu/hr boiler will be installed with an identical redundant unit for emergency purposes. According to current University planning, Phase II has been scheduled to be completed in first quarter 2019.

This BACT analysis reviews potential emission control strategies for the new units proposed as part of Phases I and II of the hospital transformation as well as updates the BACT conclusions previously submitted in April 2017 at UDAQ's request. This BACT analysis is an excerpt from the University's NOI to be submittal to UDAQ shortly. Please feel free to reach out to Michael Brehm at the University of Utah at (801) 585-1617 or Brian Mensinger at (801) 272-3000 ext. 308 with any questions related to this BACT analysis.

[1] See BACT Analysis Summary in Appendix G for design requirements and specifications. This is consistent with the emission calculations submitted to UDAQ on June 8, 2018.

BACT ANALSYSIS - CAMPUS TRANSFORMATION AT UNIVERSITY HOSPITAL

The University hospital is an Adult Level I Trauma Center which cares for patients across the spectrum of health care, from routine screenings to trauma emergencies including trauma surgery. The University's hospital is undergoing new expansions in three phases. Phase I Ambulatory Care Center (ACC) and Phase II Rehabilitation are addressed in this BACT analysis. The proposed boiler installations for Phase I and II have been selected in consideration of both the design and accreditation requirements of the hospital and the BACT requirements established by UDAQ. In addition, the boiler installations were selected based on the energy efficient design of the new building, allowing the University to optimize heat load and sizing for the most efficient operation of utility equipment.

As a Level I trauma center, the University Hospital maintains accreditation from the Det Norske Veritas (DMV) Healthcare, Inc. DMV is approved by the Centers for Medicare and Medicaid Services (CMS) to deem hospitals in compliance with the CMS Conditions of Participation (CoPs). To meet accreditation requirements, the hospital's expansion project's design is based upon the following:

- 2010 Facility Guidelines Institute (FGI) Guidelines for Design and Construction of Health Care Facilities, which includes design codes from the following national organizations:
    - American Society of Heating and Air-Conditioning Engineers (ASHRAE); and
    - American Institute of Architects (AIA).
- DNV, the certifying body, follows the Ambulatory Care Complex Construction National Integrated Accreditation for Healthcare Organization (NIAHO) standards while integrating ISO 9001 with Medicare conditions.

Relative to the boiler installations selected for the University Hospital's Phase I and II expansions, ASHRAE and AIA standards require reserve capacity for heating sources and essential accessories both in number and arrangement that are sufficient to accommodate facility needs even when any one of the heat sources is not operating due to breakdown or routine maintenance.[2,3] Furthermore AIA design code specifies, "… the capacity of remaining sources shall be sufficient to provide for sterilization and dietary purposes and provide heating for operating, delivery, birthing, labor, recovery, emergency, intensive care, nursery, and impatient rooms."[4] Additionally in consideration of these standards, changeover timing is critical to ensure hot water and steam can be adequately supplied.

To meet the aforementioned standards, Phase I ACC and Phase II Rehabilitation the University Hospital is installing boilers that are duel fuel (i.e., both natural gas and back up fuel oil) to provide reserve capacity during breakdowns, natural gas curtailment, or maintenance activities. Specifically, to offer application flexibility and to meet changeover requirements, a duel fuel burner provides reliable steam and hot water supply.[5]

---

[2] FGI 2010 Guidelines: ASHRAE 170 Part 2.1-8.2.6.1

[3] FGI 2010 Guidelines: AIA (2001) Annex B, Part 6.1.2 Reserve Heating and Cooling Sources.

[4] Ibid.

[5] As specified in NESHAP Subpart JJJJJJ, (NESHAP for Industrial, Commercial, and Institutional Boilers Area Sources), typically boilers, intended to be normally operated on gaseous fuels are subject to gaseous fuels requirements, despite a limited allowance to burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year. Per these standards, burning liquid fuel during periods of gas curtailment or gas supply interruptions of any duration (emphasis included) are also included in this definition. In these regulations, a Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected boiler or process heater is restricted or halted for reasons beyond the control of the facility. Similar to the question we raise concerning emergency engines, should the PTE from these units, which normally fire a gaseous fuel, be based upon 48 hours of intended

Natural gas is the second most-consumed fuel source in the United States, comprising 27% of the nation's energy consumption. Technology and equipment innovations have improved dramatically, along with gaseous fuel and system reliability. The need still remains for backup fuel systems when natural gas supply is interrupted due to curtailment and unplanned conditions like storms, floods or extreme cold temperatures. Diesel fuel offers a high thermal efficiency and is a proven and reliable technology for power generation applications. Additionally diesel fuel is stable when stored and offers a relatively safe storage option in a populated location, such as the University Hospital.

As previously discussed the University intends to shift heating for the main hospital building (buildings 522, 525, and 529) away from the UCHTWP to new heating water boilers specific to the hospital. The University proposes to install the following equipment:

Table 1. Hospital Transformation Boilers

Capacity of Boilers	Number of Units	Purpose	Hospital Phase	NO_x Emission Rate
10 MMBtu/hr	5	Hot Water	Phase I - ACC	30 PPM
5 MMbtu/hr	2	Hot Water	Phase I - ACC	30 PPM
12 MMbtu/hr	3	Steam	Phase I - ACC	30 PPM
8.84 MMbtu/hr	2	Hot Water	Phase II - Rehabilitation	30 PPM

[1] One of the 8.84 MMBtu/hr boilers for Phase II is a back-up boiler.

The following sections address the University's BACT analysis for modifications of installations as addressed in this NOI air quality application.

UCHTWP Boilers

NOx

As discussed in the April 2017 BACM report, the UCHTWP boilers are currently using 15% Flue Gas Recirculation (FGR) and achieve an emission rate of 0.05 lb/MMBtu. Technically feasible options for NOx control include:

- Selective Catalytic Reduction (SCR) = 9 ppm or 0.011 lb/MMBtu;[6]
- Ultra-Low NOx Burner (ULNB) = 9 ppm or 0.011 lb/MMBtu;
- Low NOx Burner (LNB) = 30 ppm or 0.036 lb/MMBtu; and
- FGR = 42ppm or 0.05 lb/MMBtu.

To achieve an emission rate of 9 ppm, an SCR may be installed on each boiler. Assuming 70% control efficiency for the SCR, it would cost $158,660/ton of NOx removed.[7] Calculations were originally completed as part of the BACM report submitted in April 2017 and were based on generally provided capital costs from EPA's Air

---

testing, maintenance or training as allowed by the regulation. However, the University only proposes to operate 8 hours per year of fuel oil similar to other units on the campus.

[6] Several sources listed within RBLC with an emission rate of 9 ppm. Each of these technology combinations have been shown to meet this level of control

[7] An efficiency of 70% was assumed, given that SCR can generally operate between 70% and 90% control efficiency. The University has not obtained a vendor guarantee for this level of control for a unit with such a low concentration exhaust stream and would require consultation with a vendor prior to installation of this equipment.

Pollution Control Cost Manual. This cost per ton value has been updated as a result of the reduced heat load. The cost per ton of NO_X removed is beyond acceptable cost control effectiveness levels therefore, the University has determined that this technology is economically infeasible for these units.

The University also reviewed replacing the current burner with an UNLB with an emission rate of 9 ppm NO_X or less in the April 2017 BACM Report. The University determined that it would cost $124,783/ton of NO_x removed to achieve the 9 ppm emission rate. This cost per ton value has been updated as a result of the reduced heat load anticipated. The cost per ton of NOx removed is beyond acceptable cost control effectiveness levels and therefore, the University is considering this burner technology economically infeasible for these units. Detailed cost calculations for this control technology are included at the end of this subsection.

Installation of a lower efficiency burner, i.e. LNB technology, is not expected to decrease the capital investment substantially. Therefore, the University has assumed replacing the current burner with a LNB is also economically infeasible.

All Other Pollutants

The 2017 BACM report reviewed potential control technologies for other pollutants as described in the table below.

Table 2. UCHTWP BACM Review

Pollutant	Control Technologies Evaluated	Result of Analysis
$PM/PM_{10}/PM_{2.5}$	Fabric Filter	Technically Infeasible
	Wet Scrubber	Technically Infeasible
	Dry Electrostatic Precipitator	Technically Infeasible
	Good Combustion Practices & Clean Burning Fuels	Feasible and In Use
SO_2	Scrubbers	Technically Infeasible
	Good Combustion Practices & Clean Burning Fuels	Feasible and In Use
VOC	Simple Thermal Oxidizer or Afterburner	No Reduction Potential
	Regenerative Thermal Oxidizer	No Reduction Potential
	Catalytic Oxidation	No Reduction Potential
	Good Combustion Practices & Clean Burning Fuels	Feasible and In Use

As documented in Table 2 the 2017 BACM established that good combustion practices and the use of natural gas as a primary fuel were considered BACT for all other pollutants as all other control technologies were established as technically infeasible. The reduced heat load for these boilers has no effect on the technical feasibility of reviewed control technologies, therefore the University proposes that good combustion practices and the use of natural gas as a primary fuel is still considered BACT.

BACT CONTROL COST EVALUATION

Technology: Selective Catalytic Reduction (SCR)
Application: UCHTWP Natural Gas Fired Boiler
Pollutants: Oxides of Nitrogen (NOx)

Selective Catalytic Reduction (SCR)

Key Assumptions	Each UCHTWP Boiler	Notes
Process Information		
Uncontrolled Emissions (tpy)	4.56	
Heat Input (MMBtu/hr)	87.50	
Control Efficiency (%)	70%	- 70% efficiency assumed due to low concentration in exhaust
Catalyst Volume (ft^3)	487	
SCR Height (ft)	17	
Ammonia Reagent (lb/hr)	10.20	
Electrical Consumption (kWh/year)	429,240	
Gas Consumption (MMBtu/year)	7,665	
Water Consumption (Mgal/year)	0	
Utility Costs		
Electricity ($/kWh)	$ 0.089	Average Utah prices
Natural Gas ($/MMBtu)	$ 2.83	Average U.S. Prices (Jan 2017)
Water ($/Mgal)	$ 33.45	Sandy Utah (2" Meter, July 2016)
Ammonia Reagent ($/lb)	$ 0.48	
Labor Costs		
Operator ($/hour)	$ 15.00	
Supervisor ($/hour)	$ 20.00	
Maintenance ($/hour)	$ 20.00	
Economic Factors		
Dollar Inflation (2002 to 2017)	1.3416	U.S. Consumer Price Index
Equipment Life Expectancy (Years)	10	
Interest Rate (%)	7%	Current Avg SBA Loan Rate
Capital Recovery Factor (CRF)	0.1424	

DIRECT COSTS

Capital Cost	Each UCHTWP Boiler	Notes
Purchased Equipment Costs		
Total Equipment Cost[1]	880,422	A
Instrumentation	88,042	0.10 × A
Sales Tax	52,825	0.06 × A
Freight	44,021	0.05 × A
Total Purchased Equipment Costs	*1,065,311*	*B = 1.18 × A*
Direct Installation Costs [2]		
Foundations and Supports	85,225	0.08 × B
Handling and Erection	149,143	0.14 × B
Electrical	42,612	0.04 × B
Piping	21,306	0.02 × B
Insulation	10,653	0.01 × B
Painting	10,653	0.01 × B
Site Preparation & Buildings	-	No estimate / Site specific
Additional duct work	-	No estimate / Site specific
Total Direct Installation Costs	*319,593*	*C = 0.30 × B*
Indirect Installation Costs [2]		
Engineering	106,531	0.10 × B
Construction and Field Expense	53,266	0.05 × B
Contractor Fees	106,531	0.10 × B
Start-up	21,306	0.02 × B
Performance Test	10,653	0.01 × B
Process Contingencies	31,959	0.03 × B
Total Indirect Installation Costs	*330,246*	*D = 0.31 × B*
Total Capital Investment ($)	**1,715,150**	**TCI = B + C + D**

ANNUAL COSTS

Operating Cost	Each UCHTWP Boiler	Notes
Direct Annual Costs [3]		
Operating Labor (0.5 hr, per 8-hr shift)	8,213	E
Supervisory Labor (15% operating labor)	1,232	F = 0.15 × E
Maintenance Labor (0.5 hr, per 8-hr shift)	10,950	G
Maintenance Materials	8,576	H = 0.005 x TCI
Electricity	38,202	I
Natural Gas	21,692	J
Water	0	K
Reagent	42,443	L
Catalyst Replacement (Cost x CRF for 3 yrs)	44,577	M
Total Direct Annual Costs	*175,885*	*DAC = E +F+ G+ H+ I+ J +K+L+M*
Indirect Annual Costs [3]		
Overhead	17,382	N = 0.60 × (E + F + G + H)
Administrative Charges	34,303	O = 0.02 × TCI
Property Tax	17,151	P = 0.01 × TCI
Insurance	17,151	Q = 0.01 × TCI
Capital Recovery[4]	244,199	R
Total Indirect Annual Costs	*330,187*	*IDAC = N+O+P+Q+R*
Total Annual Cost ($)	**506,072**	*TAC = DAC + IDAC*
Pollutant Removed (tpy)	3.19	
Cost per ton of Pollutant Removed ($)	**158,660**	*$/ton = TAC / Pollutant Removed*
New Emission Rate (tpy)	1.37	
New Emission Factor (lb/MMBtu)	0.004	

1. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (7th Edition)* , May 2016, Section 4.2, Chapter 2 (Selective Catalytic Reduction), Tab
2. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)* , January 2002, Section 3.2, Chapter 2, Table 2.8 (assume same as cata
3. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)* , January 2002, Section 3.2, Chapter 2, Table 2.10 (assume same as cat
4. Capital Recovery factor calculated based on Equation 2.8a (Section 1, Chapter 2, page 2-21) and Table 1.13 (Section 2, Chapter 1, page 1-52) of U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual (6th Edition), January 2002.

BACT CONTROL COST EVALUATION

Technology: Ultra Low NO_X Burner
Application: Natural Gas Fired Boiler
Pollutants: Oxides of Nitrogen (NOx)

Ultra Low NOX Burner

Key Assumptions	**Each UCHTWP Boiler**	**Notes**
Process Information		
Uncontrolled Emissions (tpy)	4.56	
Heat Input (MMBtu/hr)	87.50	
Controlled Emissions (tpy)	2.81	
Utility Costs		
Labor Costs		
Operator ($/hour)	$ 15.00	
Supervisor ($/hour)	$ 20.00	
Maintenance ($/hour)	$ 20.00	
Economic Factors		
Dollar Inflation (2002 to 2017)	1.3416	U.S. Consumer Price Index
Equipment Life Expectancy (Years)	10	
Interest Rate (%)	7.00%	Current Avg SBA Loan Rate
Capital Recovery Factor (CRF)	0.1424	

DIRECT COSTS

Capital Cost	**Each UCHTWP Boiler**	**Notes**
Purchased Equipment Costs		
Total Equipment Cost[1]	400,000	A
Instrumentation	40,000	0.10 × A
Sales Tax	24,000	0.06 × A
Freight	20,000	0.05 × A
Total Purchased Equipment Costs	*484,000*	*B = 1.18 × A*
Direct Installation Costs [2]		
Foundations and Supports	38,720	0.08 × B
Handling and Erection	67,760	0.14 × B
Electrical	19,360	0.04 × B
Piping	9,680	0.02 × B
Insulation	4,840	0.01 × B
Painting	4,840	0.01 × B
Site Preparation & Buildings	-	No estimate / Site specific
Additional duct work	-	No estimate / Site specific
Total Direct Installation Costs	*145,200*	*C = 0.30 × B*
Indirect Installation Costs [2]		
Engineering	48,400	0.10 × B
Construction and Field Expense	24,200	0.05 × B
Contractor Fees	48,400	0.10 × B
Start-up	9,680	0.02 × B
Performance Test	4,840	0.01 × B
Process Contingencies	14,520	0.03 × B
Total Indirect Installation Costs	*150,040*	*D = 0.31 × B*
Total Capital Investment ($)	**779,240**	**TCI = B + C + D**

ANNUAL COSTS

Operating Cost	Each UCHTWP Boiler	Notes
Direct Annual Costs [3]		
Operating Labor (0.5 hr, per 8-hr shift)	8,213	E
Supervisory Labor (15% operating labor)	1,232	F = 0.15 × E
Maintenance Labor (0.5 hr, per 8-hr shift)	10,950	G
Maintenance Materials	3,896	H = 0.005 x TCI
Total Direct Annual Costs	*24,291*	*DAC = E +F+ G+ H+ J*
Indirect Annual Costs [3]		
Overhead	14,574	N = 0.60 × (E + F + G + H)
Administrative Charges	15,585	O = 0.02 × TCI
Property Tax	7,792	P = 0.01 × TCI
Insurance	7,792	Q = 0.01 × TCI
Capital Recovery[4]	110,946	R
Total Indirect Annual Costs	*156,690*	*IDAC = N+O+P+Q+R*
Total Annual Cost ($)	**180,981**	*TAC = DAC + IDAC*
Pollutant Removed (tpy)	1.74	
Cost per ton of Pollutant Removed ($)	**103,791**	*$/ton = TAC / Pollutant Removed*

1. Allan Woodbury with North Associate, Inc. provided estimate.

2. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)* , January 2002, Section 3.2, Chapter 2, Table 2.8 (assume same as catalytic incineration)

3. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)* , January 2002, Section 3.2, Chapter 2, Table 2.10 (assume same as catalytic incineration)

4. Capital Recovery factor calculated based on Equation 2.8a (Section 1, Chapter 2, page 2-21) and Table 1.13 (Section 2, Chapter 1, page 1-52) of U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual (6th Edition), January 2002.

5. It is assumed that the cost and consumption of natural gas will not be influenced by the purchase of a new unit.

Hospital Boilers – Phase I and II BACT Analysis

PM, PM_{10} and $PM_{2.5}$ Emissions

According to EPA's AP-42, Section 1.4, since natural gas is a gaseous fuel, filterable PM emissions are typically low. Particulate matter from natural gas combustion has been estimated to be less than one micrometer in size and has filterable and condensable fractions. Particulate matter in natural gas combustion is usually larger molecular weight hydrocarbons that are not fully combusted. Increased particulate matter emissions can result from poor air/fuel mixing or maintenance problems. As demonstrated in the April 2017 BACM submission no control technology is technically feasible for the control of particulate matter; therefore, using good combustion practices and primarily natural gas is considered BACT.

The use of good combustion practices usually include the following components: (1) proper fuel mixing in the combustion zone; (2) high temperatures and low oxygen levels in primary zone; (3) overall excess oxygen levels high enough to complete combustion while maximizing boiler efficiency, and (4) sufficient residence time to complete combustion. Good combustion practices are accomplished through boiler design as it relates to time, temperature, and turbulence, and boiler operation as it related to excess oxygen levels. Good combustion practices and use of natural gas fuels during regular operations but have the ability to fire on diesel during natural gas curtailment or an emergency.[8]

NO_x Emissions

The NO_X formed during combustion is from two major mechanisms: thermal NO_X and fuel NO_X. Since natural gas is relatively free of fuel-bound nitrogen, the contribution of this second mechanism to the formation of NO_X emissions in natural gas-fired equipment is minimal, leaving thermal NO_X as the main source of NO_x emissions. Thermal NO_X formation is a function of residence time, oxygen level, and flame temperature, and can be minimized by controlling these elements in the design of the combustion equipment. As established in the 2017 BACM Report options for NOx control include:

- SCR = 9 ppm or 0.011 lb/MMBtu;[9]
- ULNB = 9 ppm or 0.011 lb/MMBtu;
- LNB = 30 ppm or 0.036 lb/MMBtu; and
- FGR = 42ppm or 0.05 lb/MMBtu.

<u>SCR</u>

SCR has been applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. It has been applied to large (>250 MMBtu/hr) utility and industrial boilers, process heaters, and combined cycle gas turbines. SCR can be applied as a stand-alone NO_X control or with other technologies such as combustion controls. The reagent reacts selectively with the flue gas NO_X within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NO_X into molecular nitrogen (N_2) and water vapor (H_2O).[10] The optimum operating temperature is dependent on the type of catalyst and the flue gas composition.

---

[8] Boilers proposed for the Hospital Transformation project >10 MMBtu are subject to NSPS, Subpart Dc.

[9] Several sources listed within RBLC with an emission rate of 9 ppm. Each of these technology combinations have been shown to meet this level of control

[10] Ibid.

Generally, the optimum temperature ranges from 480°F to 800°F.[11] In practice, SCR systems operate at efficiencies in the range of 70% to 90%.[12]

SCR is listed in the RBLC search as technically feasible. In some cases, this control technology is listed in combination with LNB and FGR. However, in reviewing permits issued by the South Coast Air Management District, this control method is not considered BACT for boilers of this size which are located at hospitals.

The ammonia "slip" associated with the SCR is a documented problem. The increased ammonia emissions (currently zero) from the implementation of this technology would offset the marginal air quality benefits the SCR option would provide from NO_X emissions reduction. Additionally, ammonia has recently been designated as a precursor in Salt Lake County. Ammonia slip emissions have the potential to increase secondary $PM_{2.5}$ levels in the area more than the SCR controlled NO_X mass. The exhaust stream entering the SCR will require additional heat to meet the SCR operating temperature requirements (minimum of 480°F). This increase in exhaust temperature would require an additional combustion device, also increasing NO_X, SO_2, and $PM_{2.5}$ emissions.

More importantly storage and handling of ammonia poses significant safety risks when applied at the hospital. Ammonia is toxic if swallowed or inhaled and can irritate or burn the skin, eyes, nose, or throat. While ammonia is a commonly used material that is typically handled safely and without incident, vapors emitted due to slippage present a health and safety hazard. By definition the hospital cares for people seeking medical attention and the inhalation of ammonia vapors has the potential to compound the effects of other illnesses or pre-existing conditions. Locating ammonia tanks in these premises poses an amplified health risk which is unacceptable at a hospital therefore SCR is not further considered.

<u>ULNB and LNB</u>

As indicated in the name ULNB and LNB rely on burner design features and fuel staging to reduce NO_X. Nozzle construction is the limiting component when establishing combustion efficiency and NO_X production for both of these technologies.

The nozzle which maximizes combustion efficiency and minimizes NOx when burning natural gas is designed to finely disperse natural gas into the combustion chamber. This type of nozzle is not possible when burning diesel due to the viscosity of the fuel, therefore the diesel nozzles produce larger droplets which then mix with air and ignite in the combustion chamber. In this case the hospital boilers must be dual fueled. Achieving this dual-fuel specification can be accomplished in one of three ways:

- One burner with interchangeable nozzles specific to fuel type;
- Two burners, one with nozzles specific to natural gas and the other with nozzles specific to diesel; or
- One burner with duel fuel compatible nozzles.

The most common design for a duel fuel boiler is to install nozzles compatible with diesel combustion which are covered with a fine mesh like material for combustion of natural gas. This allows the boiler to achieve ultra- low NOx emissions while firing natural gas; however, in order to allow the boiler to be fueled with diesel this mesh must be removed. This changeover process will be completed in greater than two (2) hours. Changeover will likely take an extended time beyond 2 hours to account for cool down of the boiler and burner assembly for a

---

[11] OAQPS, *EPA Air Pollution Control Cost Manual*, Sixth Edition, EPA/424/B-02-001 (http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf); January 2002

[12] OAQPS, *EPA Air Pollution Control Cost Manual*, Sixth Edition, EPA/424/B-02-001 (http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf); January 2002

safe work environment. This would be required on all 7 boilers. As previously mentioned, the University's hospital operates as a Level I trauma center and in the event of a regional emergency, patients will likely be directed to the University's hospital. Boilers proposed as part of the hospital renovation will provide hot water and steam for patient critical services such as autoclaves, humidification, backup hot domestic water, and other hospital equipment. To be accredited as a Level 1 trauma center, ASHRAE and AIA standards require backup systems to be available for the previously mentioned health care needs. Due to critical nature of the services provided by these boilers a change-over period is unacceptable and this boiler design is not further considered for BACT.

Another option is to install two completely independent burners, one with nozzles specific to natural gas and the other with nozzles specific to diesel. This option significantly increases the combustion chamber size and the space allocated for the boilers. However, the current available space is not large enough to accommodate this design; therefore, this option is not technically feasible.

The remaining option is to install one burner with duel fuel compatible nozzles. These nozzles are designed to accommodate the viscosity of diesel fuel while maximizing combustion efficiency for natural gas. The multiflam® 3LN version burners proposed for the Hospital Phase I ACC have been designed to further reduce NOx emissions below the level which can be achieved by standard mixing head. These additional reductions are accomplished by using special mixing assembly applying fuel distribution principles. Combustion values also depend on combustion chamber geometry. Volumetric loading and boiler design. Certain conditions such combustion chamber dimensions, measurement tolerances, temperature, humidity, etc. must be verified in order to guarantee emission levels. This design represents BACT and allows the manufacturer to guarantee a NOx emission rate of 30 ppm.

<u>FGR</u>

FGR involves the recycling of post-combustion air into the air-fuel mixture to reduce the available oxygen and help cool the burner flame. External FGR requires the use of ductwork to route a portion of the flue gas in the stack back to the burner windbox; FGR can be either forced draft (where hot side fans are used) or induced draft. This technology is listed in the RBLC search as technically feasible and is often paired with LNB for the BACT determined control technology.

The low NO_X emission rate guaranteed by the manufacturer for Phase I hospital boilers is achieved by increased recirculation of combustion gases. The 3LN multiflam® version Low NO_X - Oil/ Gas/ Dual fuel burner proposed is equipped with multiflam mixing head for the most stringent emission requirements. The low NO_X emission is achieved by fuel distribution principle. Compliance to certain emission requirement is also dependent on combustion chamber geometry, volume loading and design of the combustion system. Although not traditional FGR, the burners have been designed with a mixing head for low NO_X emissions feasible for a dual fuel purpose.

<u>Comparison to South Coast Air Management District</u>

In an effort to review all possible control technologies specific to dual fueled hospital boilers the University conducted a search for Level I trauma centers in air quality districts with similar air quality issues. Upon review the University identified several Level I trauma centers in the South Coast Air Management District (SCAQMD).

Since 2005 these Level I trauma centers have permitted a variety of small duel fuel boilers, however rather than using diesel as the alternative fuel to natural gas these hospitals have permitted the use of AMBER® 363-II FUEL (Amber 363). Amber 363 was originally developed as a stand-by fuel with the emission requirements of SCAQMD Regulation 1146, which establishes NOx emission limits, in mind. This fuel has been designed as a replacement for #2 diesel, and little, if any, capital investment is required to change to this clean stand-by fuel alternative. Depending on the specific boiler/burner configuration, NOx emissions in the range of 10-30 ppm can be achieved. Table 3 summarizes the permits reviewed:

Table 3. – SCQMD Hospital Inventory

Level I Trauma Center	Permit ID Number	Permit Date	Boiler Size	NOx Limit
Keck Hospital of USC	R-G3304 A/N497889	9/25/2012	5 MMbtu/hr	12 ppm on Natural Gas 40 ppm on Amber 363
Keck Hospital of USC	G21317 A/N531671	11/2/2012	8.5 MMbtu/hr	9 ppm on Natural Gas 40 ppm on Amber 363
Santa Monica – UCLA Medical Center	G30649 A/N519089	4/9/2014	16.3 MMbtu/hr	9 ppm on Natural Gas 40 ppm on Amber 363
NME Hospitals Inc. USC University Hospital	F79855 A/N448805	12/20/2005	5 MMbtu/hr	12 ppm on Natural Gas 40 ppm on Amber 363

In order to achieve the bifurcated emission rates cited above two completely independent burners must be installed, one with nozzles specific to natural gas and the other with nozzles specific to Amber 363. As previously discussed with a secondary diesel burner, this option significantly increases the combustion chamber size and the space allocated for the boilers is not large enough to accommodate this design; therefore, this option is not technically feasible.

Additionally, Amber 363 is the proprietary product of Amber Industrial Services which is primarily located in California. While Amber 363 could be shipped to the University via truck or railcar it is not readily available in the state of Utah and potential shipping complications represent an unacceptable risk to patient care.

<u>BACT Proposal</u>

The University proposes that the use of the dual fuel compatible burner which has been designed to achieve low NO_x emissions through the use of specialized mixing heads, mixing assemblies, and advanced use of fuel distribution principles is considered BACT. This design represents BACT and allows the manufacturer to guarantee a NOx emission rate of 30 ppm.

SO_2 Emissions

The use of pipeline-quality natural gas as the primary fuel is the only feasible SO_2 control technology for the boilers to control SO_2 emissions as demonstrated in the April 2017 BACM report. Therefore, the University is proposing good combustion practices and use pipeline-quality natural gas as the primary fuel is considered BACT.

The University is currently permitted to use ultra-low sulfur diesel (ULSD) which is required to be less than 15 ppm as specified in Condition II.B.1.d of its AO. Whereas NSPS Subpart Dc requires fuel oil to be less than 0.05 weight percent of sulfur. As a result, the University's current fuel sulfur requirements meet BACT.

VOC Emissions

BACT for VOC control for the boilers is good combustion practices and the use of clean burning fuel. Good combustion practices for VOCs include adequate fuel residence times, proper fuel-air mixing, and temperature control. The University Hospital will use good combustion practices and natural gas during regular operations but have the ability to fire on diesel during natural gas curtailment or an emergency.

Table 1a. University of Utah Emissions Summary

Unit Group	Potential Annual Emissions Estimate (tpy)							
	NO_X	CO	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC	NH_3
UCHTWP Current Configuration	17.94	29.34	3.58	3.57	3.57	0.21	1.92	1.12
UCHTWP Reduced Heat Load	13.67	22.30	2.73	2.72	2.71	0.16	1.46	0.85
LCHTWP Current Operations	81.15	53.58	8.70	8.70	8.70	0.39	5.59	2.10
LCHTWP Replacement and Decommission of Boilers	36.86	63.54	9.60	9.60	9.60	0.47	6.24	2.48
Hospital Boilers Current Configuration	2.49	2.06	0.19	0.19	0.19	0.02	0.13	0.08
Hospital Expansion	5.66	10.62	0.40	0.40	0.40	0.09	0.53	0.17
Huntsman Cancer Center Boilers	4.78	4.00	0.37	0.36	0.36	0.03	0.26	0.15
All Other Primary Boilers	0.75	0.63	0.06	0.06	0.06	0.00	0.04	0.02
All Other Backup Boilers	0.50	0.42	0.04	0.04	0.04	0.00	0.03	0.02
Currently Permitted Generators	54.35	22.39	1.41	1.41	1.41	1.20	3.01	
Previously Unaccounted for Generators	0.12	0.14	0.01	0.01	0.01	0.04	0.04	
New Generators	2.74	1.58	0.09	0.09	0.09	0.06	0.24	
Carpentry Shop			0.86	0.86	0.86			
Flash Ironmaking	To be Decommissioned	To be Decommissioned	To be Decommissioned	To be Decommissioned	To be Decommissioned	To be Decommissioned	To be Decommissioned	
Parts Washer							0.01	
Print Plant	Decommissioned	Decommissioned	Decommissioned	Decommissioned	Decommissioned	Decommissioned	Decommissioned	
Paint Booth							0.71	
Ethylene Oxide Sterilizer							1.00	
Underground Storage Tanks							0.2511	
Total (Current Operations)	161.95	112.41	15.20	15.19	15.19	1.86	12.95	3.50
Totals (Revised)	121.90	127.68	15.75	15.73	15.73	2.07	13.95	3.78
Permit Limit	100.05	128.09	19.29	19.29	19.29	3.85	14.07	
Total Change for Revised Emissions	21.85	-0.41	-3.54	-3.56	-3.56	-1.78	-0.12	
Significant Emission Increase Threshold[1]	25.00	Not Applicable	Not Applicable	Not Applicable	Not Applicable	25.00	25.00	Not Applicable
Threshold Exceeded?	*No*	*No*	*No*	*No*	*No*	*No*	*No*	*No*
Modeling Limits[2]	40	100	Not Applicable	15	Not Applicable	40	Not Applicable	Not Applicable
Threshold Exceeded?	*No*	*No*	*No*	*No*	*No*	*No*	*No*	*No*

1. This threshold is the lower limit given in R307-420-2 and R307-421-3.

2. Per Emissions Impact Assessment Guidelines published by UDAQ.

Table 1b. Natural Gas Limits

Parameter	Value	Units
Total Natural Gas Usage Accounted For (Boilers Only)	1,246.18	MMscf/yr
Total Natural Gas Usage Permitted (Boilers Only)	1,624.68	MMscf/yr
Total Natural Gas Usage Proposed (Boilers Only)	1,908.60	MMscf/yr

Table 1c. Total HAP Emissions

Pollutant	Total Hourly Emissions	Revised Hourly Emissions	Total Annual Emissions	UDAQ ETV[1]	Modeling Required?
	lb/hr	lb/hr	tpy	lb/hr	
2-Methylnaphthalene	1.13E-04	0.00E+00	5.66E-06	Not Applicable	No
1,3-Butadiene	2.17E-03	9.36E-05	1.09E-04	2.92E-01	No
1,1,2,2-Tetrachloroethane	1.36E-04	0.00E+00	6.82E-06	1.36E+00	No
1,1,2-Trichloroethane	1.09E-04	0.00E+00	5.43E-06	1.08E+01	No
1,1,1-Trichloroethane	8.33E-04	1.77E-04	3.33E-06	3.78E+02	No
1,3-Dichloropropene	9.01E-05	0.00E+00	4.50E-06	8.99E-01	No
2,2,4-Trimethylpentane	8.53E-04	0.00E+00	4.27E-05	Not Applicable	No
1,2,4 - Trimethylbenzene	5.19E-05	4.25E-04	2.28E-03	Not Applicable	No
Acrolein	2.16E-02	6.50E-04	3.65E-03	3.53E-02	No
Acenaphthene	7.88E-05	1.58E-05	5.11E-07	Not Applicable	No
Acenaphthylene	1.98E-05	1.89E-07	9.47E-07	Not Applicable	No
Acetaldehyde	5.65E-02	2.67E-03	6.91E-03	6.94E+00	No
Anthracene	4.31E-06	9.14E-07	1.72E-08	Not Applicable	No
Benz(a)anthracene	4.31E-06	9.14E-07	1.72E-08	Not Applicable	No
Benzene	1.25E-01	1.30E-02	1.63E-02	3.16E-01	No
Benzo(b)fluoranthene	5.66E-07	0.00E+00	2.83E-08	Not Applicable	No
Benzo(g,h,i)perylene	9.39E-06	1.69E-06	1.03E-07	Not Applicable	No
Benzo(b,k)flouranthene	5.23E-06	1.11E-06	2.09E-08	Not Applicable	No
Biphenyl	7.23E-04	0.00E+00	3.62E-05	2.50E-01	No
Carbon Tetrachloride	1.25E-04	0.00E+00	6.26E-06	2.08E+00	No
Chlorobenzene	1.04E-04	0.00E+00	5.19E-06	9.12E+00	No
Chloroform	9.72E-05	0.00E+00	4.86E-06	9.67E+00	No
Chrysene	1.08E-05	1.78E-06	1.52E-07	Not Applicable	No
Cyclohexane	7.90E-04	0.00E+00	3.46E-03	Not Applicable	No
Dibenzo(a,h)anthracene	5.90E-06	1.25E-06	2.36E-08	Not Applicable	No
Ethylbenzene	1.32E-03	1.22E-03	1.05E-02	Not Applicable	No
Ethylene Dibromide	1.51E-04	0.00E+00	7.56E-06	Not Applicable	No
Fluoranthene	3.75E-06	0.00E+00	1.88E-07	Not Applicable	No
Fluorene	3.51E-05	3.35E-06	1.03E-06	Not Applicable	No
Formaldehyde	3.45E-01	3.06E-02	2.81E-02	5.67E-02	No
Hexane	5.76E-03	7.76E-04	1.31E-02	3.49E+01	No
Methanol	8.53E-03	0.00E+00	4.27E-04	5.51E+01	No
Methylene Chloride	9.54E-04	0.00E+00	3.88E-03	3.44E+01	No
Naphthalene	2.23E-02	2.67E-03	1.22E-03	1.04E+01	No
OCDD	1.09E-08	2.32E-09	4.38E-11	Not Applicable	No
Polycyclic Aromatic Hydrocarbons (PAH)	3.05E-02	3.04E-03	1.90E-03	Not Applicable	No
Phenol	8.19E-05	0.00E+00	4.09E-06	3.81E+00	No
Propylene	4.79E-02	8.99E-02	6.98E-01	Not Applicable	No
Pyrene	1.96E-05	3.18E-06	2.92E-07	Not Applicable	No
Styrene	8.05E-05	0.00E+00	4.03E-06	Not Applicable	No
Tetrachloroethane	8.46E-06	0.00E+00	4.23E-07	Not Applicable	No
Toluene	7.25E-02	1.37E-02	4.00E-02	1.49E+01	No
Vinyl Chloride	5.08E-05	0.00E+00	2.54E-06	1.69E-01	No
Xylene	1.52E-02	3.85E-03	8.21E-02	8.60E+01	No
o-Xylene	3.85E-04	8.16E-05	1.54E-06	8.60E+01	No
Arsenic	5.19E-05	1.10E-05	2.08E-07	1.98E-03	No
Mercury	4.94E-05	1.05E-05	1.98E-07	1.98E-03	No
Nickel	7.91E-05	1.68E-05	3.16E-07	6.60E-03	No
Selenium	1.07E-04	2.27E-05	4.28E-07	Not Applicable	No
Zinc	3.67E-03	7.79E-04	1.47E-05	Not Applicable	No
Maximum HAP	**0.35**	**0.09**	**0.70**	-	-
Total HAP	**0.76**	**0.16**	**0.91**	-	-
Previously Permitted HAP Limit	-	-	**2.38**	-	-

1. Significant contributors to revised emissions are UCHTWP, LCHTWP and New Hospital boilers, therefore the UDAQ ETV threshold for vertically unrestricted sources within 50 m of the boundary line has been repo

Table 1d. Total GHG Emissions

Fuel	Pollutant	Emission Factor[1] lb/MMBtu	Global Warming Potential[2]	Total Emissions tpy
Natural Gas	CO_2	116.98	1	96,926
	CH_4	2.20E-03	25	46
	N_2O	2.20E-04	298	54
Diesel	CO_2	163.05	1	3,294
	CH_4	6.61E-03	25	3
	N_2O	1.32E-03	298	8
Total Emissions	**CO_2e**	**-**	**-**	**100,331**
Previously Permitted Emission Limit	**CO_2e**	**-**	**-**	**101,025**

1. GHG emission factors per Tables C-1 and C-2, 40 CFR 98, Subpart C.

2. Global warming potentials per Table A-1 of 40 CFR Part 98.

Table 2a. UCHTWP Boiler Parameters

Parameter	Value	Units
Unit 1 Input Heat Capacity[1]	87.5	MMBtu/hr
Unit 3 Input Heat Capacity[1]	87.5	MMBtu/hr
Unit 4 Input Heat Capacity[1]	87.5	MMBtu/hr
Total Input Heat Capacity	262.5	MMBtu/hr
Permitted Time for Diesel Usage (Maintenance Only)[2]	8	hr/yr
Total Potential Diesel Usage	15.00	10^3 gal/yr

1. DAQE-AN103540025-13 Condition II.A.5
2. DAQE-AN103540025-13 Condition II.B.2.a

Table 2b. UCHTWP Natural Gas Usage for Existing Load

Parameter	Value	Units
Natural Gas Usage Reported[1]	591.17	MMscf/yr
Potential Natural Gas Usage Factor[2]	18.00	%
Total Potential Natural Gas Usage	697.58	MMscf/yr
Resulting Hours of Operation	2,710.60	hr/yr
Resulting Hourly Natural Gas Usage	0.26	MMscf/hr

1. Natural Gas quantities are representative of 2016 quantities.
2. The Usage Factor has been included to account for operational variability and contingencies which are encompassed in University Operations.

Table 2c. UCHTWP Natural Gas Usage for Revised Load

Parameter	Value	Units
Heat Load to be Replaced[1]	164,000	MMBtu/yr
Estimated Boiler Effciency[2]	78	%
Total Potential Natural Gas Reduction	196.16	MMscf/yr
Estimated Natural Gas Usage Upon Project Completion	501.42	MMscf/yr
Saftey Factor for Extreme Weather Conditions	5.00	%
Estimated Natural Gas Usage Upon Project Completion Assuming Extreme Weather Conditions	530.00	MMscf/yr
Resulting Hours of Operation	2,059.43	hr/yr
Resulting Hourly Natural Gas Usage	0.26	MMscf/hr

1. This represents the heat load provided by the new hospital boilers.
2. Based on engineering design.

Table 2d. UCHTWP Boiler Emission Factors

Pollutant	Natural Gas		Diesel	
	Value	Unit	Value	Unit
NO_x[1,3]	0.050	lb/MMBtu	20.00	lb/10^3 gal
CO[2,3]	84	lb/MMscf	5.00	lb/10^3 gal
PM[1,3]	0.010	lb/MMBtu	3.30	lb/10^3 gal
PM_{10}[1,3]	0.010	lb/MMBtu	1.82	lb/10^3 gal
$PM_{2.5}$[1,3]	0.010	lb/MMBtu	1.39	lb/10^3 gal
SO_2[2,3]	0.60	lb/MMscf	0.21	lb/10^3 gal
VOC[2,3]	5.50	lb/MMscf	0.20	lb/10^3 gal
NH_3[4]	3.20	lb/MMscf	0.80	lb/10^3 gal

1. Natural Gas Emission Factor from Manufacturer Provided Data.
2. Natural Gas Emission Factor from AP-42 Section 1.4
3. Diesel Emission Factor from AP-42 Section 1.3
4. EPA's Final Report on Ammonia Emission Factors, August 1994, Table 7-4 Recommended Emissions Factors for Combustion Sources

Table 2e. UCHTWP Boiler Emissions Existing Load

Pollutant	Natural Gas Emissions		Diesel Emissions		Maximum Potential Emissions	
	Hourly (lb/hr)	Annually (tpy)	Hourly (lb/hr)	Annually (tpy)	Hourly (lb/hr)	Annually (tpy)
NO_x	13.13	17.79	37.50	0.15	50.63	17.94
CO	21.62	29.30	9.38	0.038	30.99	29.34
PM	2.63	3.56	6.19	0.025	8.81	3.58
PM_{10}	2.63	3.56	3.40	0.014	6.03	3.57
$PM_{2.5}$	2.63	3.56	2.60	0.010	5.22	3.57
SO_2	0.15	0.21	0.40	0.0016	0.55	0.21
VOC	1.42	1.92	0.38	0.0015	1.79	1.92
NH_3	0.82	1.12	1.50	0.0060	2.32	1.12

Table 2f. UCHTWP Boiler Emissions Revised Load

Pollutant	Natural Gas Emissions		Diesel Emissions		Maximum Potential Emissions	
	Hourly (lb/hr)	Annually (tpy)	Hourly (lb/hr)	Annually (tpy)	Hourly (lb/hr)	Annually (tpy)
NO_x	13.13	13.52	37.50	0.15	50.63	13.67
CO	21.62	22.26	9.38	0.038	30.99	22.30
PM	2.63	2.70	6.19	0.025	8.81	2.73
PM_{10}	2.63	2.70	3.40	0.014	6.03	2.72
$PM_{2.5}$	2.63	2.70	2.60	0.010	5.22	2.71
SO_2	0.15	0.16	0.40	0.0016	0.55	0.16
VOC	1.42	1.46	0.38	0.0015	1.79	1.46
NH_3	0.82	0.85	1.50	0.0060	2.32	0.85

Table 3a. New Hospital Boiler Parameters - Phase I

Parameter	Value	Units
Total Input Heat Capacity	96	MMBtu/hr
Total High Temperature Water Demands	164,000	MMBtu/yr
Estimated Boiler Efficiency	92	%
Natural Gas Required to Run Steam Boilers Year Round	34	MMscf/yr
Permitted Time for Diesel Usage (Maintenance Only)[1]	8	hr/yr
Total Potential Diesel Usage	5.49	10^3 gal/yr
Total Natural Gas Required	208.00	MMscf/yr
Potential Hours of Operation	8,760.00	hr/yr
Total Hourly Natural Gas Usage	0.02	MMscf/hr

1. Per current University procedure.

Table 3b. New Hospital Boiler Emission Factors - Phase I

Pollutant	Natural Gas		Diesel	
	Value	Unit	Value	Unit
NO_x[1]	29	ppm	29	ppm
	0.04	lb/MMBtu	0.07	lb/MMBtu
CO[1]	100.00	ppm	100.00	ppm
	0.07	lb/MMBtu	0.07	lb/MMBtu
PM[1]	0.025	lb/hr	0.025	lb/hr
PM_{10}[1]	0.025	lb/hr	0.025	lb/hr
$PM_{2.5}$[1]	0.025	lb/hr	0.025	lb/hr
SO_2[2,3]	0.60	lb/MMscf	0.21	lb/10^3 gal
VOC[1]	0.003	lb/MMBtu	0.003	lb/MMBtu
NH_3[4]	0.49	lb/MMscf	0.80	lb/10^3 gal

1. A emission rate guaranteed by the manufacturer.
2. Natural Gas Emission Factor from AP-42 Section 1.4
3. Diesel Emission Factor from AP-42 Section 1.3
4. EPA's Final Report on Ammonia Emission Factors, August 1994, Table 7-4 Recommended Emissions Factors for Combustion Sources

Table 3c. New Hospital Boiler Emissions - Phase I

Pollutant	Natural Gas Emissions		Diesel Emissions		Maximum Potential Emissions	
	Hourly (lb/hr)	Annually (tpy)	Hourly (lb/hr)	Annually (tpy)	Hourly (lb/hr)	Annually (tpy)
NO_x	0.97	4.24	0.97	3.88E-03	1.94	4.25
CO	1.70	7.43	1.70	6.78E-03	3.39	7.43
PM	0.025	0.11	0.025	1.00E-04	0.050	0.11
PM_{10}	0.025	0.11	0.025	1.00E-04	0.050	0.11
$PM_{2.5}$	0.025	0.11	0.025	1.00E-04	0.050	0.11
SO_2	0.01	0.06	0.15	5.84E-04	0.16	0.06
VOC	0.07	0.32	0.07	2.91E-04	0.15	0.32
NH_3	0.01	0.05	0.55	0.0022	0.56	0.05

Table 3d. New Hospital Boiler Parameters - Phase II

Parameter	Value	Units
Total Input Heat Capacity[1]	8.84	MMBtu/hr
Permitted Time for Diesel Usage (Maintenance Only)[2]	8	hr/yr
Total Potential Diesel Usage	0.51	10^3 gal/yr
Total Natural Gas Required	75.92	MMscf/yr
Potential Hours of Operation	8,760	hr/yr
Total Hourly Natural Gas Usage	0.01	MMscf/hr

[1] There are two boilers to be installed as part of Phase II. Only one boiler has been accounted for in emission calculations because the second boiler is a back-up boiler.

[2] Per current University procedure.

Table 3e. New Hospital Boiler Emission Factors - Phase II

Pollutant	Natural Gas		Diesel	
	Value	Unit	Value	Unit
NO_x[1]	30	ppm	30	ppm
	0.04	lb/MMBtu	0.04	lb/MMBtu
CO[2,3]	84.00	lb/MMscf	5.00	lb/10^3 gal
PM[2,3]	7.60	lb/MMscf	3.30	lb/10^3 gal
PM_{10}[2,3]	7.60	lb/MMscf	1.82	lb/10^3 gal
$PM_{2.5}$[2,3]	7.60	lb/MMscf	1.39	lb/10^3 gal
SO_2[2,3]	0.60	lb/MMscf	0.21	lb/10^3 gal
VOC[2,3]	5.50	lb/MMscf	0.20	lb/10^3 gal
NH_3[4]	3.20	lb/MMscf	0.80	lb/10^3 gal

1. This is a conservative assumption. The actual NOx emission rate will be 30 ppm or less based on patient needs and will be confirmed upon finalization of engineering.
2. Natural Gas Emission Factor from AP-42 Section 1.4
3. Diesel Emission Factor from AP-42 Section 1.3
4. EPA's Final Report on Ammonia Emission Factors, August 1994, Table 7-4 Recommended Emissions Factors for Combustion Sources

Table 3f. New Hospital Boiler Emissions - Phase II

Pollutant	Natural Gas Emissions		Diesel Emissions		Maximum Potential Emissions	
	Hourly (lb/hr)	Annually (tpy)	Hourly (lb/hr)	Annually (tpy)	Hourly (lb/hr)	Annually (tpy)
NO_x	0.32	1.41	0.32	1.29E-03	0.64	1.41
CO	0.73	3.19	0.32	1.26E-03	1.04	3.19
PM	0.07	0.29	0.21	8.33E-04	0.27	0.29
PM_{10}	0.07	0.29	0.11	4.58E-04	0.18	0.29
$PM_{2.5}$	0.07	0.29	0.09	3.50E-04	0.15	0.29
SO_2	0.01	0.02	0.01	5.38E-05	0.02	0.02
VOC	0.05	0.21	0.01	5.05E-05	0.06	0.21
NH_3	0.03	0.12	0.05	0.0002	0.08	0.12

Table 4a. LCHTWP Boiler Parameters

Parameter	Value	Units
Decommissioned - Unit 3 Input Heat Capacity[1]	105	MMBtu/hr
Decommissioned - Unit 4 Input Heat Capacity[1]	105	MMBtu/hr
Replacement Unit 3 (i.e., Unit 9) Input Heat Capacity[5]	72	MMBtu/hr
Unit 5 Input Heat Capacity[1]	50	MMBtu/hr
Unit 6 Input Heat Capacity[1]	50	MMBtu/hr
Existing Boiler Natural Gas Usage Reported[2]	223.25	MMscf/yr
Potential Natural Gas Usage Factor[3]	18.00	%
Total Potential Natural Gas Usage	263.43	MMscf/yr
Average Usage Factor: Boilers 3, and 4 and Boiler 3 Replacement[4]	10.00	%
Resulting Annual Natural Gas Usage: Boilers 3 and 4 and Boiler 3 Replacement	26.34	MMscf/yr
Resulting Hours of Operation: Boilers 3 and 4[6]	3,655.83	hr/yr
Resulting Hourly Natural Gas Usage: Boilers 3 and 4	0.01	MMscf/hr
Resulting Hours of Operation: Boiler 3 Replacement (Boiler 9)[6]	3,554.28	hr/yr
Resulting Hourly Natural Gas Usage: Boiler 3 Replacement (Boiler 9)	0.07	MMscf/hr
Average Usage Factor: Boilers 5 and 6[4]	90.00	%
Resulting Annual Natural Gas Usage: Boilers 5 and 6	237.09	MMscf/yr
Resulting Hours of Operation: Boilers 5 and 6[6]	3,609.45	hr/yr
Resulting Hourly Natural Gas Usage: Boilers 5 and 6	0.07	MMscf/hr

1. DAQE-AN103540025-13 Condition II.A.6 and II.A.7
2. Natural Gas quantities are representative of 2016 quantities.
3. The Usage Factor has been included to account for operational variability and contingencies which are encompassed in University Operations.
4. Average usage factor is based on current understanding of the distribution of heating needs.
5. Size of replacement boiler defined by University of Utah for planning purposes.
6. Resulting Hours of Operation are calculated assuming boilers commonly run at the following capacities:

Boilers 3 and 4	3.5	%
Boiler 9	10.5	%
Boilers 5 and 6	67	%

Table 4b. LCHTWP Turbine Parameters

Parameter	Value	Units
Cogeneration System Heat Capacity[1]	62.49	MMBtu/hr
Total Potential Natural Gas Usage	536.68	MMscf/yr
Hours of Operation	8,760.00	hr/yr
Hourly Natural Gas Usage	0.061	MMscf/hr

1. Based on Cogeneration permitting application (note some of the fuel is used to produce electricity and some to fuel the WHRU).

Table 4c. LCHTWP WHRU Parameters

Parameter	Value	Units
Cogeneration System Heat Capacity[1]	72.78	MMBtu/hr
Total Potential Natural Gas Usage[2]	513.74	MMscf/yr
Hours of Operation	7,200.00	hr/yr
Hourly Natural Gas Usage	0.071	MMscf/hr

1. Based on Cogeneration permitting application (note some of the fuel is used to produce electricity and some to fuel the WHRU).

Table 4d. LCHTWP NO_2 Emission Conversion Correction for Boilers 5 and 6

Parameters[1]	Value	Unit	Source
NO_2 Concentration	9	ppmdv	Permit DAQE-AN103540025-13 Condition II.B.2.c
Exhaust Flowrate	9,391.90	dscfm	Attachment Flow Rate vs. Predicted
Conversion from Volume to Mass	0.12	lb/scf	Ideal Gas Law
Reference Oxygen Content	3	%	Permit DAQE-AN103540025-13 Condition II.B.2.c
Measured Oxygen Content	2.97	%	Average Oxygen Concentration based on March 21,2017 Stack Testing
Correction for Oxygen Content	1.00	Unitless	See Equation Below
Emission Rate	0.604	lb/hr	See Equation Below

1. Parameters evaluated at 68F and 100% of maximum potential firing rate

Table 4e. LCHTWP Emission Factors (Based on Natural Gas Usage)

Pollutant	*Decommissioned* - Units 3 and 4		Units 5 and 6		Turbine Only		WHRU Only	
	Value	Unit	Value	Unit	Value	Unit	Value	Unit
NO_x[1]	25	lb/hr	0.604	lb/hr	2.65	lb/hr	6.32	lb/hr
CO[1,2]	84.00	lb/MMscf	84.00	lb/MMscf	4.48	lb/hr	6.36	lb/hr
PM[2,3]	7.60	lb/MMscf	7.60	lb/MMscf	0.021	lb/MMbtu	7.60	lb/MMscf
PM_{10}[2,3]	7.60	lb/MMscf	7.60	lb/MMscf	0.021	lb/MMbtu	7.60	lb/MMscf
$PM_{2.5}$[2,3]	7.60	lb/MMscf	7.60	lb/MMscf	0.021	lb/MMbtu	7.60	lb/MMscf
SO_2[2]	0.60	lb/MMscf	0.60	lb/MMscf	0.60	lb/MMscf	0.60	lb/MMscf
VOC[2,3]	5.50	lb/MMscf	5.50	lb/MMscf	0.01	lb/MMBtu	5.50	lb/MMscf
NH_3[4]	3.20	lb/MMscf	3.20	lb/MMscf	3.20	lb/MMscf	3.20	lb/MMscf

1. DAQE-AN103540025-13 Condition II.B.2.c
2. Natural Gas Emission Factor from AP-42 Section 1.4
3. Natural Gas Emission Factor from Manufacturer Provided Data (per 2014 Emission Inventory)
4. EPA's Final Report on Ammonia Emission Factors, August 1994, Table 7-4 Recommended Emissions Factors for Combustion Sources

Table 4f. LCHTWP Emission Factors (Based on Capacity)

Pollutant	*Replacement* Unit 3 (i.e., Unit 9)	
	Value	Unit
NO_x[1]	0.011	lb/MMBtu
CO[2]	84.00	lb/MMscf
PM[2]	7.60	lb/MMscf
PM_{10}[2]	7.600	lb/MMscf
$PM_{2.5}$[2]	7.600	lb/MMscf
SO_2[2]	0.60	lb/MMscf
VOC[2]	5.50	lb/MMscf
NH_3[3]	3.20	lb/MMscf

1. Natural gas emission factors based on manufacturer's ppm specifications for units with LNB and converted to lb/MMBtu using an F factor of 8,710 dscf/MMBtu.
2. Natural gas emission factors from AP-42 Section 1.4.
3. EPA's Final Report on Ammonia Emission Factors, August 1994, Table 7-4 Recommended Emissions Factors for Combustion Sources

Table 4g. LCHTWP Emissions

Pollutant	*Decommissioned* - Units 3 and 4		*Replacement* Unit 3 (i.e., Unit 9)		Units 5 and 6		Turbine Only		WHRU Only	
	Hourly (lb/hr)	Annually (tpy)	Hourly (lb/hr)	Annually (tpy)	Hourly (lb/hr)	Annually (tpy)	Hourly (lb/hr)	Annually (tpy)	Hourly (lb/hr)	Annually (tpy)
NO_x	25.00	45.70	0.79	1.41	0.60	1.09	2.65	11.61	6.32	22.75
CO	0.61	1.11	6.23	11.06	5.52	9.96	4.48	19.62	6.36	22.90
PM	0.05	0.10	0.56	1.00	0.50	0.90	1.31	5.75	0.542	1.95
PM_{10}	0.05	0.10	0.56	1.00	0.50	0.90	1.31	5.75	0.542	1.95
$PM_{2.5}$	0.05	0.10	0.56	1.00	0.50	0.90	1.31	5.75	0.542	1.95
SO_2	0.00	0.01	0.04	0.08	0.04	0.07	3.68E-02	1.61E-01	0.043	0.15
VOC	0.04	0.07	0.41	0.72	0.36	0.65	0.79	3.45	0.392	1.41
NH_3	0.02	0.04	0.24	0.42	0.21	0.38	0.20	0.86	0.228	0.82

Table 4h. LCHTWP Revised Emissions

Pollutant	Potential Emissions - Current Operations[1]		Potential Emissions - Revised Configuration[2]	
	Hourly (lb/hr)	Annually (tpy)	Hourly (lb/hr)	Annually (tpy)
NO_x	34.57	81.15	10.37	36.86
CO	16.96	53.58	22.58	63.54
PM	2.41	8.70	2.92	9.60
PM_{10}	2.41	8.70	2.92	9.60
$PM_{2.5}$	2.41	8.70	2.92	9.60
SO_2	0.12	0.39	0.16	0.47
VOC	1.58	5.59	1.95	6.24
NH_3	0.66	2.10	0.87	2.48

1. PTE prior to the decommission of boiler units 3 and 4.
2. PTE including replacement boiler unit 3 (unit 9).

Table 5a. Hospital Boiler Parameters

Parameter	Value	Units
Building 521 Input Heat Capacity[1]	10.5	MMBtu/hr
Building 525 Input Heat Capacity[1]	10.5	MMBtu/hr
Building 532 (Unit 1) Input Heat Capacity[1]	25.2	MMBtu/hr
Building 532 (Unit 2) Input Heat Capacity[1]	25.2	MMBtu/hr
Total Input Heat Capacity	71.4	MMBtu/hr
Permitted Time for Diesel Usage (Maintenance Only)[2]	8	hr/yr
Total Potential Diesel Usage	4.08	10^3 gal/yr
Natural Gas Usage Reported[3]	39.11	MMscf/yr
Potential Natural Gas Usage Factor[4]	25.00	%
Total Potential Natural Gas Usage	48.88	MMscf/yr
Results Hours of Operation	698.35	hr/yr
Resulting Hourly Natural Gas Usage	0.070	MMscf/hr

1. DAQE-AN103540025-13 Condition II.A.10 and II.A.12
2. DAQE-AN103540025-13 Condition II.B.2.a and evaluated base on the University Operations.
3. Natural Gas quantities are representative of 2016 quantities.
4. The Usage Factor has been included to account for operational variability and contingencies which are encompassed in University Operations.

Table 5b. Hospital Boiler Emission Factors

Pollutant	Natural Gas		Diesel	
	Value	Unit	Value	Unit
NO_x[1,2]	100	lb/MMscf	20	lb/10^3 gal
CO[1,2]	84.00	lb/MMscf	5	lb/10^3 gal
PM[1,2]	7.6	lb/MMscf	3.30	lb/10^3 gal
PM_{10}[1,2]	7.6	lb/MMscf	1.82	lb/10^3 gal
$PM_{2.5}$[1,2]	7.6	lb/MMscf	1.39	lb/10^3 gal
SO_2[1,2]	0.60	lb/MMscf	0.21	lb/10^3 gal
VOC[1,2]	5.50	lb/MMscf	0.20	lb/10^3 gal
NH_3[3]	3.20	lb/MMscf	0.80	lb/10^3 gal

1. Natural Gas Emission Factor from AP-42 Section 1.4
2. Diesel Emission Factor from AP-42 Section 1.3
3. EPA's Final Report on Ammonia Emission Factors, August 1994, Table 7-4 Recommended Emissions Factors for Combustion Sources

Table 5c. Hospital Boiler Emissions

Pollutant	Natural Gas Emissions		Diesel Emissions		Maximum Potential Emissions	
	Hourly (lb/hr)	Annually (tpy)	Hourly (lb/hr)	Annually (tpy)	Hourly (lb/hr)	Annually (tpy)
NO_x	7.00	2.44	10.20	0.04	17.20	2.49
CO	5.88	2.05	2.55	0.01	8.43	2.06
PM	0.53	0.19	1.68	0.01	2.22	0.19
PM_{10}	0.53	0.19	0.93	0.00	1.46	0.19
$PM_{2.5}$	0.53	0.19	0.71	0.00	1.24	0.19
SO_2	0.04	0.01	0.11	0.00	0.15	0.02
VOC	0.39	0.13	0.10	0.00	0.49	0.13
NH_3	0.22	0.08	0.41	0.00	0.63	0.08

Table 6a. Huntsman Boiler Parameters

Parameter	Value	Units
Building 555 (Unit 1) Input Heat Capacity[1]	16.8	MMBtu/hr
Building 555 (Unit 2) Input Heat Capacity[1]	16.8	MMBtu/hr
Building 555 (Unit 3) Input Heat Capacity[1]	5	MMBtu/hr
Building 555 (Unit 4) Input Heat Capacity[1]	5	MMBtu/hr
Building 556 (Unit 1) Input Heat Capacity[1]	6	MMBtu/hr
Building 556 (Unit 2) Input Heat Capacity[1]	6	MMBtu/hr
Total Input Heat Capacity	55.6	MMBtu/hr
Total Potential MMBTU Production in a Year	487,056	MMBtu/yr
Permitted Time for Diesel Usage (Maintenance Only)[2]	8	hr/yr
Total Potential Diesel Usage	3.18	10^3 gal/yr
Natural Gas Usage Reported[3]	75.96	MMscf/yr
Potential Natural Gas Usage Factor[4]	25.00	%
Total Potential Natural Gas Usage	94.95	MMscf/yr
Results Hours of Operation	1,275.00	hr/yr
Resulting Hourly Natural Gas Usage	0.074	MMscf/hr

.1. DAQE-AN103540025-13 Condition II.A.13 and II.A.14
2.DAQE-AN103540025-13 Condition II.B.2.a and evaluated base on the University Operations.
3. Natural Gas quantities are representative of 2016 quantities.
4. The Usage Factor has been included to account for operational variability and contingencies which are encompassed in University Operations.

Table 6b. Huntsman Boiler Emission Factors

Pollutant	Natural Gas		Diesel	
	Value	Unit	Value	Unit
NO_x[1,2]	100	lb/MMscf	20.00	lb/10^3 gal
CO[1,2]	84.00	lb/MMscf	5.00	lb/10^3 gal
PM[1,2]	7.6	lb/MMscf	3.30	lb/10^3 gal
PM_{10}[1,2]	7.6	lb/MMscf	1.82	lb/10^3 gal
$PM_{2.5}$[1,2]	7.6	lb/MMscf	1.39	lb/10^3 gal
SO_2[1,2]	0.60	lb/MMscf	0.21	lb/10^3 gal
VOC[1,2]	5.50	lb/MMscf	0.20	lb/10^3 gal
NH_3[3]	3.20	lb/MMscf	0.80	lb/10^3 gal

1. Natural Gas Emission Factor from AP-42 Section 1.4
2. Diesel Emission Factor from AP-42 Section 1.3
3. EPA's Final Report on Ammonia Emission Factors, August 1994, Table 7-4 Recommended Emissions Factors for Combustion Sources

Table 6c. Huntsman Boiler Emissions

Pollutant	Natural Gas Emissions		Diesel Emissions		Maximum Potential Emissions	
	Hourly (lb/hr)	Annually (tpy)	Hourly (lb/hr)	Annually (tpy)	Hourly (lb/hr)	Annually (tpy)
NO_x	7.45	4.75	7.94	0.03	15.39	4.78
CO	6.26	3.99	1.99	0.01	8.24	4.00
PM	0.57	0.36	1.31	0.01	1.88	0.37
PM_{10}	0.57	0.36	0.72	0.00	1.29	0.36
$PM_{2.5}$	0.57	0.36	0.55	0.00	1.12	0.36
SO_2	0.04	0.03	0.08	0.00	0.13	0.03
VOC	0.41	0.26	0.08	0.00	0.49	0.26
NH_3	0.24	0.15	0.32	0.00	0.56	0.15

Table 7a. Miscellaneous Primary Boiler Parameters

Parameter	Value	Units
Building 32 West Input Heat Capacity[1]	14.7	MMBtu/hr
Building 33 Input Heat Capacity[1]	5.25	MMBtu/hr
Building 853 (Unit 1) Input Heat Capacity[1]	2	MMBtu/hr
Building 853 (Unit 2) Input Heat Capacity[1]	2	MMBtu/hr
Building 587 (Unit 1) Input Heat Capacity[1]	13.5	MMBtu/hr
Building 587 (Unit 2) Input Heat Capacity[1]	13.5	MMBtu/hr
Building 865 Input Heat Capacity[1]	10	MMBtu/hr
Total Input Heat Capacity	60.95	MMBtu/hr
Natural Gas Usage Reported[2]	13.72	MMscf/yr
Potential Natural Gas Usage Factor[3]	10.00	%
Total Potential Natural Gas Usage	15.09	MMscf/yr
Resulting Cumulative Hours of Operation	252.49	hr/yr
Resulting Hourly Natural Gas Usage	0.060	MMscf/hr

1. DAQE-AN103540025-13 Conditions II.A.2, II.A.3, II.A.16, II.A.18, and II.A.19
3. Natural Gas quantities are representative of 2016 quantities.
4. The Usage Factor has been included to account for operational variability and contingencies which are encompassed in University Operations.

Table 7b. Miscellaneous Primary Boiler Emission Factors

Pollutant	Natural Gas	
	Value	Unit
NO_x[1]	100	lb/MMscf
CO[1]	84	lb/MMscf
PM[1]	7.6	lb/MMscf
PM_{10}[1]	7.6	lb/MMscf
$PM_{2.5}$[1]	7.6	lb/MMscf
SO_2[1]	0.60	lb/MMscf
VOC[1]	5.5	lb/MMscf
NH_3[2]	3.20	lb/MMscf

1. Natural Gas Emission Factor from AP-42 Section 1.4
2. EPA's Final Report on Ammonia Emission Factors, August 1994, Table 7-4
Recommended Emissions Factors for Combustion Sources

Table 7c. Miscellaneous Primary Boiler Emissions

Pollutant	Natural Gas Emissions	
	Hourly (lb/hr)	Annually (tpy)
NO_x	5.98	7.54E-01
CO	5.02	6.34E-01
PM	0.45	5.73E-02
PM_{10}	0.45	5.73E-02
$PM_{2.5}$	0.45	5.73E-02
SO_2	0.04	4.53E-03
VOC	0.33	4.15E-02
NH_3	0.19	2.41E-02

Table 8a. Miscellaneous Backup Boiler Parameters

Parameter	Value	Units
Building 151 Input Heat Capacity[1]	20.67	MMBtu/hr
Building 523 Input Heat Capacity[1]	8.2	MMBtu/hr
Building 565 Input Heat Capacity[1]	19	MMBtu/hr
Building 581 Input Heat Capacity[1]	17	MMBtu/hr
Total Input Heat Capacity	64.87	MMBtu/hr
Natural Gas Usage Reported[2]	8.61	MMscf/yr
Potential Natural Gas Usage Factor[3]	15.00	%
Total Potential Natural Gas Usage	9.90	MMscf/yr
Results Hours of Operation	155.74	hr/yr
Resulting Hourly Natural Gas Usage	0.06	MMscf/hr

1. DAQE-AN103540025-13 Conditions II.A.4, II.A.11, II.A.15, and II.A.17.
3. Natural Gas quantities are representative of 2016 quantities.
4. The Usage Factor has been included to account for operational variability and contingencies which are encompassed in University Operations.

Table 8b. Miscellaneous Backup Boiler Emission Factors

Pollutant	Natural Gas	
	Value	Unit
NO_x[1,2]	100	lb/MMscf
CO[1,2]	84	lb/MMscf
PM[1,2]	7.6	lb/MMscf
PM_{10}[1,2]	7.6	lb/MMscf
$PM_{2.5}$[1,2]	7.6	lb/MMscf
SO_2[1,2]	0.60	lb/MMscf
VOC[1,2]	5.5	lb/MMscf
NH_3[2]	3.20	lb/MMscf

1. Natural Gas Emission Factor from AP-42 Section 1.4
2. EPA's Final Report on Ammonia Emission Factors, August 1994, Table 7-4 Recommended Emissions Factors for Combustion Sources

Table 8c. Miscellaneous Backup Boiler Emissions

Pollutant	Natural Gas Emissions	
	Hourly (lb/hr)	Annually (tpy)
NO_x	6.36	4.95E-01
CO	5.34	4.16E-01
PM	0.48	3.76E-02
PM_{10}	0.48	3.76E-02
$PM_{2.5}$	0.48	3.76E-02
SO_2	0.04	2.97E-03
VOC	0.35	2.72E-02
NH_3	0.20	1.58E-02

Table 9. Small Diesel Engine Capacities & Emissions

Location	Tier Rating	Capacity[1]	Hourly Emissions (lb/hr)[2]							Annual Emissions (tpy)[3]						
		(hp)	NO_X	CO	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC	NO_X	CO	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC
Building 213	Pre-Tier System	20	0.62	0.13	0.04	0.04	0.04	0.04	0.05	0.03	0.01	0.00	0.00	0.00	0.00	0.00
Building 500	Unknown	34	1.05	0.23	0.07	0.07	0.07	0.07	0.09	0.05	0.01	0.00	0.00	0.00	0.00	0.00
Building 149	Tier 4i	27	0.33	0.25	0.01	0.01	0.01	0.06	0.07	0.02	0.01	0.00	0.00	0.00	0.00	0.00
Building 205	Unknown	27	0.84	0.18	0.06	0.06	0.06	0.06	0.07	0.04	0.01	0.00	0.00	0.00	0.00	0.00
Building 305	Tier 2	27	0.33	0.25	0.03	0.03	0.03	0.06	0.07	0.02	0.01	0.00	0.00	0.00	0.00	0.00
Building 540	Pre-Tier System	27	0.84	0.18	0.06	0.06	0.06	0.06	0.07	0.04	0.01	0.00	0.00	0.00	0.00	0.00
Building 19	Pre-Tier System	34	1.05	0.23	0.07	0.07	0.07	0.07	0.09	0.05	0.01	0.00	0.00	0.00	0.00	0.00
Building 28	Unknown	34	1.05	0.23	0.07	0.07	0.07	0.07	0.09	0.05	0.01	0.00	0.00	0.00	0.00	0.00
Building 210	Unknown	34	1.05	0.23	0.07	0.07	0.07	0.07	0.09	0.05	0.01	0.00	0.00	0.00	0.00	0.00
Building 66	Unknown	47	1.46	0.31	0.10	0.10	0.10	0.10	0.12	0.07	0.02	0.01	0.01	0.01	0.00	0.01
Building 815	Tier 1	47	0.74	0.43	0.06	0.06	0.06	0.10	0.12	0.04	0.02	0.00	0.00	0.00	0.00	0.01
Building 49	Unknown	54	1.67	0.36	0.12	0.12	0.12	0.11	0.14	0.08	0.02	0.01	0.01	0.01	0.01	0.01
Building 26	Tier 4 Option 1	67	0.52	0.55	0.03	0.03	0.03	0.14	0.17	0.03	0.03	0.00	0.00	0.01	0.01	0.01
Student Life Center (Building 110)	Unknown	67	2.08	0.45	0.15	0.15	0.15	0.14	0.17	0.10	0.02	0.01	0.01	0.01	0.01	0.01
Building 372	Unknown	67	2.08	0.45	0.15	0.15	0.15	0.14	0.17	0.10	0.02	0.01	0.01	0.01	0.01	0.01
Building 53	Unknown	74	2.29	0.49	0.16	0.16	0.16	0.15	0.19	0.11	0.02	0.01	0.01	0.01	0.01	0.01
Building 301	Tier 2	80	0.99	0.66	0.05	0.05	0.05	0.16	0.20	0.05	0.03	0.00	0.00	0.00	0.01	0.01
Building 512	Unknown	80	2.48	0.53	0.18	0.18	0.18	0.16	0.20	0.12	0.03	0.01	0.01	0.01	0.01	0.01
Building 892	Unknown	100	3.10	0.67	0.22	0.22	0.22	0.21	0.25	0.16	0.03	0.01	0.01	0.01	0.01	0.01
Building 892	Unknown	402	12.46	2.69	0.88	0.88	0.88	0.82	1.01	0.62	0.13	0.04	0.04	0.04	0.04	0.05
Building 197	Tier 1	107	1.33	0.88	0.07	0.07	0.07	0.22	0.27	0.07	0.04	0.00	0.00	0.00	0.01	0.01
Building 4	Tier 1	134	1.66	1.11	0.09	0.09	0.09	0.27	0.34	0.08	0.06	0.00	0.00	0.00	0.01	0.02
Building 14	Pre-Tier System	134	4.15	0.90	0.29	0.29	0.29	0.27	0.34	0.21	0.04	0.01	0.01	0.01	0.01	0.02
Building 25	Unknown	134	4.15	0.90	0.29	0.29	0.29	0.27	0.34	0.21	0.04	0.01	0.01	0.01	0.01	0.02
Building 57	Pre-Tier System	134	4.15	0.90	0.29	0.29	0.29	0.27	0.34	0.21	0.04	0.01	0.01	0.01	0.01	0.02
Building 64	Tier 1	134	1.66	1.11	0.09	0.09	0.09	0.27	0.34	0.08	0.06	0.00	0.00	0.00	0.01	0.02
Building 585	Tier 2	134	1.66	1.11	0.09	0.09	0.09	0.27	0.34	0.08	0.06	0.00	0.00	0.00	0.01	0.02
Building 7	Unknown	168	5.21	1.12	0.37	0.37	0.37	0.34	0.42	0.26	0.06	0.02	0.02	0.02	0.02	0.02
Building 212	Tier 1	168	2.08	1.39	0.11	0.11	0.11	0.34	0.42	0.10	0.07	0.01	0.01	0.01	0.02	0.02
Building 13	Tier 1	201	3.06	3.79	0.18	0.18	0.18	0.41	0.51	0.15	0.19	0.01	0.01	0.01	0.02	0.03
Building 112	Unknown	201	6.23	1.34	0.44	0.44	0.44	0.41	0.51	0.31	0.07	0.02	0.02	0.02	0.02	0.03
Building 701	Tier 3	201	1.33	1.16	0.07	0.07	0.07	0.41	0.51	0.07	0.06	0.00	0.00	0.00	0.02	0.03
Building 702	Tier 3	201	1.33	1.16	0.07	0.07	0.07	0.41	0.51	0.07	0.06	0.00	0.00	0.00	0.02	0.03
Building 35	Tier 1	208	3.16	3.92	0.19	0.19	0.19	0.43	0.52	0.16	0.20	0.01	0.01	0.01	0.02	0.03
Building 801	Unknown	229	2.50	1.33	0.08	0.08	0.08	0.47	0.58	0.12	0.07	0.00	0.00	0.00	0.02	0.03
Building 347	Pre-Tier System	241	7.47	1.61	0.53	0.53	0.53	0.49	0.61	0.37	0.08	0.03	0.03	0.03	0.02	0.03
Building 84	Unknown	260	8.06	1.74	0.57	0.57	0.57	0.53	0.65	0.40	0.09	0.03	0.03	0.03	0.03	0.03
Building 84	Unknown	260	8.06	1.74	0.57	0.57	0.57	0.53	0.65	0.40	0.09	0.03	0.03	0.03	0.03	0.03
Building 821	Tier 1	268	4.08	5.05	0.24	0.24	0.24	0.55	0.67	0.20	0.25	0.01	0.01	0.01	0.03	0.03
Beverly T. Sorenson Art & Ed. Center (Building 71)	Unknown	308	9.55	2.06	0.68	0.68	0.68	0.63	0.77	0.48	0.10	0.03	0.03	0.03	0.03	0.04
Building 588	Unknown	335	10.39	2.24	0.74	0.74	0.74	0.69	0.84	0.52	0.11	0.04	0.04	0.04	0.03	0.04
Ambulatory Care Center Parking	Unknown	335	10.39	2.24	0.74	0.74	0.74	0.69	0.84	0.52	0.11	0.04	0.04	0.04	0.03	0.04
Building 82	Tier 1	402	6.12	7.58	0.36	0.36	0.36	0.82	1.01	0.31	0.38	0.02	0.02	0.02	0.04	0.05
Building 575	Tier 2	476	5.04	2.75	0.16	0.16	0.16	0.98	1.20	0.25	0.14	0.01	0.01	0.01	0.05	0.06
Building 523	Unknown	536	16.62	3.58	1.18	1.18	1.18	1.10	1.35	0.83	0.18	0.06	0.06	0.06	0.05	0.07
Building 874	Tier 2	539	5.70	3.12	0.18	0.18	0.18	1.10	1.36	0.29	0.16	0.01	0.01	0.01	0.06	0.07
Building 95	Unknown	600	18.60	4.01	1.32	1.32	1.32	1.23	1.51	0.93	0.20	0.07	0.07	0.07	0.06	0.08
Dentistry	Tier 3	324	2.14	1.88	0.11	0.11	0.11	0.66	0.81	0.11	0.09	0.01	0.01	0.01	0.03	0.04
Building 587	Unknown	268	8.31	1.79	0.59	0.59	0.59	0.55	0.67	0.42	0.09	0.03	0.03	0.03	0.03	0.03

Table 9. Small Diesel Engine Capacities & Emissions

Location	Tier Rating	Capacity[1] (hp)	Hourly Emissions (lb/hr)[2] NO_X	CO	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC	Annual Emissions (tpy)[3] NO_X	CO	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC
BACM Identified Units																
Building 12	Tier 3	335	2.22	1.94	0.11	0.11	0.11	0.69	0.84	0.11	0.10	0.01	0.01	0.01	0.03	0.04
Building 40	Unknown	335	10.39	2.24	0.74	0.74	0.74	0.69	0.84	0.52	0.11	0.04	0.04	0.04	0.03	0.04
Building 79	Unknown	260	8.06	1.74	0.57	0.57	0.57	0.53	0.65	0.40	0.09	0.03	0.03	0.03	0.03	0.03
Building 800	Unknown	134	4.15	0.90	0.29	0.29	0.29	0.27	0.34	0.21	0.04	0.01	0.01	0.01	0.01	0.02
Building 851	Unknown	536	16.62	3.58	1.18	1.18	1.18	1.10	1.35	0.83	0.18	0.06	0.06	0.06	0.05	0.07
Building 851	Unknown	536	16.62	3.58	1.18	1.18	1.18	1.10	1.35	0.83	0.18	0.06	0.06	0.06	0.05	0.07
Building 853	Tier 3	201	1.33	1.16	0.07	0.07	0.07	0.41	0.51	0.07	0.06	0.00	0.00	0.00	0.02	0.03
Building 865	Unknown	201	6.23	1.34	0.44	0.44	0.44	0.41	0.51	0.31	0.07	0.02	0.02	0.02	0.02	0.03
Building 876	Unknown	40	1.24	0.27	0.09	0.09	0.09	0.08	0.10	0.06	0.01	0.00	0.00	0.00	0.00	0.01
Building 887	Unknown	167	5.18	1.12	0.37	0.37	0.37	0.34	0.42	0.26	0.06	0.02	0.02	0.02	0.02	0.02
New Units																
Lassonde	Tier 3	464	3.07	2.69	0.15	0.15	0.15	0.95	1.17	0.15	0.13	0.01	0.01	0.01	0.05	0.06
HSC Park	Tier 3	134	0.89	1.11	0.07	0.07	0.07	0.27	0.34	0.04	0.06	0.00	0.00	0.00	0.01	0.02
Previously Unaccounted for Unit																
NW Parking	Tier 3	99	0.77	0.82	0.07	0.07	0.07	0.20	0.25	0.04	0.04	0.00	0.00	0.00	0.01	0.01
Field House	Tier 3	86	0.67	0.71	0.06	0.06	0.06	0.18	0.22	0.03	0.04	0.00	0.00	0.00	0.01	0.01
Business Loop Parking	Tier 3	158	1.04	1.31	0.08	0.08	0.08	0.32	0.40	0.05	0.07	0.00	0.00	0.00	0.02	0.02
Units to be Removed																
Total Emissions			**279.70**	**97.46**	**18.74**	**18.74**	**18.74**	**25.98**	**31.87**	**13.98**	**4.87**	**0.94**	**0.94**	**0.94**	**1.30**	**1.59**
Total Currently Permitted Unit Emissions			**266.84**	**89.45**	**17.87**	**17.87**	**17.87**	**23.63**	**28.98**	**13.34**	**4.47**	**0.89**	**0.89**	**0.90**	**1.18**	**1.45**
Total New Unit Emissions			**3.96**	**3.79**	**0.22**	**0.22**	**0.22**	**1.23**	**1.50**	**0.20**	**0.19**	**0.01**	**0.01**	**0.01**	**0.06**	**0.08**
Total Previously Unaccounted for Unit Emissions			**2.48**	**2.84**	**0.20**	**0.20**	**0.20**	**0.70**	**0.86**	**0.12**	**0.14**	**0.01**	**0.01**	**0.01**	**0.04**	**0.04**

1. If the Capacity was unknown a capacity of 600 hp was assumed.

2. Per AP-42 Section 3.3, Table 3.3-1 (Manufacturer specification sheets may contain lower emission factors.)

3. Assumed Maintenance and Testing for each engine to be: 100 hours for potential operation.

100 house of operation is consistent with previous University permitting.

Table 10. Large Diesel Engine Capacities & Emissions

Location	Capacity (hp)	Tier Rating	Hourly Emissions (lb/hr)[1]							Annual Emissions (tpy)[2]						
			NO_X	CO	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC	NO_X	CO	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC
Building 1	268	Unknown	6.43	1.47	0.00	0.00	0.00	0.00	0.19	0.32	0.07	0.00	0.00	0.00	0.00	0.01
Building 32	1,219	Pre-Tier Rating	29.26	6.71	0.00	0.00	0.00	0.01	0.86	1.46	0.34	0.00	0.00	0.00	0.00	0.04
Building 62	871	Tier 2	9.22	5.04	0.29	0.29	0.29	0.01	0.61	0.46	0.25	0.01	0.01	0.01	0.00	0.03
Building 85	900	Unknown	21.60	4.95	0.00	0.00	0.00	0.01	0.63	1.08	0.25	0.00	0.00	0.00	0.00	0.03
Building 85	900	Unknown	21.60	4.95	0.00	0.00	0.00	0.01	0.63	1.08	0.25	0.00	0.00	0.00	0.00	0.03
Building 86	2,011	Tier 1	30.59	37.91	1.80	1.80	1.80	0.02	1.42	1.53	1.90	0.09	0.09	0.09	0.00	0.07
Building 151	1,073	Unknown	25.75	5.90	0.00	0.00	0.00	0.01	0.76	1.29	0.30	0.00	0.00	0.00	0.00	0.04
Building 151	1,073	Unknown	25.75	5.90	0.00	0.00	0.00	0.01	0.76	1.29	0.30	0.00	0.00	0.00	0.00	0.04
Building 151	1,073	Unknown	25.75	5.90	0.00	0.00	0.00	0.01	0.76	1.29	0.30	0.00	0.00	0.00	0.00	0.04
Building 179	670	Unknown	16.08	3.69	0.00	0.00	0.00	0.01	0.47	0.80	0.18	0.00	0.00	0.00	0.00	0.02
Building 302	804	Tier 1	12.23	15.16	0.72	0.72	0.72	0.01	0.57	0.61	0.76	0.04	0.04	0.04	0.00	0.03
Building 303	804	Tier 2	8.51	4.65	0.27	0.27	0.27	0.01	0.57	0.43	0.23	0.01	0.01	0.01	0.00	0.03
Building 521/525	670	Unknown	16.08	3.69	0.00	0.00	0.00	0.01	0.47	0.80	0.18	0.00	0.00	0.00	0.00	0.02
Building 521/525	1,340	Unknown	32.16	7.37	0.00	0.00	0.00	0.02	0.94	1.61	0.37	0.00	0.00	0.00	0.00	0.05
Building 523	1,675	Unknown	40.20	9.21	0.00	0.00	0.00	0.02	1.18	2.01	0.46	0.00	0.00	0.00	0.00	0.06
Building 526	1,474	Unknown	35.38	8.11	0.00	0.00	0.00	0.02	1.04	1.77	0.41	0.00	0.00	0.00	0.00	0.05
Building 526	1,474	Unknown	35.38	8.11	0.00	0.00	0.00	0.02	1.04	1.77	0.41	0.00	0.00	0.00	0.00	0.05
Building 526	1,340	Unknown	32.16	7.37	0.00	0.00	0.00	0.02	0.94	1.61	0.37	0.00	0.00	0.00	0.00	0.05
Building 526	1,340	Unknown	32.16	7.37	0.00	0.00	0.00	0.02	0.94	1.61	0.37	0.00	0.00	0.00	0.00	0.05
Building 526	1,340	Unknown	32.16	7.37	0.00	0.00	0.00	0.02	0.94	1.61	0.37	0.00	0.00	0.00	0.00	0.05
Building 533	804	Pre-Tier System	19.30	4.42	0.00	0.00	0.00	0.01	0.57	0.96	0.22	0.00	0.00	0.00	0.00	0.03
Building 550	670	Pre-Tier System	16.08	3.69	0.00	0.00	0.00	0.01	0.47	0.80	0.18	0.00	0.00	0.00	0.00	0.02
Building 555	1,005	Unknown	24.12	5.53	0.00	0.00	0.00	0.01	0.71	1.21	0.28	0.00	0.00	0.00	0.00	0.04
Building 555	2,680	Unknown	64.32	14.74	0.00	0.00	0.00	0.03	1.89	3.22	0.74	0.00	0.00	0.00	0.00	0.09
Building 556	2,010	Tier 1	30.58	37.89	1.79	1.79	1.79	0.02	1.42	1.53	1.89	0.09	0.09	0.09	0.00	0.07
Building 556	2,010	Tier 1	30.58	37.89	1.79	1.79	1.79	0.02	1.42	1.53	1.89	0.09	0.09	0.09	0.00	0.07
Building 565	1,341	Tier 1	20.40	25.28	1.20	1.20	1.20	0.02	0.95	1.02	1.26	0.06	0.06	0.06	0.00	0.05
Building 570	1,481	Pre-Tier System	35.54	8.15	0.00	0.00	0.00	0.02	1.04	1.78	0.41	0.00	0.00	0.00	0.00	0.05
Building 581	2,682	Tier 2	40.80	50.55	2.39	2.39	2.39	0.03	1.89	2.04	2.53	0.12	0.12	0.12	0.00	0.09
Building 587	804	Unknown	19.30	4.42	0.00	0.00	0.00	0.01	0.57	0.96	0.22	0.00	0.00	0.00	0.00	0.03
Building 872	697	Unknown	16.73	3.83	0.00	0.00	0.00	0.01	0.49	0.84	0.19	0.00	0.00	0.00	0.00	0.02
BACM Identified Units																
Building 45	1,073	Unknown	25.75	5.90	0.00	0.00	0.00	0.01	0.76	1.29	0.30	0.00	0.00	0.00	0.00	0.04
Building 45	1,207	Unknown	28.97	6.64	0.00	0.00	0.00	0.01	0.85	1.45	0.33	0.00	0.00	0.00	0.00	0.04
Building 74	670	Unknown	16.08	3.69	0.00	0.00	0.00	0.01	0.47	0.80	0.18	0.00	0.00	0.00	0.00	0.02
New Emissions																
HCI Phase 4	2,922	Tier 2	30.92	16.91	0.97	0.97	0.97	0.04	2.06	1.55	0.85	0.05	0.05	0.05	0.00	0.10
Crocker	1,881	Tier 2	19.91	10.89	0.62	0.62	0.62	0.02	1.33	1.00	0.54	0.03	0.03	0.03	0.00	0.07
Total Emissions			**927.81**	**401.22**	**11.84**	**11.84**	**11.84**	**0.56**	**32.61**	**46.39**	**20.06**	**0.59**	**0.59**	**0.59**	**0.03**	**1.63**
Total Currently Permitted Emissions			**806.18**	**357.20**	**10.25**	**10.25**	**10.25**	**0.47**	**27.14**	**40.31**	**17.86**	**0.51**	**0.51**	**0.51**	**0.02**	**1.36**
Total New Emissions			**50.83**	**27.80**	**1.59**	**1.59**	**1.59**	**0.06**	**3.39**	**2.54**	**1.39**	**0.08**	**0.08**	**0.08**	**0.00**	**0.17**

1. If the capacity was unknown an average capacity was used.

2. Per AP-42 Section 3.4, Table 3.4-1 (Manufacturer specification sheets may contain lower emission factors.)

3. Assumed Maintenance and Testing for each engine to be: 100 hours for potential operation.

100 house of operation is consistent with previous University permitting.

Table 11. Natural Gas Engine Capacities & Emissions

Location[1]	Capacity[2, 5]		Hourly Emissions (lb/hr)[3]							Annual Emissions (tpy)[4]						
	(kW)	(MMBtu/hr)	NO_X	CO	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC	NO_X	CO	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC
Building 64	100	0.34	1.39	1.08E-01	3.40E-03	3.40E-03	3.40E-03	2.01E-04	0.40	0.07	0.01	0.00	0.00	0.00	0.00	0.02
Building 67	300	1.02	4.18	3.24E-01	1.02E-02	1.02E-02	1.02E-02	6.02E-04	1.21	0.21	0.02	0.00	0.00	0.00	0.00	0.06
Building 350	300	1.02	4.18	3.24E-01	1.02E-02	1.02E-02	1.02E-02	6.02E-04	1.21	0.21	0.02	0.00	0.00	0.00	0.00	0.06
Building 685	300	1.02	4.18	3.24E-01	1.02E-02	1.02E-02	1.02E-02	6.02E-04	1.21	0.21	0.02	0.00	0.00	0.00	0.00	0.06
Total Emissions (All Units are Currently Permitted)			**13.92**	**1.08**	**3.40E-02**	**3.40E-02**	**3.40E-02**	**2.01E-03**	**4.03**	**0.70**	**0.05**	**0.00**	**0.00**	**0.00**	**0.00**	**0.20**

1. Per Copy of Emergency Generator Infrastructure.
2. If the Capacity was unknown a capacity of 300 kW was assumed.
3. Per AP-42 Section 3.2, Table 3.2-2 (Manufacturer specification sheets may contain lower emission factors.)
4. Assumed Maintenance and Testing for each engine to be: 100 hours for potential operation.

100 house of operation is consistent with previous University permitting.

5. MMBtu/hr value calculated as follows:

$$\text{MMBTU/hr} = \text{kW} \times \frac{3{,}412.142\ \text{BTU/hr}}{\text{kW}} \times \frac{\text{MMBtu}}{10^6\ \text{Btu}}$$

Table 12. Carpentry Shop

Parameter	Value	Units
Fabric Filter Outlet Grain Loading[1]	0.016	gr/scf
Air Flowrate[2]	12,000	scfm
Annual Operating Hours[3]	1,043	hr/yr
$PM/PM_{10}/PM_{2.5}$ Hourly Emissions	1.646	lb/hr
$PM/PM_{10}/PM_{2.5}$ Annual Emissions	0.858	tpy

[1] Fabric filter grain loading assumed to be equivalent to the UDAQ BACT limit.

[2] Based on 2014 Emission Inventory

3. Current AO DAQE-AN103540025-13 Condition II.B.5.a

Table 13a. Miscellaneous VOC Sources - Part Washer

Chemical Name	VOC Content[1]	Annual Usage	Actual Annual Product VOC Emissions
	(g/L)	(gal/yr)	(lb/hr)
Superia Pressmax JRDC Fountain Solution	25.00	120.00	2.97E-03
Total (tpy)			**0.01**

[1] Based on SDS review

Table 13b. Miscellaneous VOC Sources - Paint Booth

Product	Annual Usage	Density	VOC Percentage	HAP Percentage	HAP Name	Total VOC		Total HAP	
	(gal/yr)	(lbs/gal)	(%)	(%)		(lb/hr)	(tpy)	(lb/hr)	(tpy)
Chemstrip	1	10.35	94	75	Methylene Chloride	1.11E-03	4.86E-03	8.86E-04	3.88E-03
Varnish, Satin	22.75	7.22	72	0	-	1.35E-02	5.91E-02	0	0
Rustoleum Hardhat spray paint	12.03	8.18	100	25	Xylene	1.12E-02	4.92E-02	2.81E-03	1.23E-02
				3	Ethylbenzene			3.37E-04	1.48E-03
Thinner, acrylic nitrocellulose	20.3	6.97	100	100	-	1.61E-02	7.07E-02	0.01614748	0.070725961
Wood Stain, Pratt & Lambert	4.75	5.59	75	0	-	2.27E-03	9.96E-03	0	0
Primer Sealer, QD-30	6.5	11.60	53	0	-	4.56E-03	2.00E-02	0	0
Sanding Clear Lacquer	21	7.80	85	0	-	1.59E-02	6.96E-02	0	0
SW Industrial Enamel	41.5	9.80	58	0	-	2.69E-02	1.18E-01	0	0
Mineral spirits	2.5	6.59	100	0	-	1.88E-03	8.24E-03	0	0
Acetone	76	6.57586	100	0	-	5.71E-02	2.50E-01	0	0
Concersion Varnish	27	8.6788	5	0	-	1.34E-03	5.86E-03	0	0
Xylene	11.25	7.21008	100	100	Xylene	9.26E-03	4.06E-02	9.26E-03	4.06E-02
Total						**1.61E-01**	**7.06E-01**	**2.94E-02**	**1.29E-01**

Table 13c. Storage Tanks

Location	Bldg	Configuation[1]	Quantity	Capacity (gal)	Material	Annual Throughput (gal/yr)[5]	Total VOC Emissions (tpy)	Hexane (lb/yr)	Benzene (lb/yr)	Toluene (lb/yr)	Xylene (lb/yr)	1,2,4 Trimethyl-benzene (lb/yr)	Cyclo-Hexane (lb/yr)	Total HAP Emissions (lb/yr)
SOM[2]	521	Not Applicable	2	20,000	Diesel bulk	300,000								-
SOM[2]	521	HFR	1	12,000	Diesel bulk	300,000	0.0039	0.03	0.16	0.18	0.45	0.36		1.18
Hospital 'Gen Plant'[3]	526	Rooftop, HFR	1	35,000	Diesel bulk	2,500	0.0031	0.03	0.12	0.14	0.36	0.29		0.94
Helipad	521/525	HFR	1	10,000	Jet fuel bulk	65,000	0.2041	13.62	3.34	3.2	1.12		6.92	28.2
Huntsman Cancer Center[4]	556	Basement, HFR	2	12,000	Diesel bulk	100,000	0.004	0.02	0.08	0.09	0.23	0.18		0.6
Uppper Heating Plant	302	Outside, VFR	3	25,000	Diesel bulk	300,000	0.036		1.35	1.62	4.35	3.72		11.04
Currently Permitted Emissions (tpy)							0.009	3.50E-05	1.60E-04	1.83E-04	4.63E-04	4.15E-04	0.00E+00	1.21E-03
Previously Unaccounted for Emissions (tpy)							0.038	5.00E-06	6.95E-04	8.33E-04	2.23E-03	1.86E-03	0.00E+00	5.67E-03
Total Emissions (tpy)							**0.2511**	**6.85E-03**	**2.53E-03**	**2.62E-03**	**3.26E-03**	**2.28E-03**	**3.46E-03**	**2.10E-02**

1. HFR = Horizontal Fixed Roof, VFR = Vertical Fixed Roof.

2. Two 20,000 gallon diesel tanks are included in permit condition number II.A.24 and have been replaced by one 12,000 gallon tank (building 526). It is assumed that emissions from the decomissioned tanks is approximately equivalent to the 12,000 gallon replacement tank therefore emissions have not been calclated.

3. This tank is permitted in condition II.A.21 as an appoximately 30,000 gallon diesel tank.

4. One jet fuel tank is currently listed in permit condition number II.A.42. A second tank on the same capacity and approximate throughput is currently operating on at the same location. These tanks are located in the basement of the building.

5. Annual throughput given on a per tank basis.

Table 14a. Natural Gas Fired Boiler HAP Emissions

Pollutant	Emission Factor[1]	Units	Total Hourly Emissions lb/hr	Revised Hourly Emissions lb/hr	Annual Emissions tpy
Acrolein	2.70E-03	lb/MMscf	1.77E-04	3.32E-04	2.58E-03
Acetaldehyde	4.30E-03	lb/MMscf	2.82E-04	5.29E-04	4.10E-03
Benzene	8.00E-03	lb/MMscf	5.24E-04	9.84E-04	7.63E-03
Ethylbenzene	9.50E-03	lb/MMscf	6.23E-04	1.17E-03	9.07E-03
Formaldehyde	1.70E-02	lb/MMscf	1.11E-03	2.09E-03	1.62E-02
Hexane	6.30E-03	lb/MMscf	4.13E-04	7.75E-04	6.01E-03
Naphthalene	3.00E-04	lb/MMscf	1.97E-05	3.69E-05	2.86E-04
Polycyclic Aromatic Hydrocarbons (PAH)	4.00E-04	lb/MMscf	2.62E-05	4.92E-05	3.82E-04
Propylene	7.31E-01	lb/MMscf	4.79E-02	8.99E-02	6.98E-01
Toluene	3.66E-02	lb/MMscf	2.40E-03	4.50E-03	3.49E-02
Xylene	2.72E-02	lb/MMscf	1.78E-03	3.35E-03	2.60E-02
Max HAP			**0.05**	**0.09**	**0.70**
Total HAP			**0.06**	**0.10**	**0.80**

1. Ventura County Air Pollution Control District, AB 32588 Combustion Emission Factors, Natural Gas Fired External Combustion Equipment. One emission calculation is performed for all HAP related to Natural Gas Fired Boilers onsite. Since these boilers range in size from 10 to 88 MMbtu/hr, the most conervative (i.e. the highest) emission factor from the less than 10 MMbtu/hr and 10-100 MMbtu/hr category has been utilized.

Table 14b. Diesel Fired Boiler Emissions

Pollutant[1,2]	Emission Factor[1]	Units	Hourly Emissions	Revised Hourly Emissions	Annual Emissions
			lb/hr	lb/hr	tpy
Benzene	2.14E-04	lb/10^3 gal	7.56E-04	1.60E-04	3.02E-06
Ethylbenzene	6.36E-05	lb/10^3 gal	2.25E-04	4.76E-05	8.98E-07
Formaldehyde	3.30E-02	lb/10^3 gal	1.17E-01	2.47E-02	4.66E-04
Naphthalene	1.13E-03	lb/10^3 gal	3.99E-03	8.46E-04	1.60E-05
1,1,1-Trichloroethane	2.36E-04	lb/10^3 gal	8.33E-04	1.77E-04	3.33E-06
Toluene	6.20E-03	lb/10^3 gal	2.19E-02	4.64E-03	8.76E-05
o-Xylene	1.09E-04	lb/10^3 gal	3.85E-04	8.16E-05	1.54E-06
Acenaphthene	2.11E-05	lb/10^3 gal	7.45E-05	1.58E-05	2.98E-07
Acenaphthylene	2.53E-07	lb/10^3 gal	8.93E-07	1.89E-07	3.57E-09
Anthracene	1.22E-06	lb/10^3 gal	4.31E-06	9.14E-07	1.72E-08
Benz(a)anthracene	1.22E-06	lb/10^3 gal	4.31E-06	9.14E-07	1.72E-08
Benzo(b,k)flouranthene	1.48E-06	lb/10^3 gal	5.23E-06	1.11E-06	2.09E-08
Benzo(g,h,i)perylene	2.26E-06	lb/10^3 gal	7.98E-06	1.69E-06	3.19E-08
Chrysene	2.38E-06	lb/10^3 gal	8.40E-06	1.78E-06	3.36E-08
Dibenzo(a,h)anthracene	1.67E-06	lb/10^3 gal	5.90E-06	1.25E-06	2.36E-08
Flouranthene	4.84E-06	lb/10^3 gal	1.71E-05	3.62E-06	6.84E-08
Fluorene	4.47E-06	lb/10^3 gal	1.58E-05	3.35E-06	6.31E-08
Indo(1,2,3-cd)pyrene	2.14E-06	lb/10^3 gal	7.56E-06	1.60E-06	3.02E-08
Phenanthrene	1.05E-05	lb/10^3 gal	3.71E-05	7.86E-06	1.48E-07
Pyrene	4.25E-06	lb/10^3 gal	1.50E-05	3.18E-06	6.00E-08
OCDD	3.10E-09	lb/10^3 gal	1.09E-08	2.32E-09	4.38E-11
Arsenic	1.47E-05	lb/10^3 gal	5.19E-05	1.10E-05	2.08E-07
Mercury	1.40E-05	lb/10^3 gal	4.94E-05	1.05E-05	1.98E-07
Nickel	2.24E-05	lb/10^3 gal	7.91E-05	1.68E-05	3.16E-07
Selenium	3.03E-05	lb/10^3 gal	1.07E-04	2.27E-05	4.28E-07
Zinc	1.04E-03	lb/10^3 gal	3.67E-03	7.79E-04	1.47E-05
Max HAP			**0.12**	**0.02**	**4.66E-04**
Total HAP			**0.15**	**0.03**	**5.80E-04**

1. AP-42 Table 1.3-9, and 1.3-10.

2.Determination of Sulfur and Toxic Metals Content of Distillates and Residual Oil in the State of New York, Published by the Northeast state for Coordinated Air Use Management (NESCAUM)

Table 14c. Small Diesel Engines

Pollutant	Emission Factor[1]	Units	Hourly Emissions	Hourly Emissions for New/Revised Units	Annual Emissions
			lb/hr	lb/hr	tpy
Benzene	9.33E-04	lb/MMBtu	3.01E-02	2.23E-03	1.50E-03
Toluene	4.09E-04	lb/MMBtu	1.32E-02	9.79E-04	6.59E-04
1,3-Butadiene	3.91E-05	lb/MMBtu	1.26E-03	9.36E-05	6.30E-05
Formaldehyde	1.18E-03	lb/MMBtu	3.80E-02	2.82E-03	1.90E-03
Acetaldehyde	7.67E-04	lb/MMBtu	2.47E-02	1.84E-03	1.24E-03
Acrolein	9.25E-05	lb/MMBtu	2.98E-03	2.21E-04	1.49E-04
Naphthalene	8.48E-05	lb/MMBtu	2.73E-03	2.03E-04	1.37E-04
Polycyclic Aromatic Hydrocarbons (PAH)	1.68E-04	lb/MMBtu	5.41E-03	4.02E-04	2.71E-04
Max HAP			***3.80E-02***	***2.82E-03***	***1.90E-03***
Total HAPs			***1.18E-01***	***8.79E-03***	***0.01***

1. Emission factors Per AP-42 Section 3.3, Gasoline and Diesel Industrial Engine Table 3.3-2.
Additional polycyclic aromatic hydrocarbon may be emitted but for regulatory purposes, this list is only inclusive of HAPs regulated under the clean air act.

Table 14d. Large Diesel Engines

Pollutant	Emission Factor[1]	Units	Hourly Emissions	Hourly Emissions for New/Revised Units	Annual Emissions
			lb/hr	lb/hr	tpy
Benzene	7.76E-04	lb/MMBtu	9.13E-02	9.48E-03	4.56E-03
Toluene	2.81E-04	lb/MMBtu	3.30E-02	3.43E-03	1.65E-03
Xylenes	1.93E-04	lb/MMBtu	2.27E-02	2.36E-03	1.13E-03
Formaldehyde	7.89E-05	lb/MMBtu	9.28E-03	9.63E-04	4.64E-04
Acetaldehyde	2.52E-05	lb/MMBtu	2.96E-03	3.08E-04	1.48E-04
Acrolein	7.88E-06	lb/MMBtu	9.27E-04	9.62E-05	4.63E-05
Naphthalene	1.30E-04	lb/MMBtu	1.53E-02	1.59E-03	7.64E-04
Polycyclic Aromatic Hydrocarbons (PAH)	2.12E-04	lb/MMBtu	2.49E-02	2.59E-03	1.25E-03
Max HAP			***9.13E-02***	***9.48E-03***	***4.56E-03***
Total HAPs			***2.00E-01***	***2.08E-02***	***1.00E-02***

1. Emission factors Per AP-42 Section 3.4, Large Stationary Diesel and All Stationary Dual-fuel Engines Tables 3.4-3 and 3.4-4.
Additional polycyclic aromatic hydrocarbon may be emitted but for regulatory purposes, this list is only inclusive of HAPs regulated under the clean air act.

Table 14e. Natural Gas Engine HAP Emissions

Pollutant	Emission Factor[1]	Units	Hourly Emissions	Hourly Emissions for New/Revised Units	Annual Emissions
			lb/hr	lb/hr	tpy
1,1,2,2-Tetrachloroethane	4.00E-05	lb/MMBtu	1.36E-04	0.00E+00	6.82E-06
1,1,2-Trichloroethane	3.18E-05	lb/MMBtu	1.09E-04	0.00E+00	5.43E-06
1,3-Butadiene	2.67E-04	lb/MMBtu	9.11E-04	0.00E+00	4.56E-05
1,3-Dichloropropene	2.64E-05	lb/MMBtu	9.01E-05	0.00E+00	4.50E-06
2-Methylnaphthalene	3.32E-05	lb/MMBtu	1.13E-04	0.00E+00	5.66E-06
2,2,4-Trimethylpentane	2.50E-04	lb/MMBtu	8.53E-04	0.00E+00	4.27E-05
Acenaphthene	1.25E-06	lb/MMBtu	4.27E-06	0.00E+00	2.13E-07
Acenaphthylene	5.53E-06	lb/MMBtu	1.89E-05	0.00E+00	9.43E-07
Acetaldehyde	8.36E-03	lb/MMBtu	2.85E-02	0.00E+00	1.43E-03
Acrolein	5.14E-03	lb/MMBtu	1.75E-02	0.00E+00	8.77E-04
Benzene	4.40E-04	lb/MMBtu	1.50E-03	0.00E+00	7.51E-05
Benzo(b)fluoranthene	1.66E-07	lb/MMBtu	5.66E-07	0.00E+00	2.83E-08
Benzo(e)pyrene	4.15E-07	lb/MMBtu	1.42E-06	0.00E+00	7.08E-08
Benzo(g,h,i)perylene	4.14E-07	lb/MMBtu	1.41E-06	0.00E+00	7.06E-08
Biphenyl	2.12E-04	lb/MMBtu	7.23E-04	0.00E+00	3.62E-05
Carbon Tetrachloride	3.67E-05	lb/MMBtu	1.25E-04	0.00E+00	6.26E-06
Chlorobenzene	3.04E-05	lb/MMBtu	1.04E-04	0.00E+00	5.19E-06
Chloroform	2.85E-05	lb/MMBtu	9.72E-05	0.00E+00	4.86E-06
Chrysene	6.93E-07	lb/MMBtu	2.36E-06	0.00E+00	1.18E-07
Ethylbenzene	3.97E-05	lb/MMBtu	1.35E-04	0.00E+00	6.77E-06
Ethylene Dibromide	4.43E-05	lb/MMBtu	1.51E-04	0.00E+00	7.56E-06
Fluoranthene	1.10E-06	lb/MMBtu	3.75E-06	0.00E+00	1.88E-07
Fluorene	5.67E-06	lb/MMBtu	1.93E-05	0.00E+00	9.67E-07
Formaldehyde	5.28E-02	lb/MMBtu	1.80E-01	0.00E+00	9.01E-03
Methanol	2.50E-03	lb/MMBtu	8.53E-03	0.00E+00	4.27E-04
Methylene Chloride	2.00E-05	lb/MMBtu	6.82E-05	0.00E+00	3.41E-06
Hexane	1.11E-03	lb/MMBtu	3.79E-03	0.00E+00	1.89E-04
Naphthalene	7.44E-05	lb/MMBtu	2.54E-04	0.00E+00	1.27E-05
Polycyclic Aromatic Hydrocarbons (PAH)	2.69E-05	lb/MMBtu	9.18E-05	0.00E+00	4.59E-06
Phenanthrene	1.04E-05	lb/MMBtu	3.55E-05	0.00E+00	1.77E-06
Phenol	2.40E-05	lb/MMBtu	8.19E-05	0.00E+00	4.09E-06
Pyrene	1.36E-06	lb/MMBtu	4.64E-06	0.00E+00	2.32E-07
Styrene	2.36E-05	lb/MMBtu	8.05E-05	0.00E+00	4.03E-06
Tetrachloroethane	2.48E-06	lb/MMBtu	8.46E-06	0.00E+00	4.23E-07
Toluene	4.08E-04	lb/MMBtu	1.39E-03	0.00E+00	6.96E-05
Vinyl Chloride	1.49E-05	lb/MMBtu	5.08E-05	0.00E+00	2.54E-06
Xylene	1.84E-04	lb/MMBtu	6.28E-04	0.00E+00	3.14E-05
Max HAP			***1.80E-01***	***0.00E+00***	***9.01E-03***
Total HAPs			***2.46E-01***	***0.00E+00***	***1.23E-02***

1. Per AP-42 Section 3.2, Table 3.2-2

University of Utah Emission Inventory - Draft

Table 1a. Unversity of Utah Emissions Summary

Unit Group	Potential Annual Emissions Estimate (tpy)						
	NO_X	CO	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC
UCHTWP	14.70	27.35	2.93	2.92	2.92	0.20	1.79
LCHTWP	21.52	31.08	2.91	2.91	2.91	0.23	2.10
Hospital Boilers	2.39	1.98	0.19	0.18	0.18	0.01	0.13
Huntsman Cancer Center Boilers	4.59	3.84	0.35	0.35	0.35	0.03	0.25
All Other Primary Boilers	0.72	0.60	0.05	0.05	0.05	0.00	0.04
All Other Backup Boilers	0.47	0.40	0.04	0.04	0.04	0.00	0.03
Small Diesel Engines	12.63	4.25	0.85	0.85	0.85	1.11	1.36
Large Diesel Engines	44.25	18.76	0.51	0.51	0.51	0.03	1.47
Natural Gas Engines	0.70	0.05	0.00	0.00	0.00	0.00	0.20
Carpentary Shop			7.21	7.21	7.21		
Flash Ironmaking							
Parts Washer							
Print Plant							
Paint Booth							
Ethylene Oxide Sterilizer							1.00
Underground Storage Tanks							
Total	101.97	88.31	15.04	15.02	15.01	1.61	8.37
Permit Limit	100.05	128.09	19.29	19.29	19.29	3.85	14.07
Exceeding Permit Limit	Yes	No	No	No	No	No	No
Comparison to Permit Limit	2%	-45%	-28%	-28%	-28%	-139%	-68%

Table 1b. Natural Gas Limits

Parameter	Value	Units
Total Natural Gas Usage Accounted For (Boilers Only)	1,552.35	MMscf/yr
Total Natural Gas Usage Permitted (Boilers Only)	1,624.68	MMscf/yr

Table 2a. UCHTWP Boiler Parameters

Parameter	Value	Units
Unit 1 Input Heat Capacity[1]	87.5	MMBtu/hr
Unit 3 Input Heat Capacity[1]	87.5	MMBtu/hr
Unit 4 Input Heat Capacity[1]	87.5	MMBtu/hr
Total Input Heat Capacity	262.5	MMBtu/hr
Total Potential MMBtu Production in a Year	2,299,500	MMBtu/yr
Permitted Time for Diesel Usage (Maintenance Only)[2]	8	hr/yr
Total Potential Diesel Usage	15.00	10^3 gal/yr
Natural Gas Usage Reported[3]	591.17	MMscf/yr
Potential Natural Gas Usage Factor[4]	10.00	%
Total Potential Natural Gas Usage	650.29	MMscf/yr
Results Hours of Operation	2,217.18	hr/yr
Resulting Hourly Natural Gas Usage	0.29	MMscf/hr

1. DAQE-AN103540025-13 Condition II.A.5
2. DAQE-AN103540025-13 Condition II.B.2.a
3. Natural Gas quantities are representative of 2016 quantities. (File names: Copy of Natural Gas Totals 1-2013 to 02-2017 and Copy of the EHS Gas Report 3-16-17)
4. The Usage Factor has been included to account for operational varability and contingencies which are encompassed in University Operations.

Table 2b. UCHTWP Boiler Emission Factors

Pollutant	Natural Gas		Diesel	
	Value	Unit	Value	Unit
NO_x[1,3]	0.050	lb/MMBtu	20.00	lb/10^3 gal
CO[2,3]	84	lb/MMscf	5.00	lb/10^3 gal
PM[1,3]	0.010	lb/MMBtu	3.30	lb/10^3 gal
PM_{10}[1,3]	0.010	lb/MMBtu	1.82	lb/10^3 gal
$PM_{2.5}$[1,3]	0.010	lb/MMBtu	1.39	lb/10^3 gal
SO_2[2,3]	0.60	lb/MMscf	0.21	lb/10^3 gal
VOC[2,3]	5.5	lb/MMscf	0.20	lb/10^3 gal

1. Natural Gas Emission Factor from Manufacturer Provided Data (per 2014 Emission Inventory),
2. Natural Gas Emission Factor from AP-42 Section 1.4
3. Diesel Emission Factor from AP-42 Section 1.3

Table 2c. UCHTWP Boiler Emissions

Pollutant	Natural Gas Emissions		Diesel Emissions		Maximum Potential Emissions	
	Hourly	Annually	Hourly	Annually	Hourly	Annually
	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
NO_x	13.13	14.55	37.50	0.15	50.63	14.70
CO	24.64	27.31	9.38	0.038	34.01	27.35
PM	2.63	2.91	6.19	0.025	8.81	2.93
PM_{10}	2.63	2.91	3.40	0.014	6.03	2.92
$PM_{2.5}$	2.63	2.91	2.60	0.010	5.22	2.92
SO_2	0.18	0.20	0.40	0.0016	0.58	0.20
VOC	1.61	1.79	0.38	0.0015	1.99	1.79

Table 3a. LCHTWP Boiler Parameters

Parameter	Value	Units
Unit 3 Input Heat Capacity[1]	105	MMBtu/hr
Unit 4 Input Heat Capacity[1]	105	MMBtu/hr
Unit 5 Input Heat Capacity[1]	50	MMBtu/hr
Unit 6 Input Heat Capacity[1]	50	MMBtu/hr
Total Input Heat Capacity	310	MMBtu/hr
Boiler Natural Gas Usage Reported[2]	223.25	MMscf/yr
Potential Natural Gas Usage Factor[3]	10.00	%
Total Potential Natural Gas Usage	245.57	MMscf/yr
Average Usage Factor: Boilers 3 and 4[4]	10.00	%
Resulting Annual Natural Gas Usage: Boilers 3 and 4	24.56	MMscf/yr
Resulting Hours of Operation: Boilers 3 and 4	104.66	hr/yr
Resulting Hourly Natural Gas Usage: Boilers 3 and 4	2.35	MMscf/hr
Average Usage Factor: Boilers 6 and 7[4]	90.00	%
Resulting Annual Natural Gas Usage: Boilers 6 and 7	221.02	MMscf/yr
Resulting Hours of Operation: Boilers 6 and 7	1,978.12	hr/yr
Resulting Hourly Natural Gas Usage: Boilers 6 and 7	0.11	MMscf/hr

1. DAQE-AN103540025-13 Condition II.A.6 and II.A.7
2. Natural Gas quantities are representative of 2016 quantities (File names: Copy of Natural Gas Totals 1-2013 to 02-2017 and Copy of the EHS Gas Report 3-16-17)
3. The Usage Factor has been included to account for operational varability and contingencies which are encompassed in University Operations.
4. Average usage factor is based on current understanding of the distribution of heating needs

Table 3b. LCHTWP Turbine Parameters

Parameter	Value	Units
Cogeneration System Heat Capacity[1]	62.49	MMBtu/hr
Natural Gas Usage Reported[2]	382.84	MMscf/yr
Potential Natural Gas Usage Factor[3]	55.00	%
Total Potential Natural Gas Usage	593.40	MMscf/yr
Results Hours of Operation	8,498.97	hr/yr
Resulting Hourly Natural Gas Usage	0.070	MMscf/hr

1. Based on Cogeneration permitting application (note some of the fuel is used to produce electricty and some to fuel the WHRU).
2. Natural Gas quantities are representative of 2016 quantities, (File names: Copy of Natural Gas Totals 1-2013 to 02-2017 and Copy of the EHS Gas Report 3-16-17)
3. The Usage Factor has been included to account for operational varability and contingencies which are encompassed in University Operations.

Table 3c. LCHTWP WHRU Parameters

Parameter	Value	Units
Cogeneration System Heat Capacity[1]	71.16	MMBtu/hr
Natural Gas Usage Reported[2]	150.46	MMscf/yr
Potential Natural Gas Usage Factor[3]	245.00	%
Total Potential Natural Gas Usage	519.09	MMscf/yr
Results Hours of Operation	6,528.77	hr/yr
Resulting Hourly Natural Gas Usage	0.080	MMscf/hr

1. Based on Cogeneration permitting application (note some of the fuel is used to produce electricty and some to fuel the WHRU).
2. Natural Gas quantities are representative of 2016 quantities. (File names: Copy of Natural Gas Totals 1-2013 to 02-2017 and Copy of the EHS Gas Report 3-16-17)
3. The Usage Factor has been included to account for operational varability and contingencies which are encompassed in University Operations.

Table 3d. LCHTWP Emssion Factors

Pollutant	Units 3 and 4		Units 6 and 7		Turbine Only		Turbine and WHRU	
	Value	Unit	Value	Unit	Value	Unit	Value	Unit
NO_x[1]	12.285	lb/hr	0.25	lb/hr	2.65	lb/hr	6.32	lb/hr
CO[1,2]	84.00	lb/MMscf	84.00	lb/MMscf	4.48	lb/hr	6.36	lb/hr
PM[2,3]	7.60	lb/MMscf	7.60	lb/MMscf	0.021	lb/MMscf	7.60	lb/MMscf
PM_{10}[2,3]	7.60	lb/MMscf	7.60	lb/MMscf	0.021	lb/MMscf	7.60	lb/MMscf
$PM_{2.5}$[2,3]	7.60	lb/MMscf	7.60	lb/MMscf	0.021	lb/MMscf	7.60	lb/MMscf
SO_2[2]	0.60	lb/MMscf	0.60	lb/MMscf	0.60	lb/MMscf	0.60	lb/MMscf
VOC[2,3]	5.50	lb/MMscf	5.50	lb/MMscf	0.01	lb/MMBtu	5.50	lb/MMscf

1. DAQE-AN103540025-13 Condition II.B.2.a
2. Natural Gas Emission Factor from AP-42 Section 1.4
3. Natural Gas Emission Factor from Manufacturer Provided Data (per 2014 Emission Inventory)

Table 3e. LCHTWP Emssions

Pollutant	Units 3 and 4		Units 6 and 7		Turbine Only		WHRU Only		Maximum Potential Emissions	
	Hourly (lb/hr)	Annually (tpy)	Hourly (lb/hr)	Annually (tpy)	Hourly (lb/hr)	Annually (tpy)	Hourly (lb/hr)	Annually (tpy)	Hourly (lb/hr)	Annually (tpy)
NO_x	12.29	0.64	0.25	0.25	2.65	11.26	6.32	20.63	18.86	21.52
CO	197.09	1.03	9.39	9.28	4.48	19.04	6.36	20.76	212.84	31.08
PM	17.83	0.09	0.85	0.84	1.47E-03	6.23E-03	0.604	1.97	19.29	2.91
PM_{10}	17.83	0.09	0.85	0.84	1.47E-03	6.23E-03	0.604	1.97	19.29	2.91
$PM_{2.5}$	17.83	0.09	0.85	0.84	1.47E-03	6.23E-03	0.604	1.97	19.29	2.91
SO_2	1.41	0.01	0.07	0.07	4.19E-02	1.78E-01	0.048	0.16	1.52	0.23
VOC	12.90	0.07	0.61	0.61	0.79	3.35	0.437	1.43	13.96	2.10

Table 4a. Hospital Boiler Parameters

Parameter	Value	Units
Building 521 Input Heat Capacity[1]	10.5	MMBtu/hr
Building 525 Input Heat Capacity[1]	10.5	MMBtu/hr
Building 532 (Unit 1) Input Heat Capacity[1]	25.2	MMBtu/hr
Building 532 (Unit 2) Input Heat Capacity[1]	25.2	MMBtu/hr
Total Input Heat Capacity	71.4	MMBtu/hr
Total Potential MMBTU Production in a Year	625,464	MMBtu/yr
Permitted Time for Diesel Usage (Maintenance Only)[2]	8	hr/yr
Total Potential Diesel Usage	4.08	10^3 gal/yr
Natural Gas Usage Reported[3]	39.11	MMscf/yr
Potential Natural Gas Usage Factor[4]	20.00	%
Total Potential Natural Gas Usage	46.93	MMscf/yr
Results Hours of Operation	588.26	hr/yr
Resulting Hourly Natural Gas Usage	0.080	MMscf/hr

1. DAQE-AN103540025-13 Condition II.A.10 and II.A.12
2. DAQE-AN103540025-13 Condition II.B.2.a and evaluated base on the University Operations.
3. Natural Gas quantities are representative of 2016 quantities. (File names: Copy of Natural Gas Totals 1-2013 to 02-2017 and Copy of the EHS Gas Report 3-16-17)
4. The Usage Factor has been included to account for operational varability and contingencies which are encompassed in University Operations.

Table 4b. Hospital Boiler Emssion Factors

Pollutant	Natural Gas		Diesel	
	Value	Unit	Value	Unit
NO_x[1,2]	100	lb/MMscf	20	lb/10^3 gal
CO[1,2]	84.00	lb/MMscf	5	lb/10^3 gal
PM[1,2]	7.6	lb/MMscf	3.30	lb/10^3 gal
PM_{10}[1,2]	7.6	lb/MMscf	1.82	lb/10^3 gal
$PM_{2.5}$[1,2]	7.6	lb/MMscf	1.39	lb/10^3 gal
SO_2[1,2]	0.60	lb/MMscf	0.21	lb/10^3 gal
VOC[1,2]	5.50	lb/MMscf	0.20	lb/10^3 gal

1. Natural Gas Emission Factor from AP-42 Section 1.4
2. Diesel Emission Factor from AP-42 Section 1.3

Table 4c. Hospital Boiler Emssions

Pollutant	Natural Gas Emissions		Diesel Emissions		Maximum Potenial Emissions	
	Hourly (lb/hr)	Annually (tpy)	Hourly (lb/hr)	Annually (tpy)	Hourly (lb/hr)	Annually (tpy)
NO_x	7.98	2.35	10.20	0.04	18.18	2.39
CO	6.70	1.97	2.55	0.01	9.25	1.98
PM	0.61	0.18	1.68	0.01	2.29	0.19
PM_{10}	0.61	0.18	0.93	0.00	1.53	0.18
$PM_{2.5}$	0.61	0.18	0.71	0.00	1.31	0.18
SO_2	0.05	0.01	0.11	0.00	0.16	0.01
VOC	0.44	0.13	0.10	0.00	0.54	0.13

Table 5a. Huntsman Boiler Parameters

Parameter	Value	Units
Building 555 (Unit 1) Input Heat Capacity[1]	16.8	MMBtu/hr
Building 555 (Unit 2) Input Heat Capacity[1]	16.8	MMBtu/hr
Building 555 (Unit 3) Input Heat Capacity[1]	5	MMBtu/hr
Building 555 (Unit 4) Input Heat Capacity[1]	5	MMBtu/hr
Building 556 (Unit 1) Input Heat Capacity[1]	6	MMBtu/hr
Building 556 (Unit 2) Input Heat Capacity[1]	6	MMBtu/hr
Total Input Heat Capacity	55.6	MMBtu/hr
Total Potential MMBTU Production in a Year	487,056	MMBtu/yr
Permitted Time for Diesel Usage (Maintenance Only)[2]	8	hr/yr
Total Potential Diesel Usage	3.18	10^3 gal/yr
Natural Gas Usage Reported[3]	75.96	MMscf/yr
Potential Natural Gas Usage Factor[4]	20.00	%
Total Potential Natural Gas Usage	91.16	MMscf/yr
Results Hours of Operation	1,074.01	hr/yr
Resulting Hourly Natural Gas Usage	0.085	MMscf/hr

.1. DAQE-AN103540025-13 Condition II.A.13 and II.A.14

2.DAQE-AN103540025-13 Condition II.B.2.a and evaluated base on the University Operations.

3. Natural Gas quantities are representative of 2016 quantities. (File names: Copy of Natural Gas Totals 1-2013 to 02-2017 and Copy of the EHS Gas Report 3-16-17)

4. The Usage Factor has been included to account for operational varability and contingencies which are encompassed in University Operations.

Table 5b. Huntsman Boiler Emssion Factors

Pollutant	Natural Gas		Diesel	
	Value	Unit	Value	Unit
NO_x[1,2]	100	lb/MMscf	20.00	lb/10^3 gal
CO[1,2]	84.00	lb/MMscf	5.00	lb/10^3 gal
PM[1,2]	7.6	lb/MMscf	3.30	lb/10^3 gal
PM_{10}[1,2]	7.6	lb/MMscf	1.82	lb/10^3 gal
$PM_{2.5}$[1,2]	7.6	lb/MMscf	1.39	lb/10^3 gal
SO_2[1,2]	0.60	lb/MMscf	0.21	lb/10^3 gal
VOC[1,2]	5.50	lb/MMscf	0.20	lb/10^3 gal

1. Natural Gas Emission Factor from AP-42 Section 1.4
2. Diesel Emission Factor from AP-42 Section 1.3

Table 5c. Huntsman Boiler Emssions

Pollutant	Natural Gas Emissions		Diesel Emissions		Maximum Potenial Emissions	
	Hourly (lb/hr)	Annually (tpy)	Hourly (lb/hr)	Annually (tpy)	Hourly (lb/hr)	Annually (tpy)
NO_x	8.49	4.56	7.94	0.03	16.43	4.59
CO	7.13	3.83	1.99	0.01	9.12	3.84
PM	0.65	0.35	1.31	0.01	1.96	0.35
PM_{10}	0.65	0.35	0.72	0.00	1.37	0.35
$PM_{2.5}$	0.65	0.35	0.55	0.00	1.20	0.35
SO_2	0.05	0.03	0.08	0.00	0.14	0.03
VOC	0.47	0.25	0.08	0.00	0.55	0.25

Table 6a. Miscellaneous Primary Boiler Parameters

Parameter	Value	Units
Building 32 West Input Heat Capacity[1]	14.7	MMBtu/hr
Building 33 Input Heat Capacity[1]	5.25	MMBtu/hr
Building 853 (Unit 1) Input Heat Capacity[1]	2	MMBtu/hr
Building 853 (Unit 2) Input Heat Capacity[1]	2	MMBtu/hr
Building 587 (Unit 1) Input Heat Capacity[1]	13.5	MMBtu/hr
Building 587 (Unit 2) Input Heat Capacity[1]	13.5	MMBtu/hr
Building 865 Input Heat Capacity[1]	10	MMBtu/hr
Total Input Heat Capacity	60.95	MMBtu/hr
Natural Gas Usage Reported[2]	13.72	MMscf/yr
Potential Natural Gas Usage Factor[3]	5.00	%
Total Potential Natural Gas Usage	14.40	MMscf/yr
Resulting Cummulative Hours of Operation	211.47	hr/yr
Resulting Hourly Natural Gas Usage	0.068	MMscf/hr

1. DAQE-AN103540025-13 Conditions II.A.2, II.A.3, II.A.16, II.A.18, and II.A.19
3. Natural Gas quantities are representative of 2016 quantities.
(File names: Copy of Natural Gas Totals 1-2013 to 02-2017 and Copy of the EHS Gas Report 3-16-17)
4. The Usage Factor has been included to account for operational varability and contingencies which are encompassed in University Operations.

Table 6b. Miscellaneous Primary Boiler Emssion Factors

Pollutant	Natural Gas	
	Value	Unit
NO_x[1,2]	100	lb/MMscf
CO[1,2]	84	lb/MMscf
PM[1,2]	7.6	lb/MMscf
PM_{10}[1,2]	7.6	lb/MMscf
$PM_{2.5}$[1,2]	7.6	lb/MMscf
SO_2[1,2]	0.60	lb/MMscf
VOC[1,2]	5.5	lb/MMscf

1. Natural Gas Emission Factor from AP-42 Section 1.4

Table 6c. Miscellaneous Primary Boiler Emssions

Pollutant	Natural Gas Emissions	
	Hourly (lb/hr)	Annually (tpy)
NO_x	6.81	0.72
CO	5.72	0.60
PM	0.52	0.05
PM_{10}	0.52	0.05
$PM_{2.5}$	0.52	0.05
SO_2	0.04	0.00
VOC	0.37	0.04

Table 7a. Miscellaneous Backup Boiler Parameters

Parameter	Value	Units
Building 151 Input Heat Capacity[1]	20.67	MMBtu/hr
Building 523 Input Heat Capacity[1]	8.2	MMBtu/hr
Building 565 Input Heat Capacity[1]	19	MMBtu/hr
Building 581 Input Heat Capacity[1]	17	MMBtu/hr
Total Input Heat Capacity	64.87	MMBtu/hr
Total Potential MMBTU Production in a Year	568,261	MMBtu/yr
Natural Gas Usage Reported[2]	8.61	MMscf/yr
Potential Natural Gas Usage Factor[3]	10.00	%
Total Potential Natural Gas Usage	9.47	MMscf/yr
Results Hours of Operation	130.71	hr/yr
Resulting Hourly Natural Gas Usage	0.07	MMscf/hr

1. DAQE-AN103540025-13 Conditions II.A.4, II.A.11, II.A.15, and II.A.17.
3. Natural Gas quantities are representative of 2016 quantities.
(File names: Copy of Natural Gas Totals 1-2013 to 02-2017 and Copy of the EHS Gas Report 3-16-17)

4. The Usage Factor has been included to account for operational varability and contingencies which are encompassed in University Operations.

Table 7b. Miscellaneous Backup Boiler Emssion Factors

Pollutant	Natural Gas	
	Value	Unit
NO_x [1,2]	100	lb/MMscf
CO[1,2]	84	lb/MMscf
PM[1,2]	7.6	lb/MMscf
PM_{10} [1,2]	7.6	lb/MMscf
$PM_{2.5}$ [1,2]	7.6	lb/MMscf
SO_2 [1,2]	0.60	lb/MMscf
VOC[1,2]	5.5	lb/MMscf

1. Natural Gas Emission Factor from AP-42 Section 1.4

Table 7c. Miscellaneous Backup Boiler Emssions

Pollutant	Natural Gas Emissions Hourly (lb/hr)	Natural Gas Emissions Annually (tpy)
NO_x	7.25	0.47
CO	6.09	0.40
PM	0.55	0.04
PM_{10}	0.55	0.04
$PM_{2.5}$	0.55	0.04
SO_2	0.04	0.00
VOC	0.40	0.03

Table 8. Small Diesel Engine Capacities & Emissions

Location	Tier Rating	Capacity[1]	Reference #	Hourly Emissions (lb/hr)[2]							Annual Emissions (tpy)[3]						
		(hp)		NO_X	CO	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC	NO_X	CO	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC
Building 213	Pre-Tier System	20	1	0.62	0.13	0.04	0.04	0.04	0.04	0.05	0.03	0.01	0.00	0.00	0.00	0.00	0.00
Building 149	Tier 4i	27	5	0.33	0.25	0.01	0.01	0.01	0.06	0.07	0.02	0.01	0.00	0.00	0.00	0.00	0.00
Building 205	Unknown	27	1	0.84	0.18	0.06	0.06	0.06	0.06	0.07	0.04	0.01	0.00	0.00	0.00	0.00	0.00
Building 305	Tier 2	27	3	0.33	0.25	0.03	0.03	0.03	0.06	0.07	0.02	0.01	0.00	0.00	0.00	0.00	0.00
Building 540	Pre-Tier System	27	1	0.84	0.18	0.06	0.06	0.06	0.06	0.07	0.04	0.01	0.00	0.00	0.00	0.00	0.00
Building 19	Pre-Tier System	34	1	1.05	0.23	0.07	0.07	0.07	0.07	0.09	0.05	0.01	0.00	0.00	0.00	0.00	0.00
Building 28	Unknown	34	1	1.05	0.23	0.07	0.07	0.07	0.07	0.09	0.05	0.01	0.00	0.00	0.00	0.00	0.00
Building 210	Unknown	34	1	1.05	0.23	0.07	0.07	0.07	0.07	0.09	0.05	0.01	0.00	0.00	0.00	0.00	0.00
Building 500	Pre-Tier System	34	1	1.05	0.23	0.07	0.07	0.07	0.07	0.09	0.05	0.01	0.00	0.00	0.00	0.00	0.00
Building 876	Unknown	40	1	1.24	0.27	0.09	0.09	0.09	0.08	0.10	0.06	0.01	0.00	0.00	0.00	0.00	0.01
Building 66	Unknown	47	1	1.46	0.31	0.10	0.10	0.10	0.10	0.12	0.07	0.02	0.01	0.01	0.01	0.00	0.01
Building 815	Tier 1	47	2	0.74	0.43	0.06	0.06	0.06	0.10	0.12	0.04	0.02	0.00	0.00	0.00	0.00	0.01
Building 49	Unknown	54	1	1.67	0.36	0.12	0.12	0.12	0.11	0.14	0.08	0.02	0.01	0.01	0.01	0.01	0.01
Building 26	Tier 4 Option 1	67	6	0.52	0.55	0.03	0.03	0.03	0.14	0.17	0.03	0.03	0.00	0.00	0.00	0.01	0.01
Building 110	Unknown	67	1	2.08	0.45	0.15	0.15	0.15	0.14	0.17	0.10	0.02	0.01	0.01	0.01	0.01	0.01
Building 372	Unknown	67	1	2.08	0.45	0.15	0.15	0.15	0.14	0.17	0.10	0.02	0.01	0.01	0.01	0.01	0.01
Building 53	Unknown	74	1	2.29	0.49	0.16	0.16	0.16	0.15	0.19	0.11	0.02	0.01	0.01	0.01	0.01	0.01
Building 301	Tier 2	80	7	0.99	0.66	0.05	0.05	0.05	0.16	0.20	0.05	0.03	0.00	0.00	0.00	0.01	0.01
Building 512	Unknown	80	1	2.48	0.53	0.18	0.18	0.18	0.16	0.20	0.12	0.03	0.01	0.01	0.01	0.01	0.01
Building 892	Unkown	100	1	3.10	0.67	0.22	0.22	0.22	0.21	0.25	0.16	0.03	0.01	0.01	0.01	0.01	0.01
Building 197	Tier 1	107	8	1.33	0.88	0.07	0.07	0.07	0.22	0.27	0.07	0.04	0.00	0.00	0.00	0.01	0.01
Building 4	Tier 1	134	8	1.66	1.11	0.09	0.09	0.09	0.27	0.34	0.08	0.06	0.00	0.00	0.00	0.01	0.02
Building 14	Pre-Tier System	134	1	4.15	0.90	0.29	0.29	0.29	0.27	0.34	0.21	0.04	0.01	0.01	0.01	0.01	0.02
Building 25	Unkown	134	1	4.15	0.90	0.29	0.29	0.29	0.27	0.34	0.21	0.04	0.01	0.01	0.01	0.01	0.02
Building 57	Pre-Tier System	134	1	4.15	0.90	0.29	0.29	0.29	0.27	0.34	0.21	0.04	0.01	0.01	0.01	0.01	0.02
Building 64	Tier 1	134	8	1.66	1.11	0.09	0.09	0.09	0.27	0.34	0.08	0.06	0.00	0.00	0.00	0.01	0.02
Building 585	Tier 2	134	9	1.66	1.11	0.09	0.09	0.09	0.27	0.34	0.08	0.06	0.00	0.00	0.00	0.01	0.02
Building 800	Unknown	134	1	4.15	0.90	0.29	0.29	0.29	0.27	0.34	0.21	0.04	0.01	0.01	0.01	0.01	0.02
Building 887	Unkown	167	1	5.18	1.12	0.37	0.37	0.37	0.34	0.42	0.26	0.06	0.02	0.02	0.02	0.02	0.02
Building 7	Unkown	168	1	5.21	1.12	0.37	0.37	0.37	0.34	0.42	0.26	0.06	0.02	0.02	0.02	0.02	0.02
Building 212	Tier 1	168	8	2.08	1.39	0.11	0.11	0.11	0.34	0.42	0.10	0.07	0.01	0.01	0.01	0.02	0.02
Building 13	Tier 1	201	10	3.06	3.79	0.18	0.18	0.18	0.41	0.51	0.15	0.19	0.01	0.01	0.01	0.02	0.03
Building 112	Unknown	201	1	6.23	1.34	0.44	0.44	0.44	0.41	0.51	0.31	0.07	0.02	0.02	0.02	0.02	0.03
Building 701	Tier 3	201	12	1.33	1.16	0.07	0.07	0.07	0.41	0.51	0.07	0.06	0.00	0.00	0.00	0.02	0.03
Building 702	Tier 3	201	12	1.33	1.16	0.07	0.07	0.07	0.41	0.51	0.07	0.06	0.00	0.00	0.00	0.02	0.03
Building 840	Unknown	201	1	6.23	1.34	0.44	0.44	0.44	0.41	0.51	0.31	0.07	0.02	0.02	0.02	0.02	0.03
Building 853	Tier 3	201	12	1.33	1.16	0.07	0.07	0.07	0.41	0.51	0.07	0.06	0.00	0.00	0.00	0.02	0.03
Building 35	Tier 1	208	10	3.16	3.92	0.19	0.19	0.19	0.43	0.52	0.16	0.20	0.01	0.01	0.01	0.02	0.03
Building 801	Tier 2	229	11	2.50	1.33	0.08	0.08	0.08	0.47	0.58	0.12	0.07	0.00	0.00	0.00	0.02	0.03
Building 347	Pre-Tier System	241	1	7.47	1.61	0.53	0.53	0.53	0.49	0.61	0.37	0.08	0.03	0.03	0.03	0.02	0.03
Building 84	Unknown	260	1	8.06	1.74	0.57	0.57	0.57	0.53	0.65	0.40	0.09	0.03	0.03	0.03	0.03	0.03
Building 84	Unknown	260	1	8.06	1.74	0.57	0.57	0.57	0.53	0.65	0.40	0.09	0.03	0.03	0.03	0.03	0.03
Building 587	Unknown	268	1	8.31	1.79	0.59	0.59	0.59	0.55	0.67	0.42	0.09	0.03	0.03	0.03	0.03	0.03
Building 821	Tier 1	268	10	4.08	5.05	0.24	0.24	0.24	0.55	0.67	0.20	0.25	0.01	0.01	0.01	0.03	0.03
Building 71	Unknown	308	1	9.55	2.06	0.68	0.68	0.68	0.63	0.77	0.48	0.10	0.03	0.03	0.03	0.03	0.04
Building 12	Tier 3	335	15	2.22	1.94	0.11	0.11	0.11	0.69	0.84	0.11	0.10	0.01	0.01	0.01	0.03	0.04
Building 588	Unkown	335	1	10.39	2.24	0.74	0.74	0.74	0.69	0.84	0.52	0.11	0.04	0.04	0.04	0.03	0.04
Ambulatory Care Center Parking	Unkown	335	1	10.39	2.24	0.74	0.74	0.74	0.69	0.84	0.52	0.11	0.04	0.04	0.04	0.03	0.04
Building 82	Tier 1	402	13	6.12	7.58	0.36	0.36	0.36	0.82	1.01	0.31	0.38	0.02	0.02	0.02	0.04	0.05
Building 892	Unkown	402	1	12.46	2.69	0.88	0.88	0.88	0.82	1.01	0.62	0.13	0.04	0.04	0.04	0.04	0.05
Building 575	Tier 2	476	14	5.04	2.75	0.16	0.16	0.16	0.98	1.20	0.25	0.14	0.01	0.01	0.01	0.05	0.06
Building 523	Unkown	536	1	16.62	3.58	1.18	1.18	1.18	1.10	1.35	0.83	0.18	0.06	0.06	0.06	0.05	0.07
Building 851	Unknown	536	1	16.62	3.58	1.18	1.18	1.18	1.10	1.35	0.83	0.18	0.06	0.06	0.06	0.05	0.07
Building 851	Unknown	536	1	16.62	3.58	1.18	1.18	1.18	1.10	1.35	0.83	0.18	0.06	0.06	0.06	0.05	0.07
Building 874	Tier 2	539	14	5.70	3.12	0.18	0.18	0.18	1.10	1.36	0.29	0.16	0.01	0.01	0.01	0.06	0.07
Building 95	Unknown	600	1	18.60	4.01	1.32	1.32	1.32	1.23	1.51	0.93	0.20	0.07	0.07	0.07	0.06	0.08
Building 79	Unknown	260	1	8.06	1.74	0.57	0.57	0.57	0.53	0.65	0.40	0.09	0.03	0.03	0.03	0.03	0.03
Building 865	Unknown	201	1	6.23	1.34	0.44	0.44	0.44	0.41	0.51	0.31	0.07	0.02	0.02	0.02	0.02	0.03
Total Emissions				**252.67**	**84.98**	**16.91**	**16.91**	**16.91**	**22.17**	**27.19**	**12.63**	**4.25**	**0.85**	**0.85**	**0.85**	**1.11**	**1.36**

1. If the Capcity was unknown a capcity of 600 hp was assumed.

2. Per AP-42 Section 3.3, Table 3.3-1 (Manufacturer specification sheets may contain lower emission factors.)

3. Assumed Maintenance and Testing for each engine to be: 100 hours for potential operation.

Table 9. Large Diesel Engine Capacities & Emissions

Location	Capacity (hp)	Tier Rating	Reference #	Hourly Emissions (lb/hr)[1]							Annual Emissions (tpy)[2]						
				NO_X	CO	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC	NO_X	CO	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC
Building 45	1,207	Unknown	1	28.97	6.64	0.00	0.00	0.00	0.01	0.85	1.45	0.33	0.00	0.00	0.00	0.00	0.04
Building 1	268	Unknown	1	6.43	1.47	0.00	0.00	0.00	0.00	0.19	0.32	0.07	0.00	0.00	0.00	0.00	0.01
Building 32	1,219	Pre-Tier Rating	1	29.26	6.71	0.00	0.00	0.00	0.01	0.86	1.46	0.34	0.00	0.00	0.00	0.00	0.04
Building 40	335	Unkown	1	8.04	1.84	0.00	0.00	0.00	0.00	0.24	0.40	0.09	0.00	0.00	0.00	0.00	0.01
Building 45	1,073	Unkown	1	25.75	5.90	0.00	0.00	0.00	0.01	0.76	1.29	0.30	0.00	0.00	0.00	0.00	0.04
Building 62	871	Tier 2	5	9.22	5.04	0.29	0.29	0.29	0.01	0.61	0.46	0.25	0.01	0.01	0.01	0.00	0.03
Building 74	670	Unknown	1	16.08	3.69	0.00	0.00	0.00	0.01	0.47	0.80	0.18	0.00	0.00	0.00	0.00	0.02
Building 85	900	Unknown	1	21.60	4.95	0.00	0.00	0.00	0.01	0.63	1.08	0.25	0.00	0.00	0.00	0.00	0.03
Building 85	900	Unknown	1	21.60	4.95	0.00	0.00	0.00	0.01	0.63	1.08	0.25	0.00	0.00	0.00	0.00	0.03
Building 86	2,011	Tier 1	6	30.59	37.91	1.80	1.80	1.80	0.02	1.42	1.53	1.90	0.09	0.09	0.09	0.00	0.07
Building 151	1,073	Unknown	1	25.75	5.90	0.00	0.00	0.00	0.01	0.76	1.29	0.30	0.00	0.00	0.00	0.00	0.04
Building 151	1,073	Unknown	1	25.75	5.90	0.00	0.00	0.00	0.01	0.76	1.29	0.30	0.00	0.00	0.00	0.00	0.04
Building 151	1,073	Unknown	1	25.75	5.90	0.00	0.00	0.00	0.01	0.76	1.29	0.30	0.00	0.00	0.00	0.00	0.04
Building 179	670	Unknown	1	16.08	3.69	0.00	0.00	0.00	0.01	0.47	0.80	0.18	0.00	0.00	0.00	0.00	0.02
Building 302	804	Tier 1	4	12.23	15.16	0.72	0.72	0.72	0.01	0.57	0.61	0.76	0.04	0.04	0.04	0.00	0.03
Building 303	804	Tier 2	5	8.51	4.65	0.27	0.27	0.27	0.01	0.57	0.43	0.23	0.01	0.01	0.01	0.00	0.03
Building 521/□25	670	Unknown	1	16.08	3.69	0.00	0.00	0.00	0.01	0.47	0.80	0.18	0.00	0.00	0.00	0.00	0.02
Building 521/□25	1,340	Unknown	1	32.16	7.37	0.00	0.00	0.00	0.02	0.94	1.61	0.37	0.00	0.00	0.00	0.00	0.05
Building 523	1,675	Unknown	1	40.20	9.21	0.00	0.00	0.00	0.02	1.18	2.01	0.46	0.00	0.00	0.00	0.00	0.06
Building 526	1,474	Unknown	1	35.38	8.11	0.00	0.00	0.00	0.02	1.04	1.77	0.41	0.00	0.00	0.00	0.00	0.05
Building 526	1,474	Unknown	1	35.38	8.11	0.00	0.00	0.00	0.02	1.04	1.77	0.41	0.00	0.00	0.00	0.00	0.05
Building 526	1,340	Unknown	1	32.16	7.37	0.00	0.00	0.00	0.02	0.94	1.61	0.37	0.00	0.00	0.00	0.00	0.05
Building 526	1,340	Unknown	1	32.16	7.37	0.00	0.00	0.00	0.02	0.94	1.61	0.37	0.00	0.00	0.00	0.00	0.05
Building 526	1,340	Unknown	1	32.16	7.37	0.00	0.00	0.00	0.02	0.94	1.61	0.37	0.00	0.00	0.00	0.00	0.05
Building 533	804	Pre-Tier System	1	19.30	4.42	0.00	0.00	0.00	0.01	0.57	0.96	0.22	0.00	0.00	0.00	0.00	0.03
Building 550	670	Pre-Tier System	1	16.08	3.69	0.00	0.00	0.00	0.01	0.47	0.80	0.18	0.00	0.00	0.00	0.00	0.02
Building 555	1,005	Unknown	1	24.12	5.53	0.00	0.00	0.00	0.01	0.71	1.21	0.28	0.00	0.00	0.00	0.00	0.04
Building 555	2,680	Unknown	1	64.32	14.74	0.00	0.00	0.00	0.03	1.89	3.22	0.74	0.00	0.00	0.00	0.00	0.09
Building 556	2,010	Tier 1	6	30.58	37.89	1.79	1.79	1.79	0.02	1.42	1.53	1.89	0.09	0.09	0.09	0.00	0.07
Building 556	2,010	Tier 1	6	30.58	37.89	1.79	1.79	1.79	0.02	1.42	1.53	1.89	0.09	0.09	0.09	0.00	0.07
Building 565	1,341	Tier 1	6	20.40	25.28	1.20	1.20	1.20	0.02	0.95	1.02	1.26	0.06	0.06	0.06	0.00	0.05
Building 570	1,481	Pre-Tier System	1	35.54	8.15	0.00	0.00	0.00	0.02	1.04	1.78	0.41	0.00	0.00	0.00	0.00	0.05
Building 581	2,682	Tier 2	6	40.80	50.55	2.39	2.39	2.39	0.03	1.89	2.04	2.53	0.12	0.12	0.12	0.00	0.09
Building 587	804	Unknown	1	19.30	4.42	0.00	0.00	0.00	0.01	0.57	0.96	0.22	0.00	0.00	0.00	0.00	0.03
Building 872	697	Unkown	1	16.73	3.83	0.00	0.00	0.00	0.01	0.49	0.84	0.19	0.00	0.00	0.00	0.00	0.02
Total Emissions				**885.02**	**375.27**	**10.25**	**10.25**	**10.25**	**0.51**	**29.46**	**44.25**	**18.76**	**0.51**	**0.51**	**0.51**	**0.03**	**1.47**

1. If the capcity was unknown an average capacity was used.

2. Per AP-42 Section 3.4, Table 3.4-1 (Manufacturer specification sheets may contain lower emission factors.)

3. Assumed Maintenance and Testing for each engine to be: 100 hours for potential operation.

Table 10. Natural Gas Engine Capacities & Emissions

Location[1]	Capacity[2, 5]		Hourly Emissions (lb/hr)[3]							Annual Emissions (tpy)[4]						
	(kW)	(MMBtu/hr)	NO_X	CO	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC	NO_X	CO	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC
Building 64	100	0.34	1.39	0.11	0.00	0.00	0.00	0.00	0.40	0.07	0.01	0.00	0.00	0.00	0.00	0.02
Building 67	300	1.02	4.18	0.32	0.01	0.01	0.01	0.00	1.21	0.21	0.02	0.00	0.00	0.00	0.00	0.06
Building 350	300	1.02	4.18	0.32	0.01	0.01	0.01	0.00	1.21	0.21	0.02	0.00	0.00	0.00	0.00	0.06
Building 685	300	1.02	4.18	0.32	0.01	0.01	0.01	0.00	1.21	0.21	0.02	0.00	0.00	0.00	0.00	0.06
Total Emissions			**13.92**	**1.08**	**0.03**	**0.03**	**0.03**	**0.00**	**4.03**	**0.70**	**0.05**	**0.00**	**0.00**	**0.00**	**0.00**	**0.20**

1. Per Copy of Emergency Generator Infrastructure, provided by Christian Bueler on March 30, 2017.

2. If the Capacity was unknown a capacity of 300 kW was assumed.

3. Per AP-42 Section 3.2, Table 3.3-2 (Manufacturer specification sheets may contain lower emission factors.)

4. Assumed Maintenance and Testing for each engine to be: 100 hours for potential operation.

5. MMBtu/hr value calculated as follows:

$$\text{MMBTU/hr} = \frac{\text{kW}}{} \left| \frac{3{,}412.142 \text{ BTU/hr}}{\text{kW}} \right| \frac{\text{MMBtu}}{10^6 \text{ Btu}}$$

Table 11. Carpentry Shop

Parameter	Value	Units
Fabric Filter Outlet Grain Loading[1]	0.016	gr/scf
Air Flowrate[2]	12,000	scfm
Annual Operating Hours	8,760	hr/yr
$PM/PM_{10}/PM_{2.5}$ Hourly Emissions	1.646	lb/hr
$PM/PM_{10}/PM_{2.5}$ Annual Emissions[3]	7.208	tpy

[1] Fabric filter grain loading assumed to be equivalent to the UDAQ BACT limit.

[2] Based on 2014 Emission Inventory

[3] Calculation methodology:

$$PM = FR * GL * \frac{1}{7,000} * \frac{1}{2,000} * 60 * 8,760$$

Where:

PM	=	$PM/PM_{10}/PM_{2.5}$ emissions	(tpy)
FR	=	Design flowrate	(scfm)
GL	=	PM, PM_{10}, or $PM_{2.5}$ grain loading	$\left(\frac{gr}{dscf}\right)$
$\frac{1}{7,000}$	=	Conversion from grains to pounds	$\left(\frac{lb}{gr}\right)$
$\frac{1}{2,000}$	=	Conversion from pounds to tons	$\left(\frac{tons}{lb}\right)$
60	=	Conversion from per minute to per hour	$\left(\frac{min}{hr}\right)$
8,760	=	Hours of operation per year	$\left(\frac{hr}{yr}\right)$

BACT CONTROL COST EVALUATION

Technology: Replace Emergency Generator
Application: Diesel Fired Emergency Generator
Pollutants: Volatile Organic Compounds (VOC)

Replace Emergency Generator

Key Assumptions	Each 500 kW Emergency Generator	Each 600 kW Emergency Generator	800 kW Emergency Generator	1,000 kW Emergency Generator	1,105 kW Emergency Generator	2,000 kW Emergency Generator	Notes
Process Information							
Uncontrolled Emissions (tpy)[5]	0.024	0.028	0.043	0.047	0.052	0.094	
Controlled Emissions (tpy)[6]	0.010	0.013	0.017	0.021	0.023	0.042	
Duty (kW	500	600	800	1,000	1,105	2,000	
Duty (hp)	671	805	1,073	1,341	1,482	2,682	
Labor Costs							
Operator ($/hour)	$ 15.00	$ 15.00	$ 15.00	$ 15.00	$ 15.00	$ 15.00	
Supervisor ($/hour)	$ 20.00	$ 20.00	$ 20.00	$ 20.00	$ 20.00	$ 20.00	
Maintenance ($/hour)	$ 20.00	$ 20.00	$ 20.00	$ 20.00	$ 20.00	$ 20.00	
Economic Factors							
Dollar Inflation (2002 to 2017)	1.3416	1.3416	1.3416	1.3416	1.3416	1.3416	U.S. Consumer Price Index
Equipment Life Expectancy (Years)	10	10	10	10	10	10	
Interest Rate (%)	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	Current Avg SBA Loan Rate
Capital Recovery Factor (CRF)	0.1424	0.1424	0.1424	0.1424	0.1424	0.1424	

DIRECT COSTS

Capital Cost	Each 500 kW Emergency Generator	Each 600 kW Emergency Generator [7]	800 kW Emergency Generator [7]	1,000 kW Emergency Generator	1,105 kW Emergency Generator [7]	2,000 kW Emergency Generator	Notes
Purchased Equipment Costs							
Total Equipment Cost[1]	136,200	-	-	289,000	-	$509,550	A
Instrumentation	13,620	-	-	28,900	-	50,955	0.10 × A
Sales Tax	8,172	-	-	17,340	-	30,573	0.06 × A
Freight	6,810	-	-	14,450	-	25,478	0.05 × A
Total Purchased Equipment Costs	*164,802*	-	-	*349,690*	-	*616,556*	*B = 1.18 × A*
Direct Installation Costs [2]							
Foundations and Supports	13,184	-	-	27,975	-	49,324	0.08 × B
Handling and Erection	23,072	-	-	48,957	-	86,318	0.14 × B
Electrical	6,592	-	-	13,988	-	24,662	0.04 × B
Painting	1,648	-	-	3,497	-	6,166	0.01 × B
Site Preparation & Buildings	-	-	-	-	-	-	No estimate / Site specific
Additional duct work	-	-	-	-	-	-	No estimate / Site specific
Total Direct Installation Costs	*44,497*	-	-	*94,416*	-	*166,470*	*C = 0.30 × B*
Indirect Installation Costs [2]							
Engineering	16,480	-	-	34,969	-	61,656	0.10 × B
Construction and Field Expense	8,240	-	-	17,485	-	30,828	0.05 × B
Contractor Fees	16,480	-	-	34,969	-	61,656	0.10 × B
Start-up	3,296	-	-	6,994	-	12,331	0.02 × B
Performance Test	1,648	-	-	3,497	-	6,166	0.01 × B
Process Contingencies	4,944	-	-	10,491	-	18,497	0.03 × B
Total Indirect Installation Costs	*51,089*	-	-	*108,404*	-	*191,132*	*D = 0.31 × B*
Total Capital Investment ($)	**260,387**	**678,270**	**1,017,410**	**552,510**	**1,144,590**	**974,158**	**TCI = B + C + D**

ANNUAL COSTS

Operating Cost	Each 500 kW Emergency Generator	Each 600 kW Emergency Generator	800 kW Emergency Generator	1,000 kW Emergency Generator	1,105 kW Emergency Generator	2,000 kW Emergency Generator	Notes
Direct Annual Costs [3]							
Operating Labor (0.5 hr, per 8-hr shift)	8,213	8,213	8,213	8,213	8,213	8,213	E
Supervisory Labor (15% operating labor)	1,232	1,232	1,232	1,232	1,232	1,232	F = 0.15 × E
Maintenance Labor (0.5 hr, per 8-hr shift)	10,950	10,950	10,950	10,950	10,950	10,950	G
Maintenance Materials	1,302	3,391	5,087	2,763	5,723	4,871	H = 0.005 x TCI
Total Direct Annual Costs	*21,696*	*23,786*	*25,481*	*23,157*	*26,117*	*25,265*	*DAC = E +F+ G+ H+ J*
Indirect Annual Costs [3]							
Overhead	13,018	14,271	15,289	13,894	15,670	15,159	N = 0.60 × (E + F + G + H)
Administrative Charges	5,208	13,565	20,348	11,050	22,892	19,483	O = 0.02 × TCI
Property Tax	2,604	6,783	10,174	5,525	11,446	9,742	P = 0.01 × TCI
Insurance	2,604	6,783	10,174	5,525	11,446	9,742	Q = 0.01 × TCI
Capital Recovery[4]	37,073	96,570	144,856	78,665	162,964	138,698	R
Total Indirect Annual Costs	*60,507*	*137,973*	*200,842*	*114,660*	*224,418*	*192,824*	*IDAC = N+O+P+Q+R*
Total Annual Cost ($)	**82,203**	**161,758**	**226,323**	**137,817**	**250,535**	**218,089**	*TAC = DAC + IDAC*
Pollutant Removed (tpy)	0.01	0.02	0.03	0.03	0.03	0.05	
Cost per ton of Pollutant Removed ($)	**6,253,292**	**10,254,328**	**8,631,007**	**5,241,952**	**8,620,653**	**4,147,582**	*$/ton = TAC / Pollutant Removed*

1. Allan Woodbury with North Associate, Inc. provided estimate.
2. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)* , January 2002, Section 3.2, Chapter 2, Table 2.8
3. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)* , January 2002, Section 3.2, Chapter 2, Table 2.10
4. Capital Recovery factor calculated based on Equation 2.8a (Section 1, Chapter 2, page 2-21) and Table 1.13 (Section 2, Chapter 1, page 1-52) of U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual (6th Edition), January 2002.
5. It is assumed that the cost and consumption of natural gas will not be influenced by the purchase of a new unit.
6. Uncontrolled emissions acquired from PTE. Emissions from emergency generators provided prior to replacement. 'small/large diesel engines'
7. Controlled emissions calculated from AP-42, table 3.4-1
8. Total capital investment provided by Ken Garner as part of University of Utah audit. As such, purchased equipment costs, direct installation costs and indirect costs were not provided.

Nonroad Compression-Ignition Engines: Exhaust Emission Standards

Pollutant	Duty	Emission Factor	Units	Reference
NO_x	450- 560 kW	0.40	g/kW-hr	2
NO_x	560-900 kW	0.67	g/kW-hr	2
NO_x	900+ kW	0.67	g/kW-hr	2

1. Diesel fuel based off year 2016: https://www.eia.gov/dnav/pet/pet_pri_gnd_dcus_nus_a.htm

2. Emission standards gathered from https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100OA05.pdf

AP-42 Emission Factors

Pollutant	Emission Factor [1]	Units	Reference
VOC	0.19	g/kW-hr	https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100OA05.pdf

1. Assumed to be equivalent to NMHC value

Fuel usage

Total diesel cost for	$10,000
Emergency Generators on site	93
Diesel $/generator	$107.53
Cost of diesel fuel[1]	$2.30
Annual gallons/generator	47
Hours ran/year	100

Emergency Generator Cost

Biulding	Generator Size (kW)	Replacement Cost Estimate	Reference	Direct Capital Cost Estimate[3]
32	800	$1,017,410	1	$1,017,410
521	500	$136,200	2	$234,019
521	1000	$289,000	2	$496,560
533	600	$678,270	1	$678,270
550	500	$136,200	2	$234,019
555	2000	$509,550	2	$875,509
570	1105	$1,144,590.00	1	$1,144,590

1. Price provided from Client - Ken Garner Study.

2. Emergency Generaotr quote provided by Wheeler CAT, From Client " Egen spec - quote"

3. Estimates obtained from Cost Calcualtion sheet.

Building #	Group	Building Name	Abbrev	Cost[1]	CPI - 06/2017[2]
1	E2.05	JOHN R PARK BLDG	PARK	$501,000.00	
4	E2.01	J. T. KINGSBURY HALL	KH	$75,000.00	
7	E2.06	LIFE SCIENCE BLDG	LS	$93,750.00	
12	E2.04	F. ALBERT SUTTON GEOLOGY BLDG	FASB	$487,500.00	
13	E2.04	LEROY COWLES BLDG	LCB	$187,500.00	
14	E2.06	JAMES TALMAGE BLDG	JTB	$75,000.00	
19	E2.04	INTERMTN NETWORK SCIENTIFIC CC	INSCC	$22,500.00	
26	E2.14	GRAD. SCH SOCIAL WK	SW	$37,500.00	
28	E2.07	MARRIOTT CENTER FOR DANCE	MCD	$18,750.00	
32	E2.08	RICE-ECCLES STADIUM	STAD	$900,000.00	$1,017,410.00
35	E2.16	MARCIA & JOHN PRICE MUSEUM BLDG	PRICE	$225,000.00	
45	E2.12	TANNER IRISH HUMANITIES BLDG	CTIHB	$180,000.00	
49	E2.13	LANGUAGE & COMMUNICATION BLDG	LNCO	$30,000.00	
53	E2.12	A RAY OLPIN UNION BLDG	UNION	$41,250.00	
57	E2.11	HEDCO BUILDING	HEDCO	$75,000.00	
62	E2.10	WARNOCK ENGINEERING BLDG	WEB	$450,000.00	
64	E2.10	JOSEPH MERRILL ENGINEERING BLDG	MEB	$13,875.00	
66	E2.02	ROY W & ELIZABETH E SIMMONS PMT	PMT	$22,500.00	
82	E2.06	A. WILMOT SKAGGS BIOLOGY RES BLG	ASB	$225,000.00	
84	E2.06	BIOLOGY BLDG	BIOL	$168,750.00	
85	E2.07	HENRY EYRING BLDG NORTH	HEB N	$193,965.52	
86	E2.13	MARRIOTT LIBRARY	M LIB	$1,125,000.00	
87	E2.07	HEB SOUTH (GAUSS)	HEB S	$931,034.48	
95	E2.17	HPER BLDG MECH S/W	HPR SW	$150,000.00	
197	E2.09	ROSENBLATT HOME	ROSEN	$75,000.00	
205	E2.15	GEORGE S. ECCLES TENNIS CTR	GETC	$33,750.00	
210	E2.15	DEE GLEN SMITH ATHLETIC CTR	DSAC	$112,500.00	
212	E2.15	INDOOR/OUTDOOR PRACTICE FIELD	BUBBLE	$99,375.00	
213	E2.15	LIBRARY STORAGE	LIB SG	$35,625.00	
301	E2.18	PUBLIC SAFETY	SAFETY	$480,000.00	
302	E2.23	E. CAMPUS CHILLER/HTW PLANT	ECCP	$900,000.00	
303	E2.18	HIGH TEMPERATURE WATER PLANT	HTW	$465,000.00	
305	E2.18	PHYSICAL PLANT SERVICES	PP SER	$15,000.00	
347	E2.05	STEAM GENERATING P1	STMGEN	$195,000.00	
350	E2.18	V. RANDALL TURPIN UNIV SERV BLD	USB	$60,000.00	
500	E2.24	NORA ECCLES HARRISON	CVRTI	$18,750.00	
533	E2.22	ECCLES INSTITUTE OF HUMAN GENETICS	EIHG	$600,000.00	$678,270.00
540	E2.23	HEALTH SCIENCE PARKING CENTER	HSCPT	$834,000.00	
565	E2.23	E. E. JONES MEDICAL SCIENCE BLDG	JMSB	$1,575,000.00	
570	E2.23	BIOMEDICAL POL. RESEARCH BLDG	BPRB	$1,012,500.00	$1,144,590.00
575	E2.22	ECCLES HEALTH SCIENCE EDU. BLDG	HSEB	$262,500.00	
585	E2.21	RADIOBIOLOGY LAB	RB LAB	$75,000.00	
587	E2.21	ANIMAL RESOURCES CTR	ARC	$900,000.00	$1,017,410.00
701	E2.24	UNIV STUDENT APTS TOWER 1	BD 701	$150,000.00	
702	E2.24	UNIV STUDENT APTS TOWER 2	BD 702	$101,250.00	
801	E2.20	UNIVERSTIY GUEST HOUSE	GUEST	$52,500.00	
815	E2.24	CHASE M. PETERSON HERITAGE CEN	H CTR	$176,250.00	
821	E2.24	BENCHMARK PLAZA 821	BP 821	$262,500.00	
853	E2.25	HEALTH PROFESSION EDUCATION BLDG	HPEB	$412,500.00	
874	E2.26	383 COLOROW RESEARCH BUILDING	CO	$300,000.00	
				$15,433,875.00	
			Add 40%	$21,607,425.00	

1. Provided from Ken Garner Engineering Study, installation included.
2. CPI from Jan 2010 to June 2017. https://www.bls.gov/data/inflation_calculator.htm