PM$_{2.5}$ SIP Evaluation Report: PacifiCorp Energy – Lake Side Power Plant

Provo/Orem Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

June 1, 2018

$PM_{2.5}$ SIP EVALUATION REPORT
PacifiCorp Energy – Lake Side Power Plant

1.0 Introduction

The following is part of the Technical Support Documentation for Section IX, Part H.13 of the Utah SIP; to address the Provo/Orem $PM_{2.5}$ Nonattainment Area. This document specifically serves as an evaluation of the PacifiCorp Energy operated Lake Side Power Plant.

1.1 Facility Identification

Name: Lake Side Power Plant
Address: 1825 N Pioneer Lane, Vineyard, Utah, Utah County
Owner/Operator: PacifiCorp Energy
UTM coordinates: 4,464,500 m Northing, 436,000 m Easting, Zone 12

1.2 Facility Process Summary

The Lake Side Power Plant (LSPP) is a natural gas-fired electric generating plant consisting of four combined-cycle turbines, four heat recovery steam generators with duct burners, two auxiliary boilers, two cooling towers, one dew point heater, two diesel-fired emergency generators, and one diesel-fired fire pump. The plant is located in Utah County, which is part of the Provo, Utah $PM_{2.5}$ nonattainment area.

The plant is a Phase II acid rain source and a major source for PM_{10}/$PM_{2.5}$, NO_x, CO, VOC, HAP and GHG emissions. The source (Block #1) was originally permitted as a PSD source and a PM_{10} non-attainment area major source. When Block #2 was added in 2011, this modification was permitted as a PSD major modification, as well as a PM_{10} nonattainment area major modification. Therefore, analysis of LAER was required on both occasions for the facility's PM_{10} and NO_x emissions; analysis of BACT was required for all other emissions.

At the time of installation for both Block #1 and Block #2, BACT/LAER for the turbines was dry low-NO_x burners, SCR and oxidation catalysts. The auxiliary boilers were fitted with dry low-NO_x burners. The diesel equipment is required to operate on ultra-low sulfur diesel. The cooling towers have high-efficiency drift elimination.

1.3 Facility Criteria Air Pollutant Emissions Sources

The source consists of the following emission units:

One (1) natural gas-fired, dry low-NO_x, combined-cycle turbine – CT #1
One (1) natural gas-fired, dry low-NO_x, combined-cycle turbine – CT #2
One (1) natural gas-fired, dry low-NO_x, combined-cycle turbine – CT #3
One (1) natural gas-fired, dry low-NO_x, combined-cycle turbine – CT #4
One heat recovery steam generator, low-NO_x duct burner, 184 MMBtu/hr – HRSG #1

One heat recovery steam generator, low-NO_x duct burner, 184 MMBtu/hr – HRSG #2
One heat recovery steam generator, low-NO_x duct burner, 400 MMBtu/hr – HRSG #3
One heat recovery steam generator, low-NO_x duct burner, 400 MMBtu/hr – HRSG #4
Two (2) selective catalytic reduction systems with ammonia injection – Block #1 SCR
Two (2) selective catalytic reduction systems with ammonia injection – Block #2 SCR
Two (2) CO oxidation catalysts – Block #1 OxyCat
Two (2) CO oxidation catalysts – Block #2 OxyCat
One (1) natural gas-fired 62.765 MMBtu/hr auxiliary boiler – Aux Boiler #1
One (1) natural gas-fired 57.6 MMBtu/hr auxiliary boiler – Aux Boiler #2
Two (2) 1,500 hp emergency diesel generators – Em Gen #1, #2
One (1) 4.76 MMBtu/hr diesel-fired fuel dew point heater – Heater #1
One (1) 290 hp diesel-fired fire pump – Pump #1
Cooling Towers #1, #2

1.4 Facility 2014 Baseline Actual Emissions and Current PTE

In 2014, LSPP's baseline actual emissions were determined to be the following (in tons per year):

Table 1: Actual Emissions

Pollutant	Actual Emissions (Tons/Year)
$PM_{2.5}$	56.5
SO_2	10.3
NO_x	238.6
VOC	37.4
NH_3	147.1

The current PTE values for LSPP, as established by the most recent AO issued to the source (DAQE-AN130310012-15) are as follows:

Table 2: Current Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
$PM_{2.5}$	215.4
SO_2	55.6
NO_x	280.9
VOC	169.7
NH_3	*

* No allowable emissions or PTE were ever determined for this facility

2.0 Modeled Emission Values

A full explanation of how the modeling inputs are determined can be found elsewhere. However, a shortened explanation is provided here for context.

The base year for all modeling was set as 2014, as this is the most recent year in which a complete annual emissions inventory was submitted from each source. Each source's submission was then verified (QA-QC) – checking for condensable particulates, ammonia (NH_3) emissions, and calculation methodologies. Once the quality-checked 2014 inventory had been prepared, a set of projection year inventories was generated. Individual inventories were generated for each projection year: 2017, 2019, 2020, 2023, 2024, and 2026. If necessary, the first projection year, 2017, was adjusted to account for any changes in equipment between 2014 and 2017. For new equipment not previously listed or included in the source's inventory, actual emissions were assumed to be 90% of its individual PTE.

While some sources were adjusted by "growing" the 2014 inventory by REMI growth factors; other sources were held to zero growth. This decision was largely based on source type, and how each source type operates. Utility sources (for example) are not likely to experience a growth in sales or related production. They operate based on large-scale power demand and the needs of the entire system.

For the LSPP, a summary of the modified emission totals for 2017 are shown below in Table 3. Updated values with growth applied would then propagate through for each of the subsequent projection years.

Table 3: Modeled Emission Values (Plant-Wide)

Pollutant	2017 Projected Actual Emissions (Tons/Year)
$PM_{2.5}$	58.4
SO_2	10.6
NO_x	246.7
VOC	38.6
NH_3	152.1

* For the LSPP, no additional changes in equipment took place between 2014 and 2017 – aside from a change in an emergency generator – this had a minimal impact on emissions.

Finally, the effects of BACT were then applied during the appropriate projection year. BACT applied between 2014 and 2017, was previously taken into account during the 2017 adjustment shown above. For future BACT, meaning those items expected to be coming online between today and the regulatory attainment date (December 31, 2019), the effects of those changes would be applied during the 2019 projection year. This is included in the notes attached to the appropriate emission inventory model input spreadsheet.

3.0 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.

4.0 BACT for Combustion Turbines and HRSGs

The four combustion turbines (CTs) are each operated as combined-cycle units fired exclusively on pipeline quality natural gas. Although the HRSGs at Block #2 are designed with significantly more duct firing, the general function of both power blocks is identical. The CT provides primary power generation by spinning a generator directly. The excess heat is captured by the HRSG and the steam spins a steam turbine/generator for additional power generation. Supplemental heat can be supplied by duct firing in the HRSG.

Although identified as separate units, each CT and associated HRSG vent through a single stack and emissions from both units are controlled simultaneously with the same equipment. Since all four CT/HRSG combinations operate identically, UDAQ has chosen to treat these as a single group for purposes of the BACT analysis.

Following the emissions correction procedure outlined above in Section 2.0, emissions from all four CT/HRSGs were as follows:

$PM_{2.5}$ = 55.84 tons
SO_2 = 10.28 tons
NO_x = 199.67 tons
VOC = 36.02 tons
NH_3 = 150.54 tons

The calculations are shown on the projection emission spreadsheet.

4.1 $PM_{2.5}$

4.1.1 Available Control Technology

Controls for particulate emissions fall into one of three groups: pre-combustion controls, which seek to eliminate contaminants in the inlet air prior to the combustion chamber; combustion controls, such as specific burners or combustion design; and post-combustion controls, such as electrostatic precipitators or baghouses.

The identified controls are as follows:

Inlet air filters: primarily used to filter out small particulate matter in the inlet air to protect the combustion turbine. These filters can be static or self-cleaning, with the self-cleaning type requiring less maintenance.

Good combustion practice: this is nothing but properly operating the combustion turbines with the correct ratio of air to fuel in order to maximize combustion and minimize unburned fuel.

Clean burning fuels: includes the use of inherently low emitting fuels like natural gas.

Specific burner and/or combustion chamber design: the more efficiently a turbine is able to operate, the less pollution it will generate for a given amount of fuel combusted (or, to be more precise); as less fuel will be required to generate the same amount of power. This option includes both the use of high efficiency turbines, as well as inherently lower emitting burners such as dry low-NO_x (DLN) combustors.

Add-on particulate controls: this final option includes traditional "add-on" control systems such as baghouses or electrostatic precipitators. These types of controls would be installed post combustion, and prior to the emissions exiting the stack.

4.1.2 Evaluation of Technical Feasibility of Available Controls

Post-combustion particulate controls such as baghouses and electrostatic precipitators have not been demonstrated in practice for use on combustion turbines. There are multiple factors that combine to eliminate these types of controls from consideration. 1) Combustion turbine particulate emissions have a small aerodynamic diameter – typically on the order of 1 micron or less – which makes the use of most direct physical capture systems problematic. 2) Natural gas-fired turbines generate little in the way of particulate emissions; yet also have high volume exhaust flows. This combination results in a low concentration of PM in the exhaust. 3) Post-combustion controls have difficulty operating efficiently or effectively in low concentration environments. Baghouse-style filtration systems rely on the buildup of a filter cake of captured particulates to enhance capture efficiency, while scrubbing systems require a reasonable particulate concentration in order to operate efficiently. Electrostatic precipitators can operate in low concentration conditions, but also suffer efficiency problems. In addition, a search was conducted for the use of ESPs with natural gas-fired turbines and no results were found. A single article which discussed a bench-scale experiment was found, but no commercially available results. The UDAQ was unable to identify any combustion turbines fired on gaseous fuels using post combustion controls for the control of particulate emissions. Post-combustion controls are therefore technically infeasible and removed from additional consideration.

All of the remaining control options are considered technically feasible and require additional evaluation.

4.1.3 Evaluation and Ranking of Technically Feasible Controls

The remaining control options under consideration are not mutually exclusive. A single high-efficiency combustion turbine can be operated with inlet air filters and using good combustion practices. The turbine can be fired exclusively on natural gas as the sole fuel source, and use DLN combustors. Thus, the remaining controls do not need to be ranked – rather they need to be combined and considered as a group.

All of the remaining control options can be combined into this group (effectively: "high efficiency combustion"), so no further evaluation under step 3 is required.

4.1.4 Further Evaluation of Most Effective Controls

As the combustion turbines at this facility are already utilizing these controls, no adverse economic, environmental or energy costs will result.

4.1.5 Selection of BACT controls

The LSPP is already employing inlet air filters, DLN combustors, and pipeline quality natural gas as fuel as BACT control options. Utah rules R307-401-4(1) & (2) require that all sources maintain and operate any equipment, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions (good combustion practices). Thus, each of the identified control options is already in place and operating at the facility.

Currently, the LSPP has limits of 10.8 lb of $PM_{2.5}$/hr each for turbines #1 and #2 (Block #1), and 14.0 lb of $PM_{2.5}$/hr each for turbines #3 and #4 (Block #2). While both of these limits have a 30-day averaging period, no additional reductions in particulate emissions would be possible without a complete redesign of the combustion turbine and HRSG system; which would include the installation of newer, more efficient turbines. Such a redesign would involve a significant capital expenditure and would ultimately prove to be economically infeasible. Even then, there is no guarantee that particulate emissions would decrease, as combustion turbine design has not improved or changed significantly since the last major change at the plant in 2011. Therefore, UDAQ recommends that the existing controls be accepted as BACT for control of particulate emissions from the combustion turbines.

4.2 SO_2

Emissions of SO_2 (and H_2SO_4 as well) are directly a function of the amount of sulfur present in the fuel. As the fuel is burned, the fuel-bound sulfur is oxidized to SO_2 (some H_2SO_4 is also formed).

4.2.1 Available Control Technology

Most sulfur control technologies require the use of some sort of acid reducing agent such as a lime slurry or limestone injection. This leads to residual solid or liquid waste which requires subsequent disposal. The remaining add-on control techniques rely on the post-combustion control of emissions of particulates and allowing any residual sulfur to be captured with the particulate. A second option would be to reduce the amount of sulfur present in the fuel, thus eliminating the source of the SO_2.

4.2.2 Evaluation of Technical Feasibility of Available Controls

Neither of the possible control options is technically feasible. With all the combustion turbines being fired on natural gas, the amount of fuel-bound sulfur is inherently quite low. UDAQ has been unable to locate any technologies to further reduce the amount of sulfur present in pipeline quality natural gas.

Post-combustion desulfurization systems, such as limestone injection or dry-lime scrubbing, are typically designed for exhaust streams with much higher SO_2 (and acid gas) concentrations than those found with combustion turbines fired on natural gas. The low concentration leads to lowered control efficiencies. Effective control then requires longer residence times, longer exhaust stream runs, lowered exhaust temperatures, and worsened emission dispersal upon release.

4.2.3 Evaluation and Ranking of Technically Feasible Controls

No additional controls have been identified as being technically feasible, beyond the existing baseline control of burning only pipeline quality natural gas. Therefore, no evaluation or ranking is possible. The existing control option remains the only viable option.

4.2.4 Further Evaluation of Most Effective Controls

As no additional controls have been determined to be technically feasible, no evaluation of economics, energy consumption or adverse environmental impacts is possible.

4.2.5 Selection of BACT

No additional controls or control techniques are required. Combustion of pipeline quality natural gas as fuel for control of SO_2 emissions is recommended as BACT.

Given the relatively small amount of SO_2 estimated to be coming from the CT/HRSGs (10.28 tons/year), no limits have been set for these units. The use of only pipeline quality natural gas as fuel represents a work practice standard rather than a measureable quantity restriction (such as a production limit) or other quantifiable limitation (such as an emission limitation).

4.3 NO_x

NO_x, or oxides of nitrogen, are formed from the combustion of fuel in the turbine. There are three mechanisms for the formation of NO_x: fuel NO_x, which is the oxidation of the nitrogen bound in the fuel; thermal NO_x, or the oxidation of the nitrogen (N_2) present in the combustion air itself; and prompt NO_x, which is formed from the combination of combustion air nitrogen (N_2) with various partially-combusted intermediary products derived from the fuel. For combustion within the turbines, fuel NO_x and thermal NO_x are the major contributors, with prompt NO_x contributing slightly only in the initial stages of combustion. All three processes are temperature dependent – combustion temperatures below 2700ºF greatly inhibit NO_x formation.

4.3.1 Available Control Technology

The following technologies have been identified as potential control methodologies for control of NO_x emissions: good combustion practices; low emission combustion (LEC); selective non-catalytic reduction (SNCR), the injection of ammonia or urea directly into the late stages of the combustion zone; selective catalytic reduction (SCR); and EMx™ (previously known as $SCONO_x$™).

In the SCR process, a reducing agent, such as aqueous ammonia, is introduced into the turbine's exhaust, upstream of a metal or ceramic catalyst. As the exhaust gas mixture passes through the catalyst bed, the reducing agent selectively reduces the nitrogen oxide compounds present in the exhaust to produce elemental nitrogen (N_2) and water (H_2O). Ammonia is the most commonly used reducing agent. Adequate mixing of ammonia in the exhaust gas and control of the amount of ammonia injected (based on the inlet NO_x concentration) are critical to obtaining the required reduction. For the SCR system to operate properly, the exhaust gas must maintain minimum O_2 concentrations and remain within a specified temperature range (typically between 480ºF and 800ºF with the most effective range being between 580°F and 650°F), with the range dictated by the type of catalyst. Exhaust gas temperatures greater than the upper limit (850°F) will pass the NO_x and unreacted ammonia through the catalyst. The most widely used catalysts are vanadium, platinum, titanium, or zeolite compounds impregnated on metallic or ceramic substrates in a plate of honeycomb configuration. The catalyst life expectancy is typically 3 to 6 years, at which time the vendor can recycle the catalyst to minimize waste.

The EMx™ system uses a coated oxidation catalyst installed in the flue gas to remove both NO_x and CO without a reagent such as ammonia. The NO emissions are oxidized to NO_2 and then absorbed onto the catalyst. A dilute hydrogen gas is passed through the catalyst periodically to de-absorb the NO_2 from the catalyst and reduce it to N_2 prior to exit from the stack. EMx™ prefers an operating temperature range between 500°F and 700°F. The catalyst uses a potassium carbonate coating that reacts to form potassium nitrates and nitrites on the surface of the catalyst. When all of the carbonate absorber coating on the surface of the catalyst has reacted to form nitrogen compounds, NO_2 is no longer absorbed, and the catalyst must be regenerated. Dampers are used to isolate a portion of the catalyst for regeneration. The regeneration gas consists of steam, carbon dioxide, and a dilute concentration of hydrogen. The regeneration gas is passed through the isolated portion of the catalyst while the remaining catalyst stays in contact with the flue gas. After the isolated portion has been regenerated, the next set of dampers close to isolate and regenerate the next portion of the catalyst. This cycle repeats continuously. At any one time, four oxidation/absorption cycles are occurring and one regeneration cycle is occurring.

Two additional post-combustion control systems were also identified as being potentially applicable:

Linde's LoTOx™ technology uses ozone injection to oxidize NO and NO_2 to N_2O which is highly soluble and easier to remove through the use of another control device such as a wet scrubber. UDAQ has seen and permitted the application of this technology in combination with a wet gas scrubber for emission control at a petroleum refinery.

Enviroscrub's Pahlmann™ Process is a sorbent-based control system which functions similarly to a dry scrubber. In this system, Pahlmanite (a manganese dioxide sorbent) is injected into the exhaust stream for NO_x removal and then collected in a particulate control device like a baghouse. The sorbent is then regenerated in an aqueous process, filtered and dried, and is then ready for reinjection. The wastewater is sent offsite for disposal.

4.3.2 Evaluation of Technical Feasibility of Available Controls

All of the identified control options are potentially technically feasible; however some additional explanation is warranted:

In the case of LEC, more than one variant of combustor design exists:

- Dry-low-NO_x: The modern, dry low-NO_x (DLN) combustor is typically a three-staged, lean, premixed design, which utilizes a central diffusion flame for stabilization. The lean, premixed approach burns a lean fuel-to-air mixture for a lower combustion flame temperature resulting in lower thermal NO_x formation. The combustor operates with one of the lean premixed stages and the diffusion pilot at lower loads and the other stages at higher loads. This provides efficient combustion at lower temperatures, throughout the combustor-loading regime. The dry low-NO_x combustor reduces NO_x emissions by up to approximately 87 percent over a conventional combustor.

- Catalytic combustors: These combustors use a flameless catalytic combustion module to initiate the combustion process, followed by a more traditional combustion process downstream of the catalyst. This two-stage process lowers the overall combustion temperature.
- Xonon Cool Combustion®: Catalytica Energy Systems' Xonon Cool Combustion® System is a specific type of catalytic combustion process, and often mentioned independently in control technology reviews. In practical application, however, it functions similarly to other catalytic combustors.

Along with these types of burner designs, another pre-combustion process – water or steam injection – can also be used to lower the combustion temperature. Depending on the amount of water or steam used, this process can also increase both the maximum and actual power output of the turbine – by allowing more fuel to be burned without overheating, and by increasing the density of the exhaust flow through the turbine. However, water and steam injection tend to reduce combustion efficiency, prevent complete combustion leading to an increase in CO and VOC emissions, and are of limited effectiveness in combined cycle systems (turbine/HRSG systems) where the lowered temperature and increased specific heat of the turbine exhaust gas directly results in an increased need for duct firing in the HRSG unit.

Neither the LoTOx™ nor Pahlmann™ processes are determined to be technically feasible. While the LoTOx™ system is technically feasible from a mere engineering standpoint, it suffers from two flaws. It has not yet reached the commercial stage for large scale, combined-cycle, combustion turbines; and it requires the use of a second control system, such as a wet gas scrubber, for final removal of the N_2O. In the application of LoTOx™ UDAQ has previously permitted, the system was included as an additional module to a wet gas scrubber designed for removal of SO_2 and other acid gases. Achieving additional NO_x removal at relatively low cost (on a $/ton basis) was the ideal fit for this technology. However, requiring the addition of another control system for final pollutant removal, especially where the secondary system does not add to emission reduction of other pollutants, demonstrates that LoTOx™ is not yet technically feasible. Similarly, the Pahlmann™ Process also requires the addition of: a baghouse for particulate removal (for capture of the sorbent), an aqueous sorbent regeneration process, and a wastewater treatment/disposal process. While the technology does show promise for control of multiple pollutants, it was not intended for control of only the NO_x emissions from gas-fired turbines and is not commercially available for such units. Both processes are eliminated from further consideration.

The other control options (SNCR, SCR, good combustion practices, and burner design) are all technically feasible.

4.3.3 Evaluation and Ranking of Technically Feasible BACT Controls

The combustion turbines installed at the Lake Side facility are GE Frame 7FAs, which are built around a dry-low-NO_x combustor. Each turbine is connected to a heat recovery steam generator, also equipped with low-NO_x duct burners. Finally, each turbine/HRSG pair is further controlled by a SCR system (using ammonia injection).

The use of additional pre-combustion controls is not technically feasible at the LSPP, regardless of the type of combustion technology chosen. As discussed in the previous section, the reduction in exhaust temperature and increased specific heat greatly increase the need for duct firing in the

HRSG – a much less efficient process for generating power. Since pre-combustion controls are not being installed for NO_x reduction, the type of combustor is not limited by this consideration. Instead, the combustor type can be selected based on effectiveness and availability.

As mentioned above, the turbines installed at the LSPP are all based around a dry-low-NO_x combustor. This particular system is a lean pre-mix burner design, which uses a combination of staged combustion and differing fuel-air mixing for each combustion stage to both lower the combustion temperature and still allow for complete combustion. Xonon does not currently represent an available control technology for any large turbine. While a joint venture agreement was in place with General Electric (GE) to eventually develop Xonon as original equipment manufacturer and retrofit equipment for the entire GE turbine line, GE does not currently offer a Xonon combustor option for 7FA or any other large industrial turbine. An Application for Certification approved by CEC for the Pastoria Energy Facility Project (December 20, 2000) proposed to install Xonon on F-Class Turbines, however, Xonon was determined not to be technically feasible and the plant was constructed using DLN burners and SCR. The NO_x emission limit proposed for the Pastoria Project was being evaluated under LAER criteria. DLN/SCR was proposed as the back-up control technology in the event that the Xonon technology proved infeasible. Currently Catalytica Energy Systems is only marketing Xonon technology for gas turbines within the 1 to 15 MW size range. Hence, at this time, Xonon does not represent a currently available control technology for the LSPP. Furthermore, the Xonon system is only guaranteeing 3 ppm for a NO_x emission rate. The NO_x emissions on both Block #1 and Block #2 are limited by the most recently issued AO to 2 ppm CT/HRSGs stack (both limits on a 3-hour average at steady state operation).

In comparing SNCR and SCR, two factors come into play – the hypothetical effectiveness of control, and whether either system will work more effectively in the specific design at LSPP. In this case, all of the SNCR designs available, ranging from simple ammonia/urea injection in the main combustion zone through Fuel Tech's NO_xOUT™ process, all require an exhaust gas temperature somewhere between 1600ºF and 2100ºF for most effective conversion of NO_x to N_2. SCR systems, on the other hand, use a catalyst to lower this effective temperature range down to between 480ºF and 800ºF.

All four turbines at the LSPP are configured in combined cycle operation, with a single combustion turbine paired with a matching heat recovery steam generator or HRSG. These HRSGs can receive supplemental heat from additional "duct burners" but are primarily heated passively only from the exhaust heat out of the paired turbine (also known as a waste heat boiler configuration). The exhaust gas temperature after exiting the HRSG is most commonly between 650ºF and 800ºF with the maximum exhaust temperature less than 1100ºF. Therefore, the only remaining control technology is the use of SCR in conjunction with DLN combustors.

4.3.4 Further Evaluation of Most Effective Controls

As all of the remaining control technologies are in place and operational at the LSPP, no additional evaluation is required.

4.3.5 Selection of BACT Controls

Retention of the existing SCR systems for each of the CT/HRSGs to control NO_x emissions is recommended as BACT. Emission limits of 2.0 ppmdv on a 3-hr basis were established in the most recently issued NSR permit for the facility, and these emission limits were carried forward into the moderate $PM_{2.5}$ SIP as lb/hr limitations as follows:

SIP Section IX.H.13.d.
i. Block #1 Turbine/HRSG Stacks:
A. Emissions of NO_x shall not exceed 14.9 lb/hr on a 3-hr average basis
B. Compliance with the above conditions shall be demonstrated as follows:
I. NO_x monitoring shall be through use of a CEM as outlined in IX.H.11.f
ii. Block #2 Turbine/HRSG Stacks:
A. Emissions of NO_x shall not exceed 18.1 lb/hr on a 3-hr average basis
B. Compliance with the above conditions shall be demonstrated as follows:
I. NO_x monitoring shall be through use of a CEM as outlined in IX.H.11.f

These same emission limits should be retained with the retention of the existing controls as BACT.

4.4 VOC

VOC emissions are the result of unburned hydrocarbons formed during incomplete combustion. To some degree the formation of VOCs is dependent on combustion system design, choice of fuel, combustion temperature (itself dependent on equipment design and operating practices), and operating practices (which can control the air-to-fuel ratio, timing, temperature, and other factors).

4.4.1 Available Control Technology

Control techniques are divided into two groups: Post-combustion controls, and everything else - which includes pre-combustion controls, as well as equipment design and good operating practices.

Only one type of post combustion control has been identified by UDAQ - the use of oxidation catalysts. An oxidation catalyst is similar in design and operation to a catalytic control system on a passenger vehicle, in that an inline, self-regenerating, catalyst system is placed within the exhaust stream prior to the final stack, so that emissions of both VOC and CO can be further oxidized to CO_2 and water. Oxidation of VOC can approach efficiencies of 70%, depending on initial concentrations and stack characteristics. All four CT/HRSGs at the Lake Side facility have oxidation catalysts installed as these were required as CO/VOC BACT as part of the requirements of the PSD construction permits (UDAQ issued AOs) to initially construct and operate the turbines. The use of oxidation catalysts is thus considered the base case for comparison purposes.

One specialized example of oxidation catalyst, EMx™, has been used to oxidize and remove both NO_x and VOC. The system uses a platinum-based catalyst coated with potassium carbonate (K_2CO_3), and unlike SCR systems, does not require the use of a reagent (such as ammonia) for NO_x control (see Section 4.3 NO_x Control above).

The other available control techniques include the use of:
1. Properly designed combustion chambers/combustors
2. Good combustion practices
3. The Xonon catalytic combustion system

Currently, properly designed combustion turbines utilize “lean combustion” – where a large amount of excess combustion air is provided. This cools the overall flame temperature, and also ensures good air/fuel mixing and complete combustion of the fuel. The most effective combustor/burner design is known as the dry low-NO_x (DLN) combustor. DLN burners act as a miniature version of the main combustion chamber, by varying the flow of fuel and combustion air to different nozzles during different turbine operating modes, the burner can maintain a lean combustion process at all operating conditions.

Good combustion practices include only using pipeline quality natural gas as fuel, maintaining high combustion efficiencies, maintaining proper air-to-fuel ratios, and conducting proper maintenance.

Catalytica Energy Systems' Xonon Cool Combustion® (Xonon) system improves the combustion process by lowering the peak combustion temperature to reduce the formation of NO_x while also providing further control of CO and unburned hydrocarbon emissions that other NO_x control technologies (such as water injection and DLN) cannot provide. The Xonon system uses catalysts within the combustion chamber to oxidize the majority of the air-fuel mixture rather than burning the mixture with a flame. The burners are designed with a high degree of variability in fuel and air mixing, while still operating as lean combustors, so VOC emissions are minimized.

4.4.2 Evaluation of Technical Feasibility of Available Controls

The use of post-combustion oxidation catalysts is technically feasible as they are already installed and operational at the LSPP.

Good combustion practices, and the use of a DLN (lean combustor and burner design) combustor are similarly technically feasible and also currently in use at LSPP.

The EMx™ process can, in theory, be applied to combustion turbines of any size category; however, commercial experience with the process has not been applied to turbines greater than 50 MW in size. UDAQ conducted a search and was unable to find any commercial applications of EMx™ on large base-load units similar to those at the LSPP. EMx™ equipped turbines also experience larger pressure drops than other oxidation catalyst-equipped units.

Xonon does not currently represent an available control technology for any large turbine. While a joint venture agreement was in place with General Electric (GE) to eventually develop Xonon as original and retrofit equipment for the entire GE turbine line, GE does not currently offer a Xonon combustor option for any large industrial turbine. An Application for Certification approved by California Energy Commission (CEC) for the Pastoria Energy Facility Project (December 20, 2000) proposed to install Xonon on F-Class Turbines, however, Xonon was determined not to be technically feasible and the plant was constructed using DLN burners and SCR. Currently Catalytica Energy Systems is only marketing Xonon technology for gas turbines within the 1 to 15 MW size range. Hence, at this time, Xonon does not represent a currently available control technology for the LSPP.

4.4.3 Evaluation and Ranking of Technically Feasible Controls

The LSPP turbines have all the remaining control options (good combustion practices, DLN combustors, lean combustion, and oxidation catalysts) as existing controls. There is no need to rank these controls on control effectiveness.

4.4.4 Further Evaluation of Most Effective Controls

Further evaluation of the existing controls is not required. All technically available control options are in place and operational at the LSPP.

4.4.5 Selection of BACT

Retention of the existing control systems (good combustion practices, DLN combustors, lean combustion, and oxidation catalysts) for control of VOC emissions is recommended as BACT.

In the most recent AO DAQE-AN130310012-15 issued for the LSPP, the oxidation catalysts installed on the CT/HRSGs on Block #1 lower the CO emission rate down to 3 ppm and 14.1 lbs/hr per turbine/HRSG stack (both limits on a 3-hour average at steady state operation). While there is no specific VOC emission limit, it is assumed that VOC emissions on a ppm basis are similar to CO emissions. This is validated by the emission limitations that were added later for Block #2 (Block #1 was originally permitted in 2004, the permit limitations on Block #1 were rolled over into the 2011 permit which authorized construction and operation of Block #2. The oxidation catalysts on Block #2 have specific VOC limits (listed in the construction permit) of 2.8 ppmvd from each turbine/HRSG stack; again on a 3-hour average basis. The emission limits on CO are the same as for Block #1: 3.0 ppmvd (on a 3-hour average). The limitations on VOC and CO were not brought forward into the moderate $PM_{2.5}$ SIP, as emissions of NO_x were determined to be the limiting factor on turbine operation.

4.5 Startup and Shutdown

Operation of a natural gas-fired combustion turbine requires periods of startup and shutdown. These events are a normal part of power plant operation, but as they result in NO_x emission rates that are both highly variable and with values typically greater than during normal (steady-state) operation. The reason for higher NO_x emissions is that the emission control systems are not fully functioning during startup and shutdown periods. The DLN combustors require a minimum operating rate in order to achieve the highest level of efficiency. At lower firing rates the pre-mixing capabilities of the burner design are not fully utilized – leading to partial combustion, or the turbine's firing controls self-adjusting to improve combustion control while losing emission control. At the same time, the catalyst in the SCR control system will be too cold to be effective. Normally, the catalysts will heated to a minimum operating temperature before the system is even brought online to avoid thermal shock and premature degradation of the catalysts. Since these periods of startup and shutdown can even be defined as the period when no emission controls are operating, such as is the case with LSPP, the easiest way to minimize emissions is simply to limit the total number and total duration of these events.

The LSPP is somewhat unique, in that it operates as something of a hybrid power plant. The plant has far more total operating hours than a peaking plant such as a typical municipal power plant, but it also experiences more startups and shutdowns than a typical baseload unit such as a coal-fired boiler. Averaging between 4500 and 5200 operating hours per year, each turbine will experience several startup/shutdown events in a given rolling 12-month period.

UDAQ did search for alternative control options during startup and shutdown periods, but was unable to find any viable alternatives. The turbines are already fired on clean gaseous fuel, and already use a modern DLN combustor. Using an alternative, lower efficiency control for NO_x control – such as SNCR – during startup or shutdown is plagued by the same problems as the steady-state case (operating temperature, infrastructure, secondary control system) only these become exaggerated the more that the operating rate drops towards zero.

Since no catalytic control options can be used until a viable operating temperature has been reached, and simply injecting ammonia or urea would be similarly ineffective, the simplest solution remains limiting the frequency and duration of startup and shutdown events. Frequency of startup and shutdown is a function of power demand, equipment maintenance, and operator work experience to adjust event timing and load balance. Event duration can be adjusted by several factors: including the above work practices, manufacturer's specifications and recommendations, and the use of auxiliary boilers to supply heat to the HRSG, steam turbines and SCR systems while the main turbines are in startup mode. BACT for the auxiliary boilers is discussed in a separate section of this document.

Beyond these work practice techniques, there are no other technically feasible control methods to reduce emissions during periods of startup or shutdown. For the LSPP, startup is defined as the period beginning with turbine initial firing until the unit stabilizes at the NO_x emission limits of 2.0 ppmvd and CO emission limits of 3.0 ppmvd (each at 15% O_2). Shutdown is defined as the period beginning with the initiation of turbine shutdown sequence and ending with the cessation of firing of the gas turbine engine. There are specific limitations for startup and shutdown events established in the moderate $PM_{2.5}$ SIP as follows:

SIP Section IX.H.13.d.
iii. Startup / Shutdown Limitations:

A. Block #1:

I. Startup and shutdown events shall not exceed 613.5 hours per turbine per 12-month rolling period.
II. Total startup and shutdown events shall not exceed 14 hours per turbine in any one calendar day.
III. Cumulative short-term transient load excursions shall not exceed 160 hours per 12-month rolling period.
IV. During periods of transient load conditions, NO_x emissions from the Block #1 Catalytic-controlled Turbine/HRSG Stacks shall not exceed 25 ppmvd at 15% O_2.

B. Block #2:

I. Startup and shutdown events shall not exceed 553.6 hours per turbine per 12-month rolling period.
II. Total startup and shutdown events shall not exceed 8 hours per turbine in any one calendar day.
III. Cumulative short-term transient load excursions shall not exceed 160 hours per 12-month rolling period.
IV. During periods of transient load conditions, NO_x emissions from the Block #2 Catalytic-controlled Turbine/HRSG Stacks shall not exceed 25 ppmvd at 15% O_2.

C. Definitions:

I. Startup is defined as the period beginning with turbine initial firing until the unit meets the lb/hr emission limits listed in IX.H.13.d.i and ii above.
II. Shutdown is defined as the period beginning with the initiation of turbine shutdown sequence and ending with the cessation of firing of the gas turbine engine.
III. Transient load conditions are those periods, not to exceed four consecutive 15-minute periods, when the 15-minute average NO_x concentration exceeds 2.0 ppmv dry @ 15% O_2. Transient load conditions consist of the following:

1. Initiation/shutdown of combustion turbine inlet air-cooling.
2. Rapid combustion turbine load changes.
3. Initiation/shutdown of HRSG duct burners.
4. Provision of Ancillary Services and Automatic Generation Control.

IV. For purposes of this subsection a “day” is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

It is the recommendation of this review that these limitations be retained as BACM.

5.0 BACT for Auxiliary Boilers and Dew Point Heater

There are two auxiliary boilers at the LSPP. The first, installed at Block #1, is rated at 62.8 MMBtu/hr. The second is installed at Block #2, and is rated at 57.6 MMBtu/hr. Both are fired on pipeline quality natural gas. The purpose of the auxiliary boilers is to provide steam to preheat the steam lines and steam turbine, purge the HRSG, and provide heat to warm the SCR catalyst while the main turbine is in startup mode. A single turbine at each block is started up at once, although both Block #1 and Block #2 can be started simultaneously.

There is also a single fuel dew point heater, fired on pipeline quality natural gas and rated at 4.76 MMBtu/hr. This unit is currently out of service and is not expected to be operated in the future. The unit was installed in case of excessively low temperatures which might affect the fuel lines to the combustion turbines, but several years of operational experience have not demonstrated a need for this unit.

As with the combustion turbines, the primary pollutants of concern remain NO_x and condensable $PM_{2.5}$. As all three units are fired on pipeline quality natural gas, no available controls have been identified for further reducing emissions of SO_2. See Section 4.2 for further discussion on SO_2 control options.

5.1 $PM_{2.5}$

5.1.1 Available Control Technology

As with the combustion turbines, controls for particulate emissions fall into one of three groups: pre-combustion controls, which seek to eliminate contaminants in the inlet air prior to the boiler; combustion controls, such as specific burners or combustion design; and post-combustion controls, such as electrostatic precipitators or baghouses.

The identified controls are as follows:

Inlet air filters: primarily used to filter out small particulate matter in the inlet air. These filters are of far less use on the auxiliary boilers than on the combustion turbines. The boilers are fired at or near atmospheric pressure with low inlet and outlet gas velocities, using only pipeline quality natural gas. The chance of burner plugging, or other damage to internal components is essentially zero.

Good combustion practice: this is nothing but properly operating the boilers with the correct ratio of air to fuel in order to maximize combustion and minimize unburned fuel.

Clean burning fuels: includes the use of inherently low emitting fuels like natural gas.

Specific burner and/or combustion chamber design: the more efficiently a boiler is able to operate, the less pollution it will generate for a given amount of fuel combusted. Primarily this includes low-NO_x burners, ultra-low-NO_x burners, and staged fuel combustion with overfire air injection. For particulate control in natural gas combustion, there is little to no difference between the various burner designs or configurations as the degree of complete combustion is the ultimate deciding factor in particulate control.

Add-on particulate controls: this final option includes traditional “add-on” control systems such as baghouses or electrostatic precipitators. These types of controls would be installed post combustion, and prior to the emissions exiting the stack.

5.1.2 Evaluation of Technical Feasibility of Available Controls

With the low risk of damage to the boiler or dew point heater components by firing exclusively on pipeline quality natural gas, the use of inlet particulate filters is not technically feasible. While some filtration of inlet air would occur, these filters would result in essentially zero reduction in particulate emissions given the low inlet flow rates to the boilers. Additional ductwork, fans and control equipment would also be required.

The use of clean burning fuels, good combustion controls, and proper burner design are all technically feasible.

As with the combustion turbines, the use of add-on post-combustion particulate controls – such as baghouse filtration, scrubbers, or ESPs – is not technically feasible. Given the low concentration of particulate matter in the exhaust stream, and the generally low levels of particulate matter being generated from natural gas combustion, add-on controls are simply not effective or available for boilers or direct fired heaters of these size ratings.

5.1.3 Evaluation and Ranking of Technically Feasible Controls

The auxiliary boilers and dew point heater have all the remaining control options (good combustion practices, proper burner design, and clean burning fuel) as existing controls. There is no need to rank these controls on control effectiveness.

5.1.4 Further Evaluation of Most Effective Controls

Further evaluation of the existing controls is not required. All technically available control options are in place and operational at the LSPP.

5.1.5 Selection of BACT/BACM

Retention of the existing particulate controls should remain as BACM. There are no specific $PM_{2.5}$ emission limitations on auxiliary boiler #1, although there is a PM_{10} limit of 0.01 lb/MMBtu on a 3-hr average basis. The PM_{10} limit does include the condensable fraction. Auxiliary boiler #2 does have a PM_{10}/$PM_{2.5}$ limit, which is the same as boiler #1 at 0.01 lb/MMBtu on a 3-hr average basis. This limit also includes the condensable fraction. Both of these limits are found in AO DAQE-AN130310012-15 issued to the source, but are not present in the moderate $PM_{2.5}$ SIP. As the control techniques are primarily work practices or are inherent in the design of the boiler, they are considered BACM rather than BACT. Therefore, inclusion of a specific emission limitation is not necessary.

The fuel dew point heater is not limited in either the NSR permit or the $PM_{2.5}$ SIP as this unit was determined to be too small to warrant an emission limitation given both the expected frequency of use and the expected total level of emissions.

5.2 NO_x

5.2.1 Available Controls

For control of NO_x emissions from the auxiliary boilers there are more combustion (burner design) options available than were discussed under the turbine section above. Beside the two inherent options of clean burning fuels and good combustion practices, there are four different combustion techniques: low-NO_x burners, ultra-low-NO_x burners with internal flue gas recirculation, staged air/fuel combustion (aka overfire air injection) and external flue gas recirculation. Although no catalytic combustion techniques were identified as being available (such as the Xonon option available for some smaller combustion turbines), the same post-combustion control options can be applied: SNCR, SCR, EMx™, LoTOx™, Pahlmann™, and NO_xOUT™ are all available control options that could be applied to the auxiliary boilers.

Although also an atmospheric pressure direct fired heater similar in design to the auxiliary boilers, the fuel dew point heater is much smaller in total input heating value. This greatly limits the available control options that could be applied to the unit. Most post-combustion controls are not available as the unit is simply too small and no commercially available controls of these types are marketed as add-on controls. Similarly, different burner types are not usually available either, as the units are commercially sold as packages with only one burner option. Therefore, the fuel dew point heater will not be further discussed, as UDAQ was unable to find different control options for a unit of this size.

5.2.2 Evaluation of Technical Feasibility of Available Controls

None of the available post-combustion controls has been identified as technically feasible. Neither EMx™ or LoTOx™ has been demonstrated in practice on industrial boilers of this type. LoTOx™ still requires additional pollutant control systems to remove the N_2O which impose additional infrastructure for little to no additional pollutant removal. The Pahlmann™ system requires also requires the addition of a baghouse or other particulate control system, aqueous sorbent regeneration system, and additional wastewater treatment and disposal. This system has not been demonstrated in practice on natural gas-fired equipment, especially on smaller industrial boilers.

The effectiveness of any catalytic control system requires that the catalyst, and therefore the exhaust stream to be treated, fall within a fairly narrow temperature range. The auxiliary boilers are designed to operate during periods of startup of the combustion turbines – primarily when the associated HRSGs and SCR units are below typical operating temperature. While the boiler is brought up to full load operation initially, normal protocol is then to level off operations to a lower level just to maintain steam loads and provide a steady heat flow to those units. The auxiliary boilers are not production units; they simply supplement steam during startup of the combustion turbine in order to shorten the duration of that turbine's startup period. Stack testing of each auxiliary boiler during normal operation showed an average temperature of the exhaust gases at 279ºF for boiler #1 and 317ºF for boiler #2. These values are well below the effective range of any SCR system currently available. The same is true for any SNCR system, including the NO_xOUT™ system, which require even higher exhaust gas temperatures (1600ºF to 2100ºF) to be effective.

Therefore, all post-combustion control techniques were eliminated from further consideration. All combustion related (burner design or combustion technique) remain as technically feasible options.

5.2.3 Evaluation and Ranking of Technically Feasible Controls

For the remaining control options the following table shows the expected ranking and degree of emission control:

Table 5.2 NO_x Control Options

Control Technology	Emissions (lb/MMBtu)	Emissions (ppm @ 3% O_2)
ULNB	0.0085 – 0.011	7.0 – 9.0
LNB with FGR	0.011 – 0.020	9.0 – 16.5
LNB with GCP	0.036	29.7
LNB	0.070	57.8
FGR	0.20	165.2
Staged combustion (OFA)	0.25	206.5
GCP with conv. burners	0.30	247.8

The top control option identified is ultra-low-NO_x burners (ULNB), followed by low-NO_x burners with external flue-gas recirculation. The existing configuration at the LSPP has both boilers equipped as LNB with FGR and permitted emission rates of 0.017 lb/MMBtu (approximately 15 ppm) – required under AO DAQE-AN130310012-15. All control options other than ULNB and the existing controls are eliminated from further consideration as no additional improvement could be gained.

5.2.4 Further Evaluation of Most Effective Controls

A review of recently issued projects; using the RACT/BACT/LAER Clearinghouse, perusal of other states permitting and SIP actions, and UDAQ's own permitting and SIP actions, for natural gas-fired boilers less than 100 MMBtu/hr, yields emission rates for NO_x that range between 0.010 and 0.14 lb/MMBtu. Two boilers just larger than 100 MMBtu/hr (specifically 108 MMBtu/hr) were permitted at 9 ppm in 2014, and have demonstrated some difficulty in maintaining emissions at or below that limit.

While both the San Joaquin Air Pollution Control District and Bay Area Air Quality Management District consider lower emission values as "demonstrated in practice" and "technologically feasible" – both of those areas are located at or near sea level. The effect that the difference in elevation makes in NO_x emissions, boiler combustion tuning, $NO_x/CO/CO_2$ emission ratios, and boiler power/steam output, can be quite substantial – an adjustment of as much as 4% per 1,000 feet of elevation. Thus, emission rates of 7 ppm and 9 ppm are not considered to be demonstrated in practice or even necessarily technically feasible at this time.

Stack tests of the auxiliary boilers at the LSPP resulted in average emission rates of 0.013 lb/MMBtu for boiler #1 and 0.009 lb/MMBtu for boiler #2. The source has submitted a cost analysis for replacing the existing low-NO_x burners and FGR system with new ultra-low-NO_x burners (ULNB) with an expected emission rate of 0.009 lb/MMBtu. The anticipated annualized cost is approximately $56,000 per boiler, with an anticipated reduction in NO_x emissions of just 1.1 tons per rolling 12-months (again, per boiler). This yields an expected cost effectiveness of $51,000/ton. UDAQ does not consider this to be economically feasible, especially given the total amount of reductions gained.

5.2.5 Selection of BACT/BACM

Retention of the existing low-NO_x burners with FGR systems on the auxiliary boilers is recommended as BACT. The existing emission limits on the auxiliary boilers of 0.017 lb/MMBtu on a 3-hr average basis are also recommended as BACT. The fuel dew point heater is not expected to remain in service, thus no changes are recommended for this unit.

5.3 VOC

As with combustion turbines, VOC emissions in boilers and other atmospheric pressure-fired heaters are the result of unburned hydrocarbons formed during incomplete combustion. The formation of VOCs is dependent on combustion system design, choice of fuel, combustion temperature, and operating practices.

5.3.1 Available Control Technology

Available control techniques are: pre-combustion controls, equipment design, good operating practices, thermal oxidation and oxidation catalysts.

Most oxidation catalysts are designed to control VOCs and CO. The exhaust gas stream is sent through the catalyst "bed", which consists of a honeycomb shaped substrate material that is coated with the catalyst. The gas stream needs to be relatively particulate-free to prevent fouling of the catalyst. Oxidation catalysts do not use additional reagent chemicals like SCR systems.

One specific oxidation catalyst, EMx™, has been used to oxidize and remove both NO_x and VOC. The system uses a platinum-based catalyst coated with potassium carbonate (K_2CO_3) – see the section on NO_x control for turbines, Section 4.3, for additional information.

Good combustion practices include using pipeline quality natural gas as fuel, maintaining high combustion efficiencies, maintaining proper air-to-fuel ratios, and conducting proper maintenance.

Thermal oxidation is the use of a secondary combustion process to, in essence, burn off the remaining unburned VOCs (oxidize) into CO_2 and water vapor. This process also oxidizes CO; although it requires a separate combustion chamber, burner, and heat exchanger.

5.3.2 Evaluation of Technical Feasibility of Available Controls

None of the post-combustion controls have proven to be technically feasible for application to either the auxiliary boilers or the fuel dew point heater.

Catalytic oxidation has been applied successfully to both combustion turbines and internal combustion engines. Auxiliary boilers, being atmospherically fired, have a much lower concentration of VOCs and CO in the exhaust gas stream, due to the larger volume of combustion air present in the gas stream. A search of the RBLC, as well as recently issued permits, has identified no examples of oxidation catalysts being employed as controls for either boilers of less than 100 MMBtu/hr heat input or a direct-fired heater similar to the fuel dew point heater.

Thermal oxidation also requires a higher concentration of VOCs and CO than is typically present in the auxiliary boiler exhaust. The average exhaust gas temperature would also require a high degree of supplemental heat input to be added in the thermal combustor to raise the exhaust gas above the thermal oxidation temperature of 1500ºF. As with catalytic oxidation, no examples were identified of application of thermal oxidizers to boilers or heaters similar to those at the LSPP.

All other options having been eliminated, only good combustion practices and proper equipment design remain as viable control technologies.

5.3.3 Evaluation and Ranking of Technically Feasible Controls

Good combustion practices for the auxiliary boilers and fuel dew point heater are the continued use of pipeline quality natural gas as fuel, adjustment of combustion flame temperature and combustion residence time, proper fuel-air mixing and adequate turbulence in the flue gas. As none of these practices are contradictory, there is no need to rank these controls. All can be performed in concert.

5.3.4 Further Evaluation of Most Effective Controls

Further evaluation of the existing controls is not required. All technically available control options are in place and operational at the LSPP auxiliary boilers. The boilers have been designed with proper burner systems; while combustion controls adjust for flame temperatures to ensure high VOC destruction (flame temps above 1800ºF) while minimizing NO_x (flame temps below 2100ºF). Auxiliary boiler #2 has an emission limit on VOC of 0.006 lb/MMBtu (3-hour average) set in the most recent NSR permit (boiler #1 is not limited on VOC emissions). A search of the RBLC was made for recently issued permits, with emission limits ranging from 0.0017[1] to 0.006 lb VOC/MMBtu.

While lower emission rates are possible, as demonstrated by the review of the RBLC, these are for boilers three to ten years newer in design (boiler #2 at LSPP was installed in 2011, boiler #1 in 2007). Upgrading to match the higher performance seen via the records search would require replacement of the burners. While no direct cost analysis was supplied by the company for this scenario, the cost breakdown would be the same as for replacing the burner for NO_x reduction. Only the expected reduction in VOC emissions would change. Based on the emissions from the 2014 inventory, the expected reduction in VOC emissions could be as much as 2.94 tons per year – assuming a reduction from 0.006 lb VOC/MMBtu to 0.002 lb VOC/MMBtu (as a retrofit application). This yields a cost per ton value of \$111,318 / 2.94 = \$37,863/ton of VOC. This is not economically feasible.

5.3.5 Selection of BACT

Retention of the existing control systems (good combustion practices and proper equipment design) for control of VOC emissions is recommended as BACT. There are no existing VOC limitations in the $PM_{2.5}$ moderate SIP for the auxiliary boilers. It is recommended that this remain the case as no specific control equipment is being installed that requires monitoring. Good combustion practices such as maintenance of flame temperature can remain a condition of AO DAQE-AN130310012-15 without requiring SIP-level monitoring, given the expected low level (less than 5 tons per rolling 12-month period) of VOC emissions expected from both auxiliary boilers combined.

As the fuel dew point heater is not expected to be operated in the future, no additional controls,

1 There is a lower limit, but it is not demonstrated in practice, and was not considered at this time.

limits or monitoring are required.

6.0 BACT for the Internal Combustion Engines

The LSPP operates three internal combustion engines, all for emergency purposes, and all fired on diesel fuel. Generators #1 and #2 are 1500 horsepower (hp) engines designed to supply power to the turbine buildings – to supply power to safely shut down the turbine systems in the event of a loss of main electrical power. The third engine, a 290 hp unit, is an emergency fire pump, which will supply fire water in the event of a fire at the facility.

Diesel engines are classified as compression ignition engines. Air is drawn into the cylinder on the first down-stroke of the piston, compressed and heated during the first up-stroke, where fuel is injected under pressure. The fuel and heated air spontaneously ignite pushing the piston down (power stroke), and as the piston rises the exhaust gases are ejected. Then the cycle begins again.

Diesel fuel contains inherently more sulfur than natural gas, although recent strides in the development of low-sulfur diesel have improved (reduced) this difference. The use of diesel fuel also results in higher levels of filterable particulate emissions in the form of soot (carbon) and liquid-phase hydrocarbons versus natural gas. However, the convenience of diesel fuel-fired emergency equipment – portability, ability to operate without gaseous fuel supplies or pressurized fuel tanks, quick starting capability, and general ease of operation and maintenance, ensure that this type of equipment will remain in use despite the somewhat higher levels of emissions.

6.1 $PM_{2.5}$

Particulate emissions from the diesel-fired engines are primarily in the $PM_{2.5}$ or smaller range. This is the result of incompletely combusted hydrocarbons condensing into fine liquid droplets, as well as some elemental carbon which condenses into small particles (soot).

6.1.1 Available Control Technology

The available controls for reduction of particulates from diesel engines are good combustion practices, use of low sulfur fuels, diesel particulate filters, and diesel oxidation catalysts.

Good combustion practices: by increasing the efficiency of combustion, the less residual, unburned, hydrocarbons will remain to condense into particulate matter. Primarily this consists of following the manufacturer's operation and maintenance manuals which detail best practices.

Low sulfur fuels: limiting the sulfur content of the fuel, through the use of ultra-low sulfur diesel, prevents the formation of sulfates in the exhaust gases. Gaseous sulfates condense easily into fine particulates which contribute to diesel particulate emissions.

Diesel particulate filters (DPF): an add-on control device which filters out particulates from the exhaust stream prior to their release to the atmosphere. These primarily trap elemental carbon, by passing the exhaust gases through a porous substrate similar to a catalyst bed which physically captures the soot. After a period of time, the DPF is regenerated to burn off the soot. This can be done electrically or with microwaves (active DPFs), by replacing the DPF's substrate (cartridge units), or through additional fuel injection (passive DPFs) which simply raises the exhaust temperature briefly. Most DPF systems also include an oxidation catalyst component which removes the condensable hydrocarbon fraction (see below) and may be listed as DOC/DPF units.

Diesel oxidation catalysts: although primarily designed to control VOC and CO emissions, some oxidation catalysts are designed to also control particulate emissions. Since a large component of diesel particulate emissions are unburned hydrocarbons which can condense into liquid-phase droplets in the exhaust stream, a catalytic system which combusts VOCs can also combust these other hydrocarbons.

6.1.2 Evaluation of Technical Feasibility of Available Controls

All of the control options identified are technically feasible. Good combustion practices and the use of ultra-low sulfur diesel are considered the baseline for evaluation of these controls. It is assumed that good combustion practices will always be the baseline – unless additional add-on controls are present at a particular installation. And as of June 1, 2010, only ultra-low sulfur diesel was available for use in equipment of this type (40 CFR 60.4207, 40 CFR 80.510).

6.1.3 Evaluation and Ranking of Technically Feasible Controls

For control of particulate emissions, DPFs are the most effective control, capable of achieving above 80% additional removal of diesel-based particulates beyond the baseline. The use of oxidation catalysts at 30% additional control comes in second.

6.1.4 Further Evaluation of Most Effective Controls

The source has provided a cost effectiveness breakdown for installation of DPFs on the three diesel engines at the LSPP. Given the allowed run times of 50 hours per year for operation and maintenance (40 CFR 60 Subpart IIII) and the expected emissions from the engines, installation of DPFs would be at an average cost effectiveness of $1.2 million/ton removed (this value also includes an expected 85% reduction in both $PM_{2.5}$ and VOC emissions as explained under section 6.1.1). This is not cost effective. Although emergency standby engines have been identified with DPFs installed (primarily in California), the installation of DPFs do not appear to have been installed to meet $PM_{2.5}$ NAAQS compliance but for other issues such as odor reduction through control of VOCs.

Oxidation catalysts are somewhat less effective in removal of particulate emissions than DPFs, but have the added benefit of also controlling VOCs and CO. For purposes of this review, the economic analysis must also include the reduction in VOCs possible through use of an oxidation catalyst. The source did not directly provide this information, but did provide an economic analysis for installation of oxidation catalysts for VOC control alone. The control cost is approximately the same as for DPFs, at $1.4 million/ton $PM_{2.5}$+VOC removed. Thus the installation of oxidation catalysts is also not cost effective.

6.1.5 Selection of BACT

Retention of the existing control systems (good combustion practices and use of ultra-low sulfur diesel) for control of particulate emissions is recommended as BACT. Given the infrequent expected use of the emergency diesel-fired equipment, no emission limits are recommended, and no monitoring is necessary. Existing work-practice standards should suffice to minimize emissions.

6.2 NO_x

6.2.1 Available Control Technology

The available controls for reduction of NO_x emissions from diesel engines are: specific combustion practices (ignition timing retard, air-to-fuel ratio adjustment, and derating), SCR, non-selective catalytic reduction (NSCR), and NO_x absorption systems (Lean NO_x Traps).

Ignition timing retard: reduces NO_x formation by delaying the injection of fuel to a later period within the power stroke. This reduces the flame temperature because the compressed air volume has expanded and therefore cooled slightly.

Air-to-fuel ratio adjustment: since diesel engines are inherently lean-burn engines, they combust with excess oxygen and higher combustion temperatures. By adjusting the amount of combustion air (thus making the mixture more rich), the less oxygen is available for combustion, and the cooler the flame temperature.

Derating: simply restricting the engine to lower than normal power output levels, the less fuel is required and the lower the average flame temperature.

SCR: SCR works the same for diesel engines as for combustion turbines. A catalyst bed is used to reduce NO_x to N_2 and water, with either ammonia or urea used as a reagent to jump start the process.

NSCR: nonselective catalytic reduction is similar to SCR in that a catalyst is used to remove NO_x emissions; but is designed specifically for rich burn IC engines run fuel rich or near stoichiometric conditions. Otherwise they are similar to SCR.

6.2.2 Evaluation of Technical Feasibility of Available Controls

NSCR systems are not technically feasible as they are essentially SCR systems but for use on rich burn engines. As the engines employed at the LSPP are inherently lean burn engines, NSCR is eliminated from further consideration.

NO_x absorber systems are also eliminated as these systems are still experimental and do not represent commercially available proven technology.

The other control options are all technically feasible options and will be evaluated further.

6.2.3 Evaluation and Ranking of Technically Feasible Controls

For control of NO_x emissions, SCR represents the highest level of possible control. While various combustion controls options can reduce NO_x emissions by at most 50%, the use of SCR can reduce emissions between 70 to 90%.

6.2.4 Further Evaluation of Most Effective Controls

The addition of SCR for emergency standby equipment poses several considerations. 1) The catalyst still requires the use of a reagent, either ammonia or urea. This leads to some degree of ammonia slip – which will be discussed further in a separate section. 2) Either chemical has inherent difficulties associated with storage and use: liquid ammonia is quite hazardous; while urea can crystalize when not in use for long periods, such as when employed with emergency equipment only operated for infrequent maintenance/testing. 3) SCR systems require minimum operating temperatures for effective use, which can be difficult to achieve during short maintenance/testing cycles. 4) Cost effectiveness can be quite poor. For the LSPP emergency equipment, the source submitted a control cost effectiveness analysis for installation of SCR systems on each of the three engines. Given the infrequent maintenance and testing hours of operation allowed under 40 CFR 60, Subpart IIII, the source calculated a control cost effectiveness of approximately $230,000/ton NO_x removed. This is not cost effective.

6.2.5 Selection of BACT

There are few applications of SCR systems on diesel-fired emergency engines rated at or near 1,250 hp. While technically feasible, these systems are not cost effective. The recommendation for this facility is to adhere to good combustion practices and continue to limit the operation of the engines during non-emergency situations. As this represents a work practice standard, no emission limitations are required, and no monitoring is necessary.

6.3 VOC

6.3.1 Available Control Technology

The available controls for reduction of particulates from diesel engines are good combustion practices, diesel particulate filters, and diesel oxidation catalysts.

Good combustion practices: by increasing the efficiency of combustion, the less residual, unburned, hydrocarbons will remain to condense into particulate matter. Primarily this consists of following the manufacturer's operation and maintenance manuals which detail best practices.

Diesel particulate filters (DPF): an add-on control device which filters out particulates from the exhaust stream prior to their release to the atmosphere. However, most DPF systems also include an oxidation catalyst component which removes the condensable hydrocarbon fraction. They are considered as a separate category from diesel oxidation catalysts, since their costs of control are different, being designed primarily for particulate control.

Diesel oxidation catalysts (DOC): these systems control VOC and CO emissions using a catalyst which promotes further oxidation of unburned components by lowering the necessary combustion temperature. Although some diesel oxidation catalysts can also remove particulates by promoting combustion of condensable liquid hydrocarbons, these are a separate category from DPF systems, since they are designed to control VOCs and CO primarily, and typically do not have a filtration component for removing soot.

6.3.2 Evaluation of Technical Feasibility of Available Controls

All of the control options identified are technically feasible. Good combustion practices are considered the baseline for evaluation of these controls. It is assumed that good combustion practices will always be the baseline – unless additional add-on controls are present at a particular installation.

6.3.3 Evaluation and Ranking of Technically Feasible Controls

For control of particulate emissions, both types of add-on controls (DPF and DOC) are capable of achieving above 95% additional removal of VOCs beyond the baseline.

6.3.4 Further Evaluation of Most Effective Controls

The source has provided a cost effectiveness breakdown for installation of DOCs on the three diesel engines at the LSPP, however, this cost analysis only included the reduction of VOC emissions and did not include the additional reduction of $PM_{2.5}$ emissions (see Section 6.1.4 above for details). With the inclusion of the additional emission reduction taken into account, the cost effectiveness of adding DOCs drops to $1.4 million/ton removed. Better than originally calculated, but still not cost effective. The cost for installing DPFs was also calculated by the source (again, see Section 6.1.4 for details) and would be at an average cost effectiveness of $1.2 million/ton removed. This is also not cost effective.

6.3.5 Selection of BACT

Retention of the existing control systems (good combustion practices and use of ultra-low sulfur diesel) for control of VOC emissions is recommended as BACT. Given the infrequent expected use of the emergency diesel-fired equipment, no emission limits are recommended, and no monitoring is necessary. Existing work-practice standards should suffice to minimize emissions.

7.0 Consideration of Ammonia

There is only one source of emissions of ammonia at the LSPP. The SCR units used to control emissions of NO_x from the combustion turbines and HRSGs use ammonia injection to reduce NO_x to N_2 and water. The catalyst serves to lower the reaction temperature required and helps speed the process. Ideally, a stoichiometric amount of ammonia would be added – just enough to fully reduce the amount of NO_x present in the exhaust stream. However, some amount of ammonia will always pass through the process unreacted; and since the process possesses some degree of variability, a small amount of additional ammonia is added to account for minor fluctuations. The ammonia which passes through the process unreacted and exits in the exhaust stream is termed “slip” (sometimes “ammonia slip”). The amount varies from facility to facility, but ranges from almost zero to as high as 30 ppm in poorly controlled systems. Also, as catalyst systems degrade over time, the degree of ammonia slip will gradually increase as increasing amounts of ammonia are added to maintain NO_x reduction performance.

The unreacted ammonia can be treated as a $PM_{2.5}$ precursor. Although currently not being considered as a precursor pollutant in Utah’s $PM_{2.5}$ Serious SIP, the source’s BACT analysis did include an analysis of BACT for ammonia emissions, which is being included here for completeness.

7.1 Available Control Technology

There is only one control technique considered available for ammonia emissions. Monitoring of ammonia slip emissions and setting a “not to exceed” emission rate limitation. This allows for setting up a feedback process where the source can adjust ammonia injection rates based on both parameters: NO_x emission reduction levels and ammonia slip levels. Should catalyst activity, over time, degrade to the point where both parameters cannot be met, then the SCR catalyst should be replaced.

7.2 Evaluation of Technical Feasibility of Available Controls

This represents a work practice standard, and is inherently technically feasible.

7.3 Evaluation and Ranking of Technically Feasible Controls

A review of recently issued permits for SCR units at large combustion turbine installations reveals NH_4 emission limits ranging between 2.0 ppm and 5.0 ppm. Permits issued during the same time period as the LSPP construction permits for Block #1 and Block #2 routinely had NH_4 emission limits between 7 ppm and 10 ppm.

7.4 Further Evaluation of Most Effective Controls

The source has not provided a cost effectiveness breakdown for upgrading the ammonia injection system at the LSPP so that a new limitation of 5 ppm could be established. This is not an easy task, as it is not as simple as merely upgrading the injection system. An entire SCR upgrade might be required to guarantee that the SCR unit itself was still operating with required removal efficiency at the tighter ammonia injection levels. Increased monitoring would also be required.

However, should this be required, ammonia emissions, currently estimated at 147.04 tons per year, could be reduced to 73.52 tons.

7.5 Selection of BACT

Given the difficulty in redesigning a new SCR system for control of a pollutant not currently listed as a precursor pollutant, and the expected high cost for this process, no change in ammonia slip requirements is recommended at this time. Retention of the existing ammonia slip design parameter of 10 ppm as a limitation is recommended as BACT. This limit is based on the LSPP's existing SCR catalyst system which is designed with an "end of life" ammonia slip of 10 ppmvdc. Existing work-practice standards should suffice to minimize emissions.

8.0 Cooling Towers

The LSPP uses two cooling towers to eliminate heat from the power production processes. Cooling tower #1, which operates with Block #1, is a 10 cell tower with drift elimination; while cooling tower #2 (on Block #2) has 16 cells, also with drift elimination. As the water cools in the tower, some of it exits the tower as mist (aka drift). Cooling towers are a source of $PM_{2.5}$ emissions as the escaping water contains dissolved solids which condense to form particulate matter as the water evaporates.

8.1 Available Control Technology

There are four available control options for control of $PM_{2.5}$ from cooling towers:

1) Use of dry cooling heat exchanger units;
2) High efficiency drift eliminators;
3) Limitation on total dissolved solids (TDS) in the circulating water; and
4) A combination of drift eliminator efficiency and TDS limit.

8.2 Evaluation of Technical Feasibility of Available Controls

The source submitted that the use of dry cooling was technically infeasible. However, UDAQ disagrees with this finding as dry cooling technology has been employed at other combustion turbine plants and submitted for consideration in other permitting actions presented to UDAQ. However, the reasons presented by the source for consideration of technical infeasibility, which were primarily economic, are considered valid by UDAQ for analysis in Section 8.4 – Further

Evaluation. Thus, all control options are considered technically feasible.

8.3 Evaluation and Ranking of Technically Feasible Controls

The use of dry cooling would virtually eliminate drift, and represents the highest level of control at an efficiency rating of 99+%. The remaining controls options are as follows: combination of high efficiency drift eliminators and TDS limit, the use of high efficiency drift eliminators alone, and the setting of a TDS limit alone.

8.4 Further Evaluation of Most Effective Controls

The elimination of the existing cooling tower process at the LSPP and replacing it with a dry cooling system would represent a significant capital cost as well as several overall process design changes. While an exact cost analysis was not provided, the cost effectiveness can be estimated. The total of $PM_{2.5}$ emissions from the cooling towers prior to any change is approximately 16 tons per year. Under the assumption that dry cooling would eliminate all $PM_{2.5}$ emissions from the towers, this value would drop to zero. The source did supply a cost estimate merely to upgrade the drift eliminators from low efficiency to high efficiency, an adjustment far less involved than replacing the entire system. Even using this as the base cost and merely doubling it (an overly conservative estimate), would bring the estimated annual cost to $3.16 million. Dividing by the tons reduced, the best case cost effectiveness is $198,000/ton $PM_{2.5.}$ This is not a cost effective option.

The provided cost analysis for upgrading the drift eliminators showed their cost effectiveness to be approximately $124,000 to $140,000/ton $PM_{2.5}$ reduced. This is also not an effective option.

Experimental analysis of the circulation water available at the LSPP site has shown that no TDS limitation is required. The existing drift eliminators meet the drift limitation established in the most recent NSR permit issued to the source, and additional water treatment makes little difference in overall $PM_{2.5}$ emissions.

8.5 Selection of BACT

As neither replacement of the cooling system, nor upgrading the drift eliminators is economically feasible, retention of the existing control system is recommended as BACT. Establishment of a TDS limitation in the circulation water is not required. No specific SIP limitation or monitoring is necessary as existing work practice standards should suffice to minimize emissions.

9.0 Additional Feasible Measures and Most Stringent Measures

9.1 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).

9.2 Additional Feasible Measures at the LSPP

As defined in Subpart Z, 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 Provo 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 6/9/2021 (4 years after the date of reclassification) are classified as AFM.

After a review of the available control measures described throughout this evaluation report, UDAQ was unable to identify any additional control measures that were eliminated from BACT consideration due to extended construction or implementation periods. Although there are some instances where technologies or control systems were removed from further consideration based on a lack of commercial or technological development, such as EMx™ or NO_x absorber systems, there is no evidence to suggest that these systems will become viable for application merely by waiting 4 years. In addition, existing BACT controls on the emitting units where these alternative controls might have been applied will achieve the same or potentially greater levels of emission reduction; thus rendering the hypothetical discussion moot.

9.3 Most Stringent Measures at the LSPP

As defined in Subpart Z, MSM is defined as:

… any permanent and enforceable control measure that achieves the most stringent emissions reductions in direct $PM_{2.5}$ emissions and/or emissions of $PM_{2.5}$ 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 $PM_{2.5}$ 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 $PM_{2.5}$ and $PM_{2.5}$ 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.

9.3.1 Step 1 – Identification of MSM

For purposes of this evaluation report UDAQ has identified for consideration the most stringent methods of control for each emission unit and pollutant of concern ($PM_{2.5}$ or $PM_{2.5}$ precursor) emitted at the LSPP. A summary is provided in the following table:

Table: Most Stringent Controls by Emission Unit

Emission Unit	Pollutant	Most Stringent Control Method
Combustion Turbine/HRSG	$PM_{2.5}$	inlet air filters, DLN combustors, natural gas, GCP
	SO_2	use of natural gas
	NO_x	SCR w/ ammonia injection
	VOC	GCP, DLN, lean combustion, oxidation catalysts
	SU/SD	work practice standards
Auxiliary Boilers/Dew Point Heater	$PM_{2.5}$	GCP, proper burner design, natural gas
	SO_2	use of natural gas
	NO_x	ULNB w/ integral FGR
	VOC	upgraded higher efficiency design/burner replacement
Emergency Standby Engines	$PM_{2.5}$	DOC/DPF units
	SO_2	use of ULSD
	NO_x	SCR with urea injection
	VOC	DOC/DPF units
Ammonia	NH4	redesigned SCR w/ improved NH4 injection
Cooling Towers	$PM_{2.5}$	dry cooling system

The above listed controls represent the most stringent level of control identified from all other state SIPs or permitting actions, but do not necessarily represent the final choice of MSM. That is determined in Step 4.

9.3.2 Step 2 – Reconsideration of Previous SIP Measures

Utah has previously issued a SIP to address the moderate $PM_{2.5}$ nonattainment areas of Logan, Salt Lake City, and Provo. The SIP was issued in parts: with the section devoted to the Logan nonattainment area being found at SIP Section IX.A.23, Salt Lake City at Section IX.A.21, and Provo/Orem at Section IX.A.22. Finally, the Emission Limits and Operating Practices for Large Stationary Sources, which includes the application of RACT at those sources, can be found in the SIP at Section IX Part H. Limits and practices specific to $PM_{2.5}$ may be found in subsections 11, 12, and 13 of Part H.

Accompanying Section IX Part H was a Technical Support Document (TSD) that included multiple evaluation reports similar to this document for each large stationary source identified and listed in each nonattainment area. UDAQ conducted a review of those measures included in each previous evaluation report which contained emitting units which were at all similar to those installed and operating at the LSPP.

There were several technologies that had been eliminated from further consideration at some point during many of the previous reviews. Some emitting units were considered too small, or emissions too insignificant to merit further consideration at that time. The cost effectiveness considerations may have been set at too low a threshold (a question of cost in RACT versus BACT). And many cases of technology being technically infeasible for application – such as applying catalyst controls to infrequently used emitting units which may never reach an operating temperature where use of the catalyst becomes viable and effective.

In all but one case, these rejected control technologies were already brought forward and re-evaluated using updated information (more recent permits, emission rates and cost information) by the LSPP in its BACT analysis report. The one case which was not reconsidered was the deferment of VOC controls for the wastewater treatment systems at four Salt Lake City area refineries. This issue does not apply to the LSPP, as there is no wastewater treatment system located at the facility, and no VOC-laden water of any sort needs to be treated. Thus, there are no additional technologies identified in Step 2.

9.3.3 Step 3 – Demonstration of Feasibility

A control technology or control strategy can be eliminated as MSM if the state demonstrates that it is either technically or economically infeasible.

This demonstration of infeasibility must adhere to the criteria outlined under §51.1010(b)(3), in summary:

1) When evaluating technological feasibility, the state may consider factors including but not limited to a source's processes and operating procedures, raw materials, plant layout, and potential environmental or energy impacts
2) When evaluating the economic feasibility of a potential control measure, the state may consider capital costs, operating and maintenance costs, and cost effectiveness of the measure.
3) The SIP shall include a detailed written justification for the elimination of any potential control measure on the basis of technological or economic infeasibility.

This evaluation report serves as written justification of technological or economic feasibility/infeasibility for each control measure outlined herein. Where applicable, the most effective control option was selected, unless specifically eliminated for technological or economical infeasibility. Expanding on the previous table, the following additional information is provided:

Table: Feasibility Determination

Emission Unit	Pollutant	MSM Previously Identified	Is Method Feasible?
Turbines HRSGs	$PM_{2.5}$	inlet air filters, DLN, natural gas, GCP	Yes
	SO_2	use of natural gas	Yes
	NO_x	SCR w/ ammonia injection	Yes
	VOC	GCP, DLN, oxidation catalysts	Yes
	SU/SD	work practice standards	Yes
Auxiliary Boilers	$PM_{2.5}$	GCP, proper burner design, natural gas	Yes
	SO_2	use of natural gas	Yes
	NO_x	ULNB w/ integral FGR	No, high cost
	VOC	upgraded design/burner replacement	No, high cost
IC Engines	$PM_{2.5}$	DOC/DPF units	No, high cost
	SO_2	use of ULSD	Yes
	NO_x	SCR with urea injection	No, high cost
	VOC	DOC/DPF units	No, high cost
Ammonia	NH4	redesigned SCR, improved NH4 system	No, high cost
Cooling Towers	$PM_{2.5}$	dry cooling system	No, high cost

Approximately half of the entries in the above table were determined to be feasible on both a technology and economic basis. In each of those cases, the control technique listed represents BACT/BACM as well as MSM, so no changes need to take place if implementation of MSM becomes a requirement. For the remaining entries, a more detailed analysis is required.

Auxiliary boilers NO_x control: The installation of ultra-low-NO_x burners (ULNB) with integral flue gas recirculation (FGR) was determined to be economically infeasible for boilers of this size and emission rate. Upgrading to this level of control is technically feasible, but could only be accomplished at a cost effectiveness of $50,600/ton. This is considered outside the normal range of economic feasibility. The total tonnage reduced would be between 2 and 3 tons per year. The next best level of control is already installed on the emitting units, but could theoretically be paired with a tighter emission limit. However, the tighter emission limits found in recently issued permits have not been demonstrated in practice at the higher elevation of the LSPP. This represents a technological infeasibility constraint. The existing BACT evaluation should also serve as MSM. Should the installation of MSM be required at a future date due to monitored nonattainment concerns, this issue can be revisited.

Auxiliary Boilers VOC control: The only identified control mechanism beyond good combustion practices is to replace the burners and/or boilers themselves with a more efficient design that achieves a greater efficiency rating. With emissions of VOCs less than 1/2 the total emissions of NO_x, the total cost effectiveness of replacing the burners is approximately $100,000/ton. This is outside the range of economic feasibility.

Emergency Diesel Engines $PM_{2.5}$ and VOC control: Installation of a diesel particulate filter with integrated diesel oxidation catalyst system is technologically feasible, and have been installed and in use in several locations – primarily in California and Maine. Installation of this type of system would have a high annualized cost leading to a poor cost effectiveness rating – given the rather low frequency of operation (primarily for testing and maintenance), and associated low level of emissions. Cost effectiveness is estimated at $1.2 million/ton, although both particulates and VOC emissions would be controlled. This is not economically feasible for MSM consideration.

Emergency Diesel Engines NO_x control: The use of SCR with urea injection (which is preferred over liquid ammonia for smaller emitting units) was identified as the top control option. However, this control technique has both technical and economic issues which eliminate it from consideration as MSM. Given the short periods of operation of the engines, the ability of the engine exhaust to heat the reduction catalyst to an effective temperature is extremely limited. The capability of the control system to effectively function is severely hampered. The annualized cost is also quite high for the expected amount of emissions controlled, yielding a cost effectiveness of $230,000/ton. This is not economically feasible, and when combined with the technical challenges, eliminates the use of SCR as MSM.

Ammonia Considerations: Presently, UDAQ may yet determine, as part of the Provo SIP, that ammonia is not a precursor pollutant for $PM_{2.5}$ for each of the $PM_{2.5}$ nonattainment areas. Therefore, this section (and previous Section 7 of this document) may be removed from this document before final publication. However, at the present time, only a single control technique has been identified for reducing the amount of ammonia emissions released from the LSPP. Given that all of the ammonia is released as slip from the SCR units controlling the combustion turbine/HRSGs, reducing ammonia emissions requires reducing ammonia slip. This requires, at minimum, a redesign of the ammonia injection system on the existing SCR, and most likely a redesign of the SCR itself, in order to improve the efficiency of NO_x removal with less ammonia injection. Less ammonia added, yields less ammonia slip. A redesigned SCR, in whole or in part, has not been investigated as of the publication of this document, but most likely fall outside both the economic and technological consideration windows. The cost per ton is likely to be extremely high, but is unknown at this time, and no additional benefit to NO_x emissions will be gained. Design, timed long term shut-down of the four turbines – likely in stages – ordering of materials, construction, testing, shake down, and demonstration is then likely to fall outside the regulatory attainment window. This renders the change infeasible from both perspectives.

Cooling Towers $PM_{2.5}$ controls: The use of a dry cooling system is technologically feasible, but is not economically feasible. UDAQ has received several permit applications for dry cooled processes including at least two for turbine power plant projects. While the facilities were ultimately never built, the technology is sound from a technical point of view and has not been disputed by the source. [The source's BACT analysis does include an argument as to technical infeasibility, but this argument is primarily based on economic infeasibility concerns and should have been eliminated on that basis by the source. See Section 8 of this document for further details.] Economically, the source provided an analysis for replacing the drift eliminators in the existing cooling towers with high efficiency drift eliminators; a project presumably less costly than replacing the entire cooling tower with a new dry cooling system. Replacement of the drift eliminators had a cost effectiveness of approximately $130,000/ton, which is not cost effective, while completely eliminating the cooling towers would only eliminate an additional four (4) tons of $PM_{2.5}$ per year, with an even higher cost effectiveness rating. Both options have been eliminated as MSM.

10.0 New $PM_{2.5}$ SIP – General Requirements

The general requirements for all listed sources are found in SIP Subsection IX.H.11. These serve as a means of consolidating all commonly used and often repeated requirements into a central location for consistency and ease of reference. As specifically stated in subsection IX.H.11.a below, these general requirements apply to all sources subsequently listed in either IX.H.12 (Salt Lake City) or IX.H.13 (Provo), and are in addition to (and in most cases supplemental to) any source-specific requirements found within those two subsections.

10.1 Monitoring, Recordkeeping and Reporting

As stated above, the general requirements IX.H.11.a through IX.H.11.f primarily serve as declaratory or clarifying conditions, and do not impose compliance provisions themselves. Rather, they outline the scope of the conditions which follow in the source specific requirements of IX.H.12 and IX.H.13.

For example, most of the conditions in those subsections include some form of short-term emission limit. This limitation also includes a compliance demonstration methodology – stack test, CEM, visible opacity reading, etc. In order to ensure consistency in compliance demonstrations and avoid unnecessary repetition, all common monitoring language has been consolidated under IX.H.11.e and IX.H.11.f. Similarly, all common recordkeeping and reporting provisions have been consolidated under IX.H.11.c.

10.2 Discussion of Attainment Demonstration

As is discussed above in Items 10.0 and 10.1, these are general conditions and have few if any specific limitations and requirements. Their inclusion here serves three purposes. 1. They act as a framework upon which the other requirements can build. 2. They demonstrate a prevention of backsliding. By establishing the same or functionally equivalent general requirements as were included in both the original PM_{10} and the moderate $PM_{2.5}$ SIP, this demonstrates both that the original requirements have been considered, and either retained or updated/replaced as required. 3. When a general requirement has been removed, careful consideration was given as to its specific need, and whether its retention would in any way aid in the demonstration of attainment with the 24-hr standard. If no argument can be made in that regard, the requirement was simply removed.

11.0 New $PM_{2.5}$ SIP – LSPP Specific Requirements

The LSPP specific conditions in Section IX.H.13 address those limitations and requirements that apply only to the LSPP Power Plant in particular.

IX.H.13.b.i This condition lists the specific requirements applicable to Block #1 Turbine/HRSG Stacks.

Subparagraph A: Emissions of NO_x shall not exceed 14.9 lb/hr on a 3-hr basis.
Subparagraph B: Compliance with the above conditions shall be demonstrated as follows:
I. NO_x monitoring shall be through use of a CEM as outlined in IX.H.11.f

IX.H.13.b.ii This condition lists the specific requirements applicable to Block #2 Turbine/HRSG Stacks.

Subparagraph A: Emissions of NO_x shall not exceed 18.1 lb/hr on a 3-hr basis.
Subparagraph B: Compliance with the above conditions shall be demonstrated as follows:
I. NO_x monitoring shall be through use of a CEM as outlined in IX.H.11.f

IX.H.13.b.iii This condition lists the startup/shutdown emission minimization plan requirements applicable to all three combustion turbines. The requirement also includes a definition of startup, shutdown, and a limit on total hours of operation (2) in startup or shutdown mode, per turbine, per day.

Subparagraph A: Limits applicable to Block #1 – total starts and shut down not to exceed 14 hours per day per turbine, total NO_x emissions from the Block #1 Turbine/HRSG Stacks shall not exceed 25 ppmvd at 15% O_2.
Subparagraph B: Limits applicable to Block #2 – total starts and shut down not to exceed 8 hours per day per turbine, total NO_x emissions from the Block #2 Turbine/HRSG Stacks shall not exceed 25 ppmvd at 15% O_2.
Subparagraph C: Definitions – Startup, shutdown, transient load conditions, and a definition of operating day.

11.1 Monitoring, Recordkeeping and Reporting

Monitoring for IX.H.13.b.i.A is specifically outlined in IX.H.13.b.i.B; while IX.H.13.b.ii.A is addressed in IX.H.13.b.ii.B. NO_x monitoring is addressed by CEM. CEM monitoring requirements are found in IX.H.11.f. Recordkeeping is subject to the requirements of IX.H.11.c and IX.H.11.f.

11.2 Discussion of Attainment Demonstration

LSPP is primarily a source of direct $PM_{2.5}$, NO_x and VOC emissions. When the LSPP was originally authorized for construction, and again during the 2011 expansion to install Block #2, the owner/operator PacifiCorp Energy was required to produce and use emission offset credits as outlined under R307-403-5(1)(b).

Specifically, as both the initial installation and the expansion were both larger than the 50 ton per year threshold listed in that rule, the offset credits needed to be obtained at a ratio of 1.2:1. These offset credits also satisfied the emission offsetting requirement of 40 CFR 51.165(a)(9)(i). The emission offset credits used were generated from the closure of the Geneva Steel plant (emission credit pedigree available upon request), a source listed in both the original SIP and the Utah County updated SIP (issued July 6, 2005). Therefore, the emission increase associated with the installation of the LSPP was already included in the background emissions of the airshed and at a greater emissions ratio. In addition, during the establishment of the pedigree for the emission offset credits used for both projects, a specific ratio of $PM_{2.5}$ was determined for the particulate emission credits – based upon a combination of emission factors, direct emission testing and CEM data - all obtained from the Geneva Steel facility.

There are no specific limitations on $PM_{2.5}$ emissions. Although the PTE estimates would suggest that particulate (both PM_{10} and $PM_{2.5}$) emissions are similar to NO_x emissions on a lb/hr basis, recent testing and inventory reporting have demonstrated this assumption to be incorrect. The original particulate limits were based on manufacturer's guarantees, which were set much higher than required. Operational experience has demonstrated that actual particulate emissions are approximately one-fourth (1/4th) of original estimates. Given this updated information, annual particulate PTE for the LSPP is likely no greater than 75 tpy; much less than the originally estimated 215.4 tpy. Similarly, daily emissions would be expected to max out around 0.2 tons. This value is for all four combustion turbines including emissions from operating in startup/shutdown mode.

12.0 References

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