PM$_{2.5}$ SIP Evaluation Report:
Utah Municipal Power Association - West Valley Power Plant

Salt Lake City Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

July 1, 2018

DAQ-2018-006862

$PM_{2.5}$ SIP EVALUATION REPORT
Utah Municipal Power Association - West Valley Power Plant

1.0 Introduction

The following is part of the Technical Support Documentation for Section IX, Part H.12 of the Utah SIP; to address the Salt Lake City $PM_{2.5}$ Nonattainment Area. This document specifically serves as an evaluation of the Utah Municipal Power Association operated West Valley Power Plant.

1.1 Facility Identification

Name: West Valley Power Plant
Address: 5935 West 4700 South, West Valley City, Utah, Salt Lake County
Owner/Operator: Utah Municipal Power Association
UTM coordinates: 4,502,036 Northing, 412,828 Easting, Zone 12

1.2 Facility Process Summary

The West Valley Power Plant (WVPP) is a natural gas-fired electric generating plant consisting of five (5) simple cycle turbines. Each turbine has a power output rating of 43.4 MW. The plant is located in Salt Lake County, which is part of the Salt Lake City $PM_{2.5}$ nonattainment area.

The turbines are fired on pipeline quality natural gas, have water injection and evaporative mist inlet air cooling. The plant is a Phase II acid rain source and a major source for both NO_x and CO emissions. The plant was permitted in 2002 as a PSD major source and a PM_{10} nonattainment area major source for NOx emissions, and ozone maintenance area major source (again for NO_x emissions). Therefore, analysis of LAER was required for PM_{10}, NO_x, SO_2 and VOC emissions; analysis of BACT was required for all other emissions.

1.3 Facility Criteria Air Pollutant Emissions Sources

The source consists of five (5) GE LM6000PC Sprint simple cycle natural gas-fired combustion turbines. Emissions are presently controlled using a combination of exclusive firing of pipeline quality natural gas, selective catalytic reduction (SCR), oxidation catalysts and water injection.

1.4 Facility 2016 Baseline Actual Emissions and Current PTE

In 2016, WVPP's baseline actual emissions were determined to be the following (in tons per year):

Table 1-1: Actual Emissions

	Actual Emissions (Tons/Year)

Pollutant	
PM2.5	3.94
SO2	0.36
NOx	8.55
VOC	1.25
NH3	0.0

The current PTE values for WVPP, as established by the most recent AO issued to the source (DAQE-282-02) are as follows:

Table 1-2: Current Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	41.03
SO_2	29.68
NO_x	162.06
VOC	18.33
NH3	190.5*

* Ammonia emissions were never quantified in the AO, PTE is estimated.

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 2016, 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 2016 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 2016 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 power grid.

For the WVPP, a summary of the modified emission totals for 2017 are shown below in Table 3. Since a value of zero (0) growth was applied at the utility sources, these same values would then propagate through for each of the subsequent projection years.

Table 2-1: Modeled Emission Values

Pollutant	Actual Emissions (Tons/Year)
PM2.5	3.94
SO2	0.36
NOx	8.55
VOC	1.25

NH3	0.0

Finally, the effects of BACT were then applied during the appropriate projection year. Any controls applied between 2016 and 2017 (such as any RACT or RACM required as a result of the moderate $PM_{2.5}$ SIP), was previously taken into account during the 2017 adjustment performed earlier. Future BACT, meaning those items expected to be coming online between today and the regulatory attainment date (December 31, 2019), would be applied during the 2019 projection year. Notations in the appropriate table of emission inventory model input spreadsheet indicate the changes made and the source of those changes. Similarly, Additional Feasible Measures (AFM) or Most Stringent Measures (MSM), which might be applied in future projection years beyond 2019 are similarly marked on the spreadsheet. The effects of those controls are applied on the projection year subsequent to the installation of each control – e.g. controls coming online in 2021 would be applied in the 2023 projection year, while controls installed in 2023 would be shown only in 2024.

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 the GE LM6000PC Sprint Combustion Turbines

Each of the five combustion turbines (CT) is a simple cycle turbine fired exclusively on pipeline quality natural gas. Each CT provides primary power generation by spinning a generator directly. Because it operates in simple cycle mode, there is no heat recovery steam generator and no associated duct firing emissions.

As there is no other equipment located at the WVPP, an analysis of the emissions for the CTs is an analysis of the emissions for the entire plant. Thus, following the emissions correction procedure outlined in Section 2.0, emissions from the five CTs are as follows:

PM2.5 = 3.94 tons
SO2 = 0.36 tons
NOx = 8.55 tons
VOC = 1.25 tons
NH3 = 0.0 tons

The calculations can be found 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-NOx (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 operations were located in the 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 considered 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 a well-designed burner system. Thus, the remaining controls do not need to be ranked – rather they should be combined and considered as a group. When combined, this group can be treated as a single control option – “good combustion practices” – and no further evaluation under step 3 is required.

4.1.4 Further Evaluation of Most Effective Controls

All three combustion turbines at this facility are already using good combustion practices. No adverse economic, environmental or energy costs will result. The WVPP has not employed inlet air filters, but instead relies on evaporative spray mist inlet air cooling to densify the inlet air prior to combustion. This is used during hot days (average daytime temperature above 80-85ºF) to cool the inlet air stream and improve power production. The water mist is sprayed into the area before the turbines’ air inlets where the water can evaporate. The high specific heat of water leads to a rapid cooling of the surrounding air. While much of the water does evaporate, some can remain in liquid form – depending on the amount being sprayed, the overall spray pattern, instantaneous surrounding air temperature, and a number of other factors. The presence of liquid water can lead to plugging of any inlet filtration system. While this is only a problem while the misting system is in operation, the filters would need to be removed whenever the system was employed. Inlet air filters cannot be considered BACT if they cannot be in use continuously. The remaining control options remain viable.

4.1.5 Selection of BACT controls

The WVPP is already employing properly designed combustors, and the use of 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).

The most recently issued NSR permit for the WVPP does not contain any limits on direct emissions of $PM_{2.5.}$ Similarly, no $PM_{2.5}$ limits were set in the moderate $PM_{2.5}$ SIP either. Therefore, UDAQ recommends that the existing controls be accepted as BACM 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.

Rather than relying on post-combustion controls, an alternative option would be to reduce the amount of sulfur present in the fuel, thus eliminating the source of the SO_2. The use of low sulfur fuels, primarily the use of pipeline-quality natural gas, is the most common method of controlling SO_2 emissions from CTs. This also happens to be the base case at the WVPP.

4.2.2 Evaluation of Technical Feasibility of Available Controls

Neither of the possible post-combustion/add-on control options is technically feasible. With all of the combustion turbines being fired on natural gas, the amount of fuel-bound sulfur is inherently 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 CTs (0.36 tons/year combined), 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 NOx

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 by the source as potential control methodologies for control of NO_x emissions: good combustion practices; low emission combustion (LEC); selective non-catalytic reduction (SNCR), which is the injection of ammonia or urea directly into the late stages of the combustion zone; selective catalytic reduction (SCR); and EMx™ (previously known as SCONOx™).

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 by UDAQ 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. While the use of water/steam injection is of limited effectiveness in combined cycle systems (those using a HRSG in combination with the CT); employing this process on simple cycle turbines can yield substantial NO_x reductions – as much as 80 to 90% in some cases. This process is technically feasible and is currently in use on all the Gadsby turbines.

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, 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.

SNCR requires relatively high exhaust gas temperatures for effective NO_x removal. Unlike SCR systems, which rely on the use of a catalyst bed to lower the activation temperature of the reagent, SNCR systems simply inject the reagent directly into the hot exhaust stream (or into the late stages of combustion), and rely on turbulence and residence time for the control of NO_x to take place. However, the temperature of the exhaust stream needs to be between 1,600ºF and 2,100ºF for the highest degree of control. This is well above the exhaust temperature of the LM6000 turbines in use at the WVPP. The LM6000 turbine is an aero-derivative turbine design, with a much lower exhaust temperature than the more common F-class turbine – such as the GE Frame 7-FA in use at the PacifiCorp Lake Side facility. As the control process cannot function properly without supplemental heat input (which negates the purpose of installing the system), SNCR is eliminated from further consideration.

Catalytica Energy Systems' Xonon Cool Combustion® System, and other catalytic combustion systems, would require a complete redesign of the burner system and combustion chamber – or replacement of the existing CTs with new CTs built with the alternate combustion process in place as a design element. Such a redesign and/or replacement would have exorbitant costs and would require several years to construct/install. During this time, the existing plant would not be available for power production – severely impacting the local and regional power grids and requiring far more power to be generated from other area plants. This process merely shifts the source of the pollution, rather than reducing overall pollution. UDAQ has determined that for purposes of the $PM_{2.5}$ Serious SIP, catalytic combustion systems, such as Xonon®, are not technically feasible.

The EMx™ system has been demonstrated commercially in five applications – none of which have been simple cycle combustion turbines. The unique catalyst in EMx systems has the opposite problem of SNCR systems, as it operates most effectively in a temperature range of 300-700ºF. The average exhaust temperature of the LM6000s installed at Gadsby is 825ºF – well above the operating range required for an EMx™ system. EMx™ will not be evaluated further.

The other control options (SCR, good combustion practices, water/steam injection and burner design) are all technically feasible.

4.3.3 Evaluation and Ranking of Technically Feasible BACT Controls

Each of the five LM6000 turbines are built around a standard combustor and further controlled by water injection in the inlet combustion air and downstream through use of a SCR system (complete with ammonia injection). This represents the base case for the WVPP.

The use of water/steam injection as a pre-combustion control was determined to be technically feasible; however it cannot be used in conjunction with the DLN combustor, due to how that combustor operates. Aside from the obvious problem with the name ("dry" low-NO_x), the DLN-type combustor is a lean pre-mix burner design, which uses a combination of staged combustion and differing fuel-air mixing for each combustion stage to lower the combustion temperature, yet still allowing for complete combustion. The injection of water or steam into the inlet combustion air alters the availability of oxygen in the inlet stream. While a large amount of combustion air is provided, only limited fuel is injected in the initial primary stage of the combustor. Including water vapor consumes much of the "additional" combustion air volume, reducing the leanness of the combustion mix and reducing the benefit of the staged combustion design. Plus the addition of the water vapor serves to dampen the combustibility of the fuel-air mixture even more than normal (from the initial non-stoichiometric fuel-air ratio), owing to water's high specific heat. This can prevent the turbine from maintaining consistent combustion; leading to flameouts, poor performance, or inadequate combustion and increased emissions. For this reason, turbines using water/steam injection for NOx control are fitted with standard burners, and the use of DLN in this case will not be evaluated further.

On the other hand, the use of water/steam injection has no impact on the effectiveness of the other remaining technically feasible control system – SCR. The resulting steam leaving the combustion chamber serves merely to increase the mass of the exhaust gases. It does not poison, foul, "clog up" or otherwise affect the catalyst bed of the SCR, and has no impact on the injected reagent – which is most commonly liquid urea or aqueous ammonia. Water/steam injection and SCR are commonly found in use together, and represents the base case for the five turbines at the WVPP.

Since both remaining controls can be used in conjunction, there is no need to rank the two controls.

4.3.4 Further Evaluation of Most Effective Controls

Although both remaining control options already in place and operational, it is possible to evaluate the existing control system(s) to determine if improvements could be made. When installed, the NOx emission controls at the WVPP were designed with an emission limit of 5 ppmvd NO_x as the final goal. Currently, the most stringent NO_x limit among similarly designed systems is 2.5 ppmvd. The source submitted an economic analysis of retrofitting the SCRs on each of the five CTs to enable them to meet an emission limit of 2.5 ppmvd NO_x. Based on an initial capital cost of $450,000 per CT, and annual costs of roughly $10,000 in ammonia, labor and related expenses (per turbine); this yields a total annualized cost of approximately $42,000 (calculations based on a future worth factor of 0.0724).

As expected, each turbine was run for differing lengths of time, such that total hours of operation varied. As a straight peaking plant, the WVPP does not operate for many hours in a given year – total hours of operation for any single CT did not exceed 810 in a given year, and the average hours of operation for all five turbines over a 24-month period (2014-2015) was 645.8 hours/turbine. Under this type of operating scenario, the expected reduction in NO_x emissions from improving the SCR system to a 2.5 ppmvd emission limit is just 1.2 tons/year. At this level of reduction, the control cost estimate would be $42,000/1.2 = $35,000/ton. This is not economically feasible. Retention of the existing SCR system remains viable.

4.3.5 Selection of BACT Controls

Retention of the existing SCR and water/steam injection systems for each of the five CTs is recommended as BACT to control NO_x emissions. Emission limits were established in the most recently issued NSR permit for the facility, and these emission limits were then updated into daily limits for the moderate $PM_{2.5}$ SIP as follows:

i. Total emissions of NOx from all five (5) catalytic-controlled turbines combined shall be no greater than 1050 lb of NOx on a daily basis. For purposes of this subpart, a "day" is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

ii. Total emissions of NOx from all five (5) catalytic-controlled turbines shall include the sum of all periods in the day including periods of startup, shutdown, and maintenance.

iii. The NOx emission rate (lb/hr) shall be determined by CEM

These same emission limits should also be retained 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 five CTs at the WVPP 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, most properly designed combustion turbines utilize "lean combustion" – where a large amount of excess combustion air is provided. The most effective low-NOx combustor/burner design is known as the dry low-NO_x (DLN) combustor. Combustion turbines using water/steam injection for NOx control will always be equipped with standard burners (see Section 4.3.3 above).

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 is supposed to improve 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 WVPP CTs.

Good combustion practices and the use of a DLN combustor are similarly technically feasible. This is not the case at the WVPP, as the CTs use water injection for NO_x control. Thus, the WVPP CTs use standard burners.

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 units similar to those at the WVPP. EMx™ equipped turbines experience larger pressure drops than other oxidation catalyst-equipped units, and have not been designed around aero-derivative turbines like the LM6000 class.

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. 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 WVPP.

4.4.3 Evaluation and Ranking of Technically Feasible Controls

The three turbines have all the remaining control options (good combustion practices, properly designed combustors, and oxidation catalysts) as existing controls. There is no need to rank these controls on control effectiveness. However, a comparison can be made between the two burner types to determine if any difference in the control effectiveness on VOCs exists and then an evaluation of the effectiveness on NOx can be similarly made.

UDAQ conducted a search of recent permitting actions made by other states on other simple-cycle CT projects. It did not appear that any specific comparison of burner type on final VOC limit was made, or that any consideration was included with setting the final limit on VOC emissions. Rather, it appears that a well-designed oxidation catalyst system can control VOC emissions to 2 ppmv on average – regardless of the type of combustor employed.

4.4.4 Further Evaluation of Most Effective Controls

There are minor potential environmental and energy related impacts associated with the use of an oxidation catalyst, such as increased backpressure and the chance for increased H2SO4 emissions. These potential impacts are not typically considered problematic enough to prevent installation and use of oxidation catalyst systems on CTs. The existing CTs at the WVPP already have oxidation catalysts installed that are designed with a 2 ppm emission rate as the end goal.

4.4.5 Selection of BACT

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

The limitations on VOC 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.

5.0 Consideration of 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. Although the standard combustors installed on these turbines do not have the same minimum operating rate issues that DLN combustors can have, the water/steam injection system can cause problems with flame retention if the firing rate is too low. 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. The easiest way to minimize emissions is simply to limit the total number and total duration of these events.

The WVPP turbines are operated as peaking units, averaging between 500 and 825 operating hours per year per turbine. 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. 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. And using an alternative combustor during startup periods is physically impossible, as the combustor is integrated into the unit and cannot be "swapped out" during operation.

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.

Beyond these work practice techniques, there are no other technically feasible control methods to reduce emissions during periods of startup or shutdown. The WVPP does not differentiate between normal/steady-state operations and periods of startup/shutdown for emission limitation purposes. The same limits apply at all times.

6.0 Ammonia Considerations

There is only one source of emissions of ammonia at the WVPP. The SCR units used to control emissions of NO_x from the CTs 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 is treated as a $PM_{2.5}$ precursor. The source's BACT analysis did include an analysis of BACT for ammonia emissions.

6.1 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.

6.2 Evaluation of Technical Feasibility of Available Controls

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

6.3 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 WVPP construction permit routinely had NH_4 emission values around 10 ppm.

6.4 Further Evaluation of Most Effective Controls

The source provided a cost effectiveness breakdown for upgrading the ammonia injection system at the WVPP so that a new limitation of 5 ppm could be established.

The source's economic evaluation was based on two assumptions: 1) an average upgrade cost of $300,000, which accounts for the wide difference between cleaning and tuning the existing system ($100,000) and installing a new injection grid ($350,000-$500,000), and 2) that achieving a final ammonia slip of 5 ppm is possible on peaking units of this type. While this level has been achieved in practice, it is usually reserved for systems operating as primarily "base load" units – where continuous feedback and parameter adjustments can be made to fine tune the system during operations. With the limited annual hours of operation at the WVPP, this degree of adjustment may not be possible. However, under these assumptions, a final annualized cost of $15,500/ton of NH_4 reduced would be possible.

UDAQ reviewed this economic analysis and determined that retrofitting the ammonia injection system is not economically viable. While the $/ton figure is low when compared to other emission reduction options, the total amount of NH_4 removed would total just 1.41 tons/year per turbine (7.02 tons per year for all turbines combined).

6.5 Selection of BACT

Given 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 WVPP's existing SCR catalyst system which is designed with an "end of life" ammonia slip of 10 ppmv. Existing work-practice standards should suffice to minimize emissions.

7.0 Additional Feasible Measures and Most Stringent Measures

7.1 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).

7.2 Additional Feasible Measures at the WVPP

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 Salt Lake City 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 NOx 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.

7.3 Most Stringent Measures at the WVPP

As defined in Subpart Z, MSM is defined as:

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

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

Step 1) The state shall identify the most stringent measures for reducing direct $PM_{2.5}$ 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.

7.3.1 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). A summary is provided in the following table (the minor emission sources found in Section 6 are not listed):

Table 7-1: Most Stringent Controls by Emission Unit

Emission Unit	Pollutant	Most Stringent Control Method
Combustion Turbine	PM2.5	proper combustors, natural gas, GCP
	SO2	use of natural gas
	NOx	water/steam injection, SCR w/ ammonia injection
	VOC	GCP, oxidation catalysts
	SU/SD	work practice standards
Ammonia	NH4	redesigned SCR w/ improved NH4 injection

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.

7.3.2 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 WVPP 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 at the WVPP. Although some amount of water treatment does take place, this is for pre-treatment of the water used in the steam injection system at the combustion turbines and not wastewater treatment in the traditional sense. No VOC-laden water of any sort needs to be treated. Thus, there are no additional technologies identified in Step 2.

7.3.3 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 7-2: Feasibility Determination

Emission Unit	Pollutant	MSM Previously Identified	Is Method Feasible?
Turbines	PM2.5	natural gas, GCP	Yes
	SO2	use of natural gas	Yes
	NOx	water injection, SCR w/ ammonia	Yes, upgrade has high cost
	VOC	GCP, oxidation catalysts	Yes
	SU/SD	work practice standards	Yes
Ammonia	NH4	redesigned SCR, improved NH4 system	No, high cost

Most of the entries in the above table were determined to be feasible on both a technological and economic basis – the sole exception being a redesigned SCR for control of NOx and NH4. 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 SCR case, a more detailed analysis is needed.

Currently, the cost per ton values for improving the SCR are not considered economically viable. With a total expected reduction of just 6 tons of NOx (1.2 tons per turbine) and 7 tons of NH4 (1.4 tons per turbine), the benefit of replacing and upgrading the SCR and ammonia injection system to meet the emission values expected of a newly installed system are not justified.

8.0 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/Orem), and are in addition to (and in most cases supplemental to) any source-specific requirements found within those two subsections.

IX.H.11.a. This paragraph states that the terms and conditions of Subsection IX.H.11 apply to all sources subsequently addressed in the following subsections IX.H.12 and IX.H.13. It also clarifies that should any inconsistency exist between the general requirements and the source specific requirements, then the source specific requirements take precedence.

IX.H.11.b Paragraph i: States that the definitions found in State Rule 307-101-2, Definitions, apply to SIP Section IX.H. Since this is stated for the Section (IX.H), it applies equally to IX.H.11, IX.H.12 and IX.H.13. A second paragraph (ii), includes a new definition for natural gas curtailment for those sources in IX.H.12 and IX.H.13 that reference it.

IX.H.11.c This is a recordkeeping provision. Information used to determine compliance shall be recorded for all periods the source is in operation, maintained for a minimum period of five (5) years, and made available to the Director upon request. As the general recordkeeping requirement of Section IX.H, it will often be referred to and/or discussed as part of the compliance demonstration provisions for other general or source specific conditions. It also includes provisions referring to the reporting of emission inventories (paragraph ii) and reporting deviations (paragraph iii).

IX.H.11.d Statement that emission limitations apply at all times that the source or emitting unit is in operation, unless otherwise specified in the source specific conditions listed in IX.H.12 or IX.H.13. It also clarifies that particulate emissions consist of both the filterable and condensable fractions unless otherwise specified in IX.H.12 or IX.H.13.

This is the definitive statement that emission limits apply at all times – including periods of startup or shutdown. It may be that specific sources have separate defined limits that apply during alternate operating periods (such as during startup or shutdown), and these limits will be defined in the source specific conditions of either IX.H.12 or IX.H.13.

Conditions 1.a, 1.b and 1.d are declaratory statements, and have little in the way of compliance provisions. Rather, they define the framework of the other SIP conditions. As condition 1.c is the primary recordkeeping requirement, it shall be further discussed under item 4.2 below.

IX.H.11.e This is the main stack testing condition, and outlines the specific requirements for demonstrating compliance through stack testing. Several subsections detailing Sample Location, Volumetric Flow Rate, Calculation Methodologies and Stack Test Protocols are all included – as well as those which list the specific accepted test methods for each emitted pollutant species (PM10, NOx, or SO2). Finally, this subsection also discusses the need to test at an acceptable production rate, and that production is limited to a set ratio of the tested rate.

IX.H.11.f This condition covers the use of CEMs and opacity monitoring. While it specifically details the rules governing the use of continuous monitors (both emission monitors and opacity monitors), it also covers visible opacity observations through the use of EPA reference method 9.

Both conditions 11.e and 11.f serve as the mechanism through which sources conduct monitoring for the verification of compliance with a particular emission limitation.

8.1 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.

8.2 Discussion of Attainment Demonstration

As is discussed above in Items 8.0 and 8.1, 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 the original 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.

9.0 New PM2.5 SIP – WVPP Specific Requirements

The WVPP specific conditions in Section IX.H.12 address those limitations and requirements that apply only to the WVPP Power Plant in particular.

IX.H.12.t.i Emissions of NOx from all five turbines combined shall be no greater than 1050 lbs on a daily basis. It also defines what a "day" is for purposes of this subpart.

IX.H.12.t.ii States that total emissions from all five turbines include the sum of all periods – including startup, shutdown and maintenance.

IX.H.12.t.iii States that emissions shall be determined by CEM as outlined in IX.H.11.f

9.1 Monitoring, Recordkeeping and Reporting

Monitoring for IX.H.12.t.i is specifically outlined in IX.H.2.t.ii. All NOx monitoring is covered by CEM. CEM monitoring requirements are found in IX.H.11.f. Recordkeeping is subject to the requirements of IX.H.11.c.

9.2 Discussion of Attainment Demonstration

WVPP is primarily a source of NO_x emissions. While some direct particulate and SO2 emissions add to the overall contribution from WVPP, it is a listed source because of NO_x. The WVPP was originally authorized for construction using emission offset credits as outlined under R307-403-

5(1)(b). As the total emissions of the plant were larger than the 50 ton per year threshold listed in that rule, the offset credits required 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).

10.0 References

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- Exelon Generation $PM_{2.5}$ SIP Process Next Steps Information Request – dated May 7, 2014
- UAMPS – West Valley Power Plant $PM_{2.5}$ BACT Analysis Submittal, dated May 1, 2017

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Trinity Consultants

April 27, 2017

Utah Division of Air Quality
John Jenks
New Source Review Engineer
195 North 1950 West
Salt Lake City, UT 84114
(801) 536-4459

RE: ***BACM/BACT analysis for the West Valley Power Plant***

Mr. Jenks:

On behalf of Utah Municipal Power Agency (UMPA), Trinity Consultants Inc. is submitting the enclosed Best Available Control Measures or Technologies (BACM/BACT) analysis. This analysis was completed in response to the letter received by UMPA from the Utah Division of Air Quality (UDAQ), on 1/23/17.

The UMPA West Valley Power Plant (West Valley) is a natural gas-fired electric generating plant consisting of five General Electric LM6000 PC SPRINT natural gas simple cycle turbines. The enclosed analysis evaluates all applicable control measures and whether each is technically, environmentally, or economically feasible for the West Valley turbines.

If you have any questions or comments about the information presented in this analysis, please do not hesitate to call me at (208) 472 - 8837.

Sincerely,
TRINITY CONSULTANTS

Melissa Armer

Melissa Armer, P.E.
Senior Consultant

CC:
Kevin Garlick, UMPA Power Resource Manager
Jerame Blevins, West Valley Plant Manager
Dave Strohm, Trinity Consultants Inc.

Enclosure:
Request letter from UDAQ dated 1/23/17
West Valley Plant BACM/BACT analysis

State of Utah
GARY R. HERBERT
Governor
SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality
Alan Matheson
Executive Director
DIVISION OF AIR QUALITY
Bryce C. Bird
Director

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JAN 25 2017

DAQE-044-17

January 23, 2017

Kevin Garlick
Utah Municipal Power Agency
75 West 300 North
P.O. Box 818
Spanish Fork, Utah 84660

Dear Mr. Garlick:

RE: Serious Nonattainment Area (NAA) State Implementation Plan (SIP) Control Strategy Requirements

The Division of Air Quality (DAQ) has begun work on a serious area attainment control plan as required by and as detailed in 40 CFR 51 Subpart Z (See FR Vol. 81, No. 164, August 24, 2016, pp. 58151). This rule requires the DAQ to identify, adopt, and implement Best Available Control Measures (BACM) on major sources of $PM_{2.5}$ and $PM_{2.5}$ precursors. The Approval Order (AO) issued to *(Utah Municipal Power Agency)* allows emissions of 70 tons or more per year for $PM_{2.5}$ and/or $PM_{2.5}$ precursors, which is the major source threshold in an area of serious nonattainment for $PM_{2.5}$. In accordance with the implementation rule, *(Utah Municipal Power Agency)* is a major source and is therefore subject to the rule.

As a major source subject to the rule, your emission units will be included in the serious area attainment control plan, and the DAQ is requesting your assistance in determining acceptable pollution controls.

Subpart Z requires that we identify all potential control measures to reduce emissions of direct $PM_{2.5}$ as well as $PM_{2.5}$ precursors (SOx, NOx, VOC, and ammonia), and assess these potential measures for both technological and economic feasibility. Also necessary will be an assessment of when a potential measure could actually be implemented.

The criteria for determining whether these potential control measures are feasible will be more stringent than they had been when such measures were evaluated in the Moderate Area SIPs, where the benchmark had been Reasonably Available Controls (RACM/RACT). Once reclassified, Serious Areas must implement Best Available Controls (BACM/BACT) in order to meet the $PM_{2.5}$ health standards.

Should the area not be able to meet the $PM_{2.5}$ standards by the statutory Serious Area attainment date (December 31, 2019), whether by modeled prediction or actual ambient monitoring, the standard of control measure feasibility would rise once more to what are called Most Stringent Measures (MSM).

While it is possible that your company may have recently performed a BACT analysis under the new source review permitting program, or for moderate SIP control measures, please be aware that reaching attainment under the Serious SIP requires that all applicable control measures and techniques be identified and evaluated or re-evaluated to determine their applicability. This evaluation must be a detailed, written justification of each available control strategy, taking into account technological and economic feasibility, and including documentation to justify the elimination of any available controls.

A second but related evaluation must also be performed regarding the proper establishment of emission limits and emissions monitoring for each emitting unit. As you conduct your BACT analysis, the DAQ requests that you propose appropriate limits and monitoring requirements for each emitting unit, along with a justification for the adequacy of your suggested measures.

DAQ staff will be conducting related research to meet the requirements of the implementation rule so it can perform a detailed review of the information you provide, and select appropriate controls. The DAQ must complete the SIP process by the end of July so that it can be reviewed and approved for public comment by the Air Quality Board (AQB) in September and then finalized in December for submittal to the Environmental Protection Agency (EPA) by December 31, 2017. The DAQ understands the magnitude of this effort but believes it can be completed in a timely manner with your assistance. Please submit your analysis to the DAQ no later than April 30, 2017.

Given the short time period available to develop and implement these control strategies, we ask that you contact your current New Source Review (NSR) permitting engineer as soon as possible to discuss any questions you have regarding this analysis. If you are pursuing emissions reductions to no longer be a major source subject to the implementation rule, the required action (Notice of Intent (NOI) or reduction in emissions) must be submitted to the DAQ before February 15, 2017. You can also reach me at (801) 536-4151 with any questions.

Sincerely,

Martin D. Gray

Martin D. Gray, Manager
New Source Review Section
Utah Division of Air Quality

MDG:kw

PM$_{2.5}$ SERIOUS NONATTAINMENT SIP BACM ANALYSIS

Utah Municipal Power Agency > West Valley, Utah

Prepared For:

Kevin Garlick– Power Resource Manager
75 West 300 North
Spanish Fork, UT 84660

Prepared By:

Melissa Armer – Senior Consultant

TRINITY CONSULTANTS
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April 2017

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TABLE OF CONTENTS

1. EXECUTIVE SUMMARY

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

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

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

The UDAQ must complete the SIP process by the end of July 2017 so that it can be reviewed and approved for public comment by the Air Quality Board (AQB) in September and finalized in December for submittal to the EPA by December 31, 2017. As such, UMPA is submitting this BACT analysis in order to meet DAQ's submission deadline of May 1, 2017 as requested in the letter received by UMPA from UDAQ on January, 23, 2017.

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

2. INTRODUCTION

2.1. DESCRIPTION OF FACILITY

The UMPA West Valley Power Plant (West Valley) is a natural gas-fired electric generating plant consisting of five General Electric LM6000 PC SPRINT natural gas simple cycle turbines. Each turbine has power output rated at 43.4 MW and is equipped with water injection, evaporative spray mist inlet air cooling, Selective Catalytic Reduction (SCR) catalyst and CO oxidation catalyst. The primary purpose of the Plant is to produce electricity for sale via the utility power distribution system to meet the demands of the Salt Lake Valley service area.

The Plant is located in Salt Lake County and is a Phase II Acid Rain source and a major source of NO_x and CO. The Plant location and environmental contact is shown below:

Utah Municipal Power Agency
75 West 300 North Spanish Fork, UT 84660
Facility Contact: Kevin Garlick, Power Resource Manager
Phone: (801) 798-7489

2.2. PERMITTING HISTORY

On August 5, 2016 UMPA assumed ownership of the West Valley plant. The plant was previously owned by West Valley Power, LLC. The facility's Title V Operating Permit number is 3500527003 and was last renewed on July 21, 2014. The operating permit also incorporates Approval Order DAQE-282-02 dated April 28, 2002 which added the fifth turbine. Turbines 3 and 4 became operational in 2001, and turbines 1, 2 and 5 became operational in 2002.

2.3. SOURCES ONSITE

Table 2-1 Permitted Sources

Source/Source Type	Current Potential to Emit Emission Estimates (tpy)				
	$PM_{2.5}$	NO_x	SO_2	VOC	NH_3
Individual Turbines	8.21	32.41	5.94	3.67	38.1
Facility Wide	41.03	162.06	29.68	18.33	190.5

a Ammonia emissions are not quantified in the current Title V permit or in the Title V permit renewal application; estimated based on ppvd.

3. BEST AVAILABLE CONTROL MEASURES/TECHNOLOGY (BACM/BACT)

3.1. BACM/BACT METHODOLOGY

In a memorandum dated December 1, 1987, the U.S. EPA stated its preference for a "top-down" BACT analysis.[2] After determining if any New Source Performance Standard (NSPS) is applicable, the first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical source or source category. If it can be shown that this level of control is technically, environmentally, or economically infeasible for the unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections. Presented below are the five basic steps of a top-down BACT analysis as identified by the U.S. EPA.

3.1.1. Step 1 - Identify All Control Technologies

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

3.1.2. Step 2 - Eliminate Technically Infeasible Options

The second step in the BACT analysis is to eliminate any technically infeasible control technologies. Each control technology for each pollutant is considered, and those that are clearly technically infeasible are eliminated. U.S. EPA states the following with regard to technical feasibility:[3]

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

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

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

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

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

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

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

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

The economic evaluation centers on the cost effectiveness of the control option. Costs of installing and operating control technologies are estimated and annualized following the methodologies outlined in the U.S. EPA's *OAQPS Control Cost Manual* (CCM) and other industry resources.[4] Note that the analysis is not whether controls are affordable, but whether the expenditure is effective.

3.1.5. Step 5 - Select BACT

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

The U.S. EPA has consistently interpreted the statutory and regulatory BACT definitions as containing two core requirements that the agency believes must be met by any BACT determination, regardless of whether the "top-down" approach is used. First, the BACT analysis must include consideration of the most stringent available control technologies, i.e., those which provide the "maximum degree of emissions reduction." Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of "energy, environmental, and economic impacts."[5]

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

3.2. SIMPLE CYCLE GAS TURBINE-GENERATORS

The West Valley Plant consists of five GE LM6000 PC SPRINT natural gas simple cycle turbines. Each turbine has power output rated at 43.4 MW and is equipped with water injection, evaporative spray mist inlet air cooling, Selective Catalytic Reduction (SCR) catalyst and CO oxidation catalyst. Each gas turbine has a design heat input rate of 404.15 MMBtu/hr at full load operation utilizing the higher heating value of the natural gas fuel supply. The Plant is designed to operate as a peaking facility.

3.2.1. NO_x Emissions

The emissions unit for which BACT is being considered is a simple-cycle gas turbine with a nominal output of 43.4 MW. Potential control technologies were identified by searching the following sources for determinations pertaining to combustion gas turbines:

- South Coast Air Quality Management District (SCAQMD) BACT Determinations;

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

[5] Ibid.

- San Joaquin Valley Air Pollution Control District (SJVAPCD) BACT Clearinghouse;
- Bay Area Air Quality Management District (BAAQMD) BACT Guidelines;
- EPA RBLC;
- Other district and state BACT Guidelines; and
- BACT/LAER requirements in NSR permits issued by a local air district or other air pollution control agency.

Outlined below are the technologies for control of NO_x that were identified.

- Low NO_x burner design (e.g., dry low NO_x (DLN) combustors)
- Water or steam injection
- SCR system capable of continuously complying with a limit of 2.5 ppmvd @15% oxygen (O_2)
- Selective Non-Catalytic Reduction (SNCR) capable of continuously complying with a limit of 4.5 ppmvd @15% O2
- An EM_x™ (formerly $SCONO_x$™) system capable of continuously complying with a limit of 2.0 ppmvd @15% O_2

The most recent NO_x BACT listings for simple-cycle combustion turbines in this size range are summarized in Table 3.1. The most stringent NO_x limit in these recent BACT determinations is a 2.5 ppmvd limit averaged over a 1-hour averaging period, excluding startups and shutdowns. This level is achieved using water injection and SCR. The existing LM6000 gas turbines located at the West Valley plant are equipped with water injection, evaporative spray mist inlet air cooling, and SCR catalyst and achieve NO_x emissions at 5 ppmvd @ 15% O_2 which is comparable to the levels for current-generation water-injected gas turbines with SCR control, but higher than the most stringent limits.

Selective Noncatalytic Reduction

The Selective Non-Catalytic Reduction (SNCR) process reduces NO_x emissions using ammonia or urea injection similar to SCR but operates at higher temperature. NO_x reduction levels range from 30-50% for SNCR alone and between 65-75% for SNCR applied in conjunction with combustion controls. The optimal temperature range is between 1600°F and 2200°F at which NO_x, is reduced to molecular nitrogen (N_2) and water vapor (H_2O). Since SNCR does not require a catalyst, it is more attractive than SCR from an economic standpoint, however, it is not compatible with gas turbine exhaust temperatures, which do not exceed 1100°F. Because the exhaust temperature at the exit of the existing turbines (approximately 828 °F) is less than the optimum temperature range for the application of this technology, it is not technically feasible to apply and it will be eliminated from further evaluation in this BACT analysis.

SCONOx™

A relatively new post-combustion technology from Goal Line Environmental Technologies (now distributed by EmeraChem) is SCONO$_x$, which utilizes a coated oxidation catalyst to remove both NO_x and CO without a reagent such as ammonia. SCONO$_x$™ has been primarily installed on co-generation or combined cycle systems where the exhaust gas temperature is reduced by recovering energy to produce steam. The SCONO$_x$™ system catalyst is installed in the flue gas at a point where the temperature is between 280°F and 650°F. Because the exhaust temperature at the exit of the existing turbines (approximately 828°F) is greater than the optimum temperature range for the application of this technology, it is not technically feasible to apply and it will be eliminated from further evaluation in this BACT analysis.

Facility	District	NO_x Limit[a]	Avg. Period	Control Method	Date Permit Issued
City Public Service Leon Creek Plant (LM6000)	TCEQ	5 ppmv	Unknown	Water injection and SCR	6/26/2003
PacifiCorp- Gadsby Power Plant (LM6000)	UDAQ	5 ppmv	30-day rolling avg.	Water injection and SCR	6/14/2002
El Colton (LM6000)	SCAQMD	3.5 ppmv	3 hrs	Water injection and SCR	2/10/2004
Hanford LP	SJVAPCD	3.4 ppmv	3 hrs	Water injection and SCR	6/14/2001
CalPeak Power LC	SJVAPCD	3.0 ppmv	3 hrs	Water injection and SCR	5/12/2001
Bayonne Energy Center LLC (64 MW)	NJDEP LAER	2.5 ppmv	1 hr	Water injection and SCR	8/26/16
Mariposa Energy Project (LM6000)	BAAQMD	2.5 ppmv	1 hr	Water injection and SCR	11/2010
St. George City-Millcreek Power Plant (LM6000)	UDAQ	2.5 ppmv	30-day rolling avg.	Water injection and SCR	9/30/2008

Note: a. All concentrations expressed as parts per million by volume dry (ppmvd),, corrected to 15% O_2.

SCR, in combination with combustion controls, is capable of achieving a NO_x emission level of 2.5 ppmvd @ 15% O_2. It is the remaining control technology that will be evaluated in Step 4.

SCR has been achieved in practice at combustion turbine installations throughout the country. There are simple-cycle gas turbine projects that limit NO_x emissions between 2.5- 5 ppmvd using SCR technology, as shown in Table 3-1. An evaluation of the achievement of 2.5 ppmvd in comparison to the current West Valley turbines NO_x level of 5 ppmvd is summarized below.

Feasibility and Cost Impact: NO_x emissions from the LM6000 PC SPRINT natural gas turbines is generally guaranteed at 25 ppmvd. Achieving a controlled NOx limit of 2.5 ppm would require SCR technology to achieve reductions of 90 percent. UMPA reached out to several vendors to determine the changes that would be required to the existing SCR systems and the associated costs. Vendors indicated that each control system is complex and is designed to a specific emission limit. There are numerous factors that interrelate when evaluating an existing system and determining the modifications necessary to achieve the emissions reductions being evaluated in this analysis. Vendors indicated that a detailed and comprehensive technical analysis of the existing turbines and existing SCR system would be needed to definitively determine the changes necessary. However, for this analysis they were able to provide general information on the expected changes that would be required.

It is expected that the required changes will include some combination of catalyst replacement, catalyst design modification, and ammonia injection/vaporization system re-design to reduce NO_x emissions from 5 ppmvd to 2.5 ppmvd.

The estimated capital costs associated with the installation, startup and equipment costs of modifying the existing SCR/oxidation catalyst to achieve a 90% reduction in NO_x emissions is between $300,000 and $600,000. The range is dependent on the type and amount of catalyst that may be needed, as well as any redesign that may be necessary for the existing system. The annualized costs including an estimated additional 25% ammonia usage cost as well as capital cost recovery are outlined in Table 3-3 below. Included in Appendix A is supporting documentation received from vendors which was used to develop the costs. Table 3-4 below outlines the estimated cost per ton of pollutant removed to reduce NO_x emissions from 5 ppm to 2.5 ppm.

Since the West Valley turbines are peaking units, they do not operate continuously as a base load unit would operate. Therefore, the annual tons of NO_x emissions removed is based on the baseline actual operating hours from 2014 and 2015. Table 3-2 summarizes the operating hours per turbine from 2014 and 2015. The baseline actual operating hours used in the cost assessment is 646 hours per year per turbine. This is a conservative estimate based on West Valley's current run profile and available resource planning information.

Turbine	2014 Actual (hr/yr)	2015 Actual (hr/yr)	Average (hr/yr)
Turbine 1	631	693	662
Turbine 2	428	597	513
Turbine 3	674	807	741
Turbine 4	673	681	677
Turbine 5	551	720	636

Costs (AC) per Turbine	Cost Per Turbine
Capital cost to replace existing catalyst including installation (DCC)	$450,000
Additional annual ammonia cost (AC)	$9,000
Future worth factor [a] (FWF)	0.0724
Total Annual Cost = DCC*FWF + AC	$41,580

a Assumed catalyst life of each unit is 10 years with an interest rate of 7%. (EPA02; EPA, EPA Air Pollution Control Cost Manual, 2002)

Current SCR System	SCR Modification	NO_x Reduction (ton/yr)	Annual Cost of SCR Modification	$ Per Ton NO_x Removed
5 ppm (7.4 lb/hr) 2.39 tpy	2.5 ppm (3.7 lb/hr) 1.195 tpy	1.195 tpy	$41,580	$34,795

Conclusion: SCR technology capable of achieving NO_x levels of 2.5 ppmvd is considered to be achievable at the West Valley facility. However, since the West Valley turbines are peaking units and do not operate continuously, the cost associated with achieving this level of NO_x reduction is economically infeasible.

BACT is proposed to be water injection, evaporative spray mist inlet air cooling, and SCR catalyst and achieve NO_x emissions at 5 ppmvd @ 15% O2 which is comparable to the levels for current-generation water-injected gas turbines with SCR control, but higher than the most stringent limits.

MSM for the West Valley turbines would be the use of water injection, evaporative spray mist inlet air cooling, and SCR catalyst and achieve NO_x emissions at 2.5 ppmvd @ 15% O_2. This emission rate is achievable in practice, but has been shown to be economically infeasible for the West Valley turbines, due to the large capital investment and limited operating hours for these turbines.

The estimated lead time to obtain new SCR catalyst is approximately four months and installation time is estimated to be one week.

3.2.2. Volatile Organic Compound Emissions

Most VOCs emitted from natural gas-fired turbines are the result of incomplete combustion of fuel. Therefore, most of the VOCs are methane and ethane, which are not effectively controlled by an oxidation catalyst. However, oxidation catalyst technology designed to control CO can also provide some degree of control of VOC emissions, especially the more complex and toxic compounds formed in the combustion process. Therefore, the use of good combustion practices is generally considered BACT for VOC, with some additional benefit provided by an oxidation catalyst.

The only technology under consideration is combustion controls, with some additional benefit provided by an oxidation catalyst. This combination of technologies has been demonstrated to be feasible in many applications. No other technologies have been identified that are capable of achieving the same level of control. As a result, the goal of the rest of this analysis is to determine the appropriate emission limit that constitutes BACT for this analysis. A summary of recent VOC BACT determination is shown in Table 3-5.

Facility	District	VOC Limit[a]	Avg. Period	Control Method	Date Permit Issued
El Colton (LM6000)	SCAQMD	2.0 ppmv	3 hrs	Oxidation Catalyst	2/10/2004
Hanford LP	SJVAPCD	2.0 ppmv	-	Oxidation Catalyst	6/14/2001
CalPeak Power LC	SJVAPCD	2.0 ppmv	-	Oxidation Catalyst	5/12/2001
Bayonne Energy Center LLC (64 MW)	NJDEP LAER	2.0 ppmv	3 hr	Oxidation Catalyst	8/26/16
Mariposa Energy Project (LM6000)	BAAQMD	2.0 ppmv	-	Oxidation Catalyst	11/2010

Note: a. All concentrations expressed as parts per million by volume dry (ppmvd), corrected to 15% O_2.

The existing LM6000 gas turbines located at the West Valley plant are equipped with water injection, evaporative spray mist inlet air cooling, SCR catalyst, and CO oxidation catalyst and are estimated to achieve VOC emissions at 2 ppmvd @ 15% O_2 which is equivalent to the current BACT control limits.

The control technologies under consideration have the same ranking as each result in VOCs emission of 2.0 ppmvd @ 15% O_2.

This step evaluates any source-specific environmental, energy, or economic impacts that demonstrate that the top alternative listed in the previous step is inappropriate as BACT. The West Valley turbines meet a 2.0 ppmvd limit, which is the level identified as meeting BACT.

The VOC emission limit of 2.0 ppmvd is considered to be BACT for the West Valley turbines.

No other measures have been found that are more stringent than the current BACT limit.

3.2.3. Sulfur Oxide Emissions

Natural gas fired combustion turbines have inherently low SO_x emissions due to the small amount of sulfur present in the fuel. With typical pipeline quality natural gas sulfur content below 20 grain/100 scf, the SO_x emissions for natural gas fired combustion turbines are much lower than oil-fired turbines. Firing by natural gas, and the resulting control of SO_x emissions, has been used by numerous combustion turbines throughout the country. Due to the prevalence of the use of natural gas to control SO_x emissions from combustion turbines, only an abbreviated discussion of post-combustion controls will be addressed in this section.

Post-combustion SO_x control systems include dry and wet scrubber systems. These types of systems are typically installed on high SO_x emitting sources such as coal-fired power plants.

All of the control options discussed above are technically feasible.

The typical SO_x control level for a well-designed wet or dry scrubber installed on a coal-fired boiler ranges from approximately 70% to 90%[6], with some installations achieving even higher control levels.

The use of low sulfur content pipeline quality natural gas has been achieved in practice at numerous combustion turbine installations throughout the country, and the use of this fuel minimizes SO_x emissions. While it would be theoretically feasible to install some type of post-combustion control such as a dry/wet scrubber system on a natural gas fired turbine, due to the inherently low SO_x emissions associated with the use of natural gas, these systems are not cost effective and regulatory agencies do not require them. Consequently, no further discussion of post-combustion SO_x control is necessary.

BACT for this project is the use of pipeline-quality natural gas. The SO_x control method for the West Valley turbines is the use of pipeline-quality natural gas. Consequently, the existing turbine design is consistent with BACT requirements.

No other measures have been found that are more stringent than the current BACT limit.

3.2.4. $PM_{2.5}$ Emissions

Particulate Matter (PM) emissions from natural gas-fired turbines primarily result from carryover of noncombustible trace constituents in the fuel. PM emissions are minimized by using clean-burning pipeline quality natural gas with low sulfur content. A summary of recent $PM_{10}/PM_{2.5}$ BACT guidance is shown in Table 3-6.

The CARB BACT Clearinghouse, as well as the BAAQMD BACT guideline, identifies the use of natural gas as the primary fuel as "achieved in practice" for the control of $PM_{10}/PM_{2.5}$ for combustion gas turbines.

[6] Air Pollution Control Manual, Air and Waste Management Association, Second Edition, page 206.

CARB's BACT guidance document for stationary gas turbines used for power plant configurations[7] indicates that BACT for the control of PM emissions is an emission limit corresponding to natural gas with a fuel sulfur content of no more than 1 grain/100 standard cubic foot.

Facility	District	PM Limit[a]	Avg. Period	Control Method	Date Permit Issued
El Colton (LM6000)	SCAQMD	1 grain/100 scf sulfur. 11 lb/hr	-	Water injection and SCR	2/10/2004
Hanford LP	SJVAPCD	0.0066 lb/MMBtu	-	PUC-regulated natural gas, air inlet cooler/filter and lube oil coalescer	6/14/2001
CalPeak Power LC	SJVAPCD	0.0066 lb/MMBtu	-	PUC-regulated natural gas, air inlet cooler/filter and lube oil coalescer	5/12/2001
Bayonne Energy Center LLC (64 MW)	NJDEP LAER	5 lb/hr	-	Natural gas and ultra low sulfur distillate fuel oil with sulfur < 15ppm	8/26/16
Mariposa Energy Project (LM6000)	BAAQMD	-	-	CPUC-regulated grade natural gas	11/2010
St. George City-Millcreek Power Plant (LM6000)	UDAQ	20 grains/100 scf sulfur	-	Water injection and SCR	9/30/2008

The current sulfur content limit identified in West Valley's current Title V permit for natural gas used at the facility is less than 20 grains/100 scf. The fuel source for the Plant consists exclusively of pipeline quality compressed natural gas. The Plant is constructed and operated such that compressed natural gas can be supplied as required from two independent sources. Kern River and Questar have compressed natural gas pipe lines, with associated terminals located at the West Valley Plant that can be used to supply pipeline quality fuel to the Plant's five simple cycle gas turbines.

The current Kern River fuel tariff sheet states that the quality of gas provided to the West Valley plant will contain no more than 0.75 grains/100 scf.

No control technology other than use of pipeline quality natural gas fuel has been identified for this application.

[7] CARB, Guidance for Power Plant Siting and Best Available Control Technology, July 22, 1999, Table I-1. Available at https://www.arb.ca.gov/energy/powerpl/guidocfi.pdf

No control technology other than use of clean natural gas fuel has been identified for this application.

Based upon the results of this analysis, the use of natural gas with a sulfur content less than 1 grains/100 scf as the primary fuel source constitutes BACT for $PM_{10}/PM_{2.5}$ emissions from combustion gas turbines. This is the type of fuel and sulfur content that is readily available to the West Valley plant.

No other measures have been found that are more stringent than the current BACT limit.

3.2.5. Ammonia (NH_3) Emissions

SCR uses ammonia as a reducing agent in the process of controlling NO_x emissions from gas turbines. The portion of the unreacted ammonia passing through the catalyst and emitted out of the exhaust stack is called "ammonia slip." Ammonia slip does not remain constant as the SCR system operates but increases as the catalyst activity decreases. Properly designed SCR systems, which operate close to the theoretical stoichiometry and supply adequate catalyst volume, maintain low ammonia slip levels.

Gas turbines using SCR typically have been limited to between 5 ppmvd and 10 ppmvd at 15% O_2 ammonia slip. A summary of recent ammonia BACT guidance is shown in Table 3-7.

Facility	District	Ammonia Limit[a]	Avg. Period	Control Method	Date Permit Issued
Black Hills Power, Inc.	WYDEQ	10 ppmv	3 hr	Water injection and SCR	11/2010
Bosque Power Company, LLC	TCEQ	10 ppmv 7 ppmv	3 hr Annual avg.	Water injection and SCR	9/30/2008
El Colton (LM6000)	SCAQMD	5 ppmv	3 hrs	Water injection and SCR	2/10/2004

Note: a. All concentrations expressed as parts per million by volume dry (ppmvd), corrected to 15% O_2.

Ammonia (NH_3) can be monitored through tracking of NH_3 injection rate and mass balance calculation; compliance with limits during periods between source testing can be monitored with surrogate parameters that limit potential emissions or correlate with emissions.

The existing LM6000 gas turbines located at the West Valley plant are equipped with water injection, evaporative spray mist inlet air cooling, and SCR catalyst which has a manufacturer design ammonia slip of 10 ppmvd @ 15% O_2. This is comparable to the levels for current-generation water-injected gas turbines with SCR control, but higher than the most stringent limits.

SCR, in combination with combustion controls, is capable of achieving a NH_4 emission level of 5 ppmvd @ 15% O_2. It is the existing control technology that will be evaluated in Step 4.

SCR has been achieved in practice at combustion turbine installations throughout the country. There are simple-cycle gas turbine projects that limit NH_3 emissions between 5- 10 ppmv using SCR technology, as shown in Table 3-7. An evaluation of the achievement of 5 ppmv in comparison to the current West Valley turbines NH_3 level of 10 ppmv, is summarized below.

Feasibility and Cost Impact: The current SCR system is designed to have a maximum NH_3 emission concentration of 10 ppm. UMPA reached out to several vendors to determine the changes that would be required to the existing SCR systems to meet a NH_3 concentration of 5 ppm and the associated costs. Vendors indicated that at a minimum, cleaning and tuning the existing ammonia injection grid (AIG) would improve performance, however this alone may not meet a 5 ppm NH_3 emission concentration. The estimated cost to clean and tune the existing AIG was estimate to be $100,000. If replacement of the ammonia injection grid is necessary, the cost is estimated to be $350,000-$500,000 per turbine. Included in Appendix A is supporting documentation received from vendors which was used to develop the costs. Due to the uncertainty and wide cost range, the average cost of approximately $300,000 was used for the cost per ton evaluation.

Table 3-8 below outlines the estimated cost per ton of pollutant removed to reduce NH_3 emissions from 10 ppm to 5 ppm. Since the West Valley turbines are peaking units, they do not operate continuously as a base load unit would operate. Therefore, the annual tons of NH_3 emissions removed is based on baseline actual operating hours of 646 hours per year per turbine. This is a conservative estimate based on West Valley's current run profile and available resource planning information.

Costs (AC) per Turbine	Cost Per Turbine
Capital cost to replace existing NH_3 grid including installation (DCC)	$300,000
Future worth factor [a] (FWF)	0.0724
Total Annual Cost = DCC*FWF + AC	$21,720

a Assumed injection grid life of each unit is 10 years with an interest rate of 7%. (EPA02; EPA, EPA Air Pollution Control Cost Manual, 2002)

Current SCR System	SCR Modification	NH_3 Reduction (ton/yr)	Annual Cost of AIG Modification	$ Per Ton NO_X Removed
10 ppm (8.7 lb/hr) 2.81 tpy	5 ppm (4.35 lb/hr) 1.41 tpy	1.41 tpy	$21,720	$15,404

Conclusion: SCR technology capable of achieving ammonia slip levels of 5 ppm is considered to be achieved in practice. However, since the West Valley turbines are peaking units and do not operate continuously, the cost associated with achieving this level of NH_3 reduction is economically infeasible.

BACT is proposed to be water injection, evaporative spray mist inlet air cooling, and SCR catalyst and achieve NH_3 emissions at 10 ppmvd @ 15% O2 which is comparable to the levels for current-generation water-injected gas turbines with SCR control, but higher than the most stringent limits.

MSM for the West Valley turbines would be the use of water injection, evaporative spray mist inlet air cooling, and SCR catalyst and achieve NH_3 emissions at 5 ppmvd @ 15% O_2. This emission rate is achievable in practice, but has been shown to be economically infeasible for the West Valley turbines, due to the large capital investment and limited operating hours for these turbines.

The estimated lead time to obtain a new ammonia injection grid is approximately four months and installation time is estimated to be two weeks.

4.1. EMISSION JUSTIFICATION

BACT is proposed to be water injection, evaporative spray mist inlet air cooling, and SCR catalyst which is the current control technology installed on the existing turbines. UMPA is proposing that BACT emission limits are equivalent to the current emission limits achieved by the facility. However, UMPA has determined that there are MSM that have lower achievable emission limits than what the existing turbines achieve with the same control technology.

4.2. EMISSION SUMMARY

The following table provides emission limits during normal operation that are reflective of the most stringent measures identified in this analysis. Normal operation is the only scenario that was identified for MSM; startup, shutdown and maintenance emissions would need to be evaluated at a later date based on further discussions with vendors.

Potential to emit is based on continuous operation or 8,760 hr/year for each turbine, consistent with the facility's current Title V permit. Projected future actual emission estimates are based on 646 hr/yr for each turbine, which is consistent with the baseline actual run profile and available resource planning information.

Table 4-1 MSM Facility-Wide Impact of Emission Units

PTE Operating Scenario	Polluant				
	$PM_{2.5}$	NO_x	SO_2	VOC	NH_3 [a]
Current Emissions Limit (ppmvd)	-	5	-	2	10
MSM Limit (ppmvd)	-	2.5	-	2	5
Potential Annual Emissions/Turbine (tpy)	8.21	32.41	5.94	3.67	38.11
MSM Annual Emissions/Turbine (tpy)	8.21	16.21	5.94	3.67	19.05
MSM Annual Facility Wide Reduction (tpy) [b]	-	81.05	-	-	95.27
Projected Actual Operating Scenario	**Polluant**				
	$PM_{2.5}$	NO_x	SO_2	VOC	NH_3 [a]
Current Emissions Limit (ppmvd)	-	5	-	2	10
MSM Limit (ppmvd)	-	2.5	-	2	5
Actual Annual Emissions/Turbine (tpy)	0.6	2.39	0.44	0.27	2.81
MSM Annual Emissions/Turbine (tpy)	0.6	1.20	0.44	0.27	1.41
MSM Annual Facility Wide Reduction (tpy) [b]	-	5.98	-	-	7.02

[a] Ammonia emissions are not quantified in the current Title V permit or in the Title V permit renewal application; estimated based on ppvd.

[b] Takes into consideration emissions reductions for all five turbines.

APPENDIX A: COST ANALYSIS REFERENCE

CALL RECORD

Title: **UMPA BACT Analysis discussion with Groome**
By: Melissa Armer **Date:** 4/20/17
Client: Utah Municipal Power Agency **Project #:** 171301.0008

BACKGROUND NOTES

- Jerame Blevins the West Valley plant manager provided Trinity Consultants Inc. with contact information for a vendor they have used to service their SCR system.

Christina Juarez
Technical Sales-Western Region HRSG
Groome Industrial Service Group
155 Franklin Turnpike
Waldwick, NJ 07463
800-505-6100 Voice
559-289-3060 Cell
Cjuarez@groomeindustrial.com

CALL AGENDA

1. Evaluate the feasibility and cost associated with reducing NOx emissions from 5 ppm to 2.5 ppm..
   - Provide a written description of the equipment or operational changes that would be necessary
   - A complete cost breakdown associated with making these changes, including but not limited to: capital equipment cost, installation cost, annual operating cost etc.

2. Ammonia slip reductions: We need to evaluate the feasibility and cost associated with reducing NH_3 slip from 10 ppm to 5 ppm. Same information needed as listed above.

PARTICIPANTS

- Christina Juarez, Groome Industrial Service Group
- Melissa Armer, Trinity Consultants Inc.

CALL SUMMARY

- Groome indicated that each control system is complex and is designed to a specific emission limit. There are numerous factors that interrelate when evaluating an existing system and determining the modifications necessary to achieve the emissions reductions being evaluated in this analysis.
- Groome provided a proposal for them to complete a detailed and comprehensive technical analysis of the existing turbines and existing SCR system in order to definitively determine the changes necessary.
- For this analysis only general estimates are needed at this time as UMPA is only considering these modifications and will present the information to UDAQ for further review.
- For this analysis we need to provide general information on the expected changes that would be required.
- Changes necessary to reduce NOx may include
  - Catalyst re-sizing
  - Catalyst design modification
  - Ammonia injection/vaporization system re-design

- The estimated capital costs associated with the installation, startup and equipment costs of modifying the existing SCR/oxidation catalyst to this removal rate is approximately $500,000 per unit.
- To reduce ammonia emissions replacement of the ammonia injection grid may be necessary
  - Cost associated with a new ammonia injection grid are estimated to be between $350,000-$500,000 per turbine.

ACTION ITEMS

1. Christina to confirm estimated costs with her engineering department. Costs were confirmed: 4/24/17

CALL RECORD

Title: **UMPA BACT Analysis discussion with Haldor Topsoe**
By: Melissa Armer **Date:** 4/26/17
Client: Utah Municipal Power Agency **Project #:** 171301.0008

BACKGROUND NOTES

- Haldor Topsoe is the vendor the supplied the catalyst currently being used in two of the four catalyst bays for the West Valley SCR systems.
- Trinity Consultants Inc. contacted Haldor Topsoe (HT) on 4/18/17 to gather information to evaluate the feasibility and cost associated with reducing NOx emissions from 5 ppm to 2.5 ppm.

Nathan White
Director | Air Emissions Control | Sustainables
Haldor Topsoe, Inc.
5510 Morris Hunt Drive
Fort Mill, SC 29708, USA
Phone (direct): +1 803 835 0571
Mobile: +1 281 684 8809

PARTICIPANTS

- Nathan White, Director | Air Emissions Control | Sustainables Haldor Topsoe, Inc.
- Melissa Armer, Trinity Consultants Inc.

CALL SUMMARY

- HT indicated that the current catalyst may be able to meet the NOx outlet of 2.5 ppm and NH_3 at 5 ppm but it would reduce the service life of the catalyst from 30,000 hrs to 20,000 hrs.
- He recommended that run tests be completed to determine what the ammonia slip would be at a NOx outlet of 2.5 ppm. This would help to determine the deactivation factor for the current catalyst and determine how close to the service life the current catalyst is.
- As indicated by other vendors, each system is unique and a more detailed evaluation of the current operating parameters and performance would be needed to definitively identify the modifications necessary for each system.
- Another option presented that would guarantee NOx outlet of 2.5 ppm and NH_3 at 5 ppm would be to change out the existing catalyst with a new DNX GT-301 catalyst. The new catalyst would have an expected service life of 30,000 hours, which is similar to the current catalyst service life.
- The current cost of a new GT-301 catalyst charge in modules plus removal of the old catalyst and installation of the new catalyst is approximately $300,000 per unit.
- Another possible option would be to add additional catalyst to the third bay of each system, which may allow for operation at a NOx outlet of 2.5 ppm and NH_3 at 5 ppm. However, this option may not be feasible from an operations standpoint because it will result in a pressure drop which would reduce the power output of each turbine.
- Since the West Valley turbines are used for peak power demand they need to be able to provide their full power output when called upon.
- When asked about the ammonia injection grid, he thought tuning may be necessary, which would have an estimated cost of $25,000.

EMAIL RECORD

From: Shane Minor [mailto:sminor@wheelercat.com]
Sent: Wednesday, April 26, 2017 6:28 PM
To: Melissa Armer <marmer@trinityconsultants.com>
Subject: FW: West Valley BACT analysis

Melissa,

See below. I hope this is helpful. David with Safety power has been awesome on this.

Shane Minor | Govt. Util, Int. Sales | Wheeler Machinery Co.

4901 West 2100 South, Salt Lake City, UT 84120

Office: 801.978.1533 | Mobile: 801.201.0929 | Fax: 801.978.1570

sminor@wheelercat.com | www.wheelercat.com

Built to Listen. Built to Deliver.

How can we better serve you? Please share your feedback.

From: David Stelzer [mailto:david.stelzer@safetypower.ca]
Sent: Wednesday, April 26, 2017 2:29 PM
To: Shane Minor <sminor@wheelercat.com>
Cc: Bob Stelzer <bob.stelzer@safetypower.ca>
Subject: RE: West Valley BACT analysis

Hi Shane,

Following up with my voicemail yesterday. The good news is that a catalyst replacement and system retuning is all that's required to achieve the new emission levels.

Unfortunately HTI won't provide the catalyst upgrade/ replacement service directly. That being said they did provide me with the catalyst pricing. Based on this info I would estimate that the upgrade would cost the following:

Catalyst Material: $515,000.
Catalyst installation and retuning of the Ammonia Injection Grid: $85,000.
Total Cost Per 40MW Turbine = $600,000 USD.

This upgrade would achieve 2.5 ppm NOx, 5 ppm NH_3 slip, 2 ppm VOC (@ 15% O_2).

Pricing is budgetary. If we had more time and if this project progressed to the next stage, I would put you in contact with a system integrator that Wheeler CAT/UMPA could deal with directly.

It's important to note that this upgrade would consume slightly more ammonia to achieve the required NOx reduction.

Kind Regards,

David Stelzer, P.E., MSc.
Senior Sales & Marketing Engineer
Safety Power Inc
Office: 1-800-657-1280 x 30
Mobile: 416-994-5925
www.safetypowerinc.com
https://www.youtube.com/c/SafetyPowerInc

CALL RECORD

Title: **UMPA BACT Analysis discussion with General Electric**
By: Melissa Armer **Date:** 4/25/17
Client: Utah Municipal Power Agency **Project #:** 171301.0008

BACKGROUND NOTES

- Trinity Consultants Inc. originally contacted General Electric (GE) on 3/15/17 to gather information to evaluate the feasibility and cost associated with reducing NOx emissions from 5 ppm to 2.5 ppm..
  - Provide a written description of the equipment or operational changes that would be necessary
  - A complete cost breakdown associated with making these changes, including but not limited to: capital equipment cost, installation cost, annual operating cost etc.

- Ammonia slip reductions: We need to evaluate the feasibility and cost associated with reducing NH3 slip from 10 ppm to 5 ppm. Same information needed as listed above.
- GE indicated that they could provide this information, but they would need to get in contact with their engineering department.
- In late April, GE responded to Trinity and indicated that they do not provide this equipment and work through vendors to specify add-on control equipment.
- Contact who specifies control equipment for new construction:
  Ty Remington
  Account Manager, Mtn West
  GE Power, Gas Power Systems
  T 518-334-0601
  8000 E. Maplewood Ave., Suite 250
  Greenwood Village, CO 80111

PARTICIPANTS

- Ty Remington, GE Power, Gas Power Systems
- Melissa Armer, Trinity Consultants Inc.

CALL SUMMARY

- GE indicated that each control system is unique and they do not typically deal with a retrofit, but rather specifying new equipment for new turbines.
- Ty confirmed that NO_x levels of 2.5 ppm and NH_3 at 5 ppm are achievable and he has seen new LM6000 SPRINT turbines meeting these levels in operation.
- He indicated that he would expect that increasing the ammonia slip may be an operational change that would further reduce the NO_x emissions, however that would also increase the ammonia slip.
- He thought that a combination of replacing the catalyst and changing the ammonia injection rate would likely get the plant to the desired emission levels. However, he was not sure if the existing system would be large enough to house new and potentially more catalyst, so he thought additional catalyst modules may also be needed.
- Since Ty does not deal with retrofits he was not sure what the cost would be for a retrofit.
- He indicated for a completely new SCR system the total installed cost was about $3 Million dollars.
- He did not have the cost breakdown for how much the catalyst alone would cost.