# COMBUSTION TURBINE POINT SOURCE CATEGORY 4-FACTOR ANALYSIS

## I. Source Description

Combustion turbines fueled by natural gas or oil are either co-located with coal-fired electric generating units or as stand-alone facilities. These units are primarily used to supplement power supply during peak demand periods when electricity use is highest. Combustion turbine units start quickly and usually operate only for a short time. However, they are capable of operating for extended periods. Combustion turbine units are also capable of operating together or independently.

Information regarding combustion turbine emissions is well recorded in the State's air emissions inventory. Typical emissions for this source type may be significant for NOx, but pipeline quality natural gas is inherently clean and low-emitting for SO2 and PM10 emissions. Combustion turbines are subject to 40 CFR Part 60, Subpart GG – Standards of Performance for Stationary Gas Turbines, which limit sulfur content to 0.8 percent by weight, supported by monitoring and testing. Subpart GG also limits nitrogen oxides to 117.8 percent by volume at 15 percent oxygen on a dry basis (60.332(a)(1)), supported by monitoring and testing. The majority of combustion turbines are installed with Continuous Emissions Monitoring Systems (CEMs).

Control strategies for this source category are:
NOx – Steam or water injection, advanced dry low NOx combustion system, and selective catalytic reduction (SCR)

Cumulatively, this emissions source category is projected to be a minimal single category of Colorado point sources with a total of 56 turbines. Of this total, turbines located as single sources at Reasonable Progress facilities are 18. Total state-wide $NO_x$ emissions (2007 inventory) are approximately 284,037 tons/year. This source category is about 0.7% of total statewide emissions; therefore, the Division considers this source category to be nominal. Regardless, the Division evaluated all combustion turbines, regardless of fuel type, at Reasonable Progress facilities. The majority of combustion turbines (assumed 17 out of 18 based on inventory limitations) are natural-gas fired.

## II. Source Emissions

| Pollutant | Total 2006 – 2008 Averaged Annual Emissions (tpy) | Total RP Turbine 2006 – 2008 Averaged Annual Emissions (tpy) | RP Turbine Emissions compared to total state-wide turbine emissions (%) |
|---|---|---|---|
| $NO_2$ | 2,003 | 473 | 24% |

The Division analyzed total state-wide combustion turbine emissions averaged over the 2006 – 2008 Reasonable Progress baseline period. There are 5 Reasonable Progress facilities with combustion turbines – PSCo Valmont Generating Station, PSCo Arapahoe

Generating Station, Colorado Springs Utilities Nixon Plant, Platte River Power Authority Rawhide Energy Station, and PSCo Pawnee Generating Station. Of these, only two emit over federal significance levels as depicted below.

For the purposes of evaluating RP, the Division has elected to set *de minimis* thresholds for any emission unit at a subject-to-RP source with actual baseline emissions of $NO_x$ equal to or exceeding the federal Prevention of Significant Deterioration (PSD) significance levels. The Division has established *de minimis* thresholds for $SO_2$, $NO_x$ and $PM_{10}$ to focus the technical emission control analysis on significant emission sources where potential controls could provide a meaningful improvement in visibility if emission controls are determined to be cost effective.

The *de minimis* levels are applicable to individual emission units at a stationary source. The Division defines "emissions unit" as "any part or activity of a stationary source that emits or has the potential to emit any air pollutant regulated under the state or Federal Acts. This term is not meant to alter or affect the definition of the term "unit" for purposes of Title IV (acid deposition control) of the federal act, or of the term "source" for purposes of the Air Pollutant Emission Notice requirements of Regulation Number 3, Part A, Section II.B.3. [1] ." These *de minimis* levels are as follows:

- $NO_x$ – 40 tons per year
- $SO_2$ – 40 tons per year
- $PM_{10}$ – 15 tons per year

| Facility – Turbine | Total 2006 – 2008 Averaged NOx Annual Emissions (tpy) | Total 2006 – 2008 Averaged SO2 Annual Emissions (tpy) | Total 2006 – 2008 Averaged PM10 Annual Emissions (tpy) | Greater than *de minimis* levels? |
|---|---|---|---|---|
| Valmont – Turbine #6 | 12.6 | 0.4 | 0.1 | No |
| Valmont – Turbine #7 | 27.4 | 0.2 | 2.8 | No |
| Valmont – Turbine #8 | 1.5 | 0.0 | 0.1 | No |
| Arapahoe – Turbine #5 | 25.5 | 0.4 | 5.0 | No |
| Arapahoe – Turbine #6 | 15.3 | 0.4 | 5.0 | No |
| Arapahoe – Turbine | 4.1 | 0.2 | 3.7 | No |
| Nixon – Turbine #2 | 0.7 | 0.0 | 0.2 | No |
| Nixon – Turbine #3 | 1.2 | 0.0 | 0.3 | No |
| Nixon – Front Range Power | 159.6 | 2.9 | 4.9 | Yes – NOx only |

[1] Colorado Department of Public Health and Environment. Air Quality Control Commission Common Provisions Regulation 5 CCR 1001-2. Amended December 17, 2009. Effective January 30, 2010. Page 19.

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|---|---|---|---|---|
| Plant – Turbine #1 | | | | |
| Nixon – Front Range Power Plant – Turbine #2 | 147.9 | 2.8 | 4.9 | Yes – NOx only |
| Rawhide Turbine A | 2.5 | 0.1 | 0.5 | No |
| Rawhide Turbine B | 4.0 | 0.1 | 0.8 | No |
| Rawhide Turbine C | 2.7 | 0.1 | 0.5 | No |
| Rawhide Turbine D | 2.9 | 0.1 | 0.5 | No |
| Pawnee – Turbine #1 | 25.4 | 0.3 | 3.3 | No |
| Pawnee – Turbine #2 | 25.0 | 0.2 | 2.7 | No |

Therefore, for the purposes of this RP planning period, the Division will evaluate the Nixon – Front Range Power Plant – Turbines #1 and #2 as they are the two combustion turbines emitting over *de minimis* levels.

## III. Control Technology Evaluation

Step 1: Identify All Available Technologies

Four technologies have been identified to lower emissions from combustion turbines:

1. Wet controls using steam or water injection to reduce combustion temperatures for NOx control

2. Dry controls using advanced combustor design to suppress NOx formation and/or promote CO burnout

3. Adding post combustion technology – selective non-catalytic reduction (SNCR) or selective catalytic reduction (SCR)

**Technology #2:** This technology (retrofitting with low-NOx burners) was identified by the EPA and is documented in the AP-42 "Compilation of Air Pollutant Emission Factors." The following is from the 5th Edition, Volume 1, Chapter 1, Section 3.1.4.1: "Water or steam injection is a technology that has been demonstrated to effectively suppress NOx emissions from gas turbines. The effect of steam and water injection is to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. With water injection, there is an additional benefit of absorbing the latent heat of vaporization from the flame zone. Water or steam is typically injected at a water-to-fuel weight ratio of less than one."

**Technology #3:** This technology was identified by the EPA and is documented in the AP-42 "Compilation of Air Pollutant Emission Factors." The following is from the 5th

Edition, Volume 1, Chapter 1, Section 3.1.4.2: "Since thermal NOX is a function of both temperature (exponentially) and time (linearly), the basis of dry controls are to either lower the combustor temperature using lean mixtures of air and/or fuel staging, or decrease the residence time of the combustor. A combination of methods may be used to reduce NOx emissions such as lean combustion and staged combustion (two stage lean/lean combustion or two stage rich/lean combustion).

Lean combustion involves increasing the air-to-fuel ratio of the mixture so that the peak and average temperatures within the combustor will be less than that of the stoichiometric mixture, thus suppressing thermal NOX formation. Introducing excess air not only creates a leaner mixture but it also can reduce residence time at peak temperatures.

Two-stage lean/lean combustors are essentially fuel-staged, premixed combustors in which each stage burns lean. The two-stage lean/lean combustor allows the turbine to operate with an extremely lean mixture while ensuring a stable flame. A small stoichiometric pilot flame ignites the premixed gas and provides flame stability. The NOx emissions associated with the high temperature pilot flame are insignificant. Low NOx emission levels are achieved by this combustor design through cooler flame temperatures associated with lean combustion and avoidance of localized "hot spots" by premixing the fuel and air.

Two stage rich/lean combustors are essentially air-staged, premixed combustors in which the primary zone is operated fuel rich and the secondary zone is operated fuel lean. The rich mixture produces lower temperatures (compared to stoichiometric) and higher concentrations of CO and H2, because of incomplete combustion. The rich mixture also decreases the amount of oxygen available for NOx generation. Before entering the secondary zone, the exhaust of the primary zone is quenched (to extinguish the flame) by large amounts of air and a lean mixture is created. The lean mixture is pre-ignited and the combustion completed in the secondary zone. NOx formation in the second stage are minimized through combustion in a fuel lean, lower temperature environment. Staged combustion is identified through a variety of names, including Dry-Low NOx (DLN), Dry-Low Emissions (DLE), or SoLoNOx."

**Technology #4**: This technology (adding SNCR or SCR) involves adding control equipment and reagent to treat turbine exhaust.

Step 2: Eliminate Technically Infeasible Options

**Technology #1:** This technology is technically feasible.

**Technology #2:** This technology is technically feasible.

**Technology #3:** This technology is technically feasible and is already installed at the Nixon – Front Range Power Plant combustion turbines.

**Technology #4:** This technology is technically feasible, although a Division of the EPA's RBLC database revealed SCR is the predominant post-combustion control technology for combustion turbines and did not find any examples of SNCR post-combustion technology applied to combustion turbines.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

**Technology #1:** Since this control technology is specific fuel type usage, control efficiency are not applicable.

**Technology #2:** EPA's AP-42 factor database cites this technology as achieving control efficiencies of 60% or greater. However, this technology will not be evaluated in this analysis further since the dry low-NOx combustion systems already installed on the turbines at the Front Range Power Plant achieve greater than 85% control, which is greater than the 60% estimate achievable by wet controls.

**Technology #3:** The Division calculated that the controlled-uncontrolled ratio for advanced dry-low NOx combustions using EPA's AP-42 emission factors is approximately 70% and may be greater in site-specific cases. The combustion turbines at the Nixon – Front Range Power Plant were installed with these systems, and based on 2006 – 2008 CEMs data and AP-42 emission factors, are achieving 89.4% and 90.1% NOx reductions (calculated using the 2006 – 2008 RP baseline period), respectively.

**Technology #4:** EPA's AP-42 emission factor description indicates that a SCR in good working order can achieve removal efficiencies ranging from 65 – 90 percent from the NOx exhaust stream. AP-42 is silent on control efficiencies regarding SNCR. During a research review, the Division could not find any instances of a commercial-scale SNCR applied at a natural-gas fired combustion turbine. Therefore, SNCR will not be considered further in this analysis.

Step 4: Evaluate Impacts and Document Results

The Division reasons that SCR requires significant capital expenditures and will result in minimal additional NOx reductions, if any. Regardless, the Division analyzed additional achievable NOx reductions if SCR was installed at these two turbines. Applying SCR at 90% to both turbines would result in about 275 additional tons of NOx reduced annually. Using another Colorado SCR analysis from the same utility (Colorado Springs Utilities), the Division estimates that annualized costs for installing SCR to both turbines will be approximately $8 million each, resulting in about $57,000 - $62,000 per ton of NOx reduced annually.

The time necessary for compliance will depend on the type of control implemented. Based on other Colorado facility submittals, the Division anticipates that the time necessary for completing design, permitting, procurement, pipeline installation, and system startup and shutdown, after SIP approval, it would take CSU approximately 3 – 5 years to implement any of the SCR control option. This timeframe may vary somewhat due to regional demand for natural gas and to schedule the necessary major maintenance outage with other regionally affected utilities.

There are no energy or non-air quality impacts for fuel usage of pipeline quality natural gas or for advanced dry low-NOx combustion systems. The energy and non-air quality impacts of SCR and SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

## Step 5: Select Reasonable Progress Control

The Division determines that any potential reductions from this source category are minimal, if any. Pipeline quality natural gas is inherently clean for SO2 and PM10. For NOx, the majority of combustion turbines already apply advanced dry-low NOx combustion systems, especially the larger turbines.

Based on its consideration of the four factors summarized herein, the state has determined that NOx RP for combustion turbines is existing controls and emission limits. Though other controls achieve better emission reductions, the expense of these options coupled with predicted minimal visibility improvement were determined to be excessive.