# San Joaquin Valley
# Unified Air Pollution Control District

## Best Performance Standard (BPS) x.x.xx

<table>
<tr><td>Class</td><td>Gaseous Fuel-Fired Boilers</td></tr>
<tr><td>Category</td><td>New Boilers with Rated Steam Pressure Less Than 75 psig, Fired Exclusively on Natural Gas or LPG</td></tr>
<tr><td rowspan="2">Best Performance Standard</td><td>Applicability Note: Boilers with operating steam pressure less than 75 psig but fired with gaseous fuels other than natural gas or LPG (either exclusively or mixed with natural gas or LPG) and which meet the following standards shall be considered to meet BPS for their respective category.</td></tr>
<tr><td>Boilers meeting this Best Performance Standard must comply with all three elements of this BPS (items 1, 2 and 3 listed below) where applicable:<br><br>1. The boiler shall be either equipped with an economizer system meeting the following design criteria or shall be equipped with an approved alternate heat recovery system which will collectively provide heat recovery from the boiler flue gas which is equivalent. Equivalent heat recovery systems may utilize recovered heat for purposes other than steam generation provided such uses offset other fuel usage which would otherwise be required.<br><br>A. Except for boilers subject to the requirements of items B or C below, the economizer system shall be designed at maximum boiler firing rate to either 1) reduce the temperature of the economizer flue gas outlet to a value no greater than 20°F above the temperature of the boiler feed water at maximum firing rate, or 2) reduce the final temperature of the boiler’s flue gas to a temperature no greater than 200°F.<br><br>Note: For purposes of this BPS, feedwater temperature is defined as the temperature of the water stream delivered to the boiler from the deaerator or feedwater tank.<br><br>B. For boilers with a water supply temperature of 170°F or greater, the boiler shall be designed, in lieu of the requirements of item A above, to achieve a flue gas temperature no greater than the sum of the steam saturation temperature (°F at the steam drum operating pressure) plus 100°F.<br><br>C. For boilers with rated capacity in excess of 20 MMBtu/hr which have a average water supply temperature which is equal to or less than 150°F, the boiler shall equipped with an economizer designed to reduce the temperature of the flue gas outlet to a value no greater than 50°F above the water supply temperature when the boiler is operating at maximum firing rate.<br><br>Note: For purposes of this BPS, water supply temperature is defined as the weighted average temperature of the combined makeup water and the recovered condensate delivered to the boiler upstream of any deaerator or other feedwater preheater but after benefit of any other heat recovery operations which recover waste heat from the boiler by transfer to the boiler water supply (such as boiler blowdown heat recovery).</td></tr>
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| | **2.** Electric motors driving combustion air fans or induced draft fans shall have an efficiency meeting the standards of the National Electrical Manufacturer's Association (NEMA) for "premium efficiency" motors and shall each be operated with a variable speed control or equivalent for control of flow through the fan.<br><br>**3.** For boilers with rated fired duty in excess of 20 MMBtu/hr and a boiler blowdown rate exceeding 8 % of steam production, the boiler shall be equipped with 1) an automatic boiler blowdown control system which will minimize boiler blowdown while controlling dissolved solids in the boiler water at an optimum level and 2) a flash steam recovery system which will recover flash steam from the blowdown pressure reduction and utilize it for feedwater heating in the deaerator or feedwater heater. |

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| **Percentage Achieved GHG Emission Reduction Relative to Baseline Emissions** | **4.8%** |

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| **District Project Number** | C-1100388 |
| **Evaluating Engineer** | Dennis Roberts, P.E. |
| **Lead Engineer** | Martin Keast |
| **Initial Public Notice Date** | October 14, 2010 |
| **Final Public Notice Date** | November 12, 2010 |
| **Determination Effective Date** | January 19, 2011 |

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# I. Best Performance Standard (BPS) Determination Introduction

## A. Purpose

To assist permit applicants, project proponents, and interested parties in assessing and reducing the impacts of project specific greenhouse gas emissions (GHG) on global climate change from stationary source projects, the San Joaquin Valley Air Pollution Control District (District) has adopted the polic*y: District Policy – Addressing GHG Emission Impacts for Stationary Source Projects Under CEQA When Serving as the Lead Agency.* This policy applies to projects for which the District has discretionary approval authority over the project and the District serves as the lead agency for CEQA purposes. Nonetheless, land use agencies can refer to it as guidance for projects that include stationary sources of emissions. The policy relies on the use of performance based standards, otherwise known as Best Performance Standards (BPS) to assess significance of project specific greenhouse gas emissions on global climate change during the environmental review process, as required by CEQA. Use of BPS is a method of streamlining the CEQA process of determining significance and is not a required emission reduction measure. Projects implementing BPS would be determined to have a less than cumulatively significant impact. Otherwise, demonstration of a 29 percent reduction in GHG emissions, from business-as-usual, is required to determine that a project would have a less than cumulatively significant impact.

## B. Definitions

Best Performance Standard for Stationary Source Projects is – a specific Class and Category, the most effective, District approved, Achieved-In-Practice means of reducing or limiting GHG emissions from a GHG emissions source, that is also economically feasible per the definition of achieved-in-practice. BPS includes equipment type, equipment design, and operational and maintenance practices for the identified service, operation, or emissions unit class and category.

Business-as-Usual is - the emissions for a type of equipment or operation within an identified class and category projected for the year 2020, assuming no change in GHG emissions per unit of activity as established for the baseline period, 2002-2004. To relate BAU to an emissions generating activity, the District proposes to establish emission factors per unit of activity, for each class and category, using the 2002-2004 baseline period as the reference.

Category is - a District approved subdivision within a “class” as identified by unique operational or technical aspects.

Class is - the broadest District approved division of stationary GHG sources based on fundamental type of equipment or industrial classification of the source operation.

### C. Determining Project Significance Using BPS

Use of BPS is a method of determining significance of project specific GHG emission impacts using established specifications. BPS is not a required mitigation of project related impacts. Use of BPS would streamline the significance determination process by pre-quantifying the emission reductions that would be achieved by a specific GHG emission reduction measure and pre-approving the use of such a measure to reduce project-related GHG emissions.

GHG emissions can be directly emitted from stationary sources of air pollution requiring operating permits from the District, or they may be emitted indirectly, as a result of increased electrical power usage, for instance. For traditional stationary source projects, BPS includes equipment type, equipment design, and operational and maintenance practices for the identified service, operation, or emissions unit class and category.

## II. Summary of BPS Determination Phases

The District has established *Gaseous Fuel-Fired Boilers with Rated Steam Pressure Less Than 75 psig* as a separate class and category which requires implementation of a Best Performance Standard (BPS) pursuant to the District's Climate Change Action Plan (CCAP). The District's determination of the BPS for this class and category has been made using the phased BPS development process established in the District's Final Staff Report, Addressing Greenhouse Gas Emissions under the California Environmental Quality Act. A summary of the specific implementation of the phased BPS development process for this specific determination is as follows:

| **BPS Development Process Phases for *New Boilers with Rated Steam Pressure Less Than 75 psig, Fired Exclusively on Natural Gas or LPG*** | | | |
|---|---|---|---|
| **Phase** | **Description** | **Date** | **Comments** |
| 1 | Initial Public Process | 02/10/10 | The District's intent notice sent by email to interested parties registered on the District's GHG web site for this class is attached as Appendix C. Comment received during the initial public process with District's responses are attached as Appendix C. |
| 2 | BPS Development | N/A | See Section III of this evaluation document. |
| 3 | Public Notice: Start Date | 10/14/10 | The District's draft BPS determination was posted on the date indicated. The District's notification is attached in Appendix D. |
| 4 | Public Comments | 11/12/10 | No public comments were received during the commenting period. |
| 5 | Finalization | 1/19/11 | The BPS established in this evaluation document is effective on the date of finalization. |

# III. Class and Category

*Gaseous Fuel-Fired Boilers* is recognized as a distinct class based on the following:

- Boilers represent a distinct operation (indirect heat transfer from combustion to heat or boil water) when compared to all other permit units currently regulated by the District.
- The District already considers this a distinct class with respect to Best Available Control Technology (BACT) for criteria pollutant emissions.
- This is a distinct class with respect to the District's prohibitory rules for criteria pollutant emissions (Rules 4306 - 4308 and 4320).
- The District's current prohibitory rules currently only allow gaseous fuel firing (with liquid fuel allowed as a backup only for PUC natural gas during curtailment periods) or solid fuel-fired boilers (Rule 4352). Gaseous fuel fired units differ substantially from solid fuel units with respect to design requirements and thus are considered to be a separate class.

*New Boilers with Rated Steam Pressure Less Than 75 psig, Fired Exclusively on Natural Gas or LPG* is recognized as a distinct category of boilers based on the following:

- New boilers are significantly less restrained by site specific conditions and thus have significantly more options in terms of implementing energy efficiency measures when compared to existing units. New boilers therefore comprise a separate category from existing.
- Gaseous fuels other than natural gas or LPG may have characteristics which will limit certain GHG emission reduction measures and therefore the firing of natural gas or LPG is considered to be a separate category.
- Boilers which produce steam at pressures between 10 and 75 psig have steam drum temperatures ranging from about 240 to 320°F and thus have lower stack temperatures when compared to high pressure boilers. As a result, this category may not be able to employ selective catalytic reduction for control of NOx emissions (a GHG reduction measure for higher pressure boilers) and may have certain other limitations with respect to the configuration of economizer heat recovery systems. This category is differentiated from:
  - Natural gas-fired boilers operating at 75 psig and above which generally have both a) an ample temperature margin between the steam drum temperature and the deaerated feedwater temperature to accommodate a non-steaming economizer with an achieved-in-practice 20 °F approach

and b) stack temperatures which are high enough to operate a selective catalytic reduction system for control of NOx emissions,

- Natural gas-fired hot water boilers (or hydronic boilers). These units typically do not have a deaerator and, since they only produce hot water rather than steam, have a significantly larger boiler feedwater flow relative to the boiler flue gas for purposes of heat recovery in comparison to units which produce steam.

# IV. Public Notice of Intent

Prior to developing the development of BPS for this class, the District published a Notice of Intent. Public notification of the District's intent to develop BPS for this class was sent on April 1, 2010 to individuals registered with the CCAP list server. The District's notification is attached as Appendix B.

Comments received during the initial public outreach are presented in Appendix C. These comments have been used in the development of this BPS as presented below.

# V. BPS Development

## STEP 1. Establish Baseline Emissions Factor for Class and Category

The Baseline Emission Factor (BEF) is defined as the three-year average (2002-2004) of GHG emissions for a particular class and category of equipment in the San Joaquin Valley (SJV), expressed as annual GHG emissions per unit of activity. The Baseline Emission Factor is calculated by first defining an operation which is representative of the average population of units of this type in the SJV during the Baseline Period and then determining the specific emissions per unit throughput for the representative unit.

### A. Representative Baseline Operation

For *New Boilers with Rated Steam Pressure Less Than 75 psig, Fired Exclusively on Natural Gas or LPG*, the representative baseline operation has been determined to be a steam boiler with the following attributes:

- *Natural gas-fired forced draft steam boiler with a rated operating pressure of 15 psig, not equipped with economizer or other heat recovery add-on equipment*
- *Ultra Low NOx burner operating with 20% flue gas recirculation (FGR)*
- *Oxygen content of 4.0 volume % dry basis in the stack gas*
- *Conventional efficiency (87%) electric motor driver, not equipped with speed control, for the combustion air fan*
- *Boiler blowdown rate = 8% of steam rate, operating with a flash steam recovery system*

This determination was based on:

Discussions with boiler manufacturer representatives indicate that average historical demand for boilers rated below 75 psig operating pressure has been at the lower end of this classification, nearer atmospheric pressure than 75 psig. Assuming some nominal positive steam pressure will be normally required for system dynamic pressure losses, a 15 psig rating was assumed to represent the average operating unit during the Baseline Period for this class and category.

To establish the thermal efficiency of the representative boiler it was assumed that the representative boiler had a flue gas temperature which was 100 $^{o}$F higher than the steam saturation temperature and was not equipped with an economizer or other heat recovery equipment.

An operating stack oxygen content of 4.0% and an FGR rate of 20% were selected for the baseline period based on estimates by boiler manufacturer representatives which were in turn based on typical excess air and FGR requirements for operation of with an ultra low NOx burner at a 30 ppmv NOx emission level (consistent with the District’s prohibitory rule for boilers during the Baseline Period).

A conventional, single speed electric motor driver was assumed for the combustion air fan based on the observation that, although premium efficiency motors with variable speed drives have been a relatively common specification for new facilities and retrofits in the last decade, commercial and industrial boilers have a useful life span of 20 to 30 years and therefore it is expected that the boiler fleet in place during the Baseline Period would not have included a significant population of boilers equipped with high efficiency mechanical drives.

A boiler blowdown rate of 8% of the steam rate was assumed based on current typical boiler operation in the range of 5-8%[1]. A flash steam recovery system, which serves to recover flash steam from the blowbown operation for use in the deaerator, was assumed to be included in the baseline facility since this is has long been a commonplace operation in steam plants.

[1] U.S. Department of Energy, Energy Efficiency and Renewable Energy, Steam Tip Sheet #9, January, 2006.

## B. Basis and Assumptions

- All direct GHG emissions are produced due to combustion of natural gas in this unit.
- The baseline case boiler for this category is not equipped with add-on heat recovery equipment. For the 15 psig boiler, steam temperature is 250 $^oF$ and stack temperature is assumed to be 350 $^oF$.
- Convection/radiation loss from the boiler is assumed to be 0.5% of fuel firing.
- Vent loss from the deaerator is assumed to be 5% of total DA steam.
- It is assumed that 50% recovery of condensate is achieved at a temperature of 200 $^oF$. The balance of the boiler water is makeup at 60 $^oF$. This results in an average temperature of the combined feed water to the boiler plant (combined flow of returned condensate and makeup water to the boiler upstream of any steam pre-heaters) of 130 $^oF$.
- GHG emissions are stated as "$CO_2$ equivalents" ($CO_2$(e)) which includes the global warming potential of methane and nitrous oxide emissions associated with gaseous fuel combustion.
- Based upon a boiler heat and mass balance for the given conditions, the following quantities are applicable:
  - Net steam production is 763 lb/MMBtu fired or a Specific Fuel Consumption (SFC) of 1,000,000/733 = 1,310 Btu/lb steam
  - Flue gas rate is 12,303 scf/MMbtu fired
  - Combustion air rate is 11,302 scf/MMBtu fired
- The GHG emission factor for natural gas combustion is 117 lb-$CO_2$(e)/MMBtu per CCAR document[2].
- Indirect emissions produced due to operation of the combustion air fan will be considered. Indirect emissions from other electric motors associated with the boiler are not considered significant.
- Static efficiency of the combustion air fan is assumed to be 60%.
- Flue gas side pressure drop for the burner + boiler is assumed to be 20 inches water column when operating without FGR with a flue gas rate of 12,303 scf/MMBtu (12 "WC for burner, 8 "WC for boiler).
- An allowance for additional dynamic loss in the boiler due to FGR will be added which is assumed to be proportional to the square of the mass flow. For an FGR rate of 20 %, flow through the boiler is estimated as:
  12,302 x 1.2 = 14,762 scf/MMBtu fired

  Pressure drop through the system is then calculated as:

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  | Burner | 12.0 " WC |
  | Boiler 8" WC x $(14,762/12,302)^2$ = | 11.5 |
  | Total | 23.5 |

- Electric motor efficiency is estimated at 87% for a conventional electric motor.

[2] California Climate Change Action Registry (CCAR), Version 3.1, January, 2009 (Appendix C, Tables C.7 and C.8)

- Indirect emissions from electric power consumption are calculated based on the current PG&E electric power generation factor of 0.524 lb-CO2(e) per kWh.

## C. Unit of Activity

To relate Business-as-Usual to an emissions generating activity, it is necessary to establish an emission factor per unit of activity, for the established class and category, using the 2002-2004 baseline period as the reference.

The resulting emissions factor is the combination of:

GHG emission reductions achieved through technology, and

GHG emission reductions achieved through changes in activity efficiencies

A unit of activity for this class and category will be taken as 1000 lbs of steam production.

For purposes of this BPS determination, it will be assumed that GHG emissions reductions achieved through changes in activity efficiencies are not significant. This assumption has been made based on:

- This class and category of equipment is used at a wide range of facilities, diverse in operation and size, making it difficult to characterize specific efficiency improvements.

- A search of available literature did not yield any data which would support an estimate of GHG emission from boilers in this class and category based on changes in activity efficiencies since the baseline period .

## D. Calculations

The Baseline Emission Factor (BEF) is the sum of the direct ($GHG_D$) and indirect ($GHG_I$) emissions (on a per unit of activity basis), stated as lb-CO2 equivalent:

$BEF = GHG_D + GHG_I$

<u>Direct Emissions:</u>

$GHG_D = E_f \times SFC$

$E_f$ = GHG emission factor = 117 lb- $CO_{2(e)}$/MMBtu of natural gas

SFC = Specific Fuel Consumption = 1,310 Btu/1000 lb steam as stated in the basis.

Direct emissions are then calculated as:

$GHG_D$ = 117 lb-$CO_{2e}$/MMBtu x 1.310 MMBtu/1000 lb steam
= 153.3 lb-$CO_{2e}$ /1000 lb steam

Indirect Emissions

Indirect emissions produced from operation of electric motors are determined by the following:

GHG (electric motor) = Electric Utility GHG Emission Factor x kWh consumed

To determine kWh consumption per 1000 lb steam produced it is necessary to first determine the Bhp requirement for the gas compression operation by the combustion air blower. Specific brake horsepower requirement by the combustion air fan is calculated from the following equation for adiabatic compression of an ideal gas[3]:

Bhp-hr/1000 lb steam = (T/520) x (0.001072M/n*E*) x $[(p_2/p_1)^n-1]$

T = gas temperature, $^oR$. Assuming constant heat capacity, gas temperature is based on the mix temperature of fresh combustion air (at 68 F) plus 20 % FGR (at 350 F):

$$T = \frac{11{,}302 \text{ scf x } 68^o + 12{,}302 \text{ scf x } 20\% \text{ x } 350^o}{11{,}302 \text{ scf} + 12{,}302 \text{ scf x } 20\%}$$

T = 118 $^oF$ or 578 $^oR$

M = scf combustion air + flue gas x $\%_{FGR}$ (per 1000 lb steam)
= (11,302 scf air/MMbtu + 12,302 scf flue gas/MMBtu x 20%) x 1.310 MMBtu/1000 lb steam = 18,029 scf gas/1000 lb steam

n = 0.2857 (typical for diatomic gases)
*E* = efficiency = 60%
$p_1$ = atmospheric pressure = 407 "WC
$p_2$ = atmospheric pressure + pressure drop
= 407.0 + 23.5 = 430.5 "WC

Substituting the given values into the equation:

Bhp-hr/1000 lb steam = 2.0

[3] See: Clarke, Loyal and Robert Davidson, Manual for Process Engineering Calculations, 2nd Edition, McGraw-Hill, New York, 1975, p.360.

Converting to kWh based on an 87% efficient electric motor and a conversion factor of 0.7457 kWh/bhp:

= (2. 0 x 0.7457)/87% = 1.7 kWh/1000 lb steam

$GHG_I$ = GHG (electric motors)
= 0.524 lb-$CO_{2(e)}$/kWh x 1.7 kWh/1000 lb steam
= 0.9 lb $CO_{2(e)}$ per 1000 lb steam production

The Baseline Emission Factor is the sum of the direct and the indirect emissions:

BEF = *153.3 + .9 = 154.2 lb-* $CO_2$(e)*/ton*

## STEP 2. Technologically Feasible GHG Emission Control Measures

### A. Analysis of Potential Control Measures

Use of Economizers

Boilers without economizers are limited to operating with a stack temperature which must exceed the saturated steam temperature for the given pressure level of the boiler, significantly limiting potential thermal efficiency. The margin between flue gas temperature and the steam temperature may vary from around 100°F for firetube boilers and up to 200°F for watertube boilers resulting in stack temperatures ranging from approximately 350°F for a 15 psig firetube boiler up to 520°F for a 75 psig watertube boiler with approximate efficiencies of 81% and 77% respectively.

An economizer is essentially additional heat transfer surface which serves to recover heat from the boiler exhaust by transferring it to the boiler feedwater or to other low temperature heat utilization in the facility. The use of economizers for recovery of thermal energy from boiler flue gases is an achieved-in-practice approach for improving boiler thermal efficiency, including the use of two-stage economizers which serve to not only heat the deaerated water flowing directly to the boiler but to also pre-heat returned condensate and fresh makeup water upstream of the deaerator. Economizers which reduce the flue gas temperature below 200°F are considered to be in condensing service since there is a potential for moisture to condense out of the flue gas at which point stainless steel construction is typically required for corrosion resistance. However, actual condensing operation does not occur until the flue gas is lowered below about 135°F at which point the bulk condensation of moisture in the flue gas begins. For flue gas temperatures above about 200°F ("standard" economizer), carbon steel construction is usually adequate. Economizer designs based on an approach of 2 °F or less (temperature differential between flue gas leaving the economizer section and the water entering the section) are achieved-in-practice for standard economizer designs while an approach of 50°F is achieved in practice for condensing service economizers (see Appendix A).

Assuming no other heat sinks are available in a particular facility, the potential thermal efficiency of a particular boiler equipped with an economizer is largely a function of the temperature of the boiler water supply temperature (the combined temperature of returned condensate and makeup water). This water temperature effectively limits the extent to which heat may be recovered from the stack gases using an economizer. When a boiler operates with cold return water temperatures (such as a once-through boiler with 60°F return water), true condensing economizer operation becomes possible wherein the stack temperature may be lowered below the dew point of the flue gas (approximately 135°F). In this case, significant additional heat recovery becomes possible due to the recovery of the latent heat of vaporization associated with the condensed water and efficiencies above 90% are achievable.

Likewise, when return water temperatures are significantly higher (such as when a facility recovers a large portion of hot condensate and returns it to the boiler), potential boiler thermal efficiency is significantly reduced unless other low temperature heat uses are available in the facility. A boiler equipped with a standard economizer system may only be capable of achieving 85-86% thermal efficiency when return water temperatures exceed 200°F. However, it is important to recognize that the collection and return of hot condensate is an energy saving measure in itself which can offset the reduction in thermal efficiency for the boiler.

Based on the above discussion, it is apparent that specification of a BPS control measure based on a single required thermal efficiency to be achieved with an economizer is problematic since the theoretical potential thermal efficiency may vary significantly depending upon the return water temperature to the boiler. To address this issue, the District proposes to establish an economizer design-based GHG reduction measure by specifying a required temperature approach of the economizer. A standard based on an approach temperature can be applied to all boilers even though they may exhibit a wide variation in return water temperature (efficiency) and when established at a maximum value of a 20°F approach for a standard economizer and 50 °F approach for a condensing economizer the standard meets the definition of BPS for this class and category.

This category of boilers (less than 75 psig steam pressure) is characterized by lower steam drum temperatures (due to the lower saturation temperature of the steam relative to higher pressure boilers). Depending upon the design of the boiler, the configuration of the boiler feedwater system and the temperature and quantity of returned condensate, the combination of a substantial return of hot condensate in combination with a low steam saturation temperature may serve to limit the extent to which an economizer can be used to transfer heat from the boiler flue gas to the feedwater. Although many lower pressure boilers operate without deaerators (in particular, those with pressure less than 50 psig), the District's analysis of this reduction measure has included the conservative assumption that the boiler operation includes a pressure deaerator operating at approximately 5 psig for removal of dissolved oxygen from the boiler feedwater prior to entering the boiler (for purposes of corrosion control in the boiler). The deaerator is essentially a feedwater heater using steam to heat the boiler return temperature to a saturated condition at the deaerator pressure. This results in a boiler feedwater temperature from the deaerator to the boiler of approximately 227$^{o}$F. Since the saturation temperature of steam for this category may be as low as 240 $^{o}$F, further heating of the deaerated water in an economizer prior to delivery to the drum will not be possible in some cases. In these cases, use of an economizer will be limited to heating the water supply to the deaerator which, for a tray-type deaerator, limits the water temperature to about 220$^{o}$F. The District's analysis indicates that if the combined water supply to the deaerator is greater than about 170$^{o}$F, heating the deaerator water supply in an economizer may result in outlet water temperature approaching 220$^{o}$F depending upon the pressure and basic efficiency of the boiler and upon the level of heat recovery achieved in the economizer. Based on this analysis, the District assumes that an economizer-based approach for efficiency improvement is not generally practical for this category of boilers with water supply temperatures above 170$^{o}$F.

When the temperature of the combined boiler water supply (combined makeup water and condensate return to the deaerator of feedwater tank) is low enough, additional condensing economizer surface may be used to further enhance the energy recovery. The District's analysis of this case indicates that when the combined boiler water supply is 150$^{o}$F or less, a minimum additional improvement of approximately 2 percentage points in boiler thermal efficiency can be achieved with a condensing economizer. Establishing a 150$^{o}$F threshold for requirement of a condensing economizer provides flexibility for a facility to either achieve additional efficiencies in recovery of hot condensate on the facility side, avoiding installation of the condensing economizer, or to elect to install the condensing unit where hot condensate recovery is not possible or is cost prohibitive. This standard has been restricted to boilers rated 20 MMBtu per hour and larger since condensing systems are not typically installed on small boilers and may be cost prohibitive in small systems. In addition, units rated less than 20 MMBtu/hr represent less than 20% of the total fired duty of boilers permitted by the District.

The District's analysis for the use of economizers has been based on a conservative approach which ignores other potential heat recovery schemes which may be feasible (and more cost effective) depending upon the site specific characteristics of the facility. Therefore, specification of an economizer design as BPS will necessarily include an allowance to use an alternate design which provides an equivalent thermal efficiency for the boiler operation.

Air Pre-heaters

Another way to recover heat from the boiler flue gases is by use of an air preheater. In this case the recovered heat is transferred to the incoming combustion air and returned to the boiler, improving boiler efficiency. Regenerative and recuperative designs are available as well as designs employing boiler feedwater as an intermediary heat transfer medium to transfer heat between the flue gas and air streams. Air pre-heaters are common on large utility boilers (particularly solid fuel-fired boilers) but are more rare on industrial boilers due to cost and complexity. When compared to economizers, they are generally more expensive per unit of energy recovery, require more space, and consume additional electrical energy to move the combustion air through the heat exchanger. In addition, use of heated combustion air may be problematic due potential impacts on $NO_x$ emissions from the unit. In general, where other low temperature heat receptors are available, the economizer is the more economical approach for increasing thermal efficiency of the unit while avoiding potential increases in $NO_x$ emissions associated with air pre-heaters. Due to potential increases in NOx emissions, air pre-heaters are determined to not be technologically feasible for a general designation as BPS. However, the BPS would allow use of air preheaters in lieu of economizers where it is demonstrated that the proposed system achieves the same level of heat recovery from the stack gases.

Basic Boiler Efficiency

In cases where use of an economizer or other flue gas heat recovery system is not feasible or practical, direct GHG emissions become a function of the basic efficiency of the boiler itself. Determination of boiler efficiency presents numerous issues with respect to definition of efficiency and the method of determination. While an actual value of efficiency can be highly variable depending upon the selected definition of efficiency, reference states selected, and site specific factors, if the losses associated with boiler blowdown are ignored, energy loss from a boiler is primarily due to the heat content of the boiler flue gas which, at a given level of excess air in the combustion, is a direct function of the flue gas temperature at the stack. As mentioned previously, the lowest flue gas temperature achievable by any particular boiler is a function of the operating pressure of the boiler. The best currently available boiler designs (such as 4-pass firetube designs or high efficiency water tube designs achieve a flue gas temperature approach (flue gas temperature – steam saturation temperature) which does not exceed 100 $^{o}$F at maximum firing rate. In the absence of a heat recovery system such as an economizer or air preheater, establishing a maximum stack temperature relative to the steam temperature at maximum firing condition provides a universal specification which can be applied to all boilers regardless of other site specific factors.

Boiler Blowdown Heat Recovery

Since the temperature of boiler blowdown water is the same as that of the steam, energy losses associated with boiler blowdown may be significant. Typical boiler operation is a continuous blowdown of 4-8% of steam production but may be as high as 20% depending upon boiler parameters and the quality and proportion of makeup water. Achieved-in-practice technology for minimization of these losses includes:

| | |
|---|---|
| 1. Blowdown minimization: | a) Water pretreatment to reduce solids content and/or b) the use of automatic blowdown control systems |
| 2. Flash steam recovery: | For boiler systems equipped with a deaerator, blowdown may be flashed into a separator vessel to allow recovery and use of the steam by the deaerator. |
| 3. Feedwater heat exchanger | Blowdown may be routed through a heat exchanger for indirect heat transfer with the boiler makeup water. Although this system effectively recovers waste heat from the blowdown stream, it reduces potential recovery of heat from the boiler stack since it increases the temperature of the water flowing to the stack economizer. Therefore, the net effect of this recovery technique may be minimal when considered in the context of the BPS. |

Consideration of the reduction measures above reveals that only Item 1b can be considered feasible for inclusion as GHG reduction measures for this BPS. This measure may provide significant improvement in boiler thermal efficiency (one percentage point or greater) when boiler blowdown exceeds 8% of total steam production.

Item 1a (water pre-treatment) presents a number of considerations and potential site-specific issues concerning its feasibility which are outside the scope of boiler design and efficiency, making it impractical for inclusion as a reduction measure for this BPS. Item 2 would not be feasible as a general reduction measure since many low pressure boilers do not utilize a deaerator. Item 3 (feedwater heat exchanger) is a potential option for any facility in that it could be employed as an alternate measure to reduce the size of the stack economizer required by this BPS. Additionally, there may be site- specific heat uses which may allow recovery of energy from the blowdown. However, since the efficiency improvement provided by the heat exchange system would offset some of the efficiency gain of the economizer requirements of this BPS and since the consideration of other site specific heat recovery would be insufficiently general for designation as BPS, Item 3 will not be included as a feasible reduction measure.

Limiting Excess Air and Flue Gas Recirculation

The combustion process in a boiler generally requires an excess of air (air in excess of the stochiometric requirement for combustion of the fuel) to ensure efficient combustion and safe operation. Operations which exceed the minimum amount of excess air required for clean and safe operation result in a loss of efficiency as a result of the increased stack losses. When boiler burners are manually tuned on a periodic basis, they are typically adjusted to a conservatively high excess air value, ensuring safe operation over the entire operating range of the boiler.

Additionally, low efficiency burners or those employing high flue gas recirculation rates to control $NO_x$ emissions may require operation with up to 4-5% excess oxygen to ensure stable operation. From an efficiency standpoint, the excess $O_2$ means that there are not only energy losses incurred to heat the excess air up to the stack temperature but, in addition, incremental electrical energy consumption is required by the combustion air blower to handle higher excess air, leading to additional indirect GHG emissions.

FGR is utilized to control combustion temperature at the burner with recirculation rates up to 40-45% in some ultra low NOx applications. This recirculation has a negative impact on boiler performance since it typically requires operation at higher excess air rates and requires substantial fan horsepower to operate.

While limiting excess air and flue gas recirculation are achieved-in-practice GHG reduction measures for higher pressure boilers, low pressure boilers have fewer options available to meet emission limits on NOx; their options are primarily limited to burner technology since their stack temperatures are generally not sufficiently high for operation of selective catalytic reduction systems. Burner options to meet NOx emission limits are generally either high FGR designs or designs which use high excess air in lieu of FGR for controlling flame temperature. Based on this, placing limits on excess air and flue gas recirculation rates is not considered to be a feasible GHG reduction measure for this category of boiler.

Use of Premium Efficiency Motors with Speed Control

An electric motor efficiency standard is published by the National Electrical Manufacturers Association (NEMA) which is identified as the “NEMA Premium Efficiency Electric Motors Program”. For large motors, the NEMA premium efficiency motor provides a gain of approximately 5-8 percentage points in motor efficiency when compared to a standard efficiency motor. The NEMA specification covers motors up to 500 horsepower and motors meeting this specification are in common use and are available from most major electric motor manufacturers.

Control of the combustion air fan operation by use of a variable speed electric motor will provide substantial energy savings when compared to operation at a fixed speed and controlled by throttling the discharge flow. The most common and economical variable speed drive is the variable frequency drive (VFD) which has become commonly available in the last decade and is typical for new boiler fan applications. The VFD provides especially significant energy savings when a boiler is operated at substantial turndown rations which can result in throttling away more than half the rated energy output of the motor.

Use of High Efficiency Combustion Air Fans

The peak efficiency of centrifugal fans may vary from 60 to 80% depending upon fan design and application. Use of a higher efficiency fan provides either savings in indirect GHG emissions due to the significant reduction in electric motor horsepower for motor-driven fans or savings in direct GHG emissions when the fan is driven by a steam turbine. However, the absolute value of efficiency which can be achieved is highly dependent upon the specific operating conditions including flow, pressure, and temperature, all of which may vary significantly for any specific boiler. Given this variability as well as the absence of any effective industry standard for fan efficiency, the District's opinion is that specification of combustion air fan efficiency cannot be realistically included as a technologically feasible reduction measure in the BPS for boilers at this time.

## B. Listing of Technologically Feasible Control Measures

For the specific equipment or operation being proposed, all technologically feasible GHG emissions reduction measures are listed, including equipment selection, design elements and best management practices, that do not result in an increase in criteria pollutant emissions compared to the proposed equipment or operation.

**Table 1**
**Technologically Feasible GHG Reduction Measures for *New Boilers with Rated Firing Capacity with Rated Steam Pressure Less Than 75 psig, Fired Exclusively on Natural Gas or LPG***

| Reduction Measure | Qualifications |
|---|---|
| **1.** The boiler shall be either equipped with an economizer system meeting the following design criteria or shall be equipped with an approved alternate heat recovery system which will collectively provide heat recovery from the boiler flue gas which is equivalent. Equivalent heat recovery systems may utilize recovered heat for purposes other than steam generation provided such uses offset other fuel usage which would otherwise be required. | |
| Economizer System Criteria<br><br>A. Except for boilers subject to the requirements of items B and C below, the economizer system shall be designed at maximum boiler firing rate to either 1) reduce the temperature of the economizer flue gas outlet to a value no greater than 20°F above the temperature of the boiler feed water at maximum firing rate, or 2) reduce the final temperature of the boiler's flue gas to a temperature no greater than 200°F.<br><br>*Note: For purposes of this BPS, boiler feedwater temperature is defined as the temperature of the water stream delivered to the boiler from the deaerator or boiler feedwater tank.* | *An economizer directly increases boiler efficiency (resulting in reduced GHG emissions) by adding heat transfer surface to the unit for recovery of energy from the flue gas* |
| B. For boilers with a water supply temperature of 170°F or greater, the boiler shall be designed, in lieu of the requirements of item A above, to achieve a flue gas temperature no greater than the sum of the steam saturation temperature (°F at the steam drum operating pressure) plus 100°F. | *This level of performance represents current achieved-in-practice performance for boilers not equipped with a heat recovery system such as an economizer or air pre-heater* |

| | |
|---|---|
| C. For boilers with rated capacity in excess of 20 MMBtu/hr which have a average water supply temperature which is equal to or less than 150°F, the boiler shall equipped with an economizer designed to reduce the temperature of the flue gas outlet to a value no greater than 50°F above the water supply temperature when the boiler is operating at maximum firing rate.<br><br>*Note: For purposes of this BPS, water supply temperature is defined as the weighted average temperature of the combined makeup water and the recovered condensate delivered to the boiler upstream of any deaerator or other feedwater preheater but after benefit of any other heat recovery operations which recover waste heat from the boiler by transfer to the boiler water supply (such as boiler blowdown heat recovery).* | *Lower water supply temperatures provide additional opportunity to recover heat from the boiler flues gas, resulting in increased efficiency and reduced GHG emissions* |
| **2.** Electric motors driving combustion air fans or induced draft fans shall have an efficiency meeting the standards of the National Electrical Manufacturer's Association (NEMA) for "premium efficiency" motors and shall each be operated with a variable speed control or equivalent for control of flow through the fan. | *Use of premium efficiency motors with variable speed drives significantly reduces electric power consumption by the boiler operation, particularly during periods of reduced-rate operation* |
| **3.** For boilers with rated fired duty in excess of 20 MMBtu/hr and a boiler blowdown rate exceeding 8 % of steam production, the boiler shall be equipped with 1) an automatic boiler blowdown control system which will minimize boiler blowdown while controlling dissolved solids in the boiler water at an optimum level. | *This measure improves overall boiler efficiency (thus reducing direct GHG emissions) by minimizing energy losses associated with excessive boiler blowdown in larger boilers* |

All of the control measures identified above are consistent with control equipment for criteria pollutants which meets current regulatory requirements. None of the identified control measures would result in an increase in emissions of criteria pollutants.

## STEP 3. Identify all Achieved-in-Practice GHG Emission Control Measures

For all technologically feasible GHG emission reduction measures, all GHG reduction measures determined to be Achieved-in-Practice are identified. Achieved-in-Practice is defined as any equipment, technology, practice or operation available in the United States that has been installed and operated or used at a commercial or stationary source site for a reasonable period of time sufficient to demonstrate that the equipment, the technology, the practice or the operation is reliable when operated in a manner that is typical for the process. In determining whether equipment, technology, practice or operation is Achieved-in-Practice, the District will consider the extent to which grants, incentives or other financial subsidies influence the economic feasibility of its use.

The following findings or considerations are applicable to this class and category:

The District reviewed project design specifications for existing boiler installations operating in the San Joaquin Valley and elsewhere. See Appendix A for details. The review indicated the following with respect this class and category:

- Standard economizer installations designed for a 20°F approach to boiler feedwater temperature are achieved-in-practice. The District has identified several boiler operations in the San Joaquin Valley (SJV) currently operating with an economizer designed to this criterion.
- Condensing economizers with a 50°F approach to the feedwater temperature are achieved in practice. Several condensing economizer operations have been identified in the SJV including one operation with a 50 °F approach to the feedwater temperature.
- Boiler section design which achieves a 100°F approach between the flue gas and the steam saturation temperature is a current industry best practice and achieves boiler efficiencies in the range of 81-83% depending upon specifics, consistent with typical published guaranteed performance by boiler manufacturers.
- The use of high efficiency motors and variable frequency drives is a common specification in many industrial and commercial applications. A number of boiler operations in the SJV have been identified which have this feature.
- Use of automatic blowdown controls is determined to be achieved-in-practice since these are recognized, well-established practices at boiler plants.

All technologically feasible GHG reduction measures listed in Table 1 meet the following criteria:

<u>All technology listed is in current commercial use.</u>

All technologically feasible GHG reduction measures listed in Table 1 are based on technology (condensing economizers, high efficiency motors with variable speed drives) which is currently in commercial use. This technology has been in place for a significant number of years and was developed and implemented without benefit of grants, incentives or other financial subsidies.

<u>Implementation of all listed technology does not result in an increase in criteria pollutant emissions.</u>

In general, since all proposed measures do not affect the criteria pollutant emission factors and generally result in a reduction in the firing of fuel, criteria pollutant emissions will generally be reduced with implementation of BPS.

Therefore, all items listed above are deemed to be Achieved-in-Practice. Since all of the achieved-in-practice measures identified are independent of each other, concurrent implementation of all measures results in a strictly additive benefit (none of the measures are mutually exclusive). Therefore, all identified reduction measures are considered to be a single measure in effect. Since there are no other mutually exclusive measures identified, there is in effect a single achieved in practice reduction measure identified. and the District proposes to deem the concurrent implementation of all identified achieved-in-practice reduction measures as BPS for this class and category.

## STEP 4. Quantify the Potential GHG Emission and Percent Reduction for Each Identified Achieved-in-Practice GHG Emission Reduction Measure

For each Achieved-in-Practice GHG emission reduction measure identified:

a. Quantify the potential GHG emissions per unit of activity ($G_a$)
b. Express the potential GHG emission reduction as a percent ($G_p$) of Baseline GHG emissions factor per unit of activity (BEF)

As stated above, there is a single identified achieved in practice control measure for this class and category. Therefore, the GHG emission quantification will be presented as a single value based on the additive contribution of each individual measure incorporated into the overall control measure.

## A. Basis and Assumptions:

As previously stated, a 15 psig boiler is most representative of this category of boiler. Therefore, consistent with the approach taken for quantification of the Baseline Emission Factor, a 15 psig boiler with a combined feedwater temperature of 130 $^oF$ has been assumed to represent the average new unit to be proposed in this class and category.

- The boiler is equipped with a surface stabilized combustion burner utilizing high excess air rate and no FGR for control of NOx emissions. Stack $O_2$ concentration is assumed to be 5.5%.
- The boiler is assumed to be rated less than 20 MMBtu/hr, more typical of low pressure boilers.
- Due to a BPS requirement to install an automatic blowdown system, it is assumed that continuous boiler blowdown will be reduced by 20%, or a blowdown rate of 6.4% of steam rate will be applicable.
- Application of the proposed BPS to this unit results in a requirement to install an economizer which achieves a stack temperature of 200 $^oF$.
- Based upon a boiler heat and mass balance for the given conditions, the following quantities are applicable:
  - Net steam production is 799 lb/MMBtu fired or a Specific Fuel Consumption (SFC) of 1,000,000/799 = 1,251 Btu/lb steam
  - Flue gas rate is 13,197 scf/MMbtu fired
  - Combustion air rate is 12,198 scf/MMBtu fired
  - Boiler efficiency = 85.2%
- Flue gas side pressure drop for the boiler is adjusted from the baseline case to account for reduced flow through the boiler as a result of limits on FGR rate. For the BPS case with 0% FGR, flue gas rate through the boiler is 12,198 x 1.0 = 12,198 scf/MMBtu fired. For the baseline case, a boiler pressure drop of 11.5 "WC was determined based on a flow rate of 14,762 scf/MMBtu. Correcting this to the lower flow rate for this case yields the following boiler pressure drop:

  11.5 "WC x $(12{,}198/14{,}762)^2$ = 7.9 "WC

- Since the BPS unit is assumed to be equipped with an economizer, an additional pressure drop of 1 "WC will be included.

- Total system flue gas pressure drop is calculated as follows:

| | |
|---|---|
| Burner | 12.0 "WC |
| Boiler | 7.9 "WC |
| Economizer | 1.0 |
| Total | 20.9 "WC |

- A 30% reduction in net specific electric power consumption is attributed to use of VFD during turndown periods.
- All other assumptions and basis are the same as the baseline case.

## B. Calculation of Potential GHG Emissions per Unit of Activity ($G_a$):

$G_a$ is the sum of the direct ($GHG_D$) and indirect ($GHG_I$) emissions (per unit of activity):

$G_a = GHG_D + GHG_I$

Direct Emissions:

$GHG_D = E_f \times SFC$

$E_f$ = GHG emission factor = 117 lb- $CO_{2(e)}$/MMBtu of natural gas

SFC = Specific Fuel Consumption = 1,251 Btu/1000 lb steam (as stated in basis)

Direct emissions are then calculated as:

$GHG_D$ = 117 lb-$CO_{2(e)}$/MMBtu x 1.251 MMBtu/1000 lb steam
= 146.4 lb/1000 lb steam

Indirect Emissions

Indirect emissions consist of emissions from operation of the electric motor driving the combustion air fan. These determined by the following:

GHG (electric motor) = Electric Utility GHG Emission Factor x kWh consumed

To determine kWh consumption per 1000 lb steam produced it is necessary to first determine the Bhp requirement for the gas compression operation by the combustion air blower. Specific brake horsepower requirement by the combustion air fan is calculated from the following equation for adiabatic compression of an ideal gas[4]:

Bhp-hr/1000 lb steam = $(T/520) \times (0.001072M/nE) \times [(p_2/p_1)^n-1]$

T = gas temperature, $^oR$. T =68 $^oF$ or 528 $^oR$
M = 12,198 scf air/MMbtu x 1.251 MMBtu/1000 lb steam
= 15,260 scf gas/1000 lb steam
n = 0.2857 (typical for diatomic gases)
*E* = efficiency = 60%
$p_1$ = atmospheric pressure = 407 "WC
$p_2$ = atmospheric pressure + pressure drop
= 407.0 + 20.9 = 427.9 "WC

[4] See: Clarke, Loyal and Robert Davidson, Manual for Process Engineering Calculations, 2nd Edition, McGraw-Hill, New York, 1975, p.360.

Substituting the given values into the equation:

Bhp-hr/1000 lb steam = 1.4

Applying a 30% reduction to account for the use of a VFD:

| | | |
|---|---|---|
| Combustion air fan specific energy consumption | = | (1-30%) x 1.4 |
| | = | 1.0 Bhp-hr/1000 lb steam |

Converting to kWh based on an 95% efficient electric motors and a conversion factor of 0.7457 kWh/bhp:

= (1.0 x 0.7457)/95% = 0.79 kWh/1000 lb steam

GHG (electric motors) = 0.524 lb- $CO_{2(e)}$/kWh x 0.79 kWh/1000 lb steam
= 0.4 lb $CO_{2(e)}$ per 1000 lb steam production

Total Indirect Emissions:

$GHG_i$ = GHG (electric motors) = 0.4 lb $CO_{2(e)}$ per 1000 lb steam production

GHG Emissions per Unit of Activity is then calculated as:

$G_a$ = $GHG_D$ + $GHG_I$ = *146.4 + 0.4 = 146.8 lb-* $CO_{2(e)}$*/1000 lb-steam*

**C. Calculation of Potential GHG Emission Reduction as a Percentage of the Baseline Emission Factor ($G_p$):**

$G_p$ = (BEF - $G_a$) / BEF = (154.2 – 146.8)/154.2 = 4.8%

**STEP 5. Rank all Achieved-in-Practice GHG emission reduction measures by order of % GHG emissions reduction**

Since only a single achieved in practice control measure is identified, no ranking is necessary.

**STEP 6. Establish the Best Performance Standard (BPS) for this Class and Category**

For Stationary Source Projects for which the District must issue permits, Best Performance Standard is – "For a specific Class and Category, the most effective, District approved, Achieved-In-Practice means of reducing or limiting GHG emissions from a GHG emissions source, that is also economically feasible per the definition of achieved-in-practice. BPS includes equipment type, equipment design, and operational and maintenance practices for the identified service, operation, or emissions unit class and category".

Based on the definition above, Best Performance Standard (BPS) for this class and category is determined as:

***Best Performance Standard for New Boilers with Rated Steam Pressure Less Than 75 psig, Fired Exclusively on Natural Gas or LPG***

**Boilers meeting this Best Performance Standard must comply with all three elements of this BPS (items 1, 2 and 3 listed below) where applicable:**

1. **The boiler shall be either equipped with an economizer system meeting the following design criteria or shall be equipped with an approved alternate heat recovery system which will collectively provide heat recovery from the boiler flue gas which is equivalent. Equivalent heat recovery systems may utilize recovered heat for purposes other than steam generation provided such uses offset other fuel usage which would otherwise be required.**

   **Economizer System Criteria**

   A. **Except for boilers subject to the requirements of items B and C below, the economizer system shall be designed at maximum boiler firing rate to either 1) reduce the temperature of the economizer flue gas outlet to a value no greater than 20$^{o}$F above the temperature of the boiler feed water at maximum firing rate, or 2) reduce the final temperature of the boiler's flue gas to a temperature no greater than 200$^{o}$F.**

***Note: For purposes of this BPS, feedwater temperature is defined as the temperature of the water stream delivered to the boiler from the deaerator or feedwater tank. For steam systems employing a high pressure condensate return, the feedwater temperature is the weighted average of the temperatures of the returned high pressure condensate and of the water from the deaerator or feedwater tank.***

**B. For boilers with a water supply temperature of 170$^o$F or greater, the boiler shall be designed, in lieu of the requirements of item A above, to achieve a flue gas temperature no greater than the sum of the steam saturation temperature ($^o$F at the steam drum operating pressure) plus 100$^o$F.**

**C. For boilers with rated capacity in excess of 20 MMBtu/hr which have a average water supply temperature which is equal to or less than 150$^o$F, the boiler shall equipped with an economizer designed to reduce the temperature of the flue gas outlet to a value no greater than 50$^o$F above the water supply temperature when the boiler is operating at maximum firing rate.**

***Note: For purposes of this BPS, water supply temperature is defined as the weighted average temperature of the combined makeup water and the recovered condensate delivered to the boiler upstream of any deaerator or other feedwater preheater but after benefit of any other heat recovery operations which recover waste heat from the boiler by transfer to the boiler water supply (such as boiler blowdown heat recovery).***

**2. Electric motors driving combustion air fans or induced draft fans shall have an efficiency meeting the standards of the National Electrical Manufacturer's Association (NEMA) for "premium efficiency" motors and shall each be operated with a variable speed control or equivalent for control of flow through the fan.**

**3. For boilers with rated fired duty in excess of 20 MMBtu/hr and a boiler blowdown rate exceeding 8 % of steam production, the boiler shall be equipped with 1) an automatic boiler blowdown control system which will minimize boiler blowdown while controlling dissolved solids in the boiler water at an optimum level and 2) a flash steam recovery system which will recover flash steam from the blowdown pressure reduction and utilize it for feedwater heating in the deaerator or feedwater heater.**

**STEP 7. Eliminate All Other Achieved-in-Practice Options from Consideration as Best Performance Standard**

The following Achieved-in-Practice GHG control measures identified and ranked are specifically eliminated from consideration as Best Performance Standard since they have GHG control efficiencies which are less than that of the selected Best Performance Standard as stated in Section II.6:

No other Achieved-in-Practice options were identified.

# V. Appendices

| | |
|---|---|
| Appendix A: | Achieved-in-Practice Analysis |
| Appendix B: | Public Notice of Intent |
| Appendix C: | Comments Received after Initial Public Outreach |
| Appendix D: | Public Comment Period Notification |

# Appendix A
# Achieved-in-Practice Analysis

## Achieved-in-Practice Summary for Proposed GHG Reduction Measures

Table A-1 lists boiler design information for six California facilities, five of which are located in the San Joaquin Valley and currently have District permits. Each facility listed demonstrates the achieved-in-practice status of one or more of the reduction measures proposed by this BPS.

GHG Reduction Measure 1A: (standard $1^{st}$ stage economizer with 20 $^{o}F$ approach)

Facilities 1, 3 and 4 are equipped with a single economizer operating on boiler feedwater designed to this standard. Facility 3 has been operating for two years with this feature and.has reported that no issues have arisen with the economizer.

GHG Reduction Measure 1B: ($2^{nd}$ Stage economizer with 50 $^{o}F$ approach for units over 20 MMBtu/hr):

Facilities 2, 5 and 6 are currently operating 2-stage economizer systems operating on boiler feedwater. All facilities report good operation. Facility 2 demonstrates a facility with a 50 $^{o}F$ design approach on the $2^{nd}$ stage economizer. All facilities have reported that no problems have been encountered with the units.

GHG Reduction Measure 2: (high efficiency electric motors and variable speed drives)

The majority of the facilities surveyed have incorporated these features. Discussion with boiler manufacturer representatives has indicated that these features are routinely recommended for all new boiler installations.

GHG Reduction Measure 3: (limited FGR and excess air for boilers exceeding 20 MMBtu/hr)

As indicated in Table A-1, a number of facilities are successfully operating in this mode with most reporting that they use no FGR at all. Most facilities reported general improvement in boiler operation (stability and turndown) when operating with reduced FGR rates.

GHG Reduction Measure 4: (recovery of flash steam and use of automatic boiler blowdown control)

The facilities listed in Table A-1 were not surveyed with respect to this criterion. However, flash steam recovery from continuous blowdown, as well as use of automatic blowdown control, are generally recognized as achieved in practice operations.[5][6]

[5] Boiler Blowdown (Best Operating Practices for Boiler Blowdown), NCDENR Fact Sheet, N.C. Division of Pollution Prevention and Environmental Assistance

[6] Energy Tips – Steam, Steam Tip Sheet #9, U.S. Department of Energy, Energy Efficiency and Renewable Energy, January 2006.

**Table A-1**
**Facilities Demonstrating Achieved-in-Practice Elements of the Best Performance Standard for Boilers**

| Facility | District Permit | Location | Pressure psig | Fired Duty MMBtu/hr | 1st Stage Approach oF | 2nd Stage Approach oF | Stack Temperature oF | Operation Since | Achieved-In-Practice Elements |
|---|---|---|---|---|---|---|---|---|---|
| Los Gatos Tomatos | C-787-7-3 | Huron | 350 | 182 | 20 | N/A | | 2009 | 1st stage economizer with 20 degree approach, variable speed drives, FGR< 10%, O2 trim system |
| Del Monte Foods | N-1626-8-1 | Modesto | 275 | 59 | 50 | 50 | 110 | 2007 | Two-stage condensing economizer with 50 degree approach on 2nd stage, variable speed drives, FGR< 10%, O2 trim system |
| Del Monte Foods | C-366-1-8 & '2-9 | Hanford | | 182 each | 20 | N/A | | 2008 | 1st stage economizer with 20 degree approach, variable speed drives, FGR< 10%, O2 trim system |
| J.G Boswell | C-7336-8-0 | Corcoran | 350 | 148.14 | 19 | N/A | 259 | June, 2010 | 1st stage economizer with 20 degree approach, variable speed drives, FGR< 10%, O2 trim system |
| Styrotek | S-1075-3-9 | Delano | 100 | 16.3 | 105 (est) | 108 | 178 | March, 2010 | Two-stage condensing economizer |
| Mars PetCare | N/A (SCAQMD) | Victorville | 110 | 23.5 | 69 (est) | 125 | 180 | March, 2010 | Two-stage condensing economizer |

# Appendix B
# Public Notice of Intent

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING

**Notice Of Development Of**
# Best Performance Standards

NOTICE IS HEREBY GIVEN that the San Joaquin Valley Air Pollution Control District solicits public comment on development of Best Performance Standards for the following Stationary Source class and category of greenhouse gas emissions:

## BOILERS
## Subject to District Permitting Requirements

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The District is soliciting public input on the following topics for the subject Class and Category of greenhouse gas emission source:

- Recommendations regarding the scope of the proposed Class and Category (Stationary GHG sources group based on fundamental type of equipment or industrial classification of the source operation),
- Recommendations regarding processes or operational activities the District should consider when establishing Baseline Emissions for the subject Class and Category,
- Recommendations regarding processes or operational activities the District should consider when converting Baseline Emissions into emissions per unit of activity, and
- Recommendations regarding technologies to be evaluated by the District, when establishing Best Performance Standards for the subject Class and Category.

Information regarding development of Best Performance Standard for the subject Class and Category of greenhouse gas emission source can be obtained from the District's website at http://www.valleyair.org/Programs/CCAP/CCAP_idx.htm.

Written comments regarding the subject Best Performance Standard should be addressed to Dennis Roberts by email, dennis.roberts@valleyair.org, or by mail at SJVUAPCD, 1990 East Gettysburg Avenue, Fresno, CA 93726 and must be received by **February 23, 2010**. For additional information, please contact Dennis Roberts by e-mail or by phone at (559) 230-5919.

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Information regarding the District's Climate Action Plan and how to address GHG emissions impacts under CEQA, can be obtained from the District's website at http://www.valleyair.org/Programs/CCAP/CCAP_idx.htm.

# Appendix C
# Comment Received After Initial Public Outreach

# Comments Received During the Public Notice of Intent and Responses to Comments

**Stakeholders Written Comments:**

Nationwide Boiler Incorporated (NBI)
Plains All America, L.P. (PAA)
Kern Oil and Refining Co. (KOR)
Enviro Tech Consultants, Inc. (ETC)
Berry Petroleum Company (BPC)
R.F. McDonald Co. (RFM)

1. **Comment:** In going forward with development of BPS for process heaters it is important to recognize that in certain facilities plant off gas is accountable for a large quantity of the fuel. The Plains LPG frac and isom facility in Shafter is currently under the refinery regulated portion of rule 4306 and 4320 for the heaters on site. It may be important to distinguish between PUC gas and plant off gas in future BPS requirements (PAA)

**Response:** The District recognizes that fuels other than natural gas or LPG may have specific limitations with respect to energy efficiency technology. The BPS will be clarified to reflect that it is applicable to these fuels only.

2. **Comment:** I would advocate that the strict prohibitory rules recently placed on this division of heaters through 4320, 4623 and 4455 would already have satisfactory BPS in place. (PAA, ETC)

**Response:** The District's prohibitory rules do not address GHG emission or energy efficiency and thus would not represent BPS.

3. **Comment:** In my opinion the District can not receive adequate information to form BPS without first meeting with industry and their representatives to discuss what the baseline period equipment is. A blanket request for information will only create confusion and the submittal of information that can only be applied to a single company. Once the District understands the difference not only between industrial types, but the differences within the same industry, can the District begin receiving adequate information to form an achievable and economical BPS. (BPC)

**Response:** The District recognizes the importance of industry responses to specific proposals. The draft BPS will be posted for public comments to ensure this input is received.

4. **Comment:** There are multiple types of equipment, facility design, and operational characteristics that make establishment of "BPS" difficult. We recommend that the District structure BPS following the existing categories and organization of the District's BACT guidelines. (ETC)

**Response:** Since BACT addresses only criteria pollutants and is determined under criteria different from that of BPS, the District cannot necessarily utilize the classifications established for BACT. To the extent that the BACT classification forms a reasonable classification for GHG emissions, it will be considered.

5. **Comment:** BPS needs to provide exemptions for small sources of GHG emissions. EPA is proposing a threshold of 25,000 MT CO2e, and a similar threshold should be part of any BPS determination. (ETC)

**Response:** Comment noted. Since this comment is general and not specific to the BPS for boilers, the District will not respond to this comment as a part of this document.

6. **Comment:** Cost effectiveness needs to be considered when determining BPS. (ETC)

**Response:** Cost effectiveness is included to the extent that is required under the definition of achieved-in-practice.

# Appendix D
# Public Comment Period Notification

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING

**Notice Of Development Of**
## Best Performance Standards

NOTICE IS HEREBY GIVEN that the San Joaquin Valley Air Pollution Control District solicits public comment on development of Best Performance Standards for the following Stationary Source class and category of greenhouse gas emissions:

**BOILERS**
**Subject to District Permitting Requirements**

---

The District is soliciting public input on the following topics for the subject Class and Category of greenhouse gas emission source:

- Recommendations regarding the scope of the proposed Class and Category (Stationary GHG sources group based on fundamental type of equipment or industrial classification of the source operation),
- Recommendations regarding processes or operational activities the District should consider when establishing Baseline Emissions for the subject Class and Category,
- Recommendations regarding processes or operational activities the District should consider when converting Baseline Emissions into emissions per unit of activity, and
- Recommendations regarding technologies to be evaluated by the District, when establishing Best Performance Standards for the subject Class and Category.

Information regarding development of Best Performance Standard for the subject Class and Category of greenhouse gas emission source can be obtained from the District's website at http://www.valleyair.org/Programs/CCAP/CCAP_idx.htm.

Written comments regarding the subject Best Performance Standard should be addressed to Dennis Roberts by email, dennis.roberts@valleyair.org, or by mail at SJVUAPCD, 1990 East Gettysburg Avenue, Fresno, CA 93726 and must be received by **November 12, 2010**. For additional information, please contact Dennis Roberts by e-mail or by phone at (559) 230-5919.

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Information regarding the District's Climate Action Plan and how to address GHG emissions impacts under CEQA, can be obtained from the District's website at http://www.valleyair.org/Programs/CCAP/CCAP_idx.htm.