San Joaquin Valley
Unified Air Pollution Control District

Best Performance Standard (BPS) x.x.xx

<table>
<tr><td>Class</td><td>Steam Generators</td></tr>
<tr><td>Category</td><td>New Industrial Steam Generators Fired Exclusively on Natural Gas or LPG</td></tr>
<tr><td rowspan="2">Best Performance Standard</td><td>Applicability Note: Steam generators 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>Steam generators meeting this Best Performance Standard must comply with both elements of this BPS (items 1 and 2 listed below) where applicable:

1. The steam generator shall be either equipped with an economizer system meeting the following design criteria <u>or</u> 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.

A. Except for steam generators subject to the requirements of item B below, the economizer system shall be designed at maximum steam generator firing rate to either 1) reduce the temperature of the economizer flue gas outlet to a value no greater than 90 ^{o}F above the temperature of the boiler feed water or 2) heat the boiler feed water to a temperature which is no less than the saturation temperature of the steam at the pressure of the steam separator, or 3) reduce the final temperature of the boiler’s flue gas to a temperature no greater than 300^{o}F .

<i>Note: For purposes of this BPS, feedwater temperature is defined as the temperature of the water stream delivered to the steam generator from the deaerator or feedwater tank.</i>

B. For steam generators 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 steam generator shall equipped with an economizer designed to reduce the temperature of the flue gas outlet to a value no greater than 90^{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 steam generator upstream of any deaerator or other feedwater preheater.

AND

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.</td></tr>
</table>

Percentage Achieved GHG Emission Reduction Relative to Baseline Emissions	**4.2%**

District Project Number	C-1100388
Evaluating Engineer	Dennis Roberts, P.E.
Lead Engineer	Martin Keast
Public Notice of Intent Date	April 1, 2012
Public Notice: Start Date	August 20, 2012
Public Notice: End Date	September 20, 2012
Determination Effective Date	TBD

TABLE OF CONTENTS

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 policy: *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.

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 ***New Steam Generators, Fired Exclusively on Natural Gas or LPG*** as a separate category of gaseous fuel-fired boilers 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:

Table 1
BPS Development Process Phases for *New Steam Generators, 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 and category is attached as Appendix C. Comment received during the initial public process with District's responses are attached a Appendix D.
2	BPS Development	N/A	See Section III of this evaluation document.
3	Public Participation: Public Notice Start Date	xx/xx/xx	A Draft BPS evaluation was provided for public comment. The District's notification is attached as Appendix xxxx
4	Public Participation: Public Notice End Date	xx/xx/xx	

III. Class and Category

Class: Steam Generator

Steam Generator has been established previously as a distinct class of equipment.:

Category: New Steam Generators Fired Exclusively with Natural Gas or LPG

Industrial Steam Generators, Fired Exclusively with Natural Gas or LPG are recognized as a distinct category of steam generator based on the following:

- Industrial steam generators are those installed in general industrial service, not located in an oilfield.

- New steam generators are considered a separate category from existing steam generators since existing units may have site specific characteristics which would make infeasible certain GHG control measures which might otherwise be achieved-in-practice for a new unit.

- Steam generators produce steam by both heating and boiling water in a single forced-flow coil arrangement similar to a counter-flow heat exchanger (see Appendix A for illustrations). Typically, water is only about 80 % vaporized in the unit and, when dry steam is desired, the effluent from the steam generator must be passed through a steam separator to remove the un-vaporized water and return the separated water to the hot well. In contrast, conventional boilers utilize counter-flow coils only to preheat feedwater (economizers). The pre-heated water is then delivered to a drum from which water circulates through the boiler tubes by natural convection while boiling to produce steam. The steam is nearly 100 % vaporized in the tubes. Since the mechanical design and operation of steam generators differs significantly from conventional boilers, steam generators are considered to be a separate category.

- Steam generators have specific characteristics which make them especially well-suited for certain industrial applications. Relative to conventional drum boilers they are 1) more compact, 2) can be started up more quickly due to their lower thermal mass and design, 3) have lower convection and radiation losses as a percentage of the fuel fired as a result of their smaller size, 4) have greatly reduced boiler blowdown rates since they are able to operate with higher dissolved solids content in the boiling operation as a result of their low vaporization rate per pass and their higher tube velocity and 5) may be considered safer in some applications due to absence of a steam drum which represents a significant energy storage within the unit due to its volume of steam and high temperature water.

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, 2012 to individuals registered with the CCAP list server. The District's notification is attached as Appendix C.

No comments were received during the initial public outreach.

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 Steam Generators, Fired Exclusively with 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 generator with the following features:

- *Rated steam pressure 125 psig*
- *Low NOx burner operating with 30% flue gas recirculation (FGR)*
- *Oxygen content of 4.5 volume % dry basis in the stack gas*
- *Rated steam pressure 125 psig*
- *Not equipped with add-on economizer, stack temperature 440 F*
- *Conventional efficiency (87%) electric motor driver, not equipped with speed control, for the combustion air fan*

This determination was based on:

Discussions with boiler manufacturer representatives indicate that historical demand for boilers in the range of 50 to 100 psig operating pressure has been very small. For boilers rated 125 psig and above, the most typical unit supplied has been in the range of 125 to 150 psig with an average closer to

125 psig. Therefore, a 125 psig boiler was selected to represent the typical operating unit for this class and category.

An operating stack oxygen content of 4.5% and an FGR rate of 30% were selected for the baseline period based on a 30 ppmv NOx emission level (consistent with the District's prohibitory rule for boilers during the Baseline Period).

A stack temperature of 440 F was assumed for the baseline unit based upon manufacturer's estimates of industrial steam generator operation without add-on economizers (the typical unit configuration for the baseline period per manufacturer).

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.

B. Basis and Assumptions

- All direct GHG emissions are produced due to combustion of natural gas in this unit.
- Unit net steam production (125 psig) is estimated at 724.8 lb-steam/MMBtu based on:
    - Stack temperature 440 F
    - Convection/radiation loss equal to 0.5% of fuel firing
    - Return water temperature (weighted average water supply to the steam generator hot well) is 120 F
    - Hotwell temperature is 210 F and vent losses are negligible.
    - The steam generator outlet stream contains 20% water which is separated in a steam separator and returned to the hotwell.
    - Blowdown is approximately 0.6 % of the total water rate to the steam generator. No blowdown heat recovery is utilized.
    - Ambient temperature is 68 F and moisture content of air is ignored.
- Based upon a unit net steam production (125 psig) of 724.8 lb-steam/MMBtu, the following quantities are applicable:
    - Specific Fuel Consumption (SFC) of 1,000,000/724.8 = 1,380 Btu/lb steam
    - Flue gas rate is 12,886 scf/MMbtu fired (inc. moisture)
    - Combustion air rate is 11,886 scf/MMBtu fired

- 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.
- The GHG emission factor for natural gas combustion is 117 lb-CO_2(e)/MMBtu per CCAR document[1].
- 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 + steam generator is assumed to be 20 inches water column when operating without FGR with a flue gas rate of 12,886 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 30 %, flow through the boiler is estimated as: 12,886 x 1.3 = 16,752 scf/MMBtu fired

  Pressure drop through the system is then calculated as:

Burner	12.0 " WC
Boiler 8" WC x $(16,752/12,886)^2$ =	<u>13.5</u>
Total	25.5

- Electric motor efficiency is estimated at 87% for a conventional electric motor.
- 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 net steam production (net steam production is defined as the usable process

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

steam available exclusive of steam used for feedwater heating and any vent losses).

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 since the baseline period based on changes in activity efficiencies.

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-CO_2 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 = 1,380 Btu/1000 lb steam

Direct emissions are then calculated as:

GHG_D = 117 lb-$CO_{2(e)}$/MMBtu x 1.380 MMBtu/1000 lb steam
= 161.5 lb/1000 lb steam

<u>Indirect Emissions</u>

Indirect emissions produced from operation of the electric motor driving the combustion air fan 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[2]:

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

Average gas temperature to the fan is a weighted average of the ambient air 68 F) and flue gas temperature (440 F):

T = gas temperature, ^oR. Assuming constant heat capacity, gas temperature is based on the mix temperature of fresh combustion air (at 68 F) plus 30 % FGR (at 440 F):

$$T = \frac{11{,}886 \text{ scf} \times 68^o + 12{,}886 \text{ scf} \times 30\% \times 440^o}{11{,}886 \text{ scf} + 12{,}886 \text{ scf} \times 30\%}$$

T = 159 ^oF or 619 ^oR

BHP is then calculated as follows:

M = scf combustion air + flue gas x $\%_{FGR}$ (per 1000 lb steam)
M = (11,886 scf air/MMbtu + 12,886 scf flue gas/MMBtu x 30%) x 1.380 MMBtu/1000 lb steam = 21,738 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 + 25.5 = 432.5 "WC

Substituting the given values into the equation:

Bhp-hr/1000 lb steam = 2.83

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

= (2.83 x 0.7457)/87% = 2.43 kWh/1000 lb steam

GHG_I = GHG (electric motors)
= 0.524 lb-$CO_{2(e)}$/kWh x 2.43 kWh/1000 lb steam
= 1.27 ~ 1.3 lb $CO_{2(e)}$ per 1000 lb steam production

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

BEF = *161.5 + 1.3 = 162.8 lb-* CO_2(e)*/1000 lb steam production*

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

STEP 2. Technologically Feasible GHG Emission Control Measures

A. Analysis of Potential Control Measures

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

Use of Economizers on Steam Generators

Economizers can be considered to be simply an extension of the available heat transfer surface area of a steam generator since they operate in a similar counter-current heat transfer mode. Figure 1 (Appendix A) illustrates the typical configuration of a steam generator installation without an economizer. Figure 2 (Appendix A) illustrates a steam generator installation with a 2-stage economizer. The addition of heat transfer surface as illustrated in Figure 2 results in recovery of additional heat from the stack gases by transferring heat to the incoming boiler feedwater, thus reducing the stack temperature.
As depicted in Figures 1 and 2, most steam generator installations feature a heated feedwater tank (hotwell) (or alternatively a deaerator) which functions to heat the boiler feedwater to reduce the dissolved oxygen in the water for purposes of reducing steam generator corrosion and/or chemical treatment requirements. In this operation, the boiler water is heated to near saturation temperature at the operating pressure of the hotwell or deaerator. Heat input to the hotwell consists of 1) the separator water from the steam separator whose temperature is equal to the steam saturation temperature at the operating pressure of the separator and 2) a portion of the steam production from the unit as required to achieve the hotwell temperature. Typical hotwell temperatures are 210-225 F. As a result of the presence of this operation, energy recovery opportunities using economizers must consider a potential 2-stage economizer operation with the 1st stage (economizer #1 in Figure 2) heating the water flowing from the hotwell to the steam generator and the 2nd stage heating the water supply to the unit upstream of the hotwell. (Note that if a hotwell or deaerator is not used, a single economizer section may be employed).

As with any counterflow heat exchanger, the theoretical limit of heat recovery occurs when the exiting flue gas temperature approaches the temperature of the incoming fluid which is being heated. At the limit, the required heat transfer surface becomes infinite as the temperature difference between the flue gas and the incoming fluid goes to zero. A 1st stage economizer (economizer #1 as shown in Figure 2) generally operates with an incoming water temperature of 210-225 F from the hotwell which would also be the theoretical lowest achievable temperature of the flue gas exiting the economizer section. Since, in practice, a finite temperature difference is required to achieve heat transfer, the flue gas exiting the 1st stage economizer section must be higher than the incoming water temperature. The use of single stage economizers for recovery of thermal energy from steam generator flue gases is an achieved-in-practice method for improving thermal efficiency. Economizer designs for steam generators based on an approach of 90°F or less (temperature differential between flue gas leaving the economizer section and the water entering the section) are achieved-in-practice down to a stack temperature of 300 F for conventional designs operating with water from the hotwell (see Appendix B). Regardless of the approach temperature or the stack temperature, heating the feedwater to the saturation temperature at the operating steam pressure would represent a theoretical upper level limitation on the economizer performance.

A 2nd stage economizer (economizer #2 in Figure 2) allows recovery of additional energy by transferring sensible heat of the flue gas to the water supply flowing to the hotwell. Assuming no heat sinks other than the hotwell water supply are available in a particular facility, the potential thermal efficiency of a particular steam generator equipped with an economizer is largely a function of the temperature of this stream which is the combined temperature of returned condensate and makeup water. When a steam generator operates with a cold water supply temperature (for example a steam generator operating with 60°F make up water only), 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. Thermal efficiency may be limited to 85-86% when water supply temperature exceeds 200°F such as would occur when a facility recovers a significant portion of steam condensate. 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.

Use of condensing economizer designs which heat the water supply (condensate return plus make-up water) to the hotwell (or deaerator) are achieved-in-practice for larger boilers (>20 MMBtu/hr). Economizers which reduce the flue gas temperature below about 200°F are considered to be "condensing" economizers 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. When the bulk flue gas temperature is lowered below about 135 F, true bulk condensation of moisture occurs and substantial heat recovery is possible with relatively small decreases in temperature due to the recovery of the latent heat of condensation. Achieved-in-practice performance for condensing units is represented by a temperature approach (difference between the stack temperature and the incoming water supply temperature) of approximately 50 F (See Appendix B for details). However, the general application of economizers for heating water going to the hot well must consider a potential limit on the amount of heat which can be delivered to the hotwell while avoiding boiling in the hotwell. This limitation is pronounced in the case of steam generators relative to boilers because steam generators achieve only about 80 % vaporization of the water, with 20% of the water delivered to the steam generator being returned to the hotwell at saturation temperature. The thermal input to the hotwell from this water return limits the amount of heat which may be transferred to the hotwell water supply from the stack gases using a condensing economizer. The District's thermal analysis indicates that an economizer approach of 90 F may be achieved without risk of boiling in the hotwell. For reference, a steam generator with a 2nd stage condensing economizer as shown in Figure 2 and operating with a 60 F water supply could achieve a stack temperature of 150 F while heating the water supply to a temperature less than 172 F before entering the hotwell. This additional thermal input to the hotwell is sufficient to significantly reduce the input of steam to the hotwell but leave sufficient margin to accommodate the thermal load from the separator return water without boiling the hotwell.

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 steam generator operation.

Air Pre-heaters

Another way to recover heat from the steam generator 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 steam generator, improving 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.

Boiler Blowdown Heat Recovery

Blowdown refers to the continuous purging of a portion of the boiler water from the system for purposes of controlling the concentration of dissolved solids in the circulating boiler water. Since the temperature of boiler blowdown water is the same as that of the steam, energy losses associated with boiler blowdown can be significant. Conventional boiler operations may have significant losses associated with blowdown and heat recovery from this stream is an achieved-in-practice technique for improving boiler efficiency. However, in the case of steam generators the blowdown is normally a very small loss due to the high concentration of dissolved solids in the separator water from which the blowdown is taken. Due to the higher concentrations achieved, blowdown rates of 0.5 % of the steam production rate are typical which represents a thermal loss of less than 0.2% of the fuel rate to the unit. Due to the low thermal loss, heat recovery from this stream is generally not cost effective and has not been achieved-in-practice.

Limiting Excess Air and Flue Gas Recirculation

The combustion process 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 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.

Steam generators generally employ burners operating with either high excess air or high recirculation rates to meet current NO_x emissions limits. Based on this, placing limits on excess air and flue gas recirculation rates is not considered to be a feasible GHG reduction measure for steam generators.

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 2 **Technologically Feasible GHG Reduction Measures for *New Boilers with Operating Steam Pressure 75 psig and Greater, Fired Exclusively on Natural Gas or LPG***	
Reduction Measure	**Qualifications**
1. Steam generators 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.	*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.*
Economizer System Criteria A. Except for steam generators subject to the requirements of item B below, the economizer system shall be designed at maximum steam generator firing rate to either 1) reduce the temperature of the economizer flue gas outlet to a value no greater than 90 ^{o}F above the temperature of the boiler feed water or 2) heat the boiler feed water to a temperature which is no less than the saturation temperature of the steam at the pressure of the steam separator, or 3) reduce the final temperature of the boiler's flue gas to a temperature no greater than 300^{o}F . *Note: For purposes of this BPS, feedwater temperature is defined as the temperature of the water stream delivered to the steam generator from the deaerator or feedwater tank.*	*The specified criterion represents achieved-in-practice performance for economizers installed on steam generators.*
B. For steam generators with rated capacity in excess of 20 MMBtu/hr which have an average water supply temperature which is equal to or less than 150^{o}F, the steam generator shall equipped with an economizer designed to reduce the temperature of the flue gas outlet to a value no greater than 90^{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 steam generator upstream of any deaerator or other feedwater preheater.*	*The specified criterion represents achieved-in-practice performance for economizers installed on larger steam generating facilities.*

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 be operated with a variable speed control or equivalent for control of flow through the fan or pump.	*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. This measure is achieved in practice.*

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 steam generator 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 90^{o}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^{o}F approach to the feedwater temperature are achieved-in-practice for steam generating plants. Several condensing economizer operations have been identified in the

SJV including one operation with a 50°F approach to the feedwater temperature. This criterion has been relaxed to an approach of 90°F for steam generators to allow for the thermal load on the hotwell due to separator water return.

- High efficiency electric motors with variable speed drives are in widespread industrial use.

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

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

  All technologically feasible GHG reduction measures listed in Table above 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 the reduction measures.

Therefore, all technologically feasible options 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.

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:

Consistent with the approach taken for quantification of the Baseline Emission Factor, a 125 psig steam generator with a combined water supply temperature of 120°F has been assumed to represent the average new unit to be proposed in this class and category. Additionally, per manufacturer's information, most units in the San Joaquin Valley are rated at 20 MMBtu/hr or less, the representative boiler will be assumed to have a rated firing capacity of 20 MMBtu/hr.

- Consistent with manufacturer's information, the unit is equipped with surface-stabilized combustion burner operating with high excess air and no external flue gas recirculation.
- Based on operating at a current NOx limit of 9 ppmv per District Rule 4320, stack O2 concentration is assumed to be 7.2%.
- The hotwell temperature is assumed to be 210 F.
- Application of the proposed BPS to this unit results in a requirement to install a single-stage economizer with a stack temperature no greater than 90°F above the hotwell temperature or no lower than 300 F. Therefore, the stack temperature would be 300°F at the maximum firing rate.
- Unit net steam production (125 psig) is estimated at 752.8 lb-steam/MMBtu based on:
    - Stack temperature 300 F
    - Convection/radiation loss equal to 0.5% of fuel firing
    - Return water temperature (weighted average water supply to the steam generator hot well) is 120 F
    - Hotwell temperature is 210 F and vent losses are negligible.
    - The steam generator outlet stream contains 20% water which is separated in a steam separator and returned to the hotwell.
    - Blowdown is approximately 0.6 % of the total water rate to the steam generator. No blowdown heat recovery is utilized.
    - Ambient temperature is 68 F and moisture content of air is ignored.
- Based upon a unit net steam production (125 psig) of 752.8 lb-steam/MMBtu, the following quantities are applicable:
    - Specific Fuel Consumption (SFC) of 1,000,000/724.8 = 1,328 Btu/lb steam
    - Flue gas rate is 14,381 scf/MMbtu fired (inc. moisture)
    - Combustion air rate is 13,381 scf/MMBtu fired

- 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.
- The GHG emission factor for natural gas combustion is 117 lb-CO_2(e)/MMBtu per CCAR document[3].
- 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%.
- Per the assumption for the Baseline Case, flue gas side pressure drop for the burner + steam generator is assumed to be 20 inches water column when operating without FGR with a flue gas rate of 12,886 scf/MMBtu (12 "WC for burner, 8 "WC for boiler).
- An allowance for additional dynamic loss in the boiler due to a higher flue gas rate will be added which is assumed to be proportional to the square of the mass flow (burner pressure drop is assumed to remain identical to the Baseline Case). For the BPS case with a flue gas rate of 14,381 scf/MMBtu, flow through the boiler is estimated as:

Burner	12.0 " WC
Boiler 8" WC x $(14{,}381/12{,}886)^2$ =	10.0
Total	22.0

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

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

SFC = Specific Fuel Consumption = 1,328 Btu/1000 lb steam (as stated in basis)

Direct emissions are then calculated as:

GHG_D = 117 lb-$CO_{2(e)}$/MMBtu x 1.328 MMBtu/1000 lb steam
= 155.4 lb/1000 lb steam

<u>Indirect Emissions</u>

Indirect emissions produced from operation of the electric motor on the combustion air fan 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[4]:

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

T	=	air temperature, ^oR = 68 + 460 = 528 ^oR
M	=	scf combustion air (per 1000 lb steam)
M	=	(13,381 scf air/MMbtu) x 1.328 MMBtu/1000 lb steam = 17,770 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 + 22.0 = 429.0 "WC

Substituting the given values into the equation:

Bhp-hr/1000 lb steam = 1.71

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

Combustion air fan specific energy consumption	=	(1-30%) x 1.71

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

Combustion air fan specific energy consumption = 1.20 Bhp-hr/1000 lb steam

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

= (1.20 x 0.7457)/95% = 0.94 kWh/1000 lb steam

GHG (electric motors) = 0.524 lb- $CO_{2(e)}$/kWh x 0.94 kWh/1000 lb steam
= 0.49 lb $CO_{2(e)}$ per 1000 lb steam production

= 0.49 ~ 0.5 lb $CO_{2(e)}$ per 1000 lb steam production

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

BEF = *155.4 + 0.5 = 155.9 lb-* CO_2(e)*/1000 lb steam production*

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

G_p = (BEF - G_a) / BEF = (162.8 – 155.9)/162.8 = 4.2%

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:

<u>Best Performance Standard for New Boilers with Operating Steam Pressure 75 psig and Greater, Fired Exclusively on Natural Gas or LPG</u>

Steam generators meeting this Best Performance Standard must comply with both elements of this BPS (items 1 and 2 listed below) where applicable:

1. ***The steam generator shall be either equipped with an economizer system meeting the following design criteria <u>or</u> 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.***

   A. ***Except for steam generators subject to the requirements of item B below, the economizer system shall be designed at maximum steam generator firing rate to either 1) reduce the temperature of the economizer flue gas outlet to a value no greater than 90 ^{o}F above the temperature of the boiler feed water or 2) heat the boiler feed water to a temperature which is no less than the saturation temperature of the steam at the pressure of the steam separator, or 3) reduce the final temperature of the boiler's flue gas to a temperature no greater than 300^{o}F .***

      Note: For purposes of this BPS, feedwater temperature is defined as the temperature of the water stream delivered to the steam generator from the deaerator or feedwater tank.

   B. ***For steam generators 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 steam generator shall equipped with an economizer designed to reduce the temperature of the flue gas outlet to a value no greater than 90^{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 steam generator upstream of any deaerator or other feedwater preheater.

AND

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.***

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

The following Achieved-in-Practice GHG control measures, identified in Step 4 and ranked in Step 5 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 Step 6:

No other Achieved-in-Practice options were identified.

VI. Appendices

Appendix A:	Steam Generator Illustrations
	Figure 1: Steam Generator w/o Economizer
	Figure 2: Steam Generator w/ Economizer
Appendix B:	Achieved-in-Practice Analysis for Use of Economizers
Appendix C:	Public Notice of Intent

Appendix A
Steam Generator Illustrations

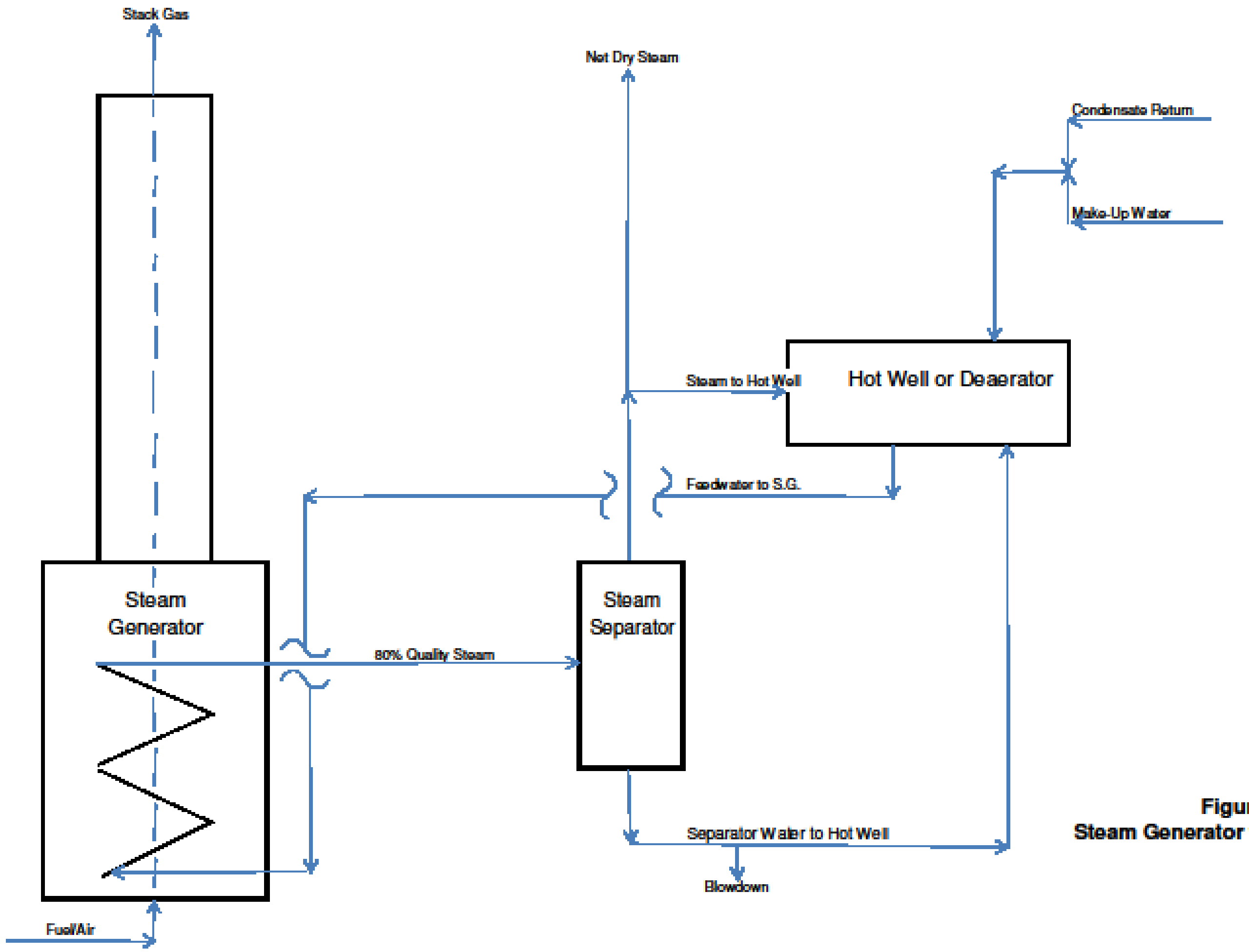

Figure 1
Steam Generator w/o Economizer

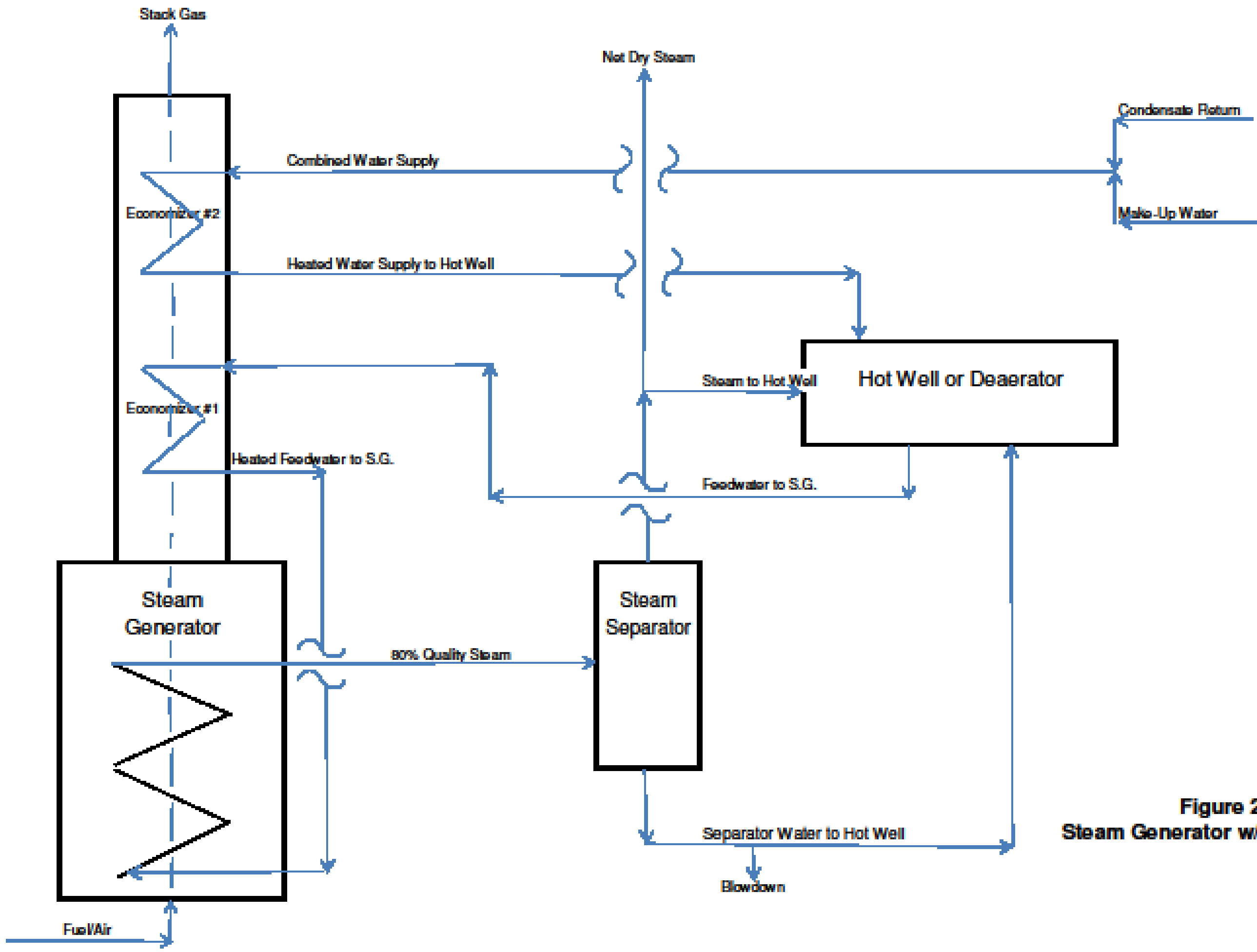

Figure 2
Steam Generator w/Economizer

Appendix B
Achieved-in-Practice Analysis for Use of Economizers

Achieved-in-Practice Summary for Use of Economizers

The use of an economizer or equivalent is proposed as a measure for reduction of GHG emissions from steam generators. The proposed measure consists of two discrete elements:

1. Installation of a single stage economizer or equivalent as a minimum requirement for all units. Proposed criteria for the economizer standard require that it be designed to either recover sufficient heat from the flue gas to reduce the flue gas temperature to a value no greater than 90 F above the feedwater temperature to the economizer or to reduce the stack temperature to 300F. Regardless of stack temperature, heat recovery in excess of that which would increase the temperature of the feedwater to the saturation temperature at the operating pressure of the boiler is not required since this would not represent economizer performance (boiling service).
2. For units with rated capacity above 20 MMBtu/hr and a water supply temperature below 150 F, The economizer system must recover sufficient heat from the flue gas to reduce the flue gas temperature to a value no greater than 90 F above the water supply temperature.

For element #1, Table B-1 presents manufacturer's actual performance test data for identified steam generators in the District equipped with single stage economizers and while firing at 100% of design capacity. Note that all have stack temperatures below 300 F and that 3 of the 5 units identified have economizer approach temperatures less than 90 F. In addition, standard estimated performance provided by Clayton Industries for steam generators in the range of approx. 5.0 to 8.3 MMBtu/hr indicates that a stack temperature of 300 F is expected when the unit is equipped with the largest economizer which has been installed on such units historically given a hotwell temperature of 210 F (90 F approach). Based on this, element #1 of the control measure listed above may be considered to be Achieved-in-Practice.

Table B-1
Manufacturer's Shop Test Performance at 100% Firing Rate for Steam Generators Equipped with 1st Stage Economizer

Facility	District Permit	Rated Capacity MMBtu/hour	Hotwell Temperature F	Stack Temperature F	Economizer Approach F
Penny Newman	N-227-39-0	7.971	210	298	88
Duraflame	N-150-21-0	6.3	200	264	64
Kozy Shack	N-7946-1-0	8.3	170	279	109
	N-7946-2-0	8.3	150	242	92
Barrel Ten	N-398-6-0	9.845	184	269	85

With respect to element #2 above, no steam generators have been identified which are equipped with a 2nd-stage condensing economizer. However, use of a 2nd-stage condensing economizer has been established by the District as BPS[5] for conventional boilers that are rated over 20 MMBtu/hour and which have a water supply temperature less than 150 F with a criterion that the flue gas temperature leaving the economizer be no higher than 50 F over the temperature of the water supply temperature to the hotwell or deaerator. From a mechanical perspective, the application of such an economizer to a steam generator is essentially identical to that on a boiler and therefore the District believes that the identified boiler applications qualify such economizers as Achieved-in-Practice for steam generators as well. Table B-2 presents design performance for three identified boilers in the District which feature a second stage condensing economizer.

Table B-2
Facilities Demonstrating 2nd Stage Condensing Economizers As Achieved-in-Practice

Facility	District Permit	Fired Duty MMBtu/hr	1st Stage Approach oF	2nd Stage Approach oF	Stack Temperature oF	Operation Since
Del Monte Foods	N-1626-8-1	59	50	50	110	2007
Styrotek	S-1075-3-9	16.3	105 (est)	108	178	March, 2010
Mars PetCare	N/A (SCAQMD)	23.5	69 (est)	125	180	March, 2010

[5] See District's BPS: *New Boilers with Operating Steam Pressure 75 psig and Greater, Fired Exclusively on Natural Gas or LPG*

As mentioned previously, one of the differentiators between steam generators and boilers is that steam generators must return a substantial amount of un-vaporized high temperature water to the hotwell whereas conventional boilers vaporize essentially all the water delivered, return nothing to the hotwell and all feedwater heating is done by adding steam to the hotwell. To avoid boiling in the hotwell, the extra thermal load delivered to the hotwell by a steam generator restricts the amount of recovered heat which can be absorbed by the hotwell relative to a conventional boiler. Therefore the design criterion for the economizer must be modified in the case of a steam generator to ensure that the hotwell remains in thermal balance. The District's thermal analysis indicates that requiring no more than a 90 F approach (consistent with the Achieved-in-Practice criteria for the 1st stage) to the water supply temperature will sufficiently limit the required heat recovery so that thermal balance will be maintained for the hotwell.

Appendix C
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 the development of Best Performance Standards for the following Stationary Source class and category of greenhouse gas emissions:

Industrial Steam Generators

Industrial steam generators are a category of the class "Steam Generators" and are used to provide steam to industrial operations, similar to boilers. Steam generators differ from boilers in that the water flow through the system is "once-through" and there is no steam drum. Only about 75% of the water charged is actually vaporized (versus almost 100% for conventional steam boilers) and an external separator is typically employed outside the unit to separate the water from the steam.

The District is soliciting public input on the following topics for this class and category of greenhouse gas emission source:

- Recommendations regarding process 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.
- Recommendations regarding technologies to be evaluated by the District when establishing control measures applicable to direct sources of greenhouse gas emissions.
- Recommendations regarding technologies to be evaluated by the District when establishing control measures applicable to indirect sources of greenhouse gas emissions.

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 SJVAPCD, 1990 E Gettysburg Ave, Fresno, CA 92726-0244. All comments must be received by 5:00 p.m. on **April 27, 2012**. For additional information, please contact Dennis Roberts by e-mail or by phone at (559) 230-5919.

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.