Final Report

Greenhouse Gas Mitigation: Landfill Gas and Industrial, Institutional and Commercial Boilers, Steam Generators and Process Heaters

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Acronyms

ABMA	American Boiler Manufacturers Association
BAAQMD	Bay Area Air Quality Management District
BACT	Best Available Control Technology
BARCT	Best Available Retrofit Control Technology
CARB	California Air Resources Board
CH_4	methane
CHP	combined heat and power
CIWMB	California Integrated Waste Management Board
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon-dioxide equivalent
CPTR	cost incurred per metric ton of reduced CO_2e
EPA	U.S. Environmental Protection Agency
FGR	flue gas recirculation
GCCS	gas collection and control system
GHG	greenhouse gas
HAP	hazardous air pollutant
ICI	Industrial/Commercial/Institutional
H_2	hydrogen
H_2S	hydrogen sulfide
LEA	low excess air
LFG	landfill gas
LFGTE	landfill gas-to-energy
LMOP	Landfill Methane Outreach Program
LNB	Low NOx Burner
MMBTU	Million British Thermal Unit
NH_3	Ammonia
NO_x	nitrogen oxides
N_2	nitrogen
N_2O	nitrous oxide
NMOC	non-methane organic compounds

NPVPP	net present value payback period
O_2	oxygen
PPMV	parts per million by volume
SO_x	sulfur oxides
SCR	selective catalytic reduction
TPY	tons per year
VOC	volatile organic compound
Vol%	volumetric percentage
YCCP	Yolo County Central Landfill

In March 2007, the Bay Area Air Quality Management District (BAAQMD) completed a region-wide study to identify and evaluate potential further opportunities to reduce greenhouse gas (GHG) emissions at stationary sources currently subject to the District's permitting requirements (URS, 2007). The overall goals of that study were as follows:

- Identify the most significant industries and subsequent source categories contributing to GHG emissions.
- Identify potential mitigation options for controlling the GHG emissions.
- Evaluate the effectiveness, costs, and impacts of each of the most promising options.

This report pursues further study of two source categories from the previous study:

- Landfills;
- Industrial, institutional, and commercial boilers, steam generators, and process heaters.

For the aforementioned source categories, estimates of potential GHG emissions are provided, potential GHG mitigation technologies are identified, capital and operating costs for the technologies are estimated, and the economic effectiveness of the technologies are reported.

This report is divided into two parts. Part 1 presents the landfill gas mitigation portion of the study. Part 2 presents the industrial, institutional, and commercial boilers; steam generators; and process heaters portion of the study.

Landfill Gas Mitigation

The major landfills in the Bay Area have for the most part already taken the important first steps in greenhouse gas (GHG) mitigation by capturing and flaring landfill gas (LFG). With the exception of old landfills, small solid waste disposal sites, and low emission landfills, LFG emissions are generally controlled by gas collection systems, flaring, or in limited cases, through gas and energy recovery systems. Progress in LFG to energy (LFGTE) could be an important next step in GHG reduction as the energy produced could lead indirectly to reduction of GHG emissions from the electrical generation utilities.

For landfills that are exempt from gas collection and control requirements, biotic control technology has the potential to oxidize the methane (CH_4) released through the permeable cover into carbon dioxide (CO_2), which has a lower global warming potential.

The actual performance of each LFG mitigation measure depends on the characteristics of the landfill. Based on the cost effectiveness, criteria pollutant trade-offs, and landfill characteristics, the types of GHG mitigation measures that are potentially applicable to Bay Area landfills can be summarized as follows.

Mitigation Measure	Cost	Comments
LFG Collection System Improvement (landfill cover improvement)	Cost and performance varies depending on the type of cover material	▪ Applicable for all landfills and many are already collecting LFG. ▪ Reduces hot spots and improves gas collection efficiency (for landfill with gas collection system).

Mitigation Measure	Cost	Comments
Flare	\$6 to \$25/ton of CO_2e reduced (for 3-acre to 40-acre landfill cases)	▪ Applicable for almost all landfills and many already are flaring. ▪ Low capital and maintenance cost. ▪ Provides high methane destruction levels. ▪ Emits secondary criteria pollutant emissions. ▪ No revenue.
Landfill Gas to Energy (conventional landfill)	Potential revenue range of income of \$24/ton of CO_2e reduced to a cost of \$51/ton of CO_2e reduced. (40-acre high density landfill with microturbine and no siloxane treatment v. with siloxane treatment)	▪ Economically feasible for larger landfill with a high waste compaction density (require site-specific feasibility assessment prior to installation). ▪ Potential to generate revenue through electricity generation or heat recovery. ▪ Reduced electricity generation by the utilities would indirectly lead to additional GHG emission reductions. ▪ Siloxane treatment issue that may negatively affect the operation cost. ▪ Emits secondary criteria pollutant emissions.
Landfill Gas to Energy (bioreactor landfill)	Potential revenue range of income of \$50/ton of CO_2e reduced to a cost of \$81/ton of CO_2e reduced. (40-acre high density landfill with microturbine and no siloxane treatment v. 40-acre high density landfill with combined heat and power turbine with siloxane treatment)	▪ Reduced electricity generation by the utilities would indirectly lead to additional GHG emission reductions. ▪ Higher LFG generation than non-bioreactor landfills. ▪ Sensitive to landfill characteristics. ▪ Higher operation cost for monitoring system. ▪ Higher siloxane treatment cost due to higher LFG generation rate. ▪ Emits secondary criteria pollutant emissions.
Biotic Control Technology	\$745/ton of CO_2e	▪ Applicable for all landfills, including the uncontrolled and old landfills. ▪ No extensive retrofit. ▪ Low secondary criteria pollutant emissions. ▪ Expensive. ▪ Still under demonstration phase.

Boiler GHG Mitigation

Boiler efficiency improvements are the best method to reduce GHG emissions from boiler systems. Boiler efficiency optimization is already in use in the Bay Area because of the high cost of fuel. Additional efficiency improvements potentially applicable include: maintaining optimum combustion efficiency, reducing the difference between the fuel gas temperature and the combustion air temperature, recovering waste heat from blowdown, and reducing heat loss in distribution. Use of alternative renewable fuels for indirect GHG emissions mitigation is limited for boilers in the Bay Area as a practical matter because virtually all are fired on natural gas and alternative fuels available today are mostly liquids.

The actual performance of each boiler efficiency measure depends on the characteristics of the boiler. The following table summarizes the available technologies that have a potential to reduce boiler GHG emission through boiler efficiency improvements and heat loss reductions.

GHG Reduction Approach	Available Technology
Excess Air Optimization	Low NOx burner, Low Excess Air control system, and FGR
Boiler Heat Transfer Improvement	FGR and Turbulator
Stack Gas Heat Recovery	Economizer, Air Preheater
Mineral Deposit Reduction	Blowdown control, Water Pretreatment, and Boiler Tuning
Steam Distribution Loss Reduction	Pipe Insulation and Steam Trap Maintenance

All mitigation measures summarized above have the potential to reduce GHG emissions from the corresponding sources. However, not all of the recommended mitigation measures are applicable to all cases. Due to the diverse nature of these sources and their individual specific characteristics, it is important to consider all aspects related to the modification prior to the actual implementation to avoid incompatibility. It is recommended that a thorough case-specific assessment be performed prior to implementing the assessed mitigation measures for these sources to ensure the compatibility, performance, and safety of the selected mitigation measure.

Part 1

Landfill Gas Methane Reduction

Methane (CH_4) is a greenhouse gas (GHG) that is a major contributor to atmospheric warming, second only to carbon dioxide (CO_2) in worldwide emissions. CH_4 has a heating potential that is 21 times higher than that of CO_2. Over the last century, the concentration of CH_4 in the earth's atmosphere has doubled. This increase is primarily attributed to human activities.

Landfills are one of the largest sources of U.S. anthropogenic CH_4 emissions. Landfilling is considered the primary method for disposal of solid waste or other refuse in the United States. In the past 5 years, an average of 6.8 million tons of waste was deposited annually in landfills across the Bay Area (California Integrated Waste Management Board [CIWMB] website). Landfills emit a mixture of gaseous products to the atmosphere, known collectively as landfill gas (LFG). LFG is primarily generated through the anaerobic decomposition of organic municipal waste, as opposed to inorganic waste. Typically, CH_4 accounts for approximately 50 percent of the total LFG composition.

Fugitive emissions of LFG are a concern to public health and the environment because they contain CH_4 (which is highly combustible), hazardous air pollutant (HAPs), and volatile organic compounds (VOCs). The term "LFG fugitive emission" refers to the portion of LFG that is not captured by gas collection and/or control systems. LFG fugitive emissions are the focus of this report. The main sources of LFG fugitive emissions are emissions from hot spots (i.e., areas with high concentrations) and inefficient control systems. Because CH_4 accounts for approximately half of the LFG volumetric composition, mitigating LFG emissions can be an effective strategy for reducing GHG emissions.

1.1 REPORT OVERVIEW

This report discusses the feasibility of reducing GHG emissions from landfills, with a specific focus on reducing CH_4 from LFG emissions through the application of mitigation measures. The mitigation measures discussed in this report include gas collection improvement; flare; energy recovery systems for conventional and bioreactor landfills; waste segregation; and biotic control technologies. This report also discusses the advantages and disadvantages of each mitigation measure, along with available cost-benefit estimates. The structure of this report is arranged as follows:

Section 2 provides a discussion of CH_4 generation in landfills and a discussion of the existing conditions in the Bay Area. Section 2 also includes an analysis of the most current Bay Area GHG inventory and an analysis of the existing air regulations from the Bay Area Air Quality Management District (BAAQMD).

Section 3 provides an analysis of the aforementioned mitigation measures, including their applicability toward various landfills in the Bay Area.

Section 4 provides an economic analysis for each mitigation measure. The analysis is based on EPA's cost estimating software for landfills, called LFG-Cost.

Section 5 provides a summary of the results based on the discussions in previous sections and provides recommendations for mitigation measures applicable to reducing the GHG emissions, specifically CH_4 in LFG.

2.1 METHANE GENERATION IN LFG

A landfill is an engineered burial of municipal solid wastes, which are subsequently degraded by chemical reactions and biological activities within the landfill cells. LFG production and CH_4 concentrations in LFG vary greatly for individual landfills, depending on site-specific characteristics such as age, moisture content, waste in place, waste composition (percent of organic materials), and regional climate.

As the LFG begins to occupy a larger volume than the waste, the pressure within the landfill cell starts to buildup. LFG escapes from the landfill cell through the permeable portion of the landfill cap/cover (escapes from hot spots) or through the gas collection system, which may be active or passive. When LFG escapes through the permeable cover, certain bacteria (naturally contained in the soil of the permeable cover) can oxidize approximately 10 percent of the CH_4 contained in the LFG. The remaining 90 percent is released as a fugitive emission. The bacteria possess a CH_4 mono-oxygenase enzyme that enables them to use CH_4 as an energy and carbon source. These bacteria oxidize CH_4 into water, CO_2, and biomass.

The decomposition of solid waste generates LFG, which is primarily CO_2, CH_4, and traces of other compounds. The approximate composition of LFG (in volumetric percentage [vol%]) is:

- CH_4 – 50 vol% typical with a range from 45 to 60 vol%
- CO_2 – 45 vol% typical with a range from 40 to 60 vol%
- Nitrogen (N_2) – 5 vol% typical with a range from 2 to 5 vol%
- Trace quantities of other gaseous elements such as oxygen (O_2), ammonia (NH_3), hydrogen (H_2), sulfur compounds (mainly hydrogen sulfide, H_2S), aromatic organics, chlorinated solvents, alcohols, and other mixed hydrocarbons.

2.2 WASTE DECOMPOSITION CYCLE AND LFG COMPOSITION CHANGES

The decomposition process of solid waste can be described in four decomposition phases. Each individual decomposition phase is explained below.

Phase I

Aerobic bacteria, which feed off of the oxygen present in waste, slowly degrade the long molecular chains of complex carbohydrates, proteins, and lipids that comprise organic waste. The duration of this decomposition phase depends on the oxygen level present in the waste, which varies with the density of the waste material. Phase I is termed aerobic decomposition; the primary byproduct of this phase is CO_2.

Phase II

Once all the oxygen present in the waste is completely consumed, anaerobic bacteria begin to grow. Anaerobic bacteria convert compounds created by aerobic bacteria into simpler molecules such as acids (i.e. acetic, lactic, and formic acid) and alcohols (i.e., methanol and ethanol). Phase II is the first step in anaerobic decomposition, with CO_2 and H_2 as its primary byproducts.

Phase III

In the third decomposition phase (second step in anaerobic decomposition), specific anaerobic bacteria consume organic acids produced in Phase II and form acetate (an organic acid). This process creates a more pH-neutral environment, in which CH_4-producing bacteria (methanogenic) begin to establish themselves. CH_4-and acid-producing bacteria have a symbiotic relationship in which acid-producing bacteria create compounds for the methanogenic bacteria to consume. Phase III is the second step in anaerobic decomposition, with CH_4 and CO_2 as its primary byproducts.

Phase IV

In the final phase of the decomposition process, both the composition and the production rate of LFG remain relatively constant. Landfills typically produce LFG for approximately 20 years. However, LFG can continue to be emitted for 50 or more years after the waste is placed in the landfill (Crawford and Smith, 1985).

Each of the phases just described alter the composition of LFG. Figure 1 shows the percent volumes of the major LFG components during each phase of the decomposition process.

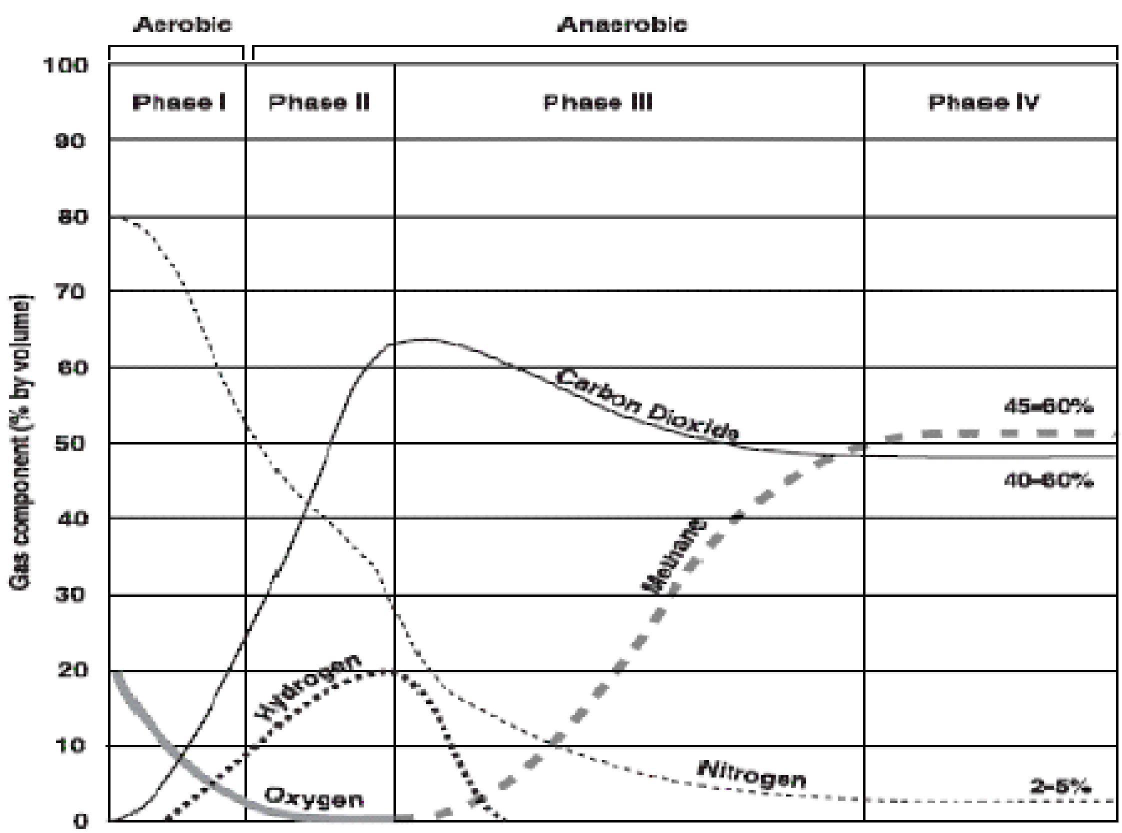

Figure 1 Composition of LFG throughout Decomposition Phases

Source: Basics of Landfill Gas, Appendix A <http://www.mass.gov/dep/recycle/laws/lfgasapp.pdf>

2.3 BAY AREA GREENHOUSE GAS EMISSION INVENTORY

CH_4 emissions from various sources accounted for 4.5 percent of the Bay Area's total carbon dioxide equivalent (CO_2e) emissions in 2002 (BAAQMD, 2006). CO_2e represents CO_2 emissions plus the equivalent warming potential of other GHG, including CH_4 and nitrous oxide (N_2O). These emissions are primarily attributed to landfills, natural gas distribution systems, agricultural activities, and fuel combustion. In 2002, 85.4 million tons of CO_2e were emitted in the Bay Area (BAAQMD, 2006). Bay Area CO_2e emissions by pollutant type and source category emissions related to waste management are shown in Table 1, Table 2, and Figure 2.

Table 1 2002 Bay Area CO_2e Emissions by Pollutant

Pollutant	CO_2e Emissions (million TPY)	Percentage
CO_2	76.79	89.90%
N_2O	4.26	5.00%
HFC, PFC, SF6	0.51	0.60%
CH_4	3.83	4.50%
Total CO_2e	85.39	100.00%

Note:
All pollutants are shown as CO_2e. For example, CH_4 has 21 times the warming potential of CO_2. To show CO_2e, CH_4 mass emissions (as shown in Table 2) are multiplied by 21 to show their CO_2e warming potential. Similar factors have been applied to all pollutants (CCAR, 2007).

Table 2 2002 Bay Area CH_4 Emissions by Source Category

Source Category	CH_4 Emissions (TPY)	Percentage
Waste Management	125,673	68.90%
Landfill Gas Combustion	3,208	1.76%
Others	53,506	29.34%
Total	**182,387**	**100.00%**

Note:
Emissions from waste management category include waste water management GHG emissions in addition to landfill emissions (BAAQMD, 2006).

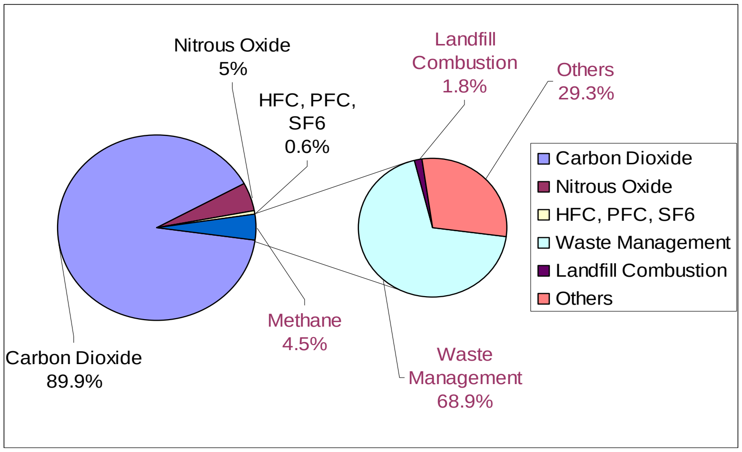

Figure 2 2002 Bay Area GHG Emissions Breakdown

2.4 EXISTING LANDFILLS

BAAQMD records show that there are currently 18 active landfill waste disposal sites permitted in the Bay Area. Among these 18 active landfill sites, 14 are major landfills that have Major Facility (Title V) permits. In addition to the active landfill sites, there are 16 inactive/closed landfill disposal sites that have active landfill gas collection systems vented to flares or other combustion devices. Four out of the 16 inactive/closed sites are major landfills that have Title V permits. Specific information regarding the permitted active landfills, inactive landfills, and landfills with passive gas collection systems in Bay Area is presented in Tables 3, 4, and 5.

As shown in Table 3 and 4, most of these landfills have active gas collection systems and flares installed to comply with BAAQMD Regulation 8, Rule 34: Solid Waste Disposal Sites. Larger landfills that have more than one million tons of waste in place and only use enclosed flares as a control system are good candidates for landfill gas-to-energy (LFGTE) projects. The potential and candidate landfills listed in Tables 3 and 4 are prospective landfills for LFGTE projects. LFGTE projects have achievable incentives, including investment return and indirect reduction of GHG emission from avoided electricity generation. These landfills might have a sufficient LFG generation rate to sustain an energy project and generate revenue or decrease the electricity costs for the landfill operations. The waste compaction density categories in Tables 3 and 4 are presented to allow comparison of the economics of LFGTE projects. Cost comparisons are further discussed in Section 4.1.

For the smaller landfills listed in Tables 3 and 4, continuing to use an active gas collection system accompanied by an enclosed flare system might be more economically feasible than developing an LFGTE project. However, these landfills can still improve their methane capture by improving the gas collection efficiency and reducing hot spots. Several control technologies that offer these improvements are further discussed in Sections 3.1 and 3.6.

In addition to the controlled landfills in Bay Area, there are some landfills that only have passive gas collection or no gas collection at all. These landfills are usually small and closed landfills or landfills that have a very low decomposable organic fraction in their waste. These landfills with no active gas collection systems are good candidates for installation of an active gas collection system and flare control system or for application of biotic control technology.

Table 3 Active Landfills in Bay Area

Landfill Name	City	Waste In Place As of 12-31-2006 (tons)	LFGTE Project Status	Density	LFGTE Project Type or Existing Control Measure	2006 Average LFG Collection Rate (SCFM)
*Altamont SLF	Livermore	40,100,000	Operational	Medium	Gas Turbines, Reciprocating Engines, Enclosed Flare, ATC issued for alternative fuel process	3,444
*Tri-Cities Landfill	Fremont	11,700,000	Candidate	Medium	Enclosed Flare	1,582
*Vasco Road SLF	Livermore	17,000,000	Candidate	Medium	Enclosed Flare	1,636
*Acme LF	Martinez	11,100,000	Operational	Medium	Boiler, Sludge Furnace, Gas Turbine/Cogeneration, Micro turbines, Enclosed Flare	842
*West Contra Costa LF	Richmond	12,300,000	Operational	Low	Reciprocating Engines, Enclosed Flares	229
*Keller Canyon LF	Pittsburg	9,610,000	Construction	High	Enclosed Flares, ATC issued for Reciprocating Engines	907
*Redwood SLF	Novato	12,500,000	Candidate	Medium	Enclosed Flares (Leachate Evaporation Source has been removed)	2,664
*Ox Mountain SLF	Half Moon Bay	19,000,000	Construction	High	Enclosed Flares, CEQA underway for Reciprocating Engines	3,291
*Hillside Solid Waste Disposal Site	Colma	4,280,000	Candidate	Low[a]	Enclosed Flare	569
*Guadalupe Sanitary Landfill	San Jose	8,550,000	Operational	High	Reciprocating Engines, Enclosed Flare	919
*Newby Island SLF Phase I, II, & III	Milpitas	25,700,000	Operational	High	Reciprocating Engines, Enclosed Flare	1,832
*Palo Alto LF	Palo Alto	4,670,000	Candidate	Low	Enclosed Flare, (off-site engines were shut down in 2005)	207
*Kirby Canyon Recycling & Disposal Facility	Morgan Hill	5,150,000	Candidate	Low	Enclosed Flare	1,317
Pacheco Pass SLF (South Valley Refuse)	Gilroy	2,250,000	Candidate	Medium	Enclosed Flare	532
*Potrero Hills SLF	Suisun City	8,220,000	Candidate	N/A	Enclosed Flare	699
Clover Flat Landfill	Calistoga	1,100,000	Candidate	Low	Enclosed Flare	92
Zanker Road (Nine Par) SLF	San Jose	1,820,000 (only 10% decomposable)	Potential	Low	No Gas Collection	
Zanker Road (Nine Par) SLF 2	San Jose	619,000 (only 1% decomposable)	Potential	Low	No Gas Collection	

Table 4 Inactive/Closed Landfills in Bay Area

Landfill Name	City	Waste In Place As of 12-31-2006 (tons)	LFGTE Project Status	Density	LFGTE Project Type or Existing Control Measure	2006 Average LFG Collection Rate (SCFM)
*Shoreline LF at Mountain View	Mountain View	12,700,000	Operational,	Low[a]	Micro turbine , Reciprocating Engines , and Enclosed Flares	1,518
*City of Santa Clara LF	Santa Clara	5,500,000	Operational-	N/A	Reciprocating Engines, Enclosed Flare	508
*American Canyon SLF	Napa	4,230,000	Operational	Low[a]	Reciprocating Engines, Enclosed Flare	587
Davis Street LF	San Leandro	5,700,000	Candidate	N/A	Enclosed Flare, off-site boilers are still permitted to accept LFG but are not in operation.	562
Marsh Road LF	Menlo Park	5,000,000	Operational	N/A	Reciprocating Engines, Enclosed Flare	628
Metro Bay Centre Landfill (Home Depot)	Colma	900,000	Potential	Low[a]	Enclosed Flare, intermittently operated	13
Central Contra Costa SLF	Antioch	3,830,000	Operational		Enclosed Flare	229
Sunnyvale Landfill	Sunnyvale	2,520,000	Operational (adjacent to WWTP)		Reciprocating Engines, Enclosed Flare	436
Turk Island Landfill	Union City	1,256,000	Candidate		Enclosed Flare	253
Pleasanton Garbage Service	Pleasanton	210,000	Potential		Enclosed Flare	44
Berkeley Landfill	Berkeley	1,690,000	Candidate		Enclosed Flare	163
Burlingame Refuse Disposal Area	Burlingame	1,200,000	Candidate		Enclosed Flare	62
Singleton Rd DS/San Jose Municipal DS	San Jose	1,025,000	Candidate		Enclosed Flare	284
Sunquest Properties (Brisbane Landfill)	Brisbane	5,600,000	Candidate		Enclosed Flare	35

Table 4 Inactive/Closed Landfills in Bay Area

Landfill Name	City	Waste In Place As of 12-31-2006 (tons)	LFGTE Project Status	Density	LFGTE Project Type or Existing Control Measure	2006 Average LFG Collection Rate (SCFM)
Doolittle Landfill	Alameda	1,040,000	Candidate	N/A	Enclosed Flare	108
*Central Disposal Site (Sonoma) Phases I, II, & III	Petaluma	13,800,000	Operational / (AF is under Construction)	N/A	Reciprocating Engines, Alternative Fuel, Enclosed Flare	2,473

Notes:
Candidate - A landfill that is accepting waste or has been closed for 5 years or less, has at least 1 million tons of waste, and does not have an operational LFGTE project (or an LFGTE project that is under construction); or is designated based on actual interest or planning
Potential - A landfill that does not meet the candidate definition, whether because of complete or incomplete data. However, the landfill could have LFGTE project potential based on site-specific factors or could have LFGTE project potential if complete data were available
*Major Landfill – A landfill that holds a major facility permit under BAAQMD Regulations
Landfill Density (tons/acre):

- < 70,000 tons/acre: Low waste compaction density
- From 70,000 to 120,000 tons/acre: Medium waste compaction density
- > 120,000 tons/acre: High waste compaction density
- N/A: Not available due to data limitations

[a] Due to data limitations, the landfill is assumed to be 50 feet deep, and the density is calculated based on maximum volumetric design capacity.

Table 5 Landfills in Bay Area with Passive Gas Collection System

Landfill Name	City	Waste In Place As of 12-31-2006 (tons)	LFGTE Project Type or Existing Control Measure
San Quentin Disposal Site	San Rafael	342,000	Passive Gas Collection System
Horst Hanf Landfill/Bay View Park	San Rafael	163,350	Passive Gas Collection System
Hamilton AFB Landfill	Novato	~ 500,000	Passive Gas Collection System

2.5 CURRENT REGULATIONS

According to specific conditions stated in the general section of BAAQMD's Regulation 8-34: Solid Waste Disposal Sites, there are limited exemptions available for certain categories of landfills. These limited exemptions excuse certain landfills from regulations according to specific conditions stated in the general section of Regulation 8-34. Based on the current regulation, the general requirements for limited exemptions for landfills are categorized as shown in Table 6.

Table 6 BAAQMD Limited Exemption Categories

Landfill Limited Exemption Categories	Gas Collection Requirements (8-34-301)	Surface Requirements (8-34-303)	Wellhead Requirements (8-34-305)	Notes:
Old Landfills (8-34-110)	Exempt	Exempt	Exempt	No Control
Small Solid Waste Disposal Sites (8-34-111)	Exempt	Exempt	Exempt	No Control
Inactive or Closed Landfills (8-34-119)	Non-Exempt	Non-Exempt	Exempt	Active Collection and flaring but exempt from surface monitoring and annual testing
Small Design Capacity Landfills (8-34-120)	Non-Exempt	Non-Exempt	Exempt	Active Collection and flaring but exempt from surface monitoring and annual testing
Low Emission Landfills (8-34-121)	Exempt	Exempt	Exempt	No Control

Landfills that fall under the categories listed above have less stringent control or monitoring requirements. These landfills could therefore use additional control and monitoring measures to reduce their GHG emissions. Retrofit control technologies, such as additional biotic alternative cover and biofiltration beds for passive gas collection, can be applied to these exempt landfills. These mitigation measures are further discussed in the next section.

In addition to the BAAQMD Regulation, there are also federal New Source Performance Standards (NSPS 40 CFR, Part 60 Subpart WWW), federal Emission Guidelines (40 CFR, Part 60 Subpart CC), and Maximum Achievable Control Technology standards for Municipal Solid Waste Landfills (40 CFR 63, Subpart AAAA) that regulate landfill operations in the Bay Area. Despite the application of all the aforementioned regulations, landfills continue to emit substantial quantities of CH_4. Landfill CH_4 emissions are primarily generated from:

- Emissions prior to the implementation of control systems (under current federal rules control systems may not be required to be implemented for up to 5 years, but BAAQMD requires controls when an area or cell adds 1,000,000 tons of waste, which often occurs well before 2 years for the larger active sites)

- Gas collection and control technology's inefficiency during operation
- Long-term emissions that may occur after control (gas collection system) termination
- Emissions from exempt landfills that have less stringent control requirements

To further reduce GHG emissions, existing (or new) regulations must be revised to target fugitive GHG emissions from the sources identified above. The following section of this report discusses methods for addressing some of the issues just identified. However, regulatory issues such as control system requirement dates, long-term emission control durations (time period of LFG gas control system required after landfill closing), and more stringent regulations for limited exemption landfills need to be refined to optimize the mitigation measure applications that are discussed in this report.

To reduce GHG emissions under The Global Warming Solutions Act (AB 32), the California Air Resources Board (CARB) approved a list of early action measures that can be adopted and implemented by January 1, 2010. The early action measures include the strategies to improve methane capture from municipal solid waste landfills. CARB is currently collaborating with CIWMB on the development of draft control measure regulations to improve the capture of methane from landfills by adding more stringent requirements on landfill control systems. Based on the draft regulatory language for ARB's landfill methane control measure (CARB, 2008), the new requirements on landfill control systems are presented as follows:

- Require the installation of gas collection and control systems (GCCS) for smaller landfills that are exempt from control requirements, as low as 400,000 tons in place (unless the conditions for limited exemption are satisfied)
- Require higher methane capture efficiencies (no component leaks that exceed 200 ppmv, measured as methane)
- Require a GCCS operation period of at least 15 years after landfill closing
- Require an increase in energy recovery from landfill methane
- Require an enclosed ground flare as the only approved flare type for landfills
- Require a specific methane destruction efficiency for control devices (at least 99 % by weight for flare)
- Require quarterly (or monthly) monitoring to ensure proper operation of the GCCS
- Require 25-foot intervals of walking pattern as landfill methane surface monitoring procedure

Because the draft regulations described above are still under development, the information necessary to perform cost analysis on the basis of these draft regulations is currently unavailable. Therefore, all the economic analyses in this report are based on the current applicable regulations.

With the exception of old landfills, small solid waste disposal sites, and low emission landfills, CH_4 emissions from landfills are generally controlled by gas collection systems, flaring, or through gas and energy recovery systems. Per Regulation 8-34-301, non-exempt landfills are required to implement GCCS in order to reduce the amount of non-methane organic compounds (NMOC) in the collected LFG by at least 98 percent by weight or meet specified NMOC outlet concentrations.

Due to its high CH_4 concentration, LFG can serve as a fuel or energy source. Thermal value recovery of LFG offers the opportunity to reduce the GHG reduction costs by selling the electricity generated from LFG, directly selling the LFG as a fuel source, or by reducing on-site fossil fuel usage costs.

For landfills that are exempt from GCCS requirements, an additional biotic cover (biocover) can reduce the amount of CH_4 released through the permeable cover. An additional biotic layer can further oxidize fugitive CH_4 into CO_2, which has a lower global warming potential. Therefore, it reduces the overall GHG emissions from fugitive LFG.

In addition to the mitigation measures mentioned above, this section discusses other landfill GHG mitigation measures such as biofiltration beds, bioreactors (leachate recirculation), and waste segregation practices.

Each mitigation measure has different applicability toward landfills in the Bay Area. Table 7 summarizes the general applicability of each type of mitigation measure discussed in this section.

Table 7 Landfill Mitigation Measure Applicability

Mitigation Measure	Applicability
Gas Collection Efficiency Improvement	All landfills with active gas collection systems (which includes both active and inactive landfills)
Adding Gas Collection and Flaring	Landfills that are NOT subject to Regulation 8-34-301
Landfill Gas to Energy (LFGTE)	Active Landfills and Larger Inactive Landfills that are subject to Regulation 8-34-301
Bioreactor Landfill (leachate recirculation)	All Active landfills
Waste Segregation	All Active landfills
Biocover	All landfills
Biofiltration Beds	Landfills with passive or no gas collection systems

3.1 GAS COLLECTION EFFICIENCY IMPROVEMENT

Per Regulation 8-34-304: Gas Collection System Installation Requirements, Bay Area landfills that are not exempt from Section 8-34-301 (Landfill Gas Collection and Emission Control System Requirements) have to install and operate gas collection wells or other approved gas collection systems prior to the prescribed dates listed in the regulation. According to the regulation, gas collection systems have to be installed and operational in each area of the landfill within 60 days, or when the following criteria are met:

- When the initial solid waste has been in place for 2 years (for inactive or closed areas)
- When the initial solid waste has been in place for 5 years (for active areas)
- When the landfill cells contain 1 million tons of waste

LFG is commonly extracted using vertical wells and horizontal trenches. This system transfers the collected LFG to a control system where the gas is processed and treated depending upon its endpoint use. Horizontal collectors are often added to cells as filling progresses. Vertical wells often replace these horizontal collectors later when the waste settles (especially in deep sites and in closed cells) and/or when the horizontal collectors start functioning poorly. Generally, active sites have a mix of vertical and horizontal collectors and closed cells have mainly vertical collectors.

There are two types of LFG collection systems, namely active and passive gas collection system. Active gas collection system uses negative pressure (a vacuum) during operation. Active gas collection is required for all landfills that are required by Regulation 8-34 to have gas collection systems. Unlike active gas collection systems, passive gas collection systems depend on natural pressure buildup within the landfill cell to vent LFG to the atmosphere or control systems.

Passive gas collection systems can be installed on active or closed landfills, but currently in the Bay Area, passive systems at active landfills are only used in non-refuse areas to prevent off-site migration of landfill gas. In a manner similar to the active systems, passive gas collection systems also use collection wells, which are typically constructed of perforated or slotted pipes and are installed throughout the refuse, to collect landfill gas.

Particularly in active systems, the gas collection efficiency is dependent on the design, maintenance, and type of final cover of the landfill cells. The permeability of a landfill's final cover affects the efficiency of gas extraction, the amount of moisture in the cell, and consequently the flow of LFG in the cell. Landfills with poor cover layers tend to have a greater occurrence of hot spots due to the high permeability of the cover layers. Conversely, a completely impermeable membrane has the potential to greatly reduce decomposition kinetics due to a lack of moisture in the cell.

The ideal situation for landfills is an environment that supports enhanced waste decomposition. This can be accomplished by using a very low permeability final cover combined with highly permeable materials that surround the perforated gas collection wells and trenches. This arrangement maximizes the amount of gas collected by the vacuum gas collection system and reduces the amount of gas that escapes through the cover layer.

There are a number of landfill final cover materials that enhance gas collection efficiency, such as soil cover, compacted clay cover, a geomembrane, and biocover. The results from a study of the performance of various landfill covers (Spokas, et. al, 2005) were used to develop default values for landfill gas emissions from French landfills for the European Pollutant Emission Register.

Table 8 shows the values of gas extraction efficiencies for various cover materials.

Table 8 LFG Collection Efficiencies for Various Cover Materials

Landfill Cover Material	Gas Collection Efficiency
Operating cell (no final cover)	35%
Temporary cover	65%
Final clay cover	85%
Final geomembrane cover	90%

Note:
The efficiencies above are for a landfill with an active LFG collection system. (Spokas, et. al, 2005)

Excluding biocover, a geomembrane offers the highest CH_4 collection compared to the other three final cover materials. In general, modern landfills with active gas extraction have clay or geomembrane covers in place. However, an additional geomembrane or clay cover can be added to older landfills with gas collection to reduce the amount of LFG escaping through hotspots.

3.2 FLARING

Flaring LFG is a basic landfill control technology that is used to reduce odors, safety concerns, CH_4 emissions, and hazardous air pollutants from LFG. This mitigation measure is suitable for landfills that are subject to Regulation 8-34-301, and may be suitable for some smaller landfills that are not currently subject to Regulation 8-34. During combustion in flares, CH_4 is converted to CO_2. Since CH_4 has 21 times the global warming potential of CO_2, flaring CH_4 reduces its global warming effect substantially.

Although this technology does not provide energy benefits or potential revenue, flaring still offers effective reductions of hazardous air pollutant and methane emissions. Per Regulation 8-34-301, flares and other control technologies are required to have a minimum standardized control performance of 98 percent by weight NMOC reduction to reduce hazardous air pollutants from the trace elements in LFG. For landfills with LFGTE projects in operation, flares are used as backup control devices for emergency situations to ensure that the emission reduction is in compliance with the existing rule.

There are two main categories of landfill flares: open and enclosed flares. Open flares, which are also known as elevated flares, burn LFG as open flames and are usually equipped only with rudimentary combustion control. Enclosed flares, which are also known as ground flares, burn landfill gas in a vertical enclosure. Enclosed flares usually have combustion control and insulation to reduce heat losses and to maintain the combustion temperature. Compared to enclosed flares, open flares have a lower control potential and a higher heat loss. Consequently, combustion in open flares is not as efficient as combustion in enclosed flares.

In the Bay Area, Regulation 8, Rule 34 requires the use of enclosed flares for any site that is subject to Regulation 8-34-301. In addition, the Best Available Control Technology (BACT) guidelines for digester gas or LFG flares recommend the use of an enclosed flare as BACT for NMOC and CO. Enclosed flares offer better control than open flares to ensure a specific destruction efficiency for methane.

Today, smaller enclosed flares are available on the market. These smaller flares are commonly available in sizes as small as 2.5 MMBTU/hr. These smaller flares are good control technology candidates for uncontrolled landfills that generate amounts of LFG that are fairly low, but are significant enough to contribute to the GHG emission inventory. However, several factors such as location, landfill size, and landfill age need to be considered before implementing this control technology.

The use of flares for remote landfills has potential disadvantages because of the extra emissions required to run the blower for LFG conveyance and the combustion of fossil fuels needed to keep the flare in operation. Landfill age and size are also significant factors that affect the amount of LFG generation. If too little LFG is generated, it might be not cost effective to implement the flare system or the limited amount of GHG destroyed by the flare might not justify the extra emissions from implementing the flaring system.

3.3 LANDFILL GAS TO ENERGY (LFGTE)

A control system can be installed at, or next to, a landfill that uses LFG for electrical power generation or fuel conversion. This report does not discuss the feasibility of LFG fuel conversion. Converting LFG to fuel and mixing the fuel into the PG&E pipeline introduces a potential quality issue due to the instability of LFG component mixture ratio and heat content value. This section discusses the available options to convert LFG into electrical power.

In lieu of flaring, LFG can be combusted in engines or other energy and/or heat generating equipments to recover its thermal value and offset part of the GHG mitigation cost with electricity sales. This method directly reduces CH_4 emissions from LFG and offers an indirect GHG emission reduction through avoidance of fossil fuel combustion to produce electricity.

There are some disadvantages to using this mitigation measure. Although the energy generation from engine use offers indirect GHG reductions, these engines may emit more secondary criteria and toxic pollutants. In addition, the presence of siloxane in LFG might cause engine failures, more frequent engine maintenance, and CO compliance problems. These problems are commonly caused by deposits of the solid product of siloxane combustion. Further discussions on the economic impact of siloxane treatment toward the overall economic feasibility of an LFGTE project is discussed in Section 4.2.

Another issue that needs to be considered in choosing the proper technology for the LFGTE projects is the methane destruction efficiency of the equipment. In general, flare and turbines have a higher methane destruction efficiency (>99.5 percent) than IC engines (~96 percent). The increase in direct methane emissions due to lower methane destruction efficiency has to be considered in choosing the optimum LFGTE project options. This consideration will increase the cost of GHG reduction since there will be lower actual GHG reduction from IC engines.

In LFGTE projects, the LFG collected from the wellhead is treated and then converted into energy through various types of energy technologies. For the purpose of a cost-benefit study, the types of energy technologies analyzed were taken from the LFG-cost Software, EPA’s project cost estimator model. The following types of energy technologies are listed in the software:

- Turbine
- Reciprocating engine
- Microturbine

- Small Engine
- CHP (Combined heat and power) engine, turbine, and microturbine.

As listed in Tables 3 and 4, the Bay Area has several candidate or potential landfills for the energy technologies. Depending on the size and age of the landfill, it may be economically feasible for these landfills to implement one of the energy technologies. Further economic analysis of the energy technologies is presented in Section 4.1.

3.4 BIOREACTOR LANDFILL SYSTEMS (LEACHATE RECIRCULATION)

A bioreactor landfill employs the addition of liquid and air into the landfill cell to enhance microbial processes. Due to its high capital cost, this mitigation measure is only suitable for newer active landfill cells that are equipped with the appropriate lining. A hybrid (both aerobic and anaerobic enhancements) bioreactor landfill uses two primary processes:

- Air is injected in the top portion of the cell to increase aerobic activity; and
- Liquid is injected into the lower (older) portions of the cell to regulate moisture and promote anaerobic activity.

Overall, bioreactor landfills result in a faster settling of waste due to augmented aerobic and anaerobic activity.

The principal concept of the bioreactor landfill is to enhance the biodegradation and decomposition of waste by recirculating a controlled amount of air and liquid. The most common liquid recirculated in bioreactor landfills is leachate (waste liquid that drains from the landfill). In regards to this discussion, bioreactor landfills promote LFG generation as a result of increased anaerobic activity. This correlates to an increased production of CH_4, which can be used for generating electrical power, which has an economic value.

Bioreactor landfills have the added benefit of reducing leachate wastewater treatment costs. An additional benefit is a lower post-closure maintenance expense due to fast decomposition rate. In addition, bioreactor landfills also optimize the landfill cell capacity due to shorter settling times compared to conventional landfills.

In California, the Yolo County Central Landfill (YCCL) is the first example of a full-scale bioreactor landfill (Yazdani et al, 2006). The bioreactor project includes:

- Improved cell final cover (using low permeability cover)
- Enhanced liner
- Leachate Recirculation System (includes collection, pumping, and monitoring system)
- Enhanced gas collection design and energy recovery system
- Highly permeable alternative daily cover

In the first phase of this project, a 12-acre module was constructed (a 6-acre and a 3.5-acre anaerobic cell, and a 2.5-acre aerobic cell). In addition to the leachate recirculation system, these cells are equipped with improved temperature and moisture sensors to continuously observe the cell conditions. The operation and monitoring of the bioreactors are performed using the

Supervisory Control and Data Acquisition system, which provides near real-time data collection for optimum control (Yazdani et al, 2006).

The full-scale demonstration of the bioreactor landfill concept resulted in a fourfold increase in the methane recovery rate and the gas collection system is very efficient compared to the conventional landfill operation (the average surface emissions were less than 1/50th of the 500 ppm allowable standard).

These results show that the bioreactor concept is a good mitigation measure candidate to reduce GHG emissions from landfills. This concept offers the benefits of a higher methane recovery rate, a better gas collection system, and a faster settling time from the improved methane recovery rate.

The disadvantages of bioreactor landfills include potential leachate leaks. Also, the feasibility of a bioreactor landfill depends on the landfill characteristics and climate. Prior to implementation, this mitigation measure requires extensive studies and experimental application to determine the best method of implementing this concept for a particular landfill. This mitigation measure does not currently have widespread use in the United States, but it offers significant benefits for the development of future landfills.

3.4.1 Siloxanes in LFG

Siloxanes are a group of anthropogenic organic compounds containing silicon that are widely used in personal care products. Waste segregation can not be utilized to selectively separate siloxane containing waste from other waste. It is impossible to segregate these common products from the collected waste. Therefore, siloxane can only be treated instead of prevented.

The presence of siloxanes in LFG has been a serious issue due to its ability to cause engine failure and catalyst failure in LFG energy projects. Combustion products of siloxanes, mainly silicone dioxide, are usually found as deposits on combustion engine surfaces. These deposits can cause damages to pistons, liners, valves, and other parts of the engines. Siloxane deposits also have a potential to increase criteria pollutant emissions from the engines because they cause the engines to perform poorly.

There are several gas pretreatment technologies that have the potential to remove siloxanes from LFG (Pierce et al, 2004).These technologies include:

- Carbon adsorption
- Refrigeration
- Silica gel

These technologies reduce siloxanes in LFG to an acceptable level that does not diminish the performance of the engines. However, the option of LFG pretreatment requires greater capital and maintenance expenses, thus decreasing the cost-effectiveness of LFGTE projects. Further economic analysis for siloxane treatment in LFGTE projects is presented in Section 4.2.

3.5 WASTE SEGREGATION

There are two waste segregation alternatives that have the potential to support landfill GHG emission mitigation measures. The alternatives are inorganic waste segregation and yard waste segregation.

Inorganic waste segregation involves dividing large non-biodegradable waste from organic waste in the cell. This method optimizes cell space and allows for more biodegradable material. Optimizing the organic waste content in a landfill cell increases the LFG production, which directly improves the efficiency of the space in the landfill.

The second type of segregation is isolation of food scraps and yard waste from municipal solid waste prior to landfilling. This is accomplished by providing separate waste bins for food scraps and yard waste. The segregated waste can then be converted into compost. Compost can be used as an alternative daily landfill cover that enhances gas flow within the cell or as a biotic control media that oxidizes CH_4.

3.6 BIOTIC CONTROL TECHNOLOGIES (BIOCOVER AND BIOFILTRATION BEDS)

For landfills that have no active gas collection systems or no control systems, biotic control technologies can be used to reduce their fugitive CH_4 emissions. The basic principle of this technology is the use of methanotrophic bacteria, which oxidize LFG, specifically CH_4, to water, CO_2, and biomass. Methanotrophic bacteria possess the CH_4 mono-oxygenase enzyme that enables them to use CH_4 as a source of energy and as a carbon source. These bacteria are usually found in agricultural soils, forest soils, and compost.

Compost has fairly high levels of bacteria, typically 10^{11} cells/g, compared to common soil, which has level of approximately 10^9 cells/g (Sylvia et al., 1998). Compost has a promising future as a biotic control media because compost production directly reduces landfill waste deposition rates. Aside from compost, the other common types of waste with the potential to be used for biotic control are chipped rubber tires, styrofoam, and yard waste (Morales et al, 2006). These alternative materials potentially serve as good methanotrophic media when they are mixed with soil or compost. The flexibility to use chipped rubber tires and styrofoam peanuts as the media mixture is beneficial in that it reduces the amount of rubber tire combustion (for alternative fuel), increases the oxygen penetration rate for oxidation, and uses a non-degradable/non-compostable material (styrofoam).

In laboratory studies, methanotrophs have shown steady-state emission reduction rates of 15 mols/day for one square meter of surface area over a maximum time frame of 175 days (DeVisscher, 1999). Because the activity of methanotrophic bacteria is highly dependent on their environmental conditions, certain conditions must be maintained in order to optimize CH_4 oxidation rates. According to several studies, optimum conditions for CH_4 oxidation are as follows:

- Ideal temperature is 77 °F to 95 °F (Visvanathan, et. al.,1999; Kjeldsen, et. al., 1997)
- Ideal moisture content is 15 to 20 percent (Boeck, et. al., 1996; Visvanathan, et. al., 1999)
- Ideal pH is between 6 and 7 (Sunghoon Park, et. al., 1991)

The disadvantage of biotic control technologies is the sensitivity of their oxidation rate to their environmental conditions. This issue is still under research to determine the best method to optimize the CH_4 oxidation rate of the bacteria by manipulating certain media characteristics and different material options.

For the purpose of this study, biotic control technologies are categorized as biocover and biofiltration beds for passive gas collection system filtration.

3.6.1 Biocover

In essence, biocover is an additional final cover that functions as a CH_4 oxidation enhancer to convert CH_4 into CO_2 prior to venting to the atmosphere. This control technology is a good candidate for control retrofit to reduce CH_4 emissions from uncontrolled landfills. Biocover is also a good candidate for an additional final cover for an active landfill because it can improve CH_4 oxidation of the escaping LFG.

Biocover is composed of two substrate layers; a gas dispersion layer, and a CH_4 oxidation layer. The gas dispersion layer is an additional permeable layer of gravel, broken glass, or sand beneath the porous media of the CH_4 metabolizing layer. This layer is added to evenly distribute the fugitive LFG to the CH_4 oxidation media and to remove excess moisture from the gas. The CH_4 oxidation media can be made of soil, compost, a mixture of chipped rubber tire, or other porous media. This media is usually seeded with methanotrophic bacteria from the waste decomposition.

Abichou et al., 2006 researched the performance of biocovers consisting of thin and thick layers of mulch, accompanied by a gas dispersion layer of crushed neon tubes, on a temporary intermediate cover in Leon County Landfill cell. The results show that biocovers are able to reduce CH_4 flux by 96 percent in comparison to CH_4 flux before mulch placement. The biocover applications increased the average percent of CH_4 oxidation by up to 32 percent.

3.6.2 Biofiltration Beds

With a similar concept to biocover, biofiltration beds aim to further oxidize CH_4 from the passively collected LFG. The passively collected LFG is passed through a vessel containing methane oxidizing media prior to venting to the atmosphere or to a control system.

A benefit of using a biofiltration bed compared to LFG combustion is that biofiltration beds produce only CO_2 and water vapor. Unlike other combustion-based mitigation measures, a biofiltration bed does not emit secondary pollutants such as NOx, particulate matter, and SOx. This technology requires few safety controls for operation, and no start up or shut down procedures. Therefore, this technology offers benefits beyond flaring and energy recovery for small landfills or landfills with passive gas collection systems. However, this mitigation method is only feasible for small landfills or landfills with passive gas collection systems due to the size of the biofiltration bed required to treat an air/LFG mixture. In addition, due the nature of passive gas collection systems, this technology also lacks the ability to control and monitor the gas collection.

Without biofiltration beds, passive gas collection pipes typically discharge LFG directly to the atmosphere or combust the LFG with a flare. In practice, perforated passive gas collection pipes are connected to the biofiltration bed vessel to distribute the gas/air mixture through a soil mixture or composted CH_4 oxidation media. The bed may be provided with a controlled source of moisture to ensure optimal conditions for the methanotrophic bacteria.

Morales et al, 2006 tested the performance of two biofiltration bed geometric designs (radial bed and vertical bed) and two methane oxidizing media (compost-styrofoam peanut mixture and compost-chipped rubber tire mixture). In the radial bed design, a perforated pipe is imbedded vertically in the center of the filter medium so that the methane flows horizontally outward. This design has a larger surface area, and thus increases the methane oxidation.

The pilot project results show that the radial bed design (18.94 percent CH_4 oxidation) outperformed the vertical bed design (2.39 percent CH_4 oxidation). As for the two biofiltration bed media, the study showed that there was no significant difference in the performance of the two media types. Both media showed a nearly equal methane oxidation average and methane removal rate during the course of the experiment.

Choosing the proper media with sufficient gas conductivity is very important to reduce the possibility of back pressure in the landfill that could result from the biofiltration bed application. The use of porous media such as a compost mixture with chipped tires or styrofoam peanuts accompanied by pressure monitoring will ensure that the back pressure will not occur in the gas collection system and will avoid a buildup of explosive methane gas within the landfill cell.

This section discusses the costs associated with reducing CO_2e emissions for each mitigation measure. The cost estimates presented in this section for flare and LFGTE projects are based on EPA's LMOP cost estimating software, LFGcost. This software estimates the costs and economic feasibility of various landfill GHG mitigation projects based on their size, age, and type. This section discusses the cost associated with reducing CO_2e emissions for each mitigation measure. Comparisons are presented as net present value payback period (NPVPP) and as cost incurred per metric ton of reduced CO_2e (CPTR). Sample calculations of the economic analyses are presented in Appendix A.

4.1 LFGTE AND BIOREACTOR PROJECTS

This section provides cost estimates for implementing LFGTE projects for a variety of landfill sizes (10-, 20-, and 40-acre sites), densities (low, medium, and high), and configurations (with/without existing LFG collection and flaring). Cost estimates are also presented for both conventional and bioreactor landfills. Varying these factors facilitates the determination of the most cost-effective landfill configuration for implementation of LFGTE projects.

Per Regulation 8-34-301, all landfills that have more than 1,000,000 tons of waste in place are required to install gas collection and control systems. Installation of a gas collection system and an enclosed flare is the minimum requirement to satisfy the regulation. The economic analyses of landfills with/without existing LFG collection and flaring are presented for comparison purposes only. All existing landfills that are subject to Regulation 8-34-301 already have a gas collection system and a flare installed.

The cost estimates provided include the cost of installed electrical generation and interconnected equipment, indirect installation cost, total operating and maintenance cost (including electrical sales), and annual capital recovery cost. Please note that the current cost estimates provided do not include the cost of siloxane treatment. Further analysis on the impact of siloxane treatment on the economics of the project is provided in a separate section of this report.

Implementing LFGTE systems reduces GHG from two sources as follows:

- By converting existing landfill CH_4 (which has 21 times the heating potential of CO_2) to CO_2 (if the site is not currently flaring the gas), and
- By selling electrical power to electrical generating facilities or consuming the electricity for onsite use, GHG emissions are avoided because the electrical generating facility can burn less fuel and sustain the same amount of power.

In some instances, selling electricity to generation facilities, using the electricity onsite, or selling the steam or hot water from CHP projects can provide an opportunity for the landfill proprietor to pay back the initial LGTGE project loan from the generated revenue or electricity expenses reduction. The numbers presented below (specifically the CPTR) were determined solely on the basis of the amount of CO_2e reduced through avoidance of electrical generation. In reality, the CPTR will be lower when the landfill CH_4 reductions are accounted for.

The LFGTE GHG reduction costs depend on a variety of factors. The following analyses provide the NPVPP and CPTR that would result from implementing an LFGTE project for each of the following:

- 10-Acre Landfill Comparison: This analysis compares small (10-acre) conventional landfills with varying densities (low, medium, and high) to small (10-acre) bioreactor landfills with varying densities (low, medium, high). The low compacted waste density applied for this analysis was taken from the YCCL full-scale bioreactor project sample case (54,750 tons of waste in place/acre).
- Medium-Density Landfill Comparison: This analysis compares various sized (10-, 20-, and 40-acre) landfills with a medium compacted waste density. The medium compacted waste density was determined from the approximate average waste density in Bay Area Landfills (100,000 tons of waste in place/acre).
- High-Density Landfill Comparison: This analysis compares various sized (10-, 20-, and 40-acre) landfills with highly compacted waste. The density for this comparison is assumed to be approximately three times that of the low-density landfills (163,155 tons of waste in place/acre).

4.1.1 10-Acre Landfill Comparison

To determine the economic feasibility of implementing an LFGTE project at a small (10-acre) landfill, the NPVPP and CPTR were determined. These cost estimates were calculated based on common assumptions used in the YCCL commercial bioreactor economic study (Yazdani et al, 2006) and default values provided by LFGcost software. The assumptions used in this analysis are listed as follows:

- Total landfill area is 10 acres.
- Landfill depth is 50 feet.
- Filling period is approximately 3 years, and the gas collection system is assumed to be operational by the landfill closure year (2001-2004).
- Assume that the reduction in the leachate treatment cost offsets the additional bioreactor expenses. This assumption is based on the YCCL economic analysis for landfills that receive abundant rainfall annually. For landfill in arid area, the additional bioreactor expenses might exceed the reduction in the cost of leachate treatment.
- Assume that the decomposition kinetics of bioreactor landfills are faster than conventional landfills.
- Expected LFG energy project lifetime is 15 years.
- Loan lifetime is 10 years with 8 percent interest.
- LFG collection efficiency is assumed to be 85 percent for both conventional and bioreactor landfill cases.
- The GHG electricity emission factor is calculated based on EPA eGRID Carbon Dioxide Electricity Emission Factors and Methane and Nitrous Oxide Electricity Emission Factors for California (CCAR, 2007).

- For CHP projects, the distance between the landfill, where the LFG is collected, and the CHP engine, turbine, or microturbine is limited to 10 miles or less to maintain integrity of the cost estimates.
- For CHP projects, the number of miles between the CHP engine, turbine, or microturbine and the end user of the hot water/steam is limited to 1 mile or less to maintain integrity of the cost estimates. The CHP unit and the hot water/steam user are typically co-located, which would be a distance of zero (0) miles.

Please note that these basic assumptions are the same for the other analyses (for both conventional and bioreactor landfills cost estimates), with the exception of the landfill area and waste compaction density. The specific characteristics of each project scenario are listed as follows:

- 10-acre low-density landfill: Assumes a low compacted waste density of 54,750 tons of waste/acre (this scenario is similar to the commercial landfill economic study from YSCL Bioreactor Project).This size of landfill is currently not required to have collection and control by regulation. However, CARB's early action measure might trigger control for this size of landfill with compacted waste densities lower than 100,000 tons of waste in place/acre;
- 10-acre medium-density landfill: Assumes a medium compacted waste density of 100,000 tons of waste in place/acre (this value is generated from the average Bay Area landfill density). Note that this size of landfill is currently required to have an LFG collection system and a flare; and
- 10-acre high-density landfill: Assumes a highly compacted waste density of 163,155 tons of waste/acre. This value is approximately triple the density of the low density landfill scenario presented above. Note that this size of landfill is currently required to have an LFG collection system and a flare.

Tables 9 and 10 show the NPVPP for low, medium and high density conventional and bioreactor landfills.

Table 9 Conventional Landfill NPVPP for 10-Acre Landfills (years)

Type of Module (Size and Density)	Turbine	Engine	Microturbine	Small Engine	CHP Engine	CHP Turbine	CHP Microturbine
10-acre Low	None	None	None	None	None	None	None
10-acre Low*	None	None	None	None	None	None	None
10-acre Medium	None	None	None	None	None	None	None
10-acre Medium*	None	None	None	None	>12	>11	None
10-acre High	None	None	None	None	>15	>13	None
10-acre High *	None	15	10	None	>10	>7	None

* Landfill with existing gas collection and flaring system

Table 10 Bioreactor Landfill NPVPP for 10-Acre Landfills (years)

Type of Module (Size and Density)	Turbine	Engine	Microturbine	Small Engine	CHP Engine	CHP Turbine	CHP Microturbine
10-acre Low	None	None	None	None	None	None	None
10-acre Low*	None	None	None	None	None	None	None
10-acre Medium	None	None	None	None	None	None	None
10-acre Medium*	None	None	None	None	>12	>11	None
10-acre High	None	None	None	None	None	>15	None
10-acre High*	None	15	7	None	>10	>8	None

* Landfill with existing gas collection and flaring system

As shown in Tables 9 and 10, no NPVPP occurs for the lifetime of the project at the four low-density conventional and bioreactor landfills. This low profitability is caused by the low waste compaction density within the landfill, which affects the magnitude of LFG volumetric flow into the gas collection system. Among the three different density scenarios, landfills with a higher waste compaction show a shorter NPVPP due to the higher LFG flow rate.

In general, bioreactor landfills are not as cost effective for this particular size of landfill, although they have a shorter NPVPP for LFGTE projects compared to conventional landfills. The actual capital, operating, and maintenance cost for bioreactor projects is higher than the value estimated from the software. In order to implement bioreactor technology to an active landfill, extensive research and expensive monitoring system is required to ensure the performance of the bioreactor. The assumption that the cost compensation from the leachate treatment cost reduction is not always enough to offset the total cost spent on the bioreactor projects. Among the estimated LFGTE project options, Microturbine projects with existing gas collection and flaring systems for the 10-acre landfills with high waste compaction density showed the shortest NPVPP.

Accounting for indirect installation cost, capital recovery, administrative, and other contingencies, the CPTRs from avoided energy generation were calculated for each of the scenarios mentioned above (refer to Appendix A for a detailed sample calculation). Tables 11 and 12 show the CPTRs for both conventional and bioreactor landfills.

Table 11 Landfill CPTR for 10-Acre Landfills ($/metric ton CO_2e reduced)

Type of Module (Size and Density)	Turbine	Engine	Microturbine	Small Engine	CHP Engine	CHP Turbine	CHP Microturbine
10-acre Low	$496	$385	$477	$474	$397 - $1,189	$414 - $1,295	$638 - $1,793
10-acre Low *	$283	$209	$279	$190	$257 - $1,049	$263 - $1,144	$434 - $1,590
10-acre Medium	$355	$270	$309	$363	$249 - $683	$253 - $745	$425 - $1,057
10-acre Medium*	$226	$164	$188	$190	$161 - $595	$157 - $650	$296 - $929
10-acre High	$286	$216	$207	$309	$179 - $445	$175 - $486	$314 - $701
10-acre High*	$197	$142	$124	$190	$116 - $382	$106 - $417	$221 - $609

* Landfill already has pre-existing gas collection and flaring system

Table 12 Bioreactor Landfill CPTR for 10-Acre Landfills ($/metric ton CO_2e reduced)

Type of Module (Size and Density)	Turbine	Engine	Microturbine	Small Engine	CHP Engine	CHP Turbine	CHP Microturbine
10-acre Low	$535	$417	$407	$525	$434 - $1,235	$454 - $1,345	$692 - $1,860
10-acre Low *	$285	$210	$233	$190	$259 - $1,060	$265 - $1,156	$437 - $1,605
10-acre Medium	$389	$299	$262	$408	$283 - $721	$289 - $787	$474 - $1,113
10-acre Medium *	$227	$164	$149	$190	$162 - $600	$158 - $656	$298 - $937
10-acre High	$318	$243	$173	$352	$212 - $480	$210 - $524	$361 - $753
10-acre High *	$197	$142	$89	$190	$117 - $385	$107 - $421	$222 - $614

* Landfill already has pre-existing gas collection and flaring system

As shown in Tables 11 and 12, the CPTR from LFGTE projects can be as low as $124 per metric ton of CO_2e for the conventional landfill scenario and $89 per metric ton of CO_2e for the bioreactor landfill scenario. In agreement with the estimates on Tables 9 and 10, microturbine projects show a lower CPTR compared to other types of LFGTE projects. This analysis shows that LFGTE projects are not economically feasible for smaller landfills, especially for landfills with low compacted waste density. For the smaller landfills, flaring is still the most economical mitigation measure that satisfies the regulation. Further details on the economic analysis of flaring are provided in Section 4.4.

4.1.2 Medium-Density Landfills Comparison

As shown in the previous section, higher waste density within the landfill cell correlates to a shorter NPVPP and a lower CPTR. This section compares the economic feasibility of implementing LFGTE projects at both conventional and bioreactor landfills with medium waste density. The tonnage and area data from major landfills across the Bay Area show that the approximate average area-based landfill density is 100,000 tons of waste in place/acre. Using the same assumptions as in the previous section (with the exception of the landfill size), the NPVPPs and CPTRs were determined, and are shown in Tables 13 through 16.

Table 13 Medium Density Conventional Landfill NPVPP (years)

Type of Module (Size and Density)	Turbine	Engine	Microturbine	Small Engine	CHP Engine	CHP Turbine	CHP Microturbine
10-acre Medium	None	None	None	None	None	None	None
10-acre Medium*	None	None	None	None	>12	>11	None
20-acre Medium	None	None	None	None	>15	>13	None
20-acre Medium *	None	14	8	None	>8	>6	None
40-acre Medium	None	None	9	None	>12	>10	None
40-acre Medium*	None	13	3	None	5 - 14	4 - 13	>11

* Landfill already has pre-existing gas collection and flaring system. Please note that Bay Area landfills that have more than 1,000,000 tons of waste in place are required to install gas collection and control systems per Regulation 8-34-301.

Table 14 Medium Density Bioreactor Landfill NPVPP (years)

Type of Module (Size and Density)	Turbine	Engine	Microturbine	Small Engine	CHP Engine	CHP Turbine	CHP Microturbine
10-acre Medium	None	None	None	None	None	None	None
10-acre Medium*	None	None	None	None	>12	>11	None
20-acre Medium	None	None	None	None	None	>15	None
20-acre Medium*	None	14	5	None	>8	>6	None
40-acre Medium	None	None	5	None	>14	>11	None
40-acre Medium*	None	13	3	None	5 - 14	4 - 13	>11

* Landfill already has pre-existing gas collection and flaring system. Please note that Bay Area landfills that have more than 1,000,000 tons of waste in place are required to install gas collection and control systems per Regulation 8-34-301.

For landfills with medium compacted waste density, the size of the landfill greatly influences the potential NPVPP. Since the waste deposition time and landfill cell density are assumed constant (3 years deposition time and 100,000 tons of waste in place/acre), larger landfills will have a higher waste deposition rate. As the landfill size and deposition rate increase, the potential NPVPP shortens due to the higher generation of LFG. This correlates to increased revenue from higher electricity or heat generation rate.

As shown in Tables 13 and 14, CHP projects for bioreactor landfills showed shorter NPVPPs than for conventional landfills. Based on the results, the shortest NPVPP occurs from the installation of a microturbine at a bioreactor landfills with larger size (20- and 40-acre landfills).

To confirm the previous conclusion, the CPTRs for this project category were calculated, and are shown in Tables 15 and 16.

Table 15 Medium-Density Conventional Landfill CPTR (\$/metric ton CO_2e reduced)

Type of Module (Size and Density)	Turbine	Engine	Microturbine	Small Engine	CHP Engine	CHP Turbine	CHP Microturbine
10-acre Medium	$355	$270	$309	$363	$249 - $683	$253 - $745	$425 - $1,057
10-acre Medium*	$226	$164	$188	$190	$161 - $595	$157 - $650	$296 - $929
20-acre Medium	$293	$223	$198	$331	$176 - $393	$170 - $428	$304 - $620
20-acre Medium*	$187	$136	$99	$190	$103 - $319	$90 - $348	$196 - $512
40-acre Medium	$253	$199	$110	$314	$139 - $248	$123 - $264	$228 - $386
40-acre Medium*	$160	$122	$23	$190	$73 - $182	$52 - $192	$132 - $290

* Landfill already has pre-existing gas collection and flaring system. Please note that Bay Area landfills that have more than 1,000,000 tons of waste in place are required to install gas collection and control systems per Regulation 8-34-301.

Table 16 Medium-Density Bioreactor Landfill CPTR ($/metric ton CO_2e reduced)

Type of Module (Size and Density)	Turbine	Engine	Microturbine	Small Engine	CHP Engine	CHP Turbine	CHP Microturbine
10-acre Medium	$389	$299	$262	$408	$283 - $721	$289 - $787	$474 - $1,113
10-acre Medium *	$227	$164	$149	$190	$162 - $600	$158 - $656	$298 - $937
20-acre Medium	$325	$250	$161	$374	$208 - $427	$205 - $465	$350 - $670
20-acre Medium *	$188	$136	$66	$190	$103 - $322	$91 - $351	$192 - $517
40-acre Medium	$284	$224	$80	$355	$170 - $280	$157 - $298	$274 - $433
40-acre Medium *	$161	$122	($5)	$190	$74 - $183	$52 - $194	$133 - $293

* Landfill already has pre-existing gas collection and flaring system. Please note that Bay Area landfills that have more than 1,000,000 tons of waste in place are required to install gas collection and control systems per Regulation 8-34-301.

As shown above, the bioreactor landfill microturbine projects showed the lowest CPTR compared to other projects. Tables 15 and 16 show that as the size and deposition rate increase, CPTRs for all projects gradually decrease due to greater revenue from the increase of electricity or heat generation. The highlighted value for the 40-acre landfill with a microturbine shows that the project has a potential to generate revenue for each ton of GHG reduced. This analysis shows that the 40-acre landfill is the minimum landfill size category that has the potential to generate revenue for each ton of GHG reduction. This result shows the concern regarding the possibility of IC engine projects that has lower methane destruction efficiency being more economical than microturbine projects mentioned earlier is not an issue for these project options since the microturbine is more economically attractive than IC engines.

4.1.3 High-Density Landfills Comparison

The LFG generation rate is influenced by the waste deposition rate, age, and the CH_4 generation rate constant. A higher landfill waste compaction density increases the LFG generation rate. Therefore, LFGTE projects on landfills with high waste compaction density are expected to be more economical because this type of landfill is expected to have higher electricity and/or heat generation rate. To confirm this trend, the NPVPPs and CPTRs were calculated for a higher landfill density. In this section, the density has been increased to 163,000 tons of waste/acre. The density for this comparison is based on the assumption of three times the density of the low density landfills discussed in the previous section. Using the same waste deposition time and other assumptions as in previous sections, the NPVPPs and CPTRs for different sized landfills (10, 20, and 40 acres) with highly compacted waste were calculated, and are shown in Tables 17 through 20.

Table 17 High-Density Conventional Landfill NPVPP (years)

Type of Module (Size and Density)	Turbine	Engine	Microturbine	Small Engine	CHP Engine	CHP Turbine	CHP Microturbine
10-acre High	None	None	None	None	>15	>13	None
10-acre High *	None	15	10	None	>10	>7	None
20-acre High	None	None	9	None	>11	>9	None
20-acre High *	None	13	4	None	>6	4 - 15	>12
40-acre High	None	None	4	None	9 - 15	6 - 13	None
40-acre High *	14	12	2	None	4 - 10	3 - 10	>7

* Landfill already has pre-existing gas collection and flaring system. Please note that Bay Area landfills that have more than 1,000,000 tons of waste in place are required to install gas collection and control systems per Regulation 8-34-301.

Table 18 High-Density Bioreactor Landfill NPVPP (years)

Type of Module (Size and Density)	Turbine	Engine	Microturbine	Small Engine	CHP Engine	CHP Turbine	CHP Microturbine
10-acre High	None	None	None	None	None	>15	None
10-acre High *	None	15	7	None	>10	>8	None
20-acre High	None	None	6	None	>13	>11	None
20-acre High *	None	13	3	None	>6	5 - 15	>12
40-acre High	None	None	3	None	>11	8 - 15	None
40-acre High *	14	12	2	None	5 - 10	3 - 10	>7

* Landfill already has pre-existing gas collection and flaring system. Please note that Bay Area landfills that have more than 1,000,000 tons of waste in place are required to install gas collection and control systems per Regulation 8-34-301.

As shown in Tables 17 and 18, the length of the NPVPP from these highly compacted LFGTE projects is greatly improved. Second only to microturbine projects, CHP turbine projects start to demonstrate better return potentials for larger, high-density landfills. In general, microturbine, CHP Turbine, and CHP Engines showed the best NPVPP for almost all sizes of projects under this section category.

Similar with the analyses from previous sections, CHP projects for bioreactor landfills showed shorter NPVPPs than for conventional landfills. Based on the results, the shortest NPVPP occurs from the installation of a microturbine at larger (20 and 40 acre) bioreactor landfills.

CHP projects for conventional landfills showed shorter NPVPPs than for bioreactor landfills. Based on the results, the shortest NPVPP occurs from the installation of a microturbine at larger (20 and 40 acre) bioreactor landfills.

Similar to the method used for the previous categories, the CPTRs for this project category were also calculated to confirm the conclusions from the NPVPP analysis. The CPTRs for the high-density landfill power projects are presented in Tables 19 and 20.

Table 19 High-Density Conventional Landfill CPTR ($/metric ton CO_2e reduced)

Type of Module (Size and Density)	Turbine	Engine	Microturbine	Small Engine	CHP Engine	CHP Turbine	CHP Microturbine
10-acre High	$286	$216	$207	$309	$179 - $445	$175 - $486	$314 - $701
10-acre High*	$197	$142	$124	$190	$116 - $382	$106 - $417	$221 - $609
20-acre High	$242	$186	$113	$289	$134 - $267	$120 - $287	$227 - $421
20-acre High*	$168	$125	$44	$190	$80 - $213	$62 - $228	$148 - $342
40-acre High	$206	$171	$37	$278	$112 - $178	$84 - $179	$172 - $269
40-acre High*	$141	$117	($24)	$190	$62 - $129	$31 - $126	$100 - $197

* Landfill already has pre-existing gas collection and flaring system. Please note that Bay Area landfills that have more than 1,000,000 tons of waste in place are required to install gas collection and control systems per Regulation 8-34-301.

Table 20 High-Density Bioreactor Landfill CPTR ($/metric ton CO_2e reduced)

Type of Module (Size and Density)	Turbine	Engine	Microturbine	Small Engine	CHP Engine	CHP Turbine	CHP Microturbine
10-acre High	$318	$243	$173	$352	$212 - $480	$210 - $524	$361 - $753
10-acre High*	$197	$142	$89	$190	$117 - $385	$107 - $421	$222 - $614
20-acre High	$273	$212	$87	$330	$165 - $300	$154 - $322	$273 - $469
20-acre High*	$168	$125	$15	$190	$80 - $215	$62 - $230	$149 - $345
40-acre High	$237	$196	$16	$318	$142 - $209	$117 - $213	$216 - $314
40-acre High*	$141	$117	($50)	$190	$62 - $130	$31 - $127	$101 - $199

* Landfill already has pre-existing gas collection and flaring system. Please note that Bay Area landfills that have more than 1,000,000 tons of waste in place are required to install gas collection and control systems per Regulation 8-34-301.

In general, the CPTR for these highly compacted landfills are lower than the costs estimated for medium density landfills. For the highly compacted landfill power projects, microturbine projects still offer the lowest CPTRs. Application of LFGTE projects for this size and density of landfill has the potential to achieve a negative cost, as shown for the microturbine projects implemented on a highly compact landfill with an existing gas collection and flaring system. Similar to the medium density economic analyses, the highlighted value for the 40 acre landfill shows that the project has the potential to generate revenue for each ton of GHG reduced. This analysis confirms that 40 acres is the minimum size category that has a revenue potential for each ton of GHG reduction for the LFGTE projects with a microturbine. The concern regarding the possibility of IC engine projects that has lower methane destruction efficiency being more economic than microturbine projects is not an issue for this project options since the microturbine is more economically attractive than IC engines.

4.2 ECONOMIC ANALYSIS FOR SILOXANE

As mentioned in Section 3.4.1, siloxane poses a potentially serious issue for LFGTE projects due to its ability to cause engine and catalyst failure. A successful LFG siloxane pretreatment process has been implemented in the Calabasas landfill in southern California (Pierce, 2004). The Calabasas landfill removes siloxane from LFG by using silica gel, which removes moisture and siloxane from LFG before the gas enters the microturbine. Silica gel functions like activated carbon in removing moisture and siloxane from LFG.

The performance and absorption capacity of silica gel or activated carbon are primarily influenced by LFG physical properties (temperature and moisture content), the type of adsorbing media (silica or the type of carbon), actual concentration, and type of siloxane in LFG. These factors are important in determining the cost of maintaining the adsorptive media that eventually dominates the cost of siloxane removal.

To determine the cost effectiveness of a siloxane removal system, an additional economic analysis subset was generated that accounts for the capital and operating cost of siloxane removal. This subset used the capital and operating cost factor from Waukesha siloxane removal system (Pierce, 2004). The Waukesha case was chosen because this case has higher siloxane concentration than the Calabasas case. This higher concentration is more representative of the siloxane concentration expected in most landfills although the treatment cost factor is substantially higher than in the Calabasas case.

The overall costs to implement the LFGTE project, including the siloxane treatment were estimated using the following assumptions:

- Capital cost for the siloxane treatment system is $82/kw.
- Adsorbent media (carbon) cost is $0.015/kwh of electricity generated.
- Assume that a gas collection and a backup flare are already installed.
- All other cost assumptions are similar to the assumptions used in Section 4.1.

The new cost estimates indicate that siloxane removal would be cost prohibitive for most LFGTE projects. The inclusion of siloxane treatment in the economic analysis shifts the economic feasibility of LFGTE projects. Among the cost estimates, all scenarios except for 20-acre and 40-acre conventional landfills with high density show NPVPPs that are longer than the project lifetime. For the aforementioned sizes and density of landfills, the LFGTE implementation with siloxane treatment is only economically feasible for the microturbine and the CHP turbine implementation on conventional landfills. For the bioreactor landfill scenarios, the implementation of LFGTE and siloxane treatment is only economically feasible for the CHP microturbine option for the 40- acre high density bioreactor landfill. The economics of bioreactor landfills are more greatly affected by the siloxane treatment issues because they have greater LFG generation rates, which correlate to higher capital and operation costs for siloxane treatment. The NVPPs and CPTRs for landfills for which it is economically feasible to implement the LFGTE projects with siloxane treatment are presented in Table 21.

Table 21 Cost Analysis for LFGTE Projects with Siloxane Treatment

	Conventional Landfill			Bioreactor Landfill
Landfill Size, Density, and LFGTE Options	20 acre High CHP Turbine	40 acre High Microturbine	40 acre High CHP Turbine	40 acre High CHP Turbine
NPVPP (years)	>14	10	>9	>9
CPTR ($/metric ton of $CO2_e$ reduced)	$112-$278	$51	$81-$176	$81-$177

As shown above, siloxane treatment negatively affects the economics of LFGTE projects implementation. The inclusion of siloxane treatment into the project economics shifted to feasibility of LFGTE projects implementation. For conventional landfills, the inclusion of siloxane treatment into the project economics reduced the potential revenue range of income of $24/ton of CO_2e reduced to a cost of $51/ton of CO_2e reduced (40-acre high density landfill with microturbine and no siloxane treatment versus with siloxane treatment). For bioreactor landfills, the inclusion of siloxane treatment into the project economics reduced the potential revenue range of income of $50/ton of CO_2e reduced to a cost of $81/ton of CO_2e reduced (40-acre high density landfill with microturbine and no siloxane treatment v. 40-acre high density landfill with combined heat and power turbine with siloxane treatment). Siloxane treatment has greater impact on bioreactor project economics than that of conventional landfills. The greater additional cost for siloxane treatment on bioreactor projects is caused by the greater LFG generation kinetics of the bioreactor landfills. Higher LFG generation rate translates to higher cost related to the siloxane treatment.

4.3 ECONOMIC INCENTIVES FOR RENEWABLE ENERGY PROJECTS

There are several incentives that are applicable for the LFGTE projects. These incentives may include but not be limited to a government construction grant, a tax credit, California Energy Commission's New Renewable Facilities Program, and the California Public Utilities Commission's Self Generation Incentive Program. These programs encourage the installation of renewable energy technologies by providing financial incentives to businesses that are eligible.

4.4 FLARING

Flaring is a common LFG control technology with the lowest total capital investment compared to other control technologies, since all landfills with gas collection systems are required to have an emergency flare regardless of their control technology. Also, note that Bay Area landfills that have more than 1,000,000 tons of waste in place are required to install gas collection and control systems per Regulation 8-34-301.

To determine the CPTR from flaring, the economic analysis accounts for many aspects such as:

- Installed gas collection well and wellhead cost
- Knockout, blower, and flare system cost
- Gas collection operation and maintenance expenses

- Operation and maintenance and electricity expenses for the blower
- Other indirect expenses, administration costs, and insurance costs

The NPVPP for additional flaring projects can not be determined because flaring does not generate any revenue. This section provides the cost estimates of adding gas collection and flare system to various sizes of landfills. Since Bay Area landfills that have more than 1,000,000 tons of waste in place are already required to install gas collection and control systems, the cost analyses for landfills with more than 1,000,000 tons of waste in place are presented for comparison purposes.

Accounting for different landfill sizes and waste deposition rates, the CPTRs for landfills with flaring and LFG collection systems were calculated, and are shown in Table 22.

Table 22 Landfill GHG Reduction Cost from Flaring

Area (Acres)	Waste Acceptance Rate (TPY)	Total Waste in Place (Tons)	Total Capital Investment	Total Annual Capital Recovery and O&M	Minimum GHG Reduction (MMT CO_2e/year)	CPTR ($/metricT CO_2e)
3	54,750	164,250	$342,259	$ 86,353	0.003	$24.81
4	73,000	219,000	$373,718	$97,279	0.005	$20.97
5	91,250	273,750	$403,499	$107,889	0.006	$18.60
5	166,667	500,000	$422,567	$118,181	0.011	$11.16
10	182,500	547,500	$540,883	$158,757	0.012	$13.69
10	333,333	999,999	$561,623	$176,055	0.021	$8.31
10	543,850	1,631,550	$579,629	$198,130	0.035	$5.73
20	666,666	1,999,998	$1,138,227	$354,941	0.042	$8.38
20	1,087,700	3,263,100	$1,177,398	$399,687	0.069	$5.78
40	1,333,332	3,999,996	$2,352,125	$724,185	0.085	$8.55
40	2,175,400	6,526,200	$2,437,341	$814,976	0.138	$5.89

* Total waste in place is based on 3 years of waste deposition.

As shown, larger landfills with higher waste deposited correlate to a lower CPTR. This decrease in CPTR is a result of increased LFG flow due to the larger landfill size and higher waste acceptance rates. A larger LFG flow rate equates to an increased amount of CH_4 destruction by the flare. Therefore, the cost to destroy each ton of CO_2e decreases as the flare system becomes more efficient. Compared with the cost estimates from LFGTE projects, this mitigation measure is the cheapest control technology applicable to most landfills. The cost of implementing flare and gas collection system ranges from $6 to $25/ton of CO_2e for landfills with a size range of 3 to 40 acre.

Although flaring appears to be the most cost effective method for reducing landfill GHG, this mitigation measure does not offer anything other than good CH_4 conversion to CO_2. This option also does not allow for payback on investment. However, compared to the LFGTE projects, the option of only installing a flare and a gas collection system is more economical for landfills that are smaller than 40 acres in size. The LFGTE project options are not economically feasible for these smaller landfills due to the high capital cost and low LFG generations.

By recovering the thermal value of LFG, CH_4 is directly destroyed and indirect reductions of GHG emission are realized by avoiding fossil fuel combustion.

4.5 BIOTIC CONTROL TECHNOLOGY

The cost estimate for biocover application in this report is based on the cover expenses for the YCCL bioreactor (Full Scale Bioreactor Landfill for Carbon Sequestration and Greenhouse Emission Control: Final Technical Progress Report, 2006) and some additional assumptions as follows:

- Biocover is applied to 10-acre bioreactor landfill with low compaction density
- Gas collection efficiency is 85 percent
- Soil oxidation efficiency is 10 percent
- Mean biocover efficiency is 32 percent (Abichou et al., 2006)
- Biocover cost is about $48,000/acre (includes geomembrane and gas distribution layer)

From that recent project and those assumptions we derived a potential average annual CO_2 reduction from biocover of 64.4TPY of CO_2e. This reduction equals a GHG reduction cost of $745.34/ton of CO_2e. The cost for biocover application may vary widely according to availability of material and the level of monitoring.

Comparing various mitigation measures and their cost effectiveness, there is no mitigation measure that offers optimum GHG mitigation, generates attractive revenue, and applies to all types of landfills at the same time. After factoring in the cost effectiveness, trade-offs, and landfill characteristics, the economic analysis results and recommendations for Bay Area landfills can be summarized as follows:

- Flare: Cost of $6 to $25/ton of CO_2e. This mitigation measure is the cheapest control technology applicable to most landfills. However, a flare does not offer any potential for revenue and indirect GHG emission reductions from avoided electricity generation.
- Landfill Gas to Energy (best result from 40-acre high-density bioreactor landfill with existing flare and gas collection system): Positive return of up to $50/ton of CO_2e for microturbine. The results show that it is possible to gain revenue while reducing GHG from the avoided energy generation. This mitigation measure is suitable for larger landfills that generate enough LFG to run the power project. However, there are size and density restrictions applicable for this option. Smaller landfills and landfills with low compacted waste density are not cost effective for this option.
- Siloxane treatment shifts the economic feasibility of LFGTE projects. Accounting for the siloxane treatment capital and operation costs, LFGTE is only economically feasible for a larger landfill with high waste compaction. It also limits the LFGTE equipment option to the microturbine or CHP turbine. From the criteria pollutant inventory point of view this result is beneficial because turbines have a higher methane destruction efficiency (almost similar to that for a flare). The result is that turbines are more economical than engines, which have a lower methane destruction efficiency. For conventional landfills, the inclusion of siloxane treatment shifts the potential revenue range of income of $24/ton of CO_2e reduced to a cost of $51/ton of CO_2e reduced (40-acre high density landfill with microturbine and no siloxane treatment versus with siloxane treatment). For bioreactor landfills, the inclusion of siloxane treatment shifts the potential revenue range of income of $50/ton of CO_2e reduced to a cost of $81/ton of CO_2e reduced (40-acre high density landfill with microturbine and no siloxane treatment v. 40-acre high density landfill with combined heat and power turbine with siloxane treatment). The siloxane treatment has greater impact on bioreactor project economics than that of conventional landfills. This is caused by the greater LFG generation kinetics of the bioreactor landfills. Higher LFG generation rate translates to higher cost related to the siloxane treatment.
- Biocover: Cost of $745.34/ton of CO_2e. Among other mitigation measures, this measure is the most expensive option to reduce GHG from landfills. This high cost estimate is based on one test site. Therefore, the actual cost estimate may vary widely. Biotic control technologies are currently under research for performance and cost effectiveness. These technologies are applicable to the uncontrolled and old landfills unlike other mitigation measures because they do not require extensive retrofit and they are relatively clean in terms of secondary criteria pollutant emissions.

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Website References

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- Bioreactor < http://bioreactor.org/>
- LMOP < http://www.epa.gov/lmop/>
- BAAQMD < http://www.baaqmd.gov/>
- John Zink Company Website <http://www.johnzink.com/>
- Basics of Landfill Gas, Appendix A < http://www.mass.gov/dep/recycle/laws/lfgasapp.pdf/>

APPENDIX A: COST ASSUMPTIONS AND SAMPLE CALCULATIONS

Appendix A.1 LFG-Cost General Assumptions

In estimating the cost for each scenario of GHG mitigation, certain LFG-Cost software default input values are used to estimate the approximate cost of the mitigation projects. The final cost estimates are further fine tuned using the generated values from the LFG-Cost by adding some cost assumptions to account to obtain the final cost of GHG mitigation per ton of CO_2e reduction.

The default input values from LFG-Cost software that are used in the power projects and flaring cost estimations are presented below.

Table 23 LFG-Cost Default Assumptions

Type of Default Input		LFG-cost Default Data
Average depth of landfill waste (ft)		50
Utilization of CHP hot water/steam potential (%)		100%
Expected LFG energy project lifetime (years)		15
Operating schedule:	Hours per day	24
	Days per week	7
	Weeks per year	52
General inflation rate (% - applied to O&M costs)		2.5%
Equipment inflation rate (%)		1.0%
Energy tax credits:	LFG utilization ($/million Btu)	$0.000
	Electricity generation ($/kWh)	$0.000
	LNG production ($/gal)	$0.000
Direct credits:	GHG reduction credit ($/MMT CO_2e)	$0.000
	Are direct CH4 reductions included in GHG credit?	Y
	Renewable electricity credit ($/kWh)	$0.000
	Avoided leachate disposal ($/gal) **	$0.000
	Construction grant ($)	$0
Royalty payment for LFG utilization ($/million Btu)		$0.000
Cost uncertainty factor (entered as % adjustment)		0.0%
Annual product price escalation rate (%)		2.0%
Electricity purchase price for projects NOT generating electricity ($/kWh) **		$0.075
Annual electricity purchase price escalation rate (%)		2.0%

** Based on initial year of operation

Appendix A.2 Economic Analysis Sample Calculations for LFGTE

ESTIMATED CAPITAL AND OPERATING COSTS

LANDFILL GAS UTILIZATION

Sample Calculation for 10 Acre Conventional Landfill with Medium Density (Microturbine)

CAPITAL COSTS		
DIRECT CAPITAL COSTS (DC)		
Purchased Equipment Costs (PE, LFGcost)		
	PE Total =	$982,687
Direct Installation Costs (DI, 56% of Equipment Cost, OAQPS Manual)		
	DI Total =	$550,305
	DC Total =	$1,532,992
INDIRECT CAPITAL COSTS (IC, 35% of Equipment costs, OAQPS Manual))		
	IC Total =	$343,940
	TOTAL CAPITAL INVESTMENT (TCI) = Sum (DC + IC) =	**$1,876,932**
	Capital Recovery at 8% interest over 10 years (0.149*TCI) =	**$279,663**
OPERATION AND MAINTENANCE (O & M)		
DIRECT ANNUAL COSTS (DA)		
Operating & Maintenance cost (LFGcost)		$62,375
Electricity Generation Sales (LFGcost)		($179,827)
	DA Total =	($117,452)
INDIRECT ANNUAL COSTS (IA)		
Overhead (60% of maintenance parts & labor costs, OAQPS Manual)		$37,425
Admin., Property Tax, Insurance (4% of TCI, OAQPS Manual)		$75,077
	IA Total =	$112,502
	Annual O & M Total =	**($4,949)**
TOTAL ANNUAL CAPITAL AND O & M COSTS (incldg. Capital Recovery)		**$274,714**
Annual CO_2/methane reduction from avoided energy generation (metric tons)		1461.22
Annual cost effectiveness, $/metric ton of CO_2 removed		**$188**

Note:
Cost Factors based on OAQPS Control Cost Manual (5th Ed., Feb 1996)

Appendix A.3 Economic Analysis Sample Calculations for Flare

ESTIMATED CAPITAL AND OPERATING COSTS

LANDFILL GAS COLLECTION SYSTEM AND FLARE

Sample Calculation for 5 Acre Conventional Landfill with 500,000 tons of waste in place

CAPITAL COSTS		
DIRECT CAPITAL COSTS (DC)		
Purchased Equipment Costs (PE, LFGcost)		
	PE Total =	$221,239
Direct Installation Costs (DI, 56% of Equipment Cost, OAQPS Manual)		
	DI Total =	$123,894
	DC Total =	$345,133
INDIRECT CAPITAL COSTS (IC, 35% of Equipment costs, OAQPS Manual))		
	IC Total =	$77,434
	TOTAL CAPITAL INVESTMENT (TCI) = Sum (DC + IC) =	**$422,567**
	Capital Recovery at 8% interest over 10 years (0.149*TCI) =	**$62,962**
OPERATION AND MAINTENANCE (O & M)		
DIRECT ANNUAL COSTS (DA)		
Operating & Maintenance cost (LFGcost)		$23,948
	DA Total =	$23,948
INDIRECT ANNUAL COSTS (IA)		
Overhead (60% of maintenance parts & labor costs, OAQPS Manual)		$14,369
Admin., Property Tax, Insurance (4% of TCI, OAQPS Manual)		$16,903
	IA Total =	$31,271
	Annual O & M Total =	**$55,219**
TOTAL ANNUAL CAPITAL AND O & M COSTS (incldg. Capital Recovery)		**$118,181**
Annual CO_2/methane reduction from flaring (metric tons)		10593.43
Annual cost effectiveness, $/ton of CO_2 from methane destruction		**$11.16**

Note:
Cost Factors based on OAQPS Control Cost Manual (5th Ed., Feb 1996)

Part II

Industrial, Institutional, and Commercial Boilers

Greenhouse gas (GHG) emissions from this category of sources account for about 2 percent of the total of Bay Area GHG emissions from stationary sources in 2002 (BAAQMD, 2006). The GHG emission inventory referenced above uses a composite value in this regard. GHG emissions from gas-fueled boilers account for about 50 percent of the Bay Area's carbon dioxide equivalent (CO_2e) emission inventory for miscellaneous industrial processes and combustion stationary sources. The remaining 50 percent of this is contributed by landfill gas combustion and residential combustion, which are not addressed in this section. GHG emissions from industrial, institutional, and commercial gas-fueled boilers, steam generators, and process heaters are primarily generated from fossil fuel combustion. Fuel efficiency improvements, heat loss reduction, and alternative renewable fuel flexibility are basic mitigation methods to reduce GHG emissions from these heaters.

In general, techniques for improving the fuel efficiency of this source category include but not limited to boiler tuning, air to fuel ratio optimization, process or burner retrofit. In addition to the efficiency improvements, preventive approaches to reduce the amount of energy loss to the ambient environment during steam generation or steam distribution system also significant to indirectly reduce boiler GHG emission. As for the renewable fuel alternative, biofuels are good candidates to reduce GHG emissions by avoiding fossil fuel combustion.

To address the non attainment status for both the state 1–hour ozone and the federal 8-hour ozone standard, Bay Area Air Quality Management District (BAAQMD) proposed an amendment to Regulation 9 Rule 7: *Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters* (Reg 9-7). This amendment is still under development and it is generally proposed to tighten nitrogen oxides (NOx) emissions limit for the gas-fueled heaters.

Because certain types of NOx or carbon monoxide (CO) control technologies offer additional benefit of fuel efficiency improvement, the implementation of this retrofit control technology to comply with the regulation shows a potential to address the boiler GHG emission issue. This report is focused on discussing various NOx retrofit control technologies and other energy-saving approaches that have the potential to reduce GHG emissions through fuel efficiency improvements and energy loss reduction.

1.1 REPORT OVERVIEW

This report discusses various opportunities for GHG emission reductions in industrial, institutional, and commercial gas-fueled heaters that are subject to BAAQMD Regulation 9-7. The mitigation measures discussed in this report include: Low NOx Burners, Flue Gas Recirculation, Low Excess Air Control Systems, Air Preheaters, Blowdown Control, Turbulators, Economizers, Piping Insulation, and Steam Traps. This report discusses the advantages and disadvantages of each mitigation measure, along with available cost-benefit estimates. The overview of this report is arranged as follows:

Section 2 provides a discussion of criteria pollutants and GHG emission generation from boiler activities and a discussion of the existing heaters in the Bay Area, including an analysis of the most current Bay Area GHG inventory and an analysis of the existing air regulations from the BAAQMD.

Section 3 provides a discussion of boiler performance, sources of heat loss in boiler operation, and possible approaches to reduce these losses. The discussion includes an energy balance of boiler operation and analyses of each heat loss reduction or prevention to improve overall fuel efficiency as a form of GHG mitigation measures.

Section 4 provides an analysis of the aforementioned mitigation measures, including their common retrofit expense estimates, advantages, and disadvantages.

Section 5 summarizes the results based on the discussions in the previous sections, and provides recommendations for the cost-effective mitigation measures to reduce GHG emissions from industrial, institutional, and commercial gas-fueled heaters.

GHGs emitted during fuel combustion in boilers include carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). This section provides the data and inventory of currently permitted gas-fueled heaters and compares the GHG emissions with the 2002 Bay Area GHG emissions inventory (BAAQMD, 2006).

In the Bay Area, there are 314 permitted heaters subject to the Regulation 9-7. These all are fueled primarily on natural gas. Tables 1 and 2 provide information about the gas-fueled heaters and their GHG emissions, drawn from 2006 annual updates provided by BAAQMD.

Table 1 Permitted Heaters Currently Subject to Regulation 9-7

Rated Heat Input (MMBTU/hr)	Number of Heaters
Greater than 200	2
100 to 200	20
50 to 100	16
10 to 50	276
Totals	314

Table 2 Bay Area CO2 Emission Inventory from Annual Update

Rated Heat Input (MMBTU/hr)	Numbers of Heaters	Fuel Type	CO_2e Emission (Tons/year)
10 to 20	164	Natural Gas	1.76E+05
>= 20	150	Natural Gas	5.81E+05
Total	314		7.57E+05

Source: BAAQMD 2006 Annual Updates

The proposed amendment will add NOx emission limits for gas-fueled heaters with rated heat input between 2 and 10 MMBTU/hour. Currently, gas-fueled heaters rated less than 10 MMBTU/hour are exempt from permit requirements. Therefore, the exact number of these devices in the Air District is unknown. As shown in Table 1, the number of smaller gas-fueled heaters is substantially higher than of larger heaters. This trend shows a probability that an even higher number of gas-fueled heaters between 2 and 10 MMBTU/hour are operating in the Bay Area.

According to the boiler service companies, the total number of gas-fueled heaters between 2 and 10 MMBTU/hour in the Bay Area is close to 10,000. Since these heaters have been exempt from the regulations and were not designed to meet them in the first place, there is a high probability that many of these heaters can not meet the proposed emission limits due to design, poor maintenance, or age. For heaters that are required to implement control measures to achieve compliance, choosing the right and most cost-efficient control measure is very important.

Not all retrofit mitigation measures for NO_x support the GHG emission reduction in heaters. Traditional NOx control measures sometimes work against the reduction of GHG. If not chosen carefully, certain mitigation measures might not be compatible or may sacrifice the efficiency of the boiler. Lower efficiency correlates to higher GHG emissions because more fuel combustion is required to fulfill the performance target of the heaters. The failure to take into account all benefits and disadvantages from each technology could increase the operation and maintenance costs, elevate GHG emissions due to the extra fuel combustion, and cause a safety hazard. Therefore, it is important to make sure that the retrofit does not sacrifice the boiler turndown, overall efficiency, and total performance.

2.1 BAY AREA GHG INVENTORY

GHG emissions from gas-fueled boilers account for about 50 percent of the Bay Area's carbon dioxide equivalent (CO_2e) emission inventory for miscellaneous industrial processes and combustion stationary sources. The 50 percent contribution includes landfill gas combustion and residential combustion. The CO_2e emission represents CO_2 emissions plus the equivalent global warming potential of other GHGs, including CH_4, and nitrous oxide (N_2O). Bay Area GHG emission inventory is divided into various source categories. Industrial, institutional, and commercial gas-fueled heaters fall under the category of miscellaneous industrial/commercial processes and miscellaneous combustion stationary sources. Bay Area CO_2e boiler emissions with respect to the source specific categories are shown in Table 3.

Table 3 Bay Area Boiler GHG Emission and Inventory

Source Category	CO_2 (TPY)	CH_4 (TPY)	N_2O (TPY)	CO_2e (TPY)
Other Industrial/Commercial Processes	682,550	967	-	702,857
Other Combustion Stationary Sources	751,900	420	-	760,720
Total	1,434,450	1,387	-	1,463,577
Permitted Gas-fueled Boiler (CO_2e TPY)				757,369
Fraction from the Source Specific GHG Inventory (%)				51.75%

Note: All pollutants are shown as CO_2e. For example, CH_4 has 21 times the warming potential of CO_2. To show CO_2e, CH_4 mass emissions (shown in Table 2) are multiplied by 21 in order to show their CO_2e warming potential. Similar factors have been applied to all pollutants (CCAR, 2007).

Compared to the GHG inventory of all stationary combustion sources, gas-fueled boilers pursuant to Regulation 9-7 account for 2 percent of the inventory fraction. When mobile sources are included, this category of boilers account for 1 percent of the entire stationary and mobile GHG emission inventory.

Current Regulations

Industrial, institutional, and commercial gas-fueled boilers, steam generators, and process heaters are regulated under BAAQMD Regulation 9 Rule 7: *Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Heaters, Steam Generators, and Process Heaters* (Reg 9-7). These regulations are applicable to all industrial, institutional, and commercial heaters, steam generators, and process heaters with a rated heat input greater than or equal to 10 MMBTU/hour. Per Regulation 9-7.301, all boilers, steam generators, or process heaters with a rated heat input greater than or equal to 10 million BTU per hour, fired by gaseous fuel, have to meet NOx and CO limits of 30 ppmv, dry at 3 percent oxygen and 400 ppmv, dry at 3 percent oxygen, respectively.

Owners of gas-fueled heaters that are not in compliance with the limit have options to retrofit the heaters or to agree with the low fuel usage exemption upon the adoption of the amendment. Per Regulation 9-7-111, any boiler, steam generator, or process heater with an annual heat input of less than 90,000 therms during each consecutive 12-month period shall meet Sections 9-7-504 and one of the following conditions:

- Operate in a manner that maintains stack-gas oxygen concentrations at less than or equal to 3 percent by volume on a dry basis; or
- Be tuned at least once every 12 months by a technician in accordance with the procedure specified in Section 9-7-604; or
- Meet the emission limits specified in Sections 9-7-301, 302, or 303.

Among the permitted gas-fueled heaters, not all heaters operate at their maximum capacities. According to the 2006 annual updates, many of these heaters consume less than 90,000 therms of gaseous fuel during the particular year. Table 4 lists the heaters that use less than 90,000 therms in year 2006 according to the annual update data.

Table 4 Heaters with Lower than 90,000 Therms Consumption in 2006

Rated Heat Input (MMBTU/hr)	Number of Heaters	Heaters with >90,000 therms usage in 2006	Percentage of Heaters with >90,000 therms usage in 2006
Greater than 200	2	2	100.00%
100 to 200	20	3	15.00%
50 to 100	16	0	0.00%
20 to 50	112	39	34.82%
10 to 20	164	79	48.17%
Totals	314	123	38.17 %

Table 4 shows that approximately 39 percent of the permitted gas-fueled heaters are using less than 90,000 therms of natural gas fuel in 2006. Smaller boilers include a larger percentage of boilers with low fuel consumption compared to the larger boilers. Table 4 and Figure 1 show that a lot of small boilers are not operated at their maximum capacities.

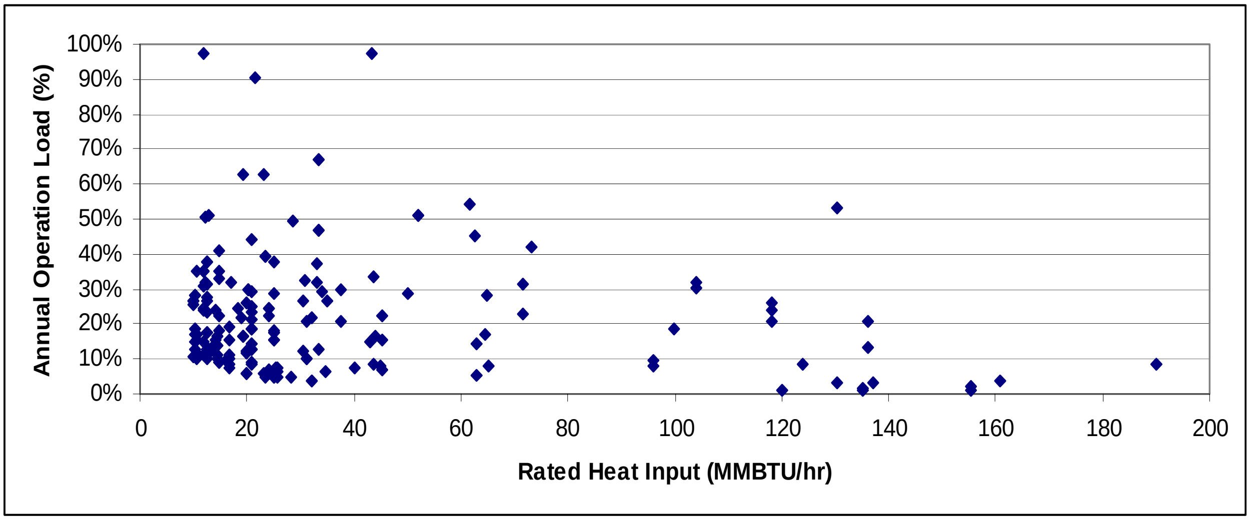


Figure 1 Boiler Operation Load Data

The amendment to Regulation 9-7 would lower the applicability from 10 MMBTU/hour input to 2 MMBTU/hour input. The amendment would also establish the NO_x and CO emissions limits for the size range mentioned. It is estimated that nearly 10,000 additional boilers with a rated heat input between 2 and 10 MMBTU/hour would be subject to the new amendment. Assuming the boilers only combust a small amount of fuel annually such that they are eligible for the low fuel usage exemption, the potential amount of GHG emissions that will be adopted by the regulation can be estimated as follows:

Table 5 Emission Factor for Low Fuel Usage Boiler

Natural Gas Annual Usage (Therms)	Greenhouse Gas Emission (Tons/year)			
	CO_2 Emission (52.78 Kg/MMBTU)	CH_4 Emission (0.0059 Kg/MMBTU)	N_2O Emission (0.0001 Kg/MMBTU)	CO_2e Emission
90,000	523.62	0.05853	0.00099	525.16

Multiplying the calculated emission factor by 10,000 additional small boilers, the proposed amendment would have an approximate increase of 5.25 million Tons/year of CO_2e emissions under the regulation. This estimated emission increase is substantial compared to the current total emissions from the gas-fueled boilers.

Boilers' performance and efficiency are highly dependent on fuel type, design, and operational requirements. With widely diversified operational scenarios and designs, efficiency improvement opportunities for Industrial/Commercial/Institutional (ICI) boilers cannot be simplified and categorized to a single common solution. A thorough engineering analysis and consideration of the impacts of each technology toward the specific boiler's operating scenario is very important. Boiler owners or operators need to make sure that the application of the chosen efficiency improvement technology would not generate negative impacts to the boiler's performance that may jeopardize the reliability or safety of the boiler's operation.

3.1 TYPES OF BOILER

The fundamental function of boilers is to transfer as much energy as possible from the fuel to the heated feed water via three heat transfer methods: radiation, conduction, and convection. In general, boilers can be categorized into two general categories: firetube and watertube. The fundamental difference between these two categories lies in the substance that flows within the boiler's tube.

As indicated by its name, a firetube boiler channels the hot flue gases from the burner through the tubes that are surrounded by the fluid to be heated. The body of the boiler is the pressurized vessel that contains the fluid. Firetube boilers are often characterized by their number of passes. Every set of tubes that the flue gas travels through as they transfer heat to the water is considered a "pass". To make another pass, the flue gas turns 180 degrees and passes back through another set of tubes to maximize the amount of heat transferred to the feed water. Firetube boilers with less passes are less efficient because these boilers have less chance to transfer the heat carried by flue gas to the water. In common practice, firetube boilers have up to four passes, depending on the design limitations and usage.

Unlike firetube boilers, a watertube boilers' heat transfer design is the exact opposite of a fire tube. In a watertube boiler, the feed water flows through the tubes. These tubes are incased in a furnace in which the burner fires into. Compared to firetube design, watertube design has an ability to withstand higher water pressure; hence, watertube boilers usually have higher efficiencies and the capability to generate saturated or superheated steam (DOE, 2001).

3.2 BOILER EFFICIENCY

In general, a boiler is a means to transfer energy contained in the combustion fuel to the feed water. To reduce the amount GHG emission from boiler's operation, boiler's efficiency needs to be improved so that less fuel is needed to be burned to produce the same amount of steam or hot water.

There are several types of efficiency in boiler terminology. For example, boiler efficiency is often substituted for thermal efficiency or fuel-to-steam efficiency. Therefore, it is important to know which type of efficiency is being represented. Note that the efficiency described is limited to the steam generation phase. The amount of energy lost during steam distribution is not accounted in these efficiency terms.

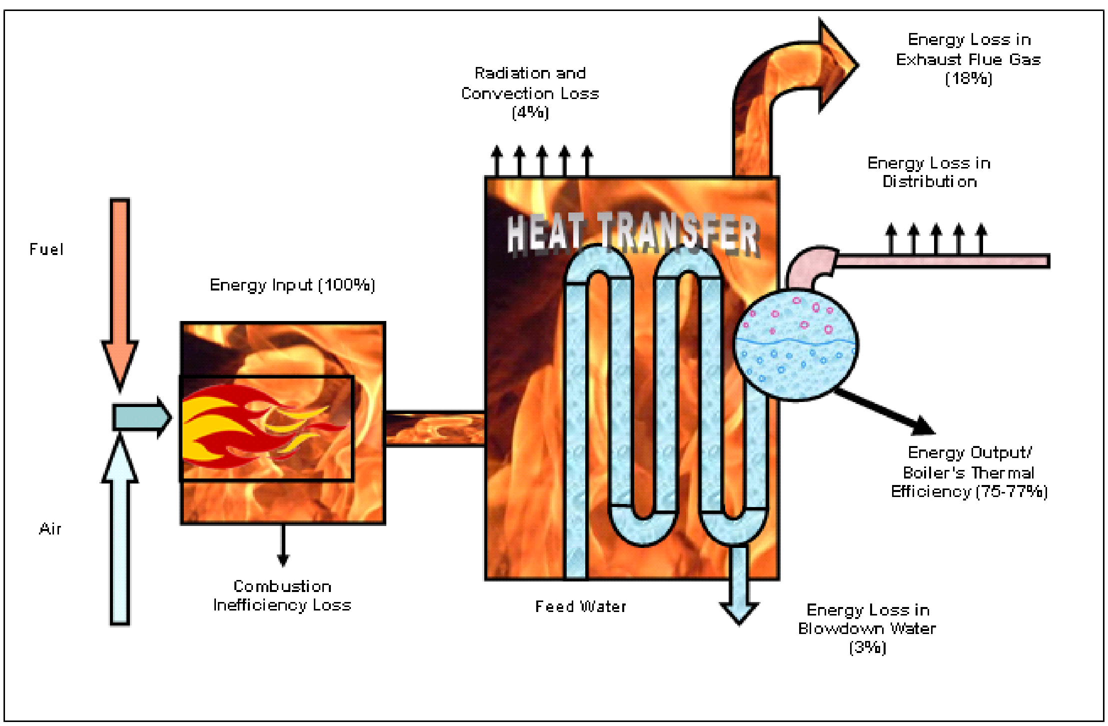
The three different types of efficiency are defined as follows:

- Combustion Efficiency: Combustion efficiency is a measure of how much of the fuel-bound energy is converted into useful thermal energy. This efficiency represents a burner's ability to completely burn fuel. The amount of unburned fuel and excess air in the exhaust are used to determine a burner's combustion efficiency. Burners that generate a low amount of unburned fuel while operating at low excess air are considered efficient. Combustion efficiency is not the same for all fuels. In general, gaseous and liquid fuels are more efficient than solid fuels.
- Thermal Efficiency: Thermal efficiency is a measure of the performance of the boiler’s heat exchanger. Because thermal efficiency is solely a measurement of the heat exchanger’s performance, it does not account for radiation and convection losses during steam generation and other losses. Therefore, it is not a true indication of the actual fuel consumption of the boiler to perform the duty.
- Fuel-To-Steam Efficiency: Fuel-to-steam efficiency is the actual measure of the overall efficiency of the boiler. It accounts for all thermal losses in the performance, including the total radiation and convection losses.

3.3 ENERGY LOSS SOURCES

It is not possible to extract each and every drop of energy from the fuel in boiler combustion into the water or steam. There are many energy loss sources that affect a boiler’s efficiency and performance. A general energy balance that lists common energy loss sources in a boiler is presented schematically in Figure 2 (CIPEC, 2001).

Figure 2 Boiler Energy Balance



Source: Energy balance ratio is taken from Canadian Industry Program for Energy Conservation (CIPEC). (2001). Boilers and Heaters, Improving Energy Efficiency

3.3.1 Combustion Inefficiency

Fuel combustion is the first step of transferring the fuel-bound energy to the water or steam. More efficient fuel combustion increases the amount of energy extracted from the fuel. Therefore, more energy is available in the flue gas to be transferred to the water. In a complete combustion reaction, the hydrocarbon molecular structure of the fuel is completely oxidized into carbon dioxide and water vapor. On the other hand, the incomplete combustion product will be emitted as CO and unburned hydrocarbon emissions. High CO emissions signalize poor combustion efficiency, and should be avoided.

In boiler systems, the oxygen used for combustion is provided by ambient air that is proportionally mixed with the fuel prior to or during combustion. Because ambient air contains about 21 percent oxygen by volume, good air and fuel mixing system is very important to assure optimum combustion and avoid safety hazards or boiler damage.

Optimum combustion is reached at a thorough mixture of air and fuel with as little excess air as possible and high enough temperature to sustain a complete combustion. Combustion is highly dependent on reactant composition, turbulence, time, and temperature. Appropriate combustion time, excess air optimization, and fuel-air mixing improvements are important solutions that potentially result in GHG emissions reduction.

Normally, boiler combustion systems operate with excess air slightly higher than the theoretical minimum or "stoichiometric" requirement. Excess air in the boiler system needs to be well controlled since this factor affects the combustion efficiency, process safety, and thermal efficiency. More air than the theoretical minimum requirement for complete combustion is usually supplied for the following reasons:

- To ensure stable and complete combustion over the operating range of the burner load.
- To prevent the toxic and explosive hazard from excessive CO formation due to incomplete combustion.
- To allow for margins in the required air-fuel ratio to accommodate combustion air property variations (i.e. humidity and temperature) and slight variations in the fuel chemical composition.

However, too much excess air in the combustion chamber is not beneficial in terms of efficiency because more energy is allocated to heat the air in order to maintain the combustion temperature. This excessive air-to-fuel ratio results in more fuel consumption required to extract the same amount of energy from the fuel. This increase in required fuel consumption translates to an increase in GHG emission.

Insufficient air is also not desired due to its explosive hazard potential. An insufficient air-to-fuel ratio in the furnace results in too much explosive gas contained within the furnace. Accounting for the benefits and disadvantages of excess air in the combustion, an appropriate amount of excess air and good control is necessary to accommodate the operation and changing load conditions during operation.

In addition to minimum excess air, good air and fuel mixing degree is important to reach complete combustion. Sufficient combustion time is important to allow the combustion reaction to occur to burn and extract the energy from the fuel. However, excessive combustion time will produce very long flames, which could cause flame impingement (a boiler maintenance hazard). Thorough mixing of fuel and air is also important to generate optimum combustion completion in the combustion chamber. Increased mixing degree of the air and fuel will further improve combustion efficiency by giving these components a better chance to react.

Further discussion on the available technologies to improve boiler's combustion efficiency is presented on Section 4. A more detailed discussion on Low NO_x burner, Flue Gas Recirculation, and Low Excess Air control systems as a form of boiler combustion improvement technologies are presented in Sections 4.1, 4.2, and 4.3 respectively.

3.3.2 Heat Transfer Inefficiency

The phase following the fuel combustion phase is the transfer of heat from the flue gas heat through the boiler tube material. For firetube and watertube boiler designs, energy carried by the flue gas is transferred from one end of boiler tube surface to the other end. The energy or heat that is not transferred to the fluid usually escapes the boiler system in the form of stack exhaust, radiation, and convection loss.

In the boiler system, heat is transferred from the flue gas through convective heat transfer, and further conducted through the boiler tubes wall to reach the flowing water. The amount of heat transferred through convection and conduction is primarily dependent on flow velocity, tube material surface area, tube material heat conductivity, and flue gas temperature. The amount of heat transferred from the flowing flue gas to the tube surface depends on the physical properties of the flue gas and the physical structure of the boiler. Typically, the convective heat transferred by laminar flow is low compared to the convective heat transferred by turbulent flow. This difference is due to turbulent flow having a thinner stagnant fluid film layer on the heat transfer surface that adds resistance to heat transfer. In addition to convection, heat is also conducted across the boiler tube shell material. Heat conductivity of the tube shell material determines the maximum overall thermal efficiency of the boiler.

Besides the boiler tube material's heat conducting properties, certain reactions or deposits on the tube wall can degrade the overall conductivity of the tube wall. Scale is one of the most common deposit-related problems that reduce thermal conductivity of a boiler tube. Scale is a buildup of solid minerals on the water-side tube surface from the reaction between the dissolved minerals in the water and the boiler tube metal. Scale acts as a resistance or insulator that reduces the overall heat conductivity. Scale not only causes a decrease in boiler efficiency, it may also lead to excessive fuel consumption and create a potential of tubes overheating and tube damage. There are several methods to avoid heat transfer inhibition by scale deposition. Scale formation can be avoided by adding feed water pretreatment, increasing blowdown rate, or more frequent tuning and inspection.

3.3.3 Heat Loss in Stack Flue Gas

Even with a good combustion system and efficient thermal conductivity, there is a lot of energy lost through the stack. As described in the energy balance (Figure 2), almost 20 percent of the energy extracted from the fuel escapes via the stack flue gas of a common boiler. This fact shows there is ample room for heat recovery opportunities to use this heat to reduce the boiler's fuel consumption. A high stack temperature indicates a large amount of energy is being vented and lost to the atmosphere. Monitoring and limiting stack temperature is a good way to identify heat transfer problem in the boiler.

Boiler combustion system improvements, flue gas pass increases, or heat transfer efficiency improvements are common approaches to reduce the stack temperature. However, these approaches might not suffice to reduce the heat loss from the stack. In most boiler operations, the thermal value from the exhaust flue gas may be recovered with the addition of heat recovery systems to reduce fuel consumption. With additional heat recovery systems, the exhaust flue gas energy can be used to preheat boiler feed water and/or combustion air. A feed water economizer exchanges heat between the flue gas and feed water prior to it entering the boiler. A combustion air preheater exchanges heat between the flue gas and the combustion air prior to it entering the boiler. Both of these retrofit components are heat exchangers that extract energy from the flue gas that would otherwise be wasted to the atmosphere.

In addition to the heat loss carried by the gaseous component of the flue gas, boilers also suffer heat loss due to the moisture generated from hydrogen combustion. The product of hydrogen combustion is water vapor which exits through the stack with other gaseous combustion products. This water vapor carries energy that is mostly stored as heat of vaporization. This energy is a good source of reclaimable heat that can help reduce fuel consumption. However, the low temperature required to condense the water vapor and the resulting moisture exposure raise another issue with the extraction of this energy. Great attention must be paid to the materials of construction to address the corrosion issue from the moisture formation.

Further discussion on the available technologies that reduce the heat loss on the stack flue gas is presented in Section 4. A more detailed discussion on the performance of air preheater and economizer in recovering the heat from the stack flue gas are presented in Sections 4.4 and 4.7 respectively.

3.3.4 Radiation and Convection Heat Loss

Although it is not as significant as the stack loss, boiler surfaces also loss heat through radiation and convection. These losses are caused by heat radiated to the ambient atmosphere and heat swept by ambient air convection. The magnitude of heat loss through radiation and convection is generally dependent on the external surface area of the boiler and its temperature. A compact boiler design is beneficial from an efficiency standpoint because it has less contact area with the ambient atmosphere.

Because radiation and convection loss from boiler operation has a complex dependency to many boiler operating factors, the American Boiler Manufacturers Association (ABMA) has compiled a standard radiation loss chart for boilers with furnace and heat exchange surface enclosed together. Typical values of radiation losses from various boiler operations are summarized below.

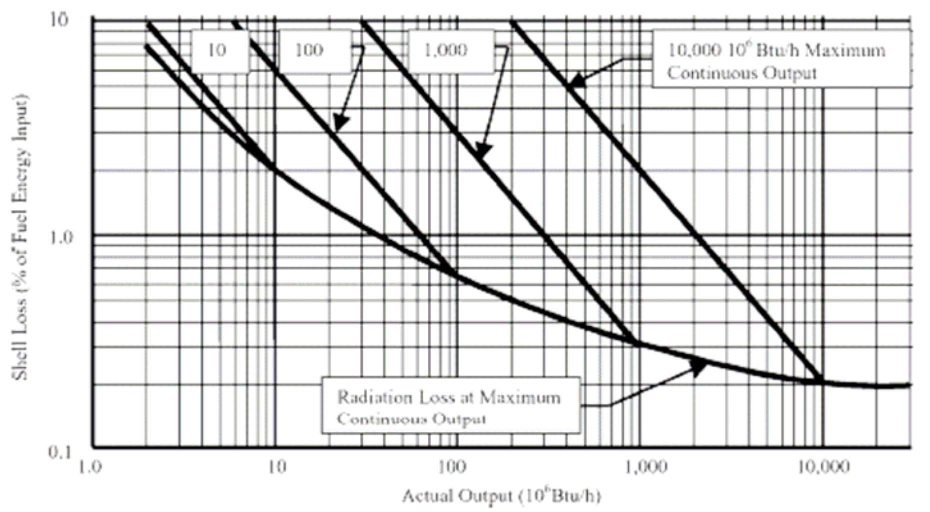


Figure 3 ABMA Typical Shell Loss

Source: Greg Harrell, Ph.D., P.E. 2002. STEAM SYSTEM SURVEY GUIDE. The University of Tennessee. Energy, Environment, and Resources Center.

As shown above, the quantity of heat loss resulting from higher firing rate or higher load is lower than the quantity of heat loss resulted from partial load operation. Therefore, an appropriate boiler size and operating load scenario is important, since they determine the magnitude of heat loss via radiation and convection. There are several ways commonly employed to address this issue. The solutions include but are not limited to adding a boiler blanket, choosing a smaller boiler to achieve higher load operation, and buying a boiler with a compact design.

3.3.5 Heat loss in blow down

Boiler feed water contains a small amount of dissolved minerals. During the heating process within the boiler, only the water is evaporated. The dissolved minerals accumulate in the remaining water and may lead to scale formation. To prevent scale buildup, a boiler's recirculating water must be blown down periodically.

The purpose of blowdown is to decrease the amount of solids and sludge in the boiler water or fluid. The magnitude of blowdown rate required depends on the feed water characteristics, boiler design limitations, and operating load. Boiler blowdown is important to reduce heat transfer resistance that affects the efficiency of a boiler. Blowdown is also important to avoid the potential of boiler tube overheating or failure due to scale deposition.

Thin layer of scale deposition on boiler tube surface reduces the heat transfer efficiency of the boiler tube material. Fuel waste due to boiler scale may be 2 percent for water-tube boilers and up to 5 percent in fire-tube boilers (DOE, 2001).

The presence of scale deposition on boiler tube surface affects boiler efficiency. For smaller boilers, intermittent blowdown will be sufficient to avoid scale deposition. However, larger boilers need more blowdown due to larger load. Larger boilers usually choose to have continuous blowdown to maintain the dissolved minerals in an acceptable range of concentration.

Because the blown down water is already heated by the system, higher blowdown will result in higher heat loss through the blowdown system. For smaller boilers with intermittent blowdown, recovering the heat loss from blowdown might not worthwhile. However, the blowdown heat loss magnitude is more significant for larger boilers. A good blowdown rate control and even the recovery of heat from the blowdown are required to optimize the blowdown rate and recover the energy loss resulted from the required blowdown.

Table 6 Energy Loss Caused by Scale Deposit

Fuel Loss, % of Total Use			
Scale Thickness (inches)	Scale Type		
	"Normal"	High Iron	Iron Plus Silica
1/64	1	1.6	3.5
1/32	2	3.1	7
3/64	3	4.7	–
1/16	3.9	6.2	–

Source: DOE, Improving Steam System Performance, a Sourcebook for Industry.

As shown in Table 6, scale deposition on boiler tubes may cause energy loss and safety issues. An appropriately minimized boiler blowdown rate and an economically feasible heat recovery have the potential to reduce the energy loss.

3.3.6 Heat loss during distribution

In addition to all heat or energy losses accounted for in the fuel to steam efficiency, steam or hot water systems also suffer heat losses during distribution. These distribution heat loses are primarily caused by insufficient piping insulation and leaks from piping or malfunctioning steam traps. Sufficient piping insulation and periodic steam traps maintenance will reduce these losses and maintain optimum steam distribution efficiency.

Pipe insulation is required to reduce distribution heat loss to the atmosphere until the steam or hot water reach the end user. For pipe insulation, the magic number that determines the necessity of installing insulation is 120° F (Payne, 1991). If the pipeline's exterior surface temperature exceeds 120° F, insulation or thicker insulation is required. Prior to installing an insulation system, there are several factors that need to be considered. These factors include but are not limited to pipeline steam pressure, insulation material, temperature of steam and ambient air, and pipe diameter. These factors greatly influence the effectiveness of the insulation and the parameters for the required insulation installation.

In addition to pipe insulation, a properly functioning steam trap is also very important in the steam distribution system. A steam-trap functions to keep steam in the system while removing water condensate and air to improve steam transfer ability and reduce corrosion potential. Steam traps are designed to operate intermittently. When a steam trap fails in the open position, it allows the steam to blow-through along with the condensate. This loss of steam can represent a substantial energy loss. A frequent stream trap inspection and repair/replacement program will be beneficial to reduce these distribution losses. Further discussions on opportunities to reduce heat losses from steam distribution systems are presented in Sections 4.8 and 4.9.

As discussed above, there are many sources of heat loss in the boiler system which create potential to be corrected to reduce GHG emissions. More detailed discussions of each efficiency improvement/GHG mitigation technology are presented in the next section of this document. The discussions include: general concepts, benefits, disadvantages of the technology, feasibility, and available economic analysis.

The basic methods to reduce GHG emissions from boiler systems are either to increase the overall efficiency of the boiler (extract as much energy as possible and reduce as much heat loss as possible) or to use alternative renewable fuels for indirect GHG emissions mitigation.

In addition to fuel efficiency enhancer and heat loss reduction devices, some of the NOx emission control technologies offer the ability to increase fuel efficiency that directly correlates to GHG emission reductions. Boiler NOx emission control technologies are categorized into the two major categories of combustion modification and post combustion treatment. Various control technologies presently exist for controlling the boiler criteria pollutant emissions. Combustion modification includes Low-NOx burners, Flue Gas Recirculation systems, Low Excess Air (LEA) Control System, and Water/Steam Injection. Post-combustion treatment includes Selective Catalytic Reduction and Selective Non-Catalytic Reduction.

Each control technology mentioned above has its own effect on implementation. For the purpose of mitigating GHG emissions from boilers, Water/Steam Injection and post combustion treatment are not discussed in this section since they have no potential to increase boiler efficiency.

Boiler efficiency is the efficiency with which the heat input to the boiler is converted to output steam or hot water. The calculation of boiler efficiency incorporates several heat losses such as combustion inefficiency loss, flue gas/stack heat loss, radiation and convection heat loss, blowdown heat loss, and heat loss during distribution. These heat losses need to be reduced to increase the overall boiler efficiency. Note that the maximum boiler efficiency for a natural gas boiler is limited to a certain value that cannot be exceeded with any additional equipment. The maximum theoretical efficiencies vary according to the characteristics of the boiler. Below are some general approaches and available technologies to improve boiler efficiency.

- Optimizing excess air (low NOx burner, low excess air control system, and FGR)
- Increasing heat transfer (FGR and turbulator)
- Preheating combustion air or feed water (economizer and air preheater)
- Reducing scale and deposits (blowdown control, water pretreatment, and tuning)
- Operating at peak efficiency (low excess air control system, turbulator)
- Reducing steam distribution loss (pipe insulation and steam traps)
- Periodic maintenance

This section discusses the applicability of each mitigation measure as a retrofit for boilers subject to the proposed amendment. The discussions include general information on the GHG reduction potential from boiler efficiency improvement, advantages, disadvantages, and available economic analysis for each opportunity.

4.1 LOW NOx BURNER

A boiler efficiency improvement should begin with the burner. Combustion efficiency is the limiting factor for the overall boiler performance. Therefore, an inefficient burner design will directly limit the total amount of extracted fuel bound energy that is available to be transferred to the water.

The main function of a burner is to insure that the fuel is evenly mixed with air to burn completely within the combustion chamber. In addition to stoichiometrically adequate oxygen in the combustion chamber, three main factors that affect boiler combustion are reaction time, combustion temperature, and turbulence of the mixture. To reach optimum combustion, fuel and oxygen must have enough reaction time, they must be at the appropriate combustion temperature, and they must be thoroughly mixed. If any factor is not achieved, the combustion completion will be reduced.

To comply with the NOx regulatory limit, a Low NOx Burner (LNB) is one of the most common heater retrofit technologies readily available in the market. LNBs are available for both new and retrofit boiler applications. This technology is usually installed individually or accompanied by other mitigation measures such as flue gas recirculation, low excess air control, and an economizer.

LNB design usually incorporates larger flame, better fuel-air mixing, low excess air, fuel and/or air staging combustion. In general, LNBs reduce thermal NOx formation by promoting a lower peak combustion temperature. This peak temperature reduction can be promoted by staged combustion techniques. Staged combustion techniques produce fuel-rich and fuel-lean zones within the flame. These stages delay the mixing of fuel and air to lower the flame temperature and to optimize complete fuel combustion downstream of the primary combustion zone.

The LNB flame lengths tend to be longer than those of conventional burners due to the staging effect. Therefore, the burner must be designed to generate a stable flame that, most importantly, fits the furnace geometry. Without this consideration, there is a possibility that flame impingement occurs on the furnace walls, resulting in tube failure and corrosion. As a retrofit option, this technology might not be suitable for all older heaters since it requires an extensive retrofit (USEPA, 1994).

Lower flame temperature reduces thermal NOx formation in the flue gas. However, it may risk a fuel efficiency penalty, as can occur with water/steam injection. Failure to take into account CO emissions as the indicator of combustion efficiency will results in a GHG emission increase. A well-designed LNB would be able to improve the combustion efficiency without suffering a significant efficiency penalty from lower flame temperature.

During combustion, carbon in the fuel oxidizes through a series of reactions to form CO_2. Complete fuel combustion to CO_2 is rarely achieved in practice since some of the fuel carbon incompletely oxidized into carbon monoxide. Older boilers generally have higher levels of CO that is primarily a result of poor uniformity within the flame zone burner. A well designed LNB promotes a perfectly mixed combustion zone and improves complete combustion in the secondary combustion zone, hence it compensates for the CO emission increase.

Various literature articles and studies present different arguments regarding this issue due to the wide variety of LNB designs on the market. Therefore, there is not enough performance data to determine the quantity of potential GHG reduction by LNB retrofit. However, LNB design that promotes lower excess air due to staged combustion and more uniform mixing in the combustion chamber shows the potential of a well designed LNB to reduce GHG without suffering a significant efficiency penalty from lower flame temperature.

The LNB retrofit cost varies widely according to the boiler's characteristics and performance. Therefore, cost analysis for this type of retrofit should be performed on a case-by-case basis. The following list is the historical quotes of LNB retrofit cost approximation for general comparison.

Table 7 Historical Boiler BARCT Cost for Low NOx Burner

Boiler Rating (MMBtu/hr)	Low NOx Burner Capital Cost ($)
24	55,000
38	64,000
62	82,000
82	120,000

Source: Implications of Future Oxides of Nitrogen Controls from Seasonal Sources in the San Joaquin Valley Regulatory Assistance Section Project Assessment Branch Stationary Source Division January 2002

4.2 FLUE GAS RECIRCULATION SYSTEM

Flue gas recirculation (FGR) systems are a NO_x emission control technology based on recycling a portion of the essentially inert flue gas to the primary combustion zone and mixing the low-oxygen flue gas with combustion air prior to it entering the combustion chamber. The FGR system reduces boiler NOx emissions by two mechanisms. Primarily, the recirculated flue gas reduces the peak combustion temperatures, thus inhibiting the formation of thermal NOx. FGR also lowers the percentage of oxygen in the combustion air/flue gas mixture, which in turn reduces the thermal NOx formation mechanism.

FGR technology can be classified into two types; external or induced. External FGR uses an external fan to recirculate the flue gases back into the flame. This design requires additional external piping to send the exhaust gases from the stack to the combustion chamber. The recirculation rate is usually controlled based on boiler input. Induced FGR uses the combustion air fan to recirculate the flue gases back into the combustion chamber. A portion of the flue gas is recirculated via duct work or internally to the combustion air fan, where it is premixed with the combustion air and re-introduced into the combustion chamber. In general, induced FGR design is less complicated because it does not require as extensive external retrofit, and it does not cause as much additional indirect GHG emissions from external fan operation.

FGR retrofit has some disadvantages that need to be considered prior to its application. In order to retrofit a boiler with FGR, the major additional components that may be needed are a gas recirculation fan and ductwork. These additional components require additional capital cost and increase the boiler operational cost. In FGR operation, a recirculation fan requires a significant amount of electricity. The indirect GHG emission from fan electricity expenses at high recirculation rate might exceed the GHG reduction from the efficiency improvements. Therefore, the recirculation rate in FGR is an important factor to consider in operating an FGR. A well-designed FGR would be able to reduce NOx emission without suffering a significant efficiency penalty from lower flame temperature and electricity cost for fan operation.

In a manner similar to LNB application, FGR application has an issue with flame stability and geometry. The lowering of excess oxygen in the combustion air with FGR causes the active combustion zone to lengthen beyond the furnace arch, which may result in flame instability and potential flame impingement. Therefore, boilers are usually not operated with more than 20 percent FGR to ensure the operational stability and safety (USEPA, 1994).

Although the lower flame temperatures due to FGR application could result in an efficiency loss, FGR application does not necessarily reduce the boiler efficiency. In fact, the recirculated flue gases increase the mass flow through the boiler, thus it increases turbulence and increases the convective heat transfer in the tube passes as a form of efficiency compensation. A well designed and controlled FGR package can lower NOx levels by reducing flame temperature without increasing CO levels. CO levels remain constant or are lowered because the flue gas is introduced into the flame in early stages of combustion and the air fuel mixing is intensified. Intensified mixing offsets the decrease in flame temperature and results in CO levels that are lower than achieved without FGR, which translates to GHG emissions reduction. However, the change in CO emission level depends on the burner design. Not all flue gas recirculation applications result in lower CO levels. The efficiency increase contributed by heat transfer improvement and combustion chamber mixing improvement potentially surpass the incomplete combustion increase due to lower peak flame temperature, hence improve the fuel efficiency of the boiler.

An FGR system can be used individually or in combination with specially designed low NOx burners that have the capability of sustaining a stable flame with the increased inert gas flow from the FGR. In general, FGR is rarely applied without the installation of a new Low NOx Burner for retrofit cases. This is because the performance of many older burner systems tends to be adversely affected when the additional inert flue gas is injected into the combustion zone (USEPA, 1994). The FGR retrofit cost and impact toward GHG emissions varies widely according to the boiler’s characteristics and performance. Therefore, cost analysis for this type of retrofit should be performed on a case-by-case basis.

4.3 LOW EXCESS AIR CONTROL SYSTEMS

As mentioned before, efficient combustion is the sole means of extracting energy from fuel in boiler operation. Combustion improvement does not depend only on burner design; instead, an efficient combustion must be supported by other boiler parts to maintain the peak efficiency during operation. To maintain peak boiler combustion efficiency, a good control of excess air present in the combustion chamber is essential.

Excess air is defined as the air supplied to the burner beyond the amount that is theoretically required for complete combustion. Too much excess air infiltration interferes with the efficiency of the fuel-burning process and wastes the fuel energy to heat the excess air. High level of excess air translates to additional energy losses. However, insufficient excess air levels may result in incomplete combustion and wasted unburned fuel. Air slightly in excess of the ideal stoichiometric fuel/air ratio is required for safety, and to reduce NOx emissions.

To minimize this loss, certain combustion parameters must be maintained to assure the optimum combustion efficiency. Figure 4 shows the correlation between combustion efficiency, CO emission level, and excess oxygen level for common boilers.

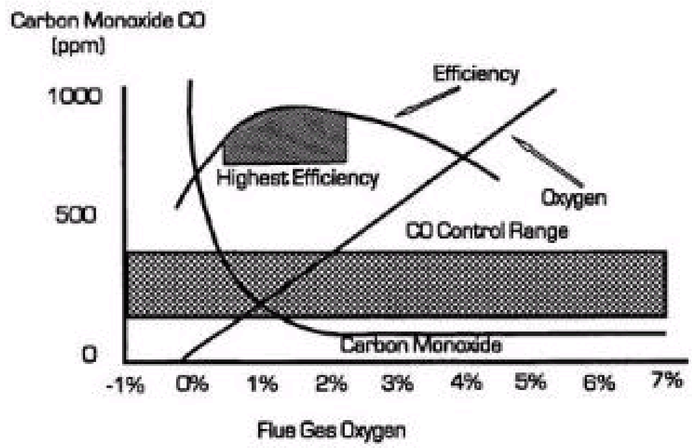


Figure 4 Boiler Efficiency, Flue Gas Oxygen, and CO Correlations

Source: Combustion Efficiency Tables, Taplin, Harry R., Fairmont Press, 1991, Chapter 5.

As shown above, optimum combustion efficiency with optimum CO reduction is reached at a 2 to 3 percent excess oxygen level. Table 8 shows further detailed data on the excess oxygen and excess air correlation with combustion efficiency.

Table 8 Combustion Efficiency for Natural Gas

Excess %		Combustion Efficiency Flue gas temperature less combustion air temp, °F				
Air	Oxygen	200	300	400	500	600
9.5	2	85.4	83.1	80.8	78.4	76
15	3	85.2	82.8	80.4	77.9	75.4
28.1	5	84.7	82.1	79.5	76.7	74
44.9	7	84.1	81.2	78.2	75.2	72.1
81.6	10	82.8	79.3	75.6	71.9	68.2

Source: DOE, Improving Steam System Performance, a Sourcebook for Industry.

Low-excess-air (LEA) control systems optimize the amount of air in the combustion process to reduce both fuel consumption and NOx formation. Lower local oxygen concentration in the combustion zone inhibits the formation of both thermal and fuel NOx. This technology also results in a lower flue gas temperature, which further reduces the thermal NOx mechanism. Thermal efficiency is increased by reducing the heat loss associated with heating excess air not required for combustion. Therefore, the fuel efficiency is increased, and the GHG emissions reduced.

There are several LEA control systems that have been widely used in industrial boilers. Examples of these systems include:

1. Bambeck System: CO Based Control Technology ($58,978- $235,402/boiler), and
2. Benz Air Engineering: Compu NOx ($80,000/boiler)

Due to the variety of products on the market, there is no standard performance data for LEA control systems. The aforementioned price quotes are for large boilers with rated heat inputs of 94 MMBTU/hour to 150 MMBTU/hour.

Over-adjusting the fuel-air ratio for combustion also has a downside. If the fuel-to-air ratio is too high, incomplete combustion occurs. This will result in carbon soot deposits inside the combustion chamber or even over the boiler tubes. The presence of soot deposits over the heat transfer surfaces and the potential for having explosive flue gases inside the boiler are much worse than losing a slight amount of energy through the exhaust stack. Therefore, a slight excess air adjustment and frequent boiler maintenance are important to maintain optimum boiler performance.

4.4 AIR PREHEATER

A common retrofit technology to utilize the heat contained in the hot flue gas is an air preheater. The air preheater functions to recover the heat carried by the stack flue gas and to raise the temperature of the combustion air to the boiler, which results in increased thermal efficiency of the boiler. As a consequence, the installation of air preheater in the boiler system reduces the flue gas stack temperature.

Air preheater designs are primarily classified into two categories, recuperative and regenerative (Payne, 1991). Recuperative air preheater design directly transfers the energy from the flue gas to the combustion air through a separating heat transfer surface. The most common types of separating surface are tubular and flat plate. Similar to the heat transfer concept in the boiler, a recuperative air preheater transfers the heat via convection and conduction through the heat exchanger shell. As the ambient temperature combustion air passes the heat exchanger, the hot flue gas flow provides a counter flow heat transfer.

Unlike a recuperative preheater, regenerative preheaters transfer the heat to an intermediate heat storage medium prior to transferring it to the combustion air. In common designs, regenerative preheaters incorporate rotating plates or wheels as the heat transfer intermediate. The heat is transferred through a regenerative heat-transfer surface in a rotor that turns continuously through the gas and air streams, effectively separating the air stream from the flue gas stream.

There are some advantages and disadvantages from each design of air preheater. In general, the recuperative air preheater design is simpler. This design is advantageous since there are no moving parts and no energy is required to run the heat exchanger. However, this design suffers from corrosion issues and space inefficiency issues due to its larger size.

The performance and cost of air preheaters varies greatly depending on its type, design, geometry, and material. Recuperative air preheaters are generally more commonly used in industry. In addition, this design has no criteria pollutant trade off and less safety issues since it has no moving parts. However, this type of preheater has to consider corrosion issues due to moisture formation within the heat exchanger. Choosing preheater material that has the ability to perform well under moisture exposure is significant to the lifetime of the preheater.

4.5 BLOWDOWN CONTROL AND BLOWDOWN HEAT EXCHANGER

Scale forms as the solubility of the scale-forming minerals in water decreases and the temperature and concentration of the dissolved minerals increases. As mentioned in the previous section, blowdown is essential to maintain an acceptable concentration of certain dissolved minerals in the boiler water. However, blowdown also represents an energy loss to the boiler system. To reduce the energy loss from blowdown boiler operators may reduce the blowdown rate, reduce the makeup water requirement, or recover the blowdown heat loss with a heat exchanger. Boiler water pretreatment and automatic blowdown control systems are solutions to reduce the blowdown rate for larger boilers.

Automatic boiler blowdown control equipment covers a range of products that are specifically designed to adjust the blowdown rate from a boiler in a manner to ensure the level of dissolved solids within the boiler water is below the pre-set limit. The benefit of this automatic control system is that it is more accurate than manual control (or simple timer-based control) and provides better control of the total dissolved solids level in steam boilers. Therefore, this control system will avoid unnecessary blowdown. The savings are dependent upon the blowdown rate, which is in turn dependent upon whether an automatic blowdown control system is in use and whether a blowdown heat recovery system is in place.

Another method of energy saving related to blowdown is a reduction of makeup water heating requirements and heat recovery. Heat recoveries from condensate and boiler blowdown are specifically designed to recover heat present in steam condensate and/or water from boiler blowdown by means of flash steam recovery vessels and/or heat exchangers. The energy saving is dependent on the blowdown rate and makeup water quantity. A heat exchanger installation to warm makeup water may also function as an energy saving approach.

In general, a boiler with continuous blowdown exceeding 5 percent of the steam rate is a good candidate for the introduction of blowdown waste heat recovery (DOE, 2001). However, an effort to salvage heat loss from blowdown may only be economically possible for boiler operations with high amount of blowdown. It is estimated that blowdown heat recovery is economical for blowdown rates as low as 500 lb/hr (CIBO, 1997).

Based on a sample case with a steam production rate of 100,000 pounds per hour, 60°F makeup water, and 90 percent heat recovery, the GHG reduction and fuel cost saving potential from a heat exchanger installation to heat boiler feed water are summarized below.

Table 8 Boiler Blowdown Recoverable Heat

Blowdown Rate (% Boiler Feedwater)	Recoverable Heat (MMBtu/hr)				
	Steam Pressure (psig)				
	50	100	150	250	300
2	0.50	0.56	0.61	0.72	0.72
4	1.00	1.11	1.22	1.44	1.44
6	1.44	1.67	1.89	2.11	2.22
8	1.89	2.22	2.44	2.89	3.00
10	2.44	2.78	3.11	3.56	3.67
20	4.89	5.56	6.22	7.11	7.33

Source: DOE, Improving Steam System Performance, a Sourcebook for Industry.

Table 9 Potential GHG Emission Reduction from Blowdown Heat Exchanger Application

Blowdown Rate (% Boiler Feedwater)	Potential GHG emission reduction (tons of CO_2e/ yr)				
	Steam Pressure (psig)				
	50	100	150	250	300
2	230	256	281	332	332
4	460	511	562	664	664
6	664	767	869	971	1,022
8	869	1,022	1,125	1,329	1,380
10	1,125	1,278	1,431	1,636	1,687
20	2,249	2,556	2,862	3,271	3,374

Note: GHG emission reduction is based on 90% heat recovery and 8760 hrs of operation/year

Table 10 Potential Fuel Cost Saving from Blowdown Heat Exchanger Application

Blowdown Rate (% Boiler Feedwater)	Potential Fuel Cost Saving ($/ yr)				
	Steam Pressure (psig)				
	50	100	150	250	300
2	39,420	43,800	48,180	56,940	56,940
4	78,840	87,600	96,360	113,880	113,880
6	113,880	131,400	148,920	166,440	175,200
8	148,920	175,200	192,720	227,760	236,520
10	192,720	219,000	245,280	280,320	289,080
20	385,440	438,000	490,560	560,640	578,160

Note: The potential fuel cost saving does not include the cost of heat exchanger installation and maintenance

4.6 TURBULATOR

Turbulators are small angular or coiled metal strips that are inserted into boiler tubes to increase the turbulence within hot combustion gases. Turbulators are only suitable for older boilers that have two or three passes. Additional turbulators installed on boilers with four passes is not efficient since these boilers have provided enough opportunities from the flue gas to transfer heat to the feed water within the boiler. The turbulence increase within the gas flow increases the convective heat transfer to the tube surface and hence results in heat transfer improvement and lower fuel cost.

Turbulators are a cheaper substitute for an economizer or air-preheater. The installed cost of a turbulator ranges from $10 to $15 per boiler tube. Turbulators are claimed to have the ability to provide about 2 to 10 percent fuel savings, and the savings have been as high as 35 percent (USEPA, 1994). In addition, a manufacturer also claimed that turbulators can cut 6 to 16 percent of the annual heating cost. The fuel cost savings directly correlate to the amount of fuel combustion avoided. Therefore, turbulators have the potential to reduce 2 to 10 percent of the GHG emissions from older boilers with a relatively low capital cost.

To estimate the GHG reduction potential and cost efficiency of this mitigation measure, the following assumptions were made for reporting purposes:

- 200 tubes/boiler: 400 HP (13.4 MMBTU/hr)
- Current boiler efficiency: 80 percent
- Turbulator Price: $15/boiler tube
- Installation cost: 50 percent of Purchased Equipment Price
- Maintenance cost: $500/year
- Turbulator life: 5 years
- Capital Recovery factor (8 percent interest, 5 years): 0.25
- Fuel Price: $10/MMBTU Nat Gas
- Conservative assumption that turbulators are only able to increase the boiler efficiency up to 3 percent.

Using the aforementioned assumptions, Table 11 shows the reduction potential and cost efficiency of turbulators at different fuel usage levels.

Table 11 Turbulator Reduction Potential

CO_2 Reduction (Tons/year CO_2e)			
	Fuel Efficiency increase (%)		
Fuel Consumption (MMBTU/yr)	1%	2%	3%
5,000	3.60	7.12	10.55
10,000	7.20	14.23	21.09
15,000	10.81	21.35	31.64
20,000	14.41	28.46	42.18
25,000	18.01	35.58	52.73
30,000	21.61	42.70	63.27
35,000	25.21	49.81	73.82
40,000	28.81	56.93	84.36

Table 12 Turbulator Cost Efficiency

CO_2 Reduction Cost ($/TPY CO_2e)			
	Fuel Efficiency increase (%)		
Fuel Consumption (MMBTU/yr)	1%	2%	3%
5,000	279.78	56.98	(17.28)
10,000	54.20	(57.20)	(94.33)
15,000	(20.99)	(95.26)	(120.01)
20,000	(58.59)	(114.29)	(132.85)
25,000	(81.15)	(125.71)	(140.56)
30,000	(96.19)	(133.32)	(145.70)
35,000	(106.93)	(138.76)	(149.37)
40,000	(114.99)	(142.83)	(152.12)

Note: The GHG emission reduction cost includes capital recovery, operating, and maintenance costs.

As shown above, turbulators are cost-effective and start showing a return when used as GHG mitigation for boilers with more than 10,000 MMBTU/year fuel usage rate. Compared to the regulatory limit on low fuel usage exemption (90,000 therms/year or 9,000 MMBTU/yr), the result that turbulators start to show a good payback at 10,000 MMBTU/year provides a good coverage for boilers with fuel usage slightly above the exemption.

4.7 ECONOMIZER

In a manner similar to turbulators, economizers are only suitable for boilers with low-heat transfer or thermal efficiency. An economizer uses the excess heat from the flue gas to preheat the feed water. An economizer is basically a heat exchanger that transfers heat from the hot flue gas exiting the stack to the feed water. The savings potential of economizers is based on the stack temperature, the volume of water, and the hours of operation.

There are two primary types of economizers, namely a non-condensing economizer and a condensing economizer. Non-condensing economizers are usually air-to-water heat exchangers that are not designed to handle flue gas condensation; hence these economizers usually operate at higher temperatures. Condensing economizers are specially designed economizers that can handle exhaust gas condensation to extract more energy from the latent heat recovery. These economizers require special materials to endure the possibility of corrosion from the gas condensates.

To estimate the GHG reduction potential and cost efficiency of the economizers, the following assumptions were made for reporting purposes:

- Current boiler efficiency: 81 percent
- Efficiency is defined as fuel to steam efficiency
- Economizer life: 5 years
- Capital Recovery factor (8 percent interest, 5 years): 0.25
- Fuel Price: $10/MMBTU Nat Gas

Using the aforementioned assumptions, Table 9 shows the reduction potential and cost efficiency of economizer for different size of heaters.

Table 13 Heat Sponge Economizer Price Quotes

Heater Size (MMBTU/hr)	Total Fuel Saving (MMBTU/yr)	Minimum GHG Reduction (TPY CO_2e)	Total Annual Capital Recovery and O&M	CPTR ($/T CO_2e)
2	1,509.33	88.07	$ (7,073)	$ (80.31)
4	1,617.17	94.36	$ (8,151)	$ (86.38)
6	1,734.88	101.23	$ (9,328)	$ (92.15)
8	1,835.22	107.08	$ (10,332)	$ (96.48)
10	2,905.47	169.53	$ (16,316)	$ (96.24)
15	4,860.10	283.59	$ (29,442)	$(103.82)
20	5,782.95	337.43	$ (36,725)	$(108.84)
25	7,389.15	431.16	$ (48,897)	$(113.41)
30	19,707.05	1,149.91	$ (144,143)	$(125.35)
40	28,401.21	1,657.21	$ (219,336)	$(132.35)
50	34,489.31	2,012.45	$ (277,399)	$(137.84)
60	42,601.83	2,485.82	$ (332,749)	$(133.86)
70	48,706.70	2,842.04	$ (381,543)	$(134.25)
80	54,724.68	3,193.19	$ (429,468)	$(134.50)

Source: http://www.heatsponge.com/economizer.shtml

Note: the GHG emission reduction cost includes capital recovery, operating, and maintenance cost

4.8 PIPE INSULATION ON STEAM DISTRIBUTION SYSTEM

A well insulated steam distribution system reduces the total heat loss to the ambient air. Consequently, it promotes GHG emission reductions through heat loss reduction. Crucial factors in choosing insulating material include low thermal conductivity, dimensional stability under temperature change, and resistance to water absorption. Other characteristics of insulating material may also be important depending on the application.

Thermal conductivity is the ability of a material to transfer heat via conduction. Thermal conductivity is stated as the amount of heat transmitted through a unit thickness in a direction normal to a surface of unit area, due to a unit temperature gradient. Thermal conductivity of an insulation material varies with temperature. Therefore, it is important to determine the right temperature range prior to material selection.

Since insulation material is subject to long term high temperature exposure, a good insulation material need to have a good dimensional stability under temperature change and long exposure. In addition, it also needs to have a good resistance toward water absorption. This property is important to ensure the insulation's dependability when it came into contact with the steam leaks from the pipeline.

Common insulating materials used in steam distribution systems include mineral fiber, fiberglass, and cellular glass. The North American Insulation Manufacturers Association (NAIMA) has developed a software program titled 3E Plus that allows users to determine the energy losses associated with various material types and thicknesses of insulation. The 3E Plus program assists the users in assessing of various insulation systems to determine the most cost-effective solution for a given specific insulation installation case. 3E Plus software has an ability to estimate energy savings, installation cost, payback period, and potential fuel cost savings from various insulation options.

Based on a sample case of horizontal steel pipe, 75ºF ambient air, no wind velocity, and 8,760 operating hr/yr, GHG reduction and fuel cost saving potential from piping insulation installation with the ability to reduce 90 percent of the heat loss are summarized below.

Table 14 Heat Loss from Uninsulated Pipeline

Nominal Pipe Diameter (inches)	Heat Loss per 100 ft of Uninsulated Steam Pipeline (MMBtu/yr)			
	Steam Pressure (psig)			
	15	150	300	600
1	140	285	375	495
2	235	480	630	840
4	415	850	1,120	1,500
8	740	1,540	2,030	2,725
12	1,055	2,200	2,910	3,920

Note: Based on horizontal steel pipe, 75ºF ambient air, no wind velocity, and 8,760 operating hr/yr.
Source: DOE, Improving Steam System Performance, a Sourcebook for Industry.

Table 15 Potential GHG Emission Reduction from Steam Pipeline Insulation Installation

Nominal Pipe Diameter (inches)	Potential GHG Reduction per 100 ft of Insulated Steam Pipeline (TPY of CO_2e)			
	Steam Pressure (psig)			
	15	150	300	600
1	7.4	15.0	19.7	26.0
2	12.3	25.2	33.1	44.1
4	21.8	44.6	58.8	78.8
8	38.9	80.9	106.6	143.1
12	55.4	115.5	152.8	205.9

Note: GHG emission reduction is based on 85% boiler efficiency and 8760 hrs of operation/year

Table 16 Potential Fuel Cost Reduction from Steam Pipeline Insulation Installation

Nominal Pipe Diameter (inches)	Potential Fuel Cost Saving per 100 ft of Insulated Steam Pipeline ($/yr)			
	Steam Pressure (psig)			
	15	150	300	600
1	1,482	3,018	3,971	5,241
2	2,488	5,082	6,671	8,894
4	4,394	9,000	11,859	15,882
8	7,835	16,306	21,494	28,853
12	11,171	23,294	30,812	41,506

Note: The potential fuel cost saving does not include the cost of insulation installation and maintenance

As shown above, pipeline insulation has a potential to reduce GHG emission from heat loss reduction. To maintain a good insulation performance, a regular inspection and maintenance system for insulation is important since some insulation materials are frequently becomes damaged due to high temperature and moisture exposure.

4.9 STEAM TRAPS ON STEAM DISTRIBUTION SYSTEM

In addition to piping insulation, failed-open or leaking steam traps also contribute a significant impact toward steam loss during distribution. During steam distribution, a steam trap collects water condensate while minimizing the accompanying loss of steam. A properly functioning steam trap should not leak or fail in open position.

In general, the common steam trap designs include the mechanical, thermostatic, and thermodynamic traps, which are described as follows:

- Mechanical traps operate by using the difference in density between steam and condensate to produce a change in the position of a float or bucket that controls the valve opening.

- Thermostatic traps detect the temperature difference between steam and condensate at the same pressure. The sensing device operates the valve in response to changes in the condensate temperature and pressure to release the condensate.
- Thermodynamic traps use the difference in dynamic response to velocity change in flow of compressible and incompressible fluids.

To reduce the amount of heat loss from a failed-open or leaking steam trap, periodic monitoring or steam trap maintenance is required. Steam trap malfunction can be detected from high temperature, leaking sound, visual steam leaks, and electronic steam leak detector. A simple system of checking steam traps to ensure they are operating properly or periodic maintenance can reduce GHG emission that would otherwise be emitted to compensate for the lost steam. In addition to energy and cost savings, a properly functioning of steam trap will reduce the risk of corrosion in the steam distribution system.

Periodic steam trap testing is one way to maintain a properly working steam traps, The frequency of the periodic testing depends on the pressure of the steam line. Higher steam pressure requires more frequent testing to avoid excessive loss during failure and to ensure the distribution pipeline operation's safety. Weekly to monthly testing frequency is recommended for steam line with high pressure (150 psig and above) (DOE, 2001); monthly to quarterly testing frequency is sufficient for steam line medium pressure (30 to 150 psig); and annual testing is recommended for low pressure steam line (below 30 psig).

The cost of steam trap maintenance or electronic steam leak detector varies greatly depending on the characteristic of the steam distribution system. In general, the energy saving potential based on the steam loss from steam trap leaks are summarized as follows:

Table 17 Steam Loss from a Steam Trap Leak

Trap Orifice Diameter (inches)	Steam Loss (lbs/hr)		
	Steam Pressure (psig)		
	100	**150**	**300**
1/32	3.3	4.8	-
1/16	13.2	18.9	36.2
1/8	52.8	75.8	145
3/16	119	170	326
1/4	211	303	579
3/8	475	682	1,303

Source: DOE, Improving Steam System Performance, a Sourcebook for Industry.

Table 18 Potential GHG Emission Reduction from a Steam Trap Leak Avoidance

Trap Orifice Diameter (inches)	Potential GHG Emission Reduction (Tons of CO_2e/ month)			Potential GHG Emission Reduction (Tons of CO_2e/ year)		
	Steam Pressure (psig)			Steam Pressure (psig)		
	100	150	300	100	150	300
1/32	0.15	0.22	-	1.8	2.6	-
1/16	0.60	0.86	1.65	7.2	10.4	19.8
1/8	2.39	3.46	6.60	28.7	41.5	79.2
3/16	5.39	7.76	14.85	64.7	93.2	178.2
1/4	9.56	13.84	26.37	114.7	166.0	316.4
3/8	21.51	31.14	59.34	258.1	373.7	712.1

Note: GHG emission reduction is based on 90% heat recovery, 85% boiler efficiency, and 8760 hrs of operation/year

Table 19 Potential Fuel Cost Saving from a Steam Trap Leak Avoidance

Trap Orifice Diameter (inches)	Potential Fuel Cost Saving ($/month)			Potential Fuel Cost Saving ($/year)		
	Steam Pressure (psig)			Steam Pressure (psig)		
	100	150	300	100	150	300
1/32	30	44	-	362	530	-
1/16	121	174	332	1,446	2,088	3,989
1/8	482	698	1,331	5,786	8,375	15,977
3/16	1,087	1,565	2,993	13,039	18,783	35,920
1/4	1,927	2,790	5,316	23,120	33,479	63,797
3/8	4,337	6,280	11,964	52,048	75,354	143,572

Note: The potential fuel cost saving does not include the cost of leak detector installation and maintenance

As discussed in the previous section, there are many mitigation measures that have potential to reduce GHG. The applicability of the aforementioned mitigation measures are summarized below:

- LNB has the potential to reduce GHG by increasing the combustion efficiency. However, its cost effectiveness can only be determined on a case-by-case basis.
- FGR and LEA controls reduce GHG by minimizing the amount of excess oxygen in the combustion chamber to increase fuel efficiency and decrease thermal NOx formation at the same time. In a manner similar to LNB, the cost effectiveness for these mitigation measures can only be determined on a case-by-case basis.
- Air preheaters have the potential to reduce fuel consumption by recovering the excess heat carried by the flue gas. For air preheater installations, corrosion issue needs to be considered prior to choosing the heat exchanger material.
- Boiler blowdown control or heat recovery has the potential to reduce the fuel consumption by minimizing the blowdown rate or recovering the heat loss from the blowdown water. The implementation of automatic blowdown control or heat recovery system is not economically feasible for small boiler operation. However, the implementation of these options potentially saves a great amount of energy for larger boiler operation.
- Turbulators offer small improvements on fuel efficiency with a low investment. This technology is widely used for older boilers. However, the actual performance of this mitigation measure varies according to the condition of the existing boiler's characteristics and it is limited to boilers that have two or three passes.
- Economizers have wider applicability than turbulators. The actual cost effectiveness analysis for this mitigation measure varies according to the condition of the existing boilers. In general, an economizer offers a good pay back when it is used frequently or in full capacity.
- Reducing the amount of heat loss or steam loss during steam distribution is also a significant factor in the effort to minimize fuel usage. By installing pipeline insulation and maintaining the steam traps, the amount of heat or steam loss during distribution may be reduced greatly.

All mitigation measures summarized above have the potential to reduce GHG emissions from boiler operation. Due to the diverse nature boiler's characteristics, not all of the recommended mitigation measures are applicable to all boilers' operating scenario. Prior to the actual implementation, it is important to consider all aspects related to the modification to avoid any incompatibility of efficiency penalty. A thorough case-specific assessment need to be performed prior to implementing the assessed mitigation measures to ensure the compatibility, performance, and safety of the selected mitigation measure.

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