Opportunities for Further Greenhouse Gas Emission Reductions for the BAAQMD Stationary Sources

Final Report

Prepared for:
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109

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Executive Summary

The Bay Area Air Quality Management District (BAAQMD) conducted a region-wide study to identify and evaluate potential greenhouse gas (GHG) emission control options for application at stationary sources in the Bay Area region in California. The overall framework of the study was to identify the most significant industries and subsequent source categories contributing to GHG emissions, identify potential mitigation options for controlling the GHG emissions, and evaluate the effectiveness, costs, and impacts of each of the most promising options.

The basis of selecting the source categories to be evaluated was the draft GHG emissions inventory from the BAAQMD. The sources identified for evaluation included the highest emitting sources within the largest industrial sectors in the region. These included stationary combustion and process sources in electrical power, refining, and other manufacturing (particularly cement production), as well as landfills and waste water treatment plants.

For each source category identified as high priority for evaluation within the study, potential GHG mitigation options were identified. The study focused in detail only on those mitigation options which could be considered as retrofit controls for existing permitted sources. A review of options available for new capacity was included; however, cost, air emission benefits, and other impacts were not evaluated in detail.

These retrofit GHG mitigation options identified for each of the priority source categories were initially screened based on relative capital investment, overall abatement amount, and commercialization status. This initial screening was intended to narrow the focus of the study to only evaluate those mitigation options that had a relatively high chance of being viable for consideration by the BAAQMD.

The mitigation options that were priority candidates in the study were evaluated based on a number of criteria for a typical application in the Bay Area, including:

- Magnitude of GHG emissions reduction possible for the source, evaluated as the difference between the baseline (or base case) emissions and the mitigation project emissions;
- Capital investment required for the mitigation option, including direct and indirect capital expenses;
- Operating and maintenance cost estimate;

- Cost effectiveness of the mitigation option, in $ per ton CO_2 equivalent emissions reduced (and $/kWh for power generation options);
- Challenges and uncertainties in abatement amounts estimated, costs, and implementation of mitigation options; and
- Energy, environmental, social and other impacts associated with mitigation measures, with emphasis on air quality impacts.

Preliminary estimates of these factors were conducted to support a comparative evaluation of the options. Based on these preliminary assessments, the mitigation measures were ranked in accordance with their overall effectiveness, costs, and impacts. The mitigation measures were rank ordered on a scale of 1 to 3, with 3 being the most favorable score possible. The following table shows the overall results of the evaluation in order of most favorable to least favorable.

Mitigation Option	Overall Ranking Score	Applicable Source Categories	Implementation Issues
Landfill or Digester Gas Recovery in IC Engine	2.3	➢ Landfill Gas with Flaring ➢ Digester Gas with Flaring	➢ NO_x emissions from IC engines versus flares
Energy Efficiency	2.3	➢ NG Steam Boiler ➢ NG Gas Turbine ➢ Refinery Process Heater ➢ Chemical Process Heater	➢ Potential for efficiency improvements in existing gas-fired sources may be limited due to optimization of performance to meet stringent NO_x limits.
Pozzolanic Cement Replacement	2.3	➢ Cement Kiln	➢ Acceptability of blended cement product in market. ➢ Source of fly ash.
Biofuel Combustion	2.0	➢ NG Steam Boiler ➢ NG Cogeneration ➢ NG Gas Turbine ➢ Cement Kiln Combustion ➢ Refinery FCCU Catalyst Regeneration ➢ Refinery Flexicoker ➢ Refinery Process Heater	➢ Availability and logistics of biomass source to site. ➢ Unknown impacts on performance of existing controls (e.g., SCR).

Mitigation Option	Overall Ranking Score	Applicable Source Categories	Implementation Issues
		➢ Chemical Process Heater	
Landfill or Digester Gas Recovery in Gas Turbine	2.0	➢ Landfill Gas with Flaring ➢ Digester Gas with Flaring	➢ NO_x emissions from gas turbines versus flares ➢ Quality/consistency of gas
Landfill or Digester Gas Recovery as Pipeline Natural Gas	2.0	➢ Landfill Gas with Flaring ➢ Digester Gas with Flaring	
Carbon Capture and Storage	1.6	➢ Refinery Hydrogen Production	➢ Suitable reservoir for sequestration. ➢ Permanence of sequestration. ➢ Safety and public acceptability risks.

All of the mitigation options evaluated in detail were ranked at a level above average (i.e., ranking of 2.0 or higher), except the carbon capture and storage option for refinery hydrogen production.

An additional mitigation option that was reviewed was the use of compost for biofiltration or biotic cover to reduce landfill gas fugitive emissions. This technology is in the demonstration phase currently and shows promise for conversion of the methane in landfill gas to cell mass and energy, releasing CO_2 instead of methane[1]. This technology could potentially be reasonable for small, passively venting landfills, for old sites where the methane content of the landfill gas has decreased to less than 30%, or for fugitive emissions from larger sites with active gas collection systems.

Based on this assessment, it is recommended that the BAAQMD consider the above average mitigation options, along with biotic cover and biofiltration options, for further evaluation of applicability in a more focused study. For example, it would be prudent to conduct further analysis across the range of sources within the applicable source categories that the mitigation

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[1] The global warming potential of methane is 21 times higher than CO_2, thus resulting in greenhouse gas emissions reductions on a CO_2 equivalent basis.

measure could potentially be applied. This would provide a more reliable assessment of the actual reductions achievable across applicable sources within the Bay Area.

Further, for each mitigation option, it is recommended that at least one site-specific feasibility assessment be conducted to confirm the costs, issues, and benefits. For example, a site feasibility assessment of installing gas turbines at a specific landfill currently flaring the landfill gas would provide confirmation of the feasibility, impacts and magnitude of reduction possible. Another example of need for further analysis is the supply, costs, transportation requirements, and on-site handling and gasification requirements for biofuel combustion. Further analysis of air quality impacts for the site feasibility study would provide a quantitative analysis of air quality impacts (e.g., gas turbine application to landfill gas source may require gas clean-up that may lead to incremental air pollutant emissions; air quality impacts from biogas life cycle).

As a final recommendation for consideration by the BAAQMD, a comparable analysis of mitigation options for new sources could be conducted to identify the technologies of most importance in achieving the long-term goals. The technologies to be reviewed could include fuel cells; wind, solar, tidal, and geothermal energy sources; advanced turbine design; ultra low emission process heaters; and other new technologies.

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Acronyms

API	American Petroleum Institute	IPECA	International Petroleum Environmental Conservation Association
BAAQMD	Bay Area Air Quality Management District	kW	Kilowatt
BACT	Best Available Control Technology	LFG	Landfill Gas
CARB	California Air Resources Board	MM Btu	Million British thermal units
CCS	Carbon Capture and Sequestration	MW	Megawatt
CEC	California Energy Commission	NG	Natural Gas
CO	Carbon Monoxide	NPOC	Non-Precursor Organic Compound
CO_2	Carbon Dioxide	POC	Precursor Organic Compound
DOD	Department of Defense	OEERE	Office of Energy Efficiency and Renewable Energy
DOE	Department of Energy	OFE	Office of Fossil Energy
EPA	Environmental Protection Agency	ONE	Office of Nuclear Energy
EPRI	Electric Power Research Institute	OTM	Oxygen Transport Membranes
FCCU	Fluidized Catalytic Cracking Unit	PAFC	Phosphoric Acid Fuel Cells
FE	Fossil Energy	PFC	Perfluorocarbon
GHG	Greenhouse Gas	SCF	Standard cubic foot
HFC	Hydrofluorocarbon	SF_6	Sulfur hexafluoride
IC	Internal Combustion	SO_2	Sulfur Dioxide
		ULE	Ultra-Low Emission

1.1 INTRODUCTION

The State of California has taken action to address the issue of climate change through policies aimed at reducing greenhouse gas (GHG) emissions from major sources. California contributes approximately one fifth of all GHG emissions in the United States, and is considered the 12th largest emission state in the world. The recent GHG emission regulations in California set a precedent in the United States, with significant implications globally to address the issue of climate change.

On June 1, 2005 and under the direction of Governor Arnold Schwarzenegger, the state established GHG emission reduction targets and the Climate Action Team. The Climate Action Team has held public meetings to determine the public's view on the best way to address greenhouse gas emissions and proposed a plan outlining a strategy to achieve GHG emission reductions. As a result, the team has suggested the development of greenhouse gas emission inventories and a greenhouse gas cap and trade program within the state. In addition, California industry has acted voluntarily in support of the Climate Action Team initiatives. This has included voluntary emission reporting through the Climate Action Registry.

Governor Schwarzenegger's Executive Order S-3-05 of June 1, 2005 called for specific emission reductions and a periodic update on the state of climate change science and the emerging understanding of potential impacts to climate sensitive sectors such as the state's water supply, public health, agriculture, coastal areas, and forestry. This Executive Order established Statewide climate change reduction targets as follows:

- By 2010, reduce emissions to 2000 levels
- By 2020, reduce emissions to 1990 levels
- By 2050, reduce emissions to 80 percent below 1990 levels

To address the 2020 emission reduction goal, the state is to have 20% of all power in the state generated by renewable resources by 2017, as per Senate Bill 1078 filed in September 2002. Many of the plan goals are related to mobile source controls including emissions from automobiles, trucks, and ships in port.

In August 2006, Assembly Bill (AB) 32 was passed in California that will require mandatory reporting and verification of GHG emissions. AB32 also requires maximum technologically feasible and cost effective reductions from sources or source categories to be achieved by 2020. Recommendations on direct emission reduction measures, alternative compliance mechanisms, market-based mechanisms and incentives will be established by 2011. Compliance with the emissions limits will be effective in January 2012.

In addition to the state efforts, there have been local Bay Area initiatives to limit GHG emissions. For example in March 2002, San Francisco adopted Resolution 158-02 directing the City to commit to a greenhouse gas pollution reduction 20% below 1990 levels by the year 2012. In Sonoma County, all nine cities and the County have pledged to reduce GHG emissions as part of the International Council for Local Environmental Initiatives (ICLEI). In June 2005, the Bay Area Air District Board of Directors adopted a resolution establishing a Climate Protection Program that acknowledges a link between climate protection and existing programs designed to reduce air pollutants. The District has taken action to develop a Bay Area GHG emission inventory and in November 2006, announced a grant program for climate protection activities in the Bay Area. In addition, the District is evaluating and implementing measures to reduce electricity and fuel consumption associated with District activities.

This report is being prepared for the Bay Area Air Quality Management District (BAAQMD) to identify potential greenhouse gas mitigation technologies specifically for permitted stationary sources in the Bay Area. The goal of this study is to provide the BAAQMD with a comprehensive evaluation of technologies and processes available for the reduction of GHG emissions by stationary sources that are currently subject to the District’s permitting requirements.

The study identifies additional or alternative processes and technologies that may be implemented to reduce GHG emissions from the highest emitting stationary sources. These processes and technologies are evaluated and compared on a relative basis to identify the most promising options for effectively reducing GHG emissions. The basis of comparison for evaluating the identified technologies included factors such as emissions reduction potential, costs (installed capital, operating, and maintenance costs), air quality benefits and disbenefits, and uncertainties and challenges to implementation.

1.2 SCOPE OF WORK

The GHG Mitigation Study addresses the following items:

1. Identify and document the major GHG emitting industrial sectors and/or permitted stationary source categories in the Bay Area using emissions data developed by BAAQMD.
2. Identify and document GHG mitigation measures by industrial sector or permitted stationary source category through literature and web-based searches. The technologies are further identified as emerging technology or demonstrated in practice.
3. Identify and document capital, installation, implementation, operational, and maintenance costs associated with GHG mitigation measures. In addition, identify and document key uncertainties associated with costs analyzed for GHG mitigation measures.
4. Identify and document challenges to implementation, operation and maintenance of GHG mitigation measures.
5. Identify and document GHG emission reduction benefits, for both the greenhouse gas in question and in equivalent CO_2 units (if greenhouse gas emission reductions are not for carbon dioxide) obtained by implementing GHG mitigation measures, along with any key uncertainties in estimating GHG emission benefits.
6. Identify and document additional air quality benefits and disbenefits for criteria pollutants and toxic air contaminants achieved by implementing GHG mitigation measures.
7. Identify and document any other important benefits and/or disbenefits achieved by implementing GHG mitigation measures.
8. Evaluate, compare, and recommend GHG mitigation measures by sector or source category on the basis of GHG emissions reductions, costs, challenges, air quality benefits and disbenefits, and any other important benefits and disbenefits as identified in all of the above efforts.

1.3 LIMITATIONS IN THE STUDY

This study does not address any cap or trade programs relating to GHG emissions reduction credits or offsets. Therefore, emission reductions achieved outside of the Bay Area geographical region through purchase of carbon credits, investment in projects, or emission reductions achieved at facilities which are not located in the Bay Area region are not considered.

In addition, the study only focuses on direct emissions from stationary sources. As such, there is no discussion of mobile sources, methane area sources, or indirect emission sources (e.g., reduction in imported electricity consumption).

Since the primary focus of the study was to identify emission reduction technologies to reduce GHG emissions from existing stationary sources, retrofit technologies were addressed in more detail than new source technologies. As such, potential new sources that may be built to meet growth demands are discussed with a cursory indication of applicability and issues, but not a detailed evaluation. New source permitting might include new power generation supply from alternative energy sources, such as hydrogen fuel cells and renewable energy sources.

1.4 STRUCTURE OF THE REPORT

The report is structured in the following sections:

- Section 2 provides an overview of the conclusions and recommendations for further consideration.
- Section 3 identifies the major GHG emission source categories in the Bay Area.
- Section 4 identifies the GHG mitigation and abatement technologies for the major sources and discusses a preliminary prioritization to narrow the focus of the study.
- Sections 5 through 9 discuss the different mitigation options identified for each of the major source categories by industrial sector.
- Section 10 includes a summary of the effectiveness of the mitigation options for reducing GHG emissions.
- Section 11 presents an overview of the results of the cost analyses performed.

- Section 12 provides an overview of the environmental, energy and other impacts associated with each mitigation option.
- Section 13 ranks the mitigation options in accordance with their potential for success in cost effectively mitigating GHG emissions.
- Section 14 provides a summary of the results of the study.

2.1 CONCLUSIONS

The study to identify and evaluate potential GHG emissions control options for application within the Bay Area used a ranking scheme for prioritizing the options. The overall ranking indicated that most of the mitigation options evaluated in detail resulted in a priority ranking of above average. The above average ranked mitigation options are concluded to have favorable benefits as compared to costs and other adverse impacts. These options with a favorable ranking included the following, in order of most favorable to least favorable:

- Landfill gas or digester gas utilization in IC engine for power generation. This option is based on utilizing the previously flared landfill or digester gas and utilizing the gas for power generation in an IC engine. This option has significant benefits in energy conservation over the flaring of landfill gas.
- Energy efficiency improvement in combustion sources across source categories. This option is based on an average 0.25 percent improvement in overall efficiency. The resulting GHG emission reduction is associated with commensurate lowered fuel utilization to produce an equivalent energy output.
- Pozzolanic clinker replacement in cement manufacturing. This is an option to utilize fly ash for blending with the cement to replace a fraction of the clinker content of the cement. This option results in avoided emissions of CO_2 from the calcination reaction and pyrolysis of the clinker being replaced by fly ash. This option has several barriers to implementation, including acceptability of a blended cement product in the local market and the availability and transport logistics for the supply of fly ash. An additional mitigation option for this sector is biomass co-firing in the cement kiln. This option is reportedly already being evaluated by the Hanson plant and was therefore not reviewed in detail in this report.
- Biofuel combustion to replace a fraction of the natural gas utilized in power generation, industrial and commercial boilers, process heaters, and other potential combustion sources. The option to utilize biofuel is based on gasification of agricultural waste, with subsequent co-firing of the biogas with natural gas. The emission reductions from the

biogas firing are based on avoiding the emissions of the replaced natural gas. Biofuels are typically considered carbon neutral, because their use results in no net emissions of CO_2. Since the fuels are produced through photosynthesis, which utilizes solar energy to convert atmospheric CO_2 into biomass, the combustion of this biomass simply returns the original quantity of CO_2 back to the atmosphere. This results in carbon neutrality for the combustion of the fuel itself, though associated emissions from the transport and processing of the biomass may result in GHG emissions from non-renewable sources.

- Landfill gas or digester gas utilization in a gas turbine for power generation. This option is based on utilizing previously flared landfill or digester gas in a gas turbine to produce power for sale to the grid.
- Landfill gas or digester gas recovery and processing as pipeline natural gas. Although this option requires more energy utilization to produce pipeline quality fuel, it may be viable for applications such as landfill or digester sites that are not in close proximity to the electric grid. The landfill gas can also be processed to produce transportation fuels, such as compressed natural gas (CNG) or biodiesel. The transportation fuel options would have significant energy penalties over on-site power generation.
- Landfill gas conversion using microorganisms in a porous medium, such as compost, soil or other synthetic materials. This option covers biotic landfill covers to oxidize the methane in passively ventilated areas of the landfill, as well as active biofiltration. Although in the demonstration phase, these options have the potential to be implemented at relatively low cost and offer improved air quality emissions as compared to flaring landfill gas. Biotic cover and biofiltration techniques avoid emissions of NO_x, SO_x, CO, particulates and other chlorinated compounds that are emitted from landfill gas combustion.
- The last option evaluated that was ranked below average was carbon capture and sequestration (CCS) for refinery hydrogen production. This option would capture the high concentration CO_2 stream from the hydrogen process and store the CO_2 in an underground formation. The high costs, coupled with uncertainties around the long-term permanence of storage, make this option less attractive than the others evaluated.

2.2 RECOMMENDATIONS

Based on the evaluation performed for the prioritized GHG mitigation options, a more in-depth assessment of application of the technology across the range of sources in each of the applicable source categories is recommended. This further assessment would provide a more reliable estimate of the actual reductions achievable across applicable sources within the Bay Area, as well as a better understanding of the potential issues and range of costs.

In addition, it is recommended that a site-specific assessment be performed for each option, based on site-specific design details. For example, a site feasibility assessment of installing a gas turbine for power generation at a specific landfill currently flaring the landfill gas would allow an analysis of the actual landfill gas composition, gas clean-up required prior to combustion in a turbine, and other site-specific issues which could play an important role in overall acceptability of the mitigation option. As another example, biogas combustion feasibility would be dependent on the supply of suitable agricultural waste, transportation costs, on-site handling requirements and costs, and combustion burner retrofits required. A site-specific analysis would provide confirmation of the feasibility, impacts and magnitude of reduction possible.

Further analysis of air quality impacts for the site feasibility study would provide a quantitative analysis of air quality impacts (e.g., gas turbine application to landfill gas source would require gas clean-up that may lead to incremental air pollutant emissions; air quality impacts from biogas life cycle).

As this study did not consider in detail new source options, this would be another area of potential additional work that would support the plans to achieve the BAAQMD's long-term goals of reducing GHG emissions in the Bay Area. This study could be expanded to include the analysis of new sources to identify the most favorable new source technologies. The technologies to be review could include, but not be limited to, fuel cells; wind, solar, and geothermal energy sources; advanced turbine design; and ultra low emissions process heaters.

3.1 APPROACH TO PRIORITIZE SOURCES

Using the GHG emissions inventory data provided by the BAAQMD, the major permitted stationary sources of GHG emissions in the Bay Area were identified. The BAAQMD has identified the data as a preliminary GHG emissions inventory, and as such actual emissions data will not be presented in this report. To most effectively focus on those sources where mitigation would have the most impact, URS has grouped sources into categories including industry sectors, area sources, and equipment type.

3.2 MAJOR GHG SOURCES

The sources have further been broken into categories requiring detailed study due to their significant contributions to GHG emissions and categories which will be discussed in a significantly less detailed manner. In consultation with the BAAQMD, URS has identified the categories presented in Table 3-1 for detailed analysis.

TABLE 3-1. MAJOR GHG STATIONARY SOURCES WITHIN THE BAY AREA

Industry Sector	GHG Source
Electric Power Generation	NG-Fired Steam Boiler with Turbine
Electric Power Generation	NG-Fired Cogeneration Unit
Electric Power Generation	NG-Fired Gas Turbine Unit
Cement Manufacturing	Cement Kiln
Landfills	Landfill Gas Recovery with Flaring
Wastewater Treatment Plants	Anaerobic Digester Gas Recovery with Flaring
Petroleum Refinery	Process Heaters
Petroleum Refining	FCCU Regenerator with CO Boiler
Petroleum Refining	Hydrogen Production (Steam/methane)
Petroleum Refining	Flexicoker with CO Boiler
Petroleum Refining	Flaring
Chemical Manufacturing	Process Heaters
Chemical Manufacturing	Flaring

TABLE 3-1. MAJOR GHG STATIONARY SOURCES WITHIN THE BAY AREA (Continued)

Industry Sector	GHG Source
Jet Aircraft Maintenance	Paint Spray Booth with Thermal Oxidizer
Jet Aircraft Maintenance	Jet Engine Test Stands
Automobile Manufacturing	Paint Spray Booth with Thermal Oxidizer
Glass Manufacturing	Glass Melting Furnaces
Area Sources	Commercial and Industrial Boilers
Area Sources	Electrical Transmission Equipment Repairs

3.3 MINOR GHG SOURCES

Other GHG emissions sources are less significant either because they have few medium to small facilities or there are numerous small facilities that do not account for significant GHG emissions. Categories which received less detailed analysis due to lower GHG emissions are shown in Table 3-2. Because these sources often have few or single instances in the Bay Area, the detailed examination of the sources is beyond the scope of this project.

TABLE 3-2. MINOR GHG STATIONARY SOURCES WITHIN THE BAY AREA

Industry Sector	GHG Source
Electric Power Generation	Petroleum Coke-fired Units
Gypsum/Wall Board Manufacturing	Wallboard Dryer
Gypsum/Wall Board Manufacturing	Calciner
Steel Coil Galvanizing and Tin Plating	Galvanizing Line
Foundries	Cupola
Foundries	Hot metal storage
Wastewater Treatment Plant	Sludge burning
Area Sources	HFC Degreasers
Area Sources	Building Chillers
Area Sources	Cold Storage Warehouses
Area Sources	Industrial Refrigeration

4.1 APPROACH TO IDENTIFY MITIGATION OPTIONS

For the prioritized sources identified through an analysis of the preliminary BAAQMD GHG inventory, an initial review of potential mitigation techniques was conducted. The mitigation options were identified through the following sources:

- URS' existing knowledge of the industry and/or source category through previous engagements;
- Conducting literature reviews and web searches for relevant information on technologies and/or operating measures to reduce GHG source emissions;
- Contacts with GHG technology vendors or vendors of equipment that can be used for reducing GHG emissions; and
- Contacts with organizations that are conducting research programs and/or studies on mitigating GHG emissions. These organizations include the Department of Energy (DOE), International Energy Association (IEA), American Petroleum Institute (API), International Petroleum Environmental Conservation Association (IPIECA), Electric Power Research Institute (EPRI), and the Environmental Protection Agency (EPA).

This study also included a thorough review of existing California related GHG activities and options that were suggested through those activities. This included local initiatives such as the San Francisco Energy Plan. Although no specific mitigation technologies have been mandated for the GHG emitting industry sectors identified in Section 3, regulatory development activities are underway in California under AB 32 requirements. GHG emissions reporting will become mandatory and allowable GHG emission levels will be capped at 1990 levels by 2020.

4.2 MITIGATION OPTIONS FOR EXISTING SOURCES BY INDUSTRY SECTOR

The potential mitigation options that were identified through the approach outlined above are presented in Table 4-1. The options were identified for each of the major identified source types within the industrial sectors of focus for this study.

To narrow the focus of this study, these identified mitigation options were screened to prioritize those options that have the highest potential for successful application in the industrial sectors in the Bay Area District. The initial screening was based on:

- Overall potential for reduction in GHG emissions from the mitigation technology as applied to the specific source type. This ranking of GHG emission reduction potential was arrived at through a qualitative assessment using existing knowledge of the technology and source as well as a literature review. The ranking of high, medium, and low for the relative emissions control level in Table 4-1 is qualitative relative to the potential for reduction in absolute emissions[2] from a representative facility in the Bay Area with this source type. Thus, the potential for reduction is a function of the control level of a typical application of the mitigation technology, as well as the magnitude of source emissions relative to total emissions from a representative facility.
- Qualitative assessment (high, medium, low) of the typical capital cost of the mitigation technique for the source under evaluation.
- The status of commercialization of the mitigation technology.

Based on this preliminary review, mitigation options were prioritized in a short list for more detailed review in this study. The options were prioritized by a favorable relative ratio of control level to capital cost, as well as a promising commercialization status. Only retrofit technologies that could potentially be applied to permitted sources were considered for detailed review. Table 4-2 presents the short list of mitigation options prioritized for review in this study, with a brief description of rationale for selection. Additional details will be provided in industry-specific sector sections of this report.

The next sections present an overview of the mitigation options prioritized for review. These mitigation options are organized by the industrial source category for which they apply. Several of the mitigation options apply across more than one industrial source category and are analyzed

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[2] Reduction in absolute emissions in this context refers to the total mass emissions reduction potential from a given source, in units of tons/year. The distinction is between total mass emissions reduction and relative emissions reduction (or percent reduction) from a given source. For example, if a given source is a large contributor to GHG emissions, then a relatively small percentage reduction may represent a relatively large absolute mass emissions reduction.

as a singular mitigation technology in later sections of this report, with discussion of any industrial source category differences in application.

Many of the primary industrial GHG emission sources are related to electric power generation. The California Energy Commission’s Integrated Energy Policy Report recommends that all long-term commitments to new electricity generation for use in California must come from sources with GHG emissions equivalent to or less than a new combined cycle natural gas-fired power plant.

TABLE 4-1. BROAD LIST OF POTENTIAL GHG EMISSIONS MITIGATION OPTIONS

Industry	Source	Potential Mitigation Options	Relative Emissions Control Level	Relative Capital Expense	Status of Commercialization
Electric Power Generation	NG-fired steam boiler with turbine	Biofuel Combustion	High	Low	Commercially available
		Energy Efficiency Improvements	Low	Low	Commercially demonstrated
		Carbon capture (oxycombustion) with carbon sequestration	High	High	Not commercially available; Not demonstrated
	NG-fired cogeneration unit	Biofuel Combustion	High	Low	Commercially available
		Oxycombustion with carbon sequestration	High	High	Not commercially available; Not demonstrated
	NG-fired gas turbine unit	Biofuel Combustion	High	Low	Commercially available
		Energy Efficiency Improvements	Low	Low	Commercially demonstrated
		Carbon capture (oxycombustion) with carbon sequestration	High	High	Not commercially available; Not demonstrated
		Advanced turbine design	Low	High	Commercially available
Cement Manufacturing	Kiln - Calcination	Pozzolanic clinker replacement	Medium - High	Low	Commercially available
		Carbon capture and sequestration	High	High	Not Demonstrated
	Kiln – combustion	Biofuel Combustion	Medium - High	Low	Commercially available
Landfills	LFG with flaring	Improved gas capture efficiency	Low - Medium	Low - Medium	Commercially available

Industry	Source	Potential Mitigation Options	Relative Emissions Control Level	Relative Capital Expense	Status of Commercialization
		LFG utilization in IC engine generators	Medium	Medium	Commercially available
		LFG utilization in gas turbine generators	Medium	Medium - High	Commercially available
		LFG purification and separation as pipeline gas or transportation fuels	Medium	High	Commercially available
		Biofiltration and biotic covers	Medium	Low-Medium	Emerging technology, undergoing demonstration in the US.
	LFG with IC engine generators	Improved gas capture efficiency	Low	Low - Medium	Commercially available
		LFG utilization in gas turbine	Low	High	Commercially available
		Biofiltration and biotic covers	Medium	Low-Medium	Emerging technology, undergoing demonstration in the US.
Waste Treatment Plants	Anaerobic Digester gas recovery with flare	Digester gas utilization in IC engine generators	Medium	Medium	Commercially available
		Digester gas utilization in gas turbine generators	Medium	Medium - High	Commercially available
		Digester gas purification and separation as pipeline gas or transportation fuels	Medium	High	Commercially available
	Anaerobic Digester gas recovery with IC engines	Improved gas capture efficiency	Low	Low - Medium	Commercially available

Industry	Source	Potential Mitigation Options	Relative Emissions Control Level	Relative Capital Expense	Status of Commercialization
Petroleum Refinery	Process Heaters	Biofuel Combustion	Medium - High	Low	Commercially available
		Energy Efficiency Improvements	Low	Low	Commercially demonstrated
		Carbon capture and storage	High	High	Not Demonstrated for low CO_2 concentration applications
	FCCU Regenerator with CO Boiler	Biofuel Combustion for CO Boiler Supplemental Fuel	Medium - High	Low	Commercially demonstrated
		Carbon capture and storage	High	High	Capture and sequestration for enhanced oil recovery (EOR) demonstrated
	Hydrogen Production (steam/methane reforming)	Carbon capture and storage	High	High	Capture and sequestration for enhanced oil recovery (EOR) demonstrated
	Flexicoker with CO boiler	Carbon capture and storage	High	High	Capture and sequestration for enhanced oil recovery (EOR) demonstrated
		Biofuel Combustion for CO Boiler Supplemental Fuel	Medium - High	Low	Commercially demonstrated
	Flaring	Flare gas reduction	Low	Low	Commercially available
Chemical Manufacturing	Process Heaters	Ultra-low-emissions, high-efficiency fired heater	Low-Medium	Medium	Demonstrated and commercially available

Industry	Source	Potential Mitigation Options	Relative Emissions Control Level	Relative Capital Expense	Status of Commercialization
		Carbon capture and storage	High	High	Not Demonstrated for low CO_2 concentration applications
	Flaring	Flare gas reduction	Low	Low	
Jet Aircraft Maintenance	Paint Spray Booth with Thermal Oxidizer	Waste heat recovery	Low	Medium	Commercially available
		Carbon capture and storage	Low	High	Not Demonstrated for low CO_2 concentration applications
	Jet engine test stands	Carbon capture and storage	High	High	Not Demonstrated for low CO_2 concentration applications
Automobile Manufacturing	Paint Spray Booth with Thermal Oxidizer	Waste heat recovery	Low	Medium	Not demonstrated?
		Carbon capture and storage	Low	High	Not Demonstrated for low CO_2 concentration applications
Glass Manufacturing	Glass Melting Furnaces	Energy Efficiency Improvements	Low - Medium	Low - Medium	Commercially demonstrated
		Carbon capture and storage	High	High	Not Demonstrated for low CO_2 concentration applications
Area Sources	Commercial and Industrial Boilers	Cogeneration	Low- Medium	Medium – High	Commercially available
Area Sources	Electrical Transmission Equipment Repairs	SF_6 monitoring and reporting program	Low	Low	Demonstrated mitigation option

TABLE 4-2. PRIORITIZED SHORT LIST OF MITIGATION TECHNOLOGIES

Industry	Source	Potential Mitigation Options	Prioritized for Detailed Review?	Rationale
Electric Power Generation	NG-fired steam boiler with turbine	Biofuel Combustion	Yes	Favorable reduction to cost relative ratio.
		Energy Efficiency Improvements	Yes	Favorable reduction to cost relative ratio.
		Carbon capture (oxycombustion) with carbon sequestration	No	Unfavorable reduction to cost relative ratio.
	NG-fired cogeneration unit	Biofuels	Yes	Favorable reduction to cost relative ratio.
		Carbon capture (oxycombustion) with carbon sequestration	No	Unfavorable reduction to cost relative ratio.
	NG-fired gas turbine unit	Biofuel Combustion	Yes	Favorable reduction to cost relative ratio.
		Energy Efficiency Improvements	Yes	Favorable reduction to cost relative ratio.
		Carbon capture (oxycombustion) with carbon sequestration	No	Unfavorable reduction to cost relative ratio.
		Advanced turbine design	No	Unfavorable reduction to cost relative ratio.
Cement Manufacturing	Kiln - Calcination	Pozzolanic clinker replacement	Yes	Favorable reduction to cost relative ratio.
		Carbon capture and sequestration	No	Unfavorable reduction to cost relative ratio.
	Kiln – combustion	Biofuel Combustion	Yes	Favorable reduction to cost relative ratio.
Landfills	LFG with flaring	Improved gas capture efficiency	No	Unfavorable reduction to cost relative ratio. Could be considered as separate study.

Industry	Source	Potential Mitigation Options	Prioritized for Detailed Review?	Rationale
		LFG utilization in IC engine generators	Yes	Favorable reduction to cost relative ratio.
		LFG utilization in gas turbine generators	Yes	Favorable reduction to cost relative ratio.
		LFG purification and separation as pipeline gas or transportation fuels	Yes	Favorable reduction to cost relative ratio.
		Biofiltration and biotic covers	Yes	Favorable reduction to cost relative ratio.
	LFG with IC engine generators	Improved gas capture efficiency	No	Unfavorable reduction to cost relative ratio. Could be considered as separate study.
		LFG utilization in gas turbine	No	Unfavorable reduction to cost relative ratio.
		Biofiltration and biotic covers	Yes	Favorable reduction to cost relative ratio.
Waste Treatment Plants	Anaerobic digester gas recovery with flare	Digester gas utilization in IC engine generators	Yes	Favorable reduction to cost relative ratio.
		Digester gas utilization in gas turbine generators	Yes	Favorable reduction to cost relative ratio.
		Digester gas purification and separation as pipeline gas or transportation fuels	No	Similar to IC engine recovery, but more costly.
	Anaerobic digester gas recovery with IC engines	Carbon capture and storage	No	Unfavorable reduction to cost relative ratio.
Petroleum Refinery	Process Heaters	Biofuel Combustion	Yes	Favorable reduction to cost relative ratio.
		Energy Efficiency Improvements	Yes	Favorable reduction to cost relative ratio.

Industry	Source	Potential Mitigation Options	Prioritized for Detailed Review?	Rationale
		Carbon capture (oxycombustion) with carbon sequestration	No	High capital costs; not demonstrated for low CO_2 applications.
	FCCU Regenerator with CO Boiler	Biofuel Combustion	Yes	Favorable reduction to cost relative ratio.
		Carbon capture and storage	No	High capital costs; not demonstrated for low CO_2 applications.
	Hydrogen Production (steam/methane reforming)	Carbon capture and storage	Yes	Applicable for future consideration; very high potential for reduction.
	Flexicoker with CO boiler	Biofuel Combustion	Yes	Favorable reduction to cost relative ratio.
		Carbon capture and storage	No	High capital costs; not demonstrated for low CO_2 applications.
	Flaring	Flare gas reduction	No	Site-specific analysis for reduction and costs would be required.
Chemical Manufacturing	Process Heaters	Biofuel Combustion	Yes	Favorable reduction to cost relative ratio.
		Energy Efficiency Improvements	Yes	Favorable reduction to cost relative ratio.
		Carbon capture (oxycombustion) and storage	No	High capital costs; not demonstrated for low CO_2 applications.
	Flaring	Flare gas reduction	No	Site-specific analysis for reduction and costs would be required.
Jet Aircraft Maintenance	Paint Spray Booth with Thermal Oxidizer	Waste heat recovery	No	Low reduction potential.
		Carbon capture and storage	No	Unfavorable reduction to cost relative ratio; High capital costs; Not demonstrated for low CO_2 applications.
	Jet engine test stands	Carbon capture and storage	No	High capital costs; not demonstrated for low CO_2 applications.
Automobile Manufacturing	Paint Spray Booth with Thermal Oxidizer	Waste heat recovery	No	Low reduction potential.

Industry	Source	Potential Mitigation Options	Prioritized for Detailed Review?	Rationale
		Carbon capture and storage	No	Unfavorable reduction to cost relative ratio; High capital costs; Not demonstrated for low CO_2 applications.
Glass Manufacturing	Glass Melting Furnaces	Energy Efficiency Improvements	Yes	Favorable reduction to cost relative ratio.
		Carbon capture and storage	No	High capital costs; Not demonstrated for low CO_2 applications.
Area Sources	Commercial and Industrial Boilers	Carbon capture (oxycombustion) with carbon sequestration	No	Unfavorable reduction to cost relative ratio.
		Cogeneration	Yes	Favorable reduction to cost relative ratio.
Area Sources	Electrical Transmission Equipment Repairs	SF_6 monitoring and reporting program	Yes	Low capital costs.

The following sections discuss greenhouse gas mitigation options for electric power generation sources in the Bay Area. Sections 5.1 through 5.3 present mitigation options for specific source categories as retrofit technologies for permitted sources, whereas Section 5.4 covers general mitigation options for power generation from new or replacement sources.

5.1 GAS-FIRED STEAM ELECTRICAL BOILERS

The use of fossil fuels for power generation is currently the major source of electrical power for the Bay Area. Table 5-1 presents the natural gas-fired steam generation units that have been identified in the Bay Area.

TABLE 5-1. NATURAL GAS-FIRED STEAM GENERATOR UNITS IN BAY AREA

Company Name	Location	Boiler Designation	Total Heat Input (MMBtu/hr)	Air Pollution Controls
Mirant Delta, LLC	Pittsburgh	Boiler No. 5	3,300	SCR
		Boiler No. 6	3,300	SCR
		Boiler No. 7	6,854	None
Mirant Delta Contra Costa	Antioch	Boiler No. 9	3,400	None
		Boiler No. 10	3,400	SCR
Mirant Potrero #3	San Francisco	Boiler No. 3-1	2,150	SCR
PG&E Hunters Point	San Francisco	Boiler No. 7 (Shutdown)	Not applicable	Not applicable

The CEC staff is examining the feasibility and advisability of CO_2 reporting in power plant licensing. Also, the staff is evaluating the requirement for monthly reporting of GHG emissions from the constructed source. Finally, the staff is examining the requirement for power plant applicants to obtain carbon dioxide emissions offsets, as is currently done in Oregon.

5.1.1 Energy Efficiency Improvements

Energy efficiency in gas-fired steam electric boilers has been studied for emission reduction of other pollutants including nitrogen oxides (NO_x). Techniques for improving overall energy efficiency include:

- Boiler tuning to improve combustion characteristics
- Air to fuel ratio controls to optimize performance
- Burner retrofits with advanced mixing, enhanced efficiency burner design
- Process optimization through modeling, enhanced process controls, and circulating pump efficiency improvements.

These techniques generally result in modest emission reductions of around 0.5 to 5 percent for units where performance optimization has not been mandated to meet stringent air quality limits. However, in the Bay Area District, stringent NOx control rules have resulted in optimization of performance in the installed base of power plant boilers. These boilers have been extensively optimized to meet the stringent 5 ppmvd NO_x @15% O_2 levels required under Regulation 9, Rule 11. While these older boilers, with an average heat rate of 10,500 Btu/kW-hr (32.5% plant thermal efficiency), are efficient as simple cycle units, they cannot match the efficiency of newly installed cogeneration plants that can achieve an average heat rate of 5785 Btu/kWh (59% plant thermal efficiency). These older simple cycle steam electrical generation boilers are needed to meet peak energy demand periods.

While improvement in energy efficiency is likely not a fruitful option to effect significant GHG emission reductions from the installed capacity of steam electricity generation boilers, there may be benefit in investigating a cooperative effort with other agencies to explore the prioritization of dispatch to meet the most beneficial environmental impacts. Agencies that would need to be considered for development of such a cooperative scheme include the California Public Utilities Commission (CPUC), the California Independent System Operator (CAISO), the California Energy Commission (CEC), and the California Air Resources Board (CARB).

For purposes of this study, a case example is included with assumed improvement in efficiency of 0.25% from a 2,150 MMBtu/hr gas-fired boiler system.

5.1.2 Use of Biofuels

The term "biomass" means any plant derived organic matter available on a renewable basis, including dedicated energy crops and trees, agricultural food and feed crops, agricultural crop wastes and residues, wood wastes and residues, aquatic plants, animal wastes, municipal wastes, and other waste materials. Handling technologies, collection and delivery logistics and infrastructure are important aspects of the biomass resource supply chain.

Biofuels refer to a variety of fuels that can be made from biomass resources, including the liquid fuels ethanol, methanol, biodiesel, Fischer-Tropsch diesel, and gaseous fuels such as hydrogen and methane. Biofuels research and development is composed of three main areas: producing the fuels, finding applications and uses for the fuels, and creating a distribution infrastructure.

Biofuels generated from gasified biomass can result in a zero net CO_2 contribution. Biomass gasifiers operate by heating biomass in an oxygen-starved environment where the solid biomass breaks down to form a flammable gas. The biogas generated is a synthesis gas (or syngas) comprised primarily of CO and H_2. The biogas generated is cleaned and filtered to remove impurities prior to delivery to the combustion process. The biomass is created by plant photosynthesis, which consumes atmospheric CO_2 as a carbon source. Thus, when biomass is combusted, either directly or as syngas, the CO_2 emitted is equivalent to that originally removed from the atmosphere.

In order to fully account for biomass-related GHG emissions, indirect emissions from the production, processing, and transportation of the biomass must be considered. In a life-cycle analysis (LCA) of a combined cycle biomass gasification power plant, researchers showed that over 95% of the total CO_2 emitted by the production, transportation, and combustion of biomass is recaptured as biomass by the fuel crop (National Renewable Energy Laboratory, December 1997). Emissions from the transport of biomass from the fuel crop plantation to the gasification plant was calculated to be about 4% of total gross emissions, assuming a total trip distance of 10 miles. For the purposes of this study, a worst case trip distance of 400 miles was assumed, since the biomass feedstock is assumed to consist of waste forest, agricultural, and municipal waste residue sourced primarily from the Central Valley. The Central Valley extends roughly 400 miles from north to south. Hence, the sources of biomass would be dispersed over a large area, rather than being concentrated in a fuel crop plantation as assumed in the LCA. The resultant biomass transportation emissions would be greater than 4% of the total gross emissions, but the additional GHG emissions related to biomass transport in this scenario would be minor when compared to the net emissions avoided by switching from fossil fuels.

Co-firing biofuels with natural gas in existing boilers and gas turbines has also been studied, with biogas blended at low firing rates of around 10% of total fuel thermal input. At a low co-firing rate, the lower heating value of syngas compared to natural gas is not expected to require significant modifications to existing combustion units to efficiently combust the natural gas/syngas mixture.

5.1.2.1 Biomass Supply

Biomass thermal generation and gasification technology may be important to California because the state is a major agricultural products state. Five categories comprise the majority of agricultural biomass in California: orchard and vineyard prunings and removals, field and seed crop residues, vegetable crop residues, animal manures, and food processing wastes. Agricultural biomass is distributed throughout California, but the Central Valley is the most concentrated source. Not all of the gross biomass residue is available for fuel, as some is needed to maintain soil fertility and tilth or for erosion control. Approximately 33.6 million dry tons per year of total biomass were estimated as available, with 43% from forestry residues, 29% from agricultural residue, and the remaining from municipal waste (landfill gas and digester gas from waste water treatment plants). Following are some estimated sources of biomass residue in California (California Energy Commission, April 2005):

- Around 2.6 million dry tons/year of woody biomass are produced as prunings and tree and vine removals from orchards and vineyards.
- Around 5 million dry tons/year of field crop residues are produced, primarily comprising cereal straws and corn stover (i.e., the stalks, and other residue from corn production). These materials are not currently used for power generation due to ash slagging and fouling in combustion systems. Other conversion approaches are under development.
- Food processing wastes, including nut shells, pits, and rice hulls, are in excess of 1 million dry tons per year.

Two potentially viable supplies of biomass residue to the Bay Area are from Fresno and San Joaquin Counties. The following biomass residue material is reportedly available (California Energy Commission, November 2005):

- Fresno County: 0.288 million tons per year field and seed crop residue at a cost ranging from $75 to $103/dry ton; 0.15 million tons per year of fruit and nut residue at a cost ranging from $49 - $69/dry ton;
- San Joaquin County: 0.217 million tons per year field and seed crop residue at a cost ranging from $45 to $71/dry ton; 0.042 million tons per year fruit and nut residue at a cost ranging from $29 to $47/dry ton.

5.1.2.2 Technical Considerations

Potential operational issues with co-firing biomass syngas in an existing natural gas boiler include slagging or fouling of the boiler. Pilot-scale studies indicate that direct firing of biomass syngas did not significantly affect these boiler characteristics, and the deposits on the boiler walls were easy to remove. However, full-scale demonstration tests would confirm impacts on boiler operations.

The lower heating value of syngas results in lower flue gas temperatures, and hence lower efficiencies than natural gas firing. The co-firing of syngas with natural gas takes advantage of more severe steam conditions (e.g., 2400 psig/1000 deg. F or 3500 psig/1000 deg. F) and the associated reheat cycles common to large boilers. Therefore, co-firing biomass syngas is expected to result in higher efficiency than biomass combustion alone. The expected heat rate for biogas co-firing in combined cycle generation is around 9,000 Btu/kWh (38% thermal efficiency), as compared to around 7,400 Btu/kWh (46% thermal efficiency) for natural gas combined cycle generation using modern equipment (California Energy Commission, November 2002).

Different low grade fuel feed stocks have different ash characteristics, which may impact combustor ash deposition, heat transfer patterns and combustor thermal efficiency. Modifications to steam generators (e.g., installing soot blowers) may be required to avoid ash deposition. However, in biomass gasification systems the gasifier will retain ash, thus reducing the ash loading in the main boiler.

Another technical challenge is the operation of selective catalytic reduction (SCR) systems for NO_x control when co-firing biomass with natural gas fuel. Only one previous instance of an SCR installation on a wood-fired boiler in Ohio is indicated in the BACT LAER Clearinghouse database. SCR systems are feasible if ammonia "slip" (the incomplete reaction of ammonia with NO_x) can be properly controlled, which can be difficult with the variable flame conditions typical of biomass fuels. For co-fired systems, the flame conditions would likely be more stable at co-firing rates of 10%. A key issue is the temperature requirements of the SCR catalyst, which is mounted between the boiler combustion zone and the stack. The optimal operating temperature for the catalyst is 675 degrees F. The expected temperature of the flue gas in a biomass power plant is substantially lower, although a co-fired system would only be marginally lower. While lower flame temperatures can result in lower NO_x concentrations, supplementary heating of the flue gas may be needed when the boiler is operating on biomass syngas alone. In addition, catalyst fouling is a potentially significant issue when attempting to utilize SCR technology with a biomass fired boiler, as the elevated concentrations of potassium and sodium in biomass can lead to "poisoning" or deactivation of the SCR catalyst.

5.1.2.3 Environmental Considerations

Metal content varies widely with biomass type. Wood waste typically has low levels of metals, whereas sewage sludge can be significantly higher than coal. Low- or semi-volatile metals in biomass fuels will be low when first gasified, because metals primarily remain in the bottom ash of the gasifier and would not partition to the syngas. Sewage sludge can contain high levels of highly volatile metals, such as mercury, that would be carried over in the syngas.

As a comparison to some current practices, the firing of biomass in a controlled combustion process will result in significantly lower emissions of most pollutants as compared to open burning of the residual matter in the fields. Much of the biomass feedstock available in California is currently either burned or disposed of in landfills. However, new legislation is leading to a phasing out of open burning of agricultural residues, and state mandates now require a 25% diversion of wastes from landfills. These biomass supplies could be utilized as energy feedstocks, and the controlled combustion of them would result in vastly reduced particulate emissions as well as reductions in landfill gas production.

5.1.2.4 Indicative Capital Costs

Installed capital costs for biomass handling, gasification, and gas cleanup have been estimated to range between $900 and $1300/kWe (California Energy Commission, November 2005). The major equipment required for a biomass co-firing retrofit application would include:

- Truck unloading and conveyor system for raw material handling;
- Dry fuel storage, which would depend on biomass type;
- Dryer may be required for wet fuels, such as sludge and manure;
- Fuel handling environmental controls for dust control and odor filtration;
- Fuel feed system to supply fuel to gasifier;
- Hot gas ducting system and burner or injection system;
- Ash handling from gasifier residual waste.

Case Example: Biomass Co-firing in Natural Gas Boiler

This case example was used as the basis for evaluating the preliminary feasibility of biofuel utilization for reducing GHG emissions from natural gas fired steam electric boilers in the Bay Area. The project is assumed to be gasification of agricultural waste biomass, with co-firing of biogas and natural gas in an existing boiler.

Project Basis:

- Biomass gasification on-site at existing 2,150 MMBtu/hr natural gas steam electric boiler
- 10% of thermal input is from biogas fuel
- Feed is agricultural waste based on the following assumptions:
    - Composition of biomass (Shinnar, et al, 2006):
        - Carbon: 44.8% dry matter,
        - Hydrogen: 5.7% dry matter, and
        - Moisture: 15%

  - 70% is converted to biogas generated (Shinnar, et al, 2006)
  - Non-delivered biomass fuel cost is $40/dry ton (Jenner, 2006)
  - Delivery cost of biomass fuel is $10/dry ton.
  - Natural gas costs are assumed at $6.00/MMBtu.

Capital Costs (California Energy Commission, November 2005):

- Assumes current gasification technology costs of $900/kW as the direct installed capital cost of the gasification and gas cleanup systems.
- Biomass handling system costs are $100/kW.

Air Quality Impacts:

- Direct air quality emissions are from the firing of biogas to replace 10% of the natural gas on a heat input basis. GHG emissions from biogas combustion are assumed to be carbon neutral. Net change in criteria pollutant emissions are based on the difference between natural gas combustion and biogas co-firing (Jenner, April 2006).[3] Laboratory studies on synthesis gas co-firing in boilers have indicated that NO_x emissions decrease as the amount of gasified biomass in the fuel increases, due to lowered flame temperatures (Coelhi, et al). In existing gas turbine applications, biofuel synthesis gas co-firing may result in higher emissions of NO_x because of fuel composition variability and non-optimal gas turbine combustor design.
- Indirect air quality emissions are from the transportation of biomass to the plant site. For purposes of this study, a worse case scenario of 400 mile transportation round trip distance via truck is assumed.
- For biomass syngas co-firing applications, trace organic emissions are expected to decrease. Trace metal emissions are not expected to increase because most biomass materials have low metal content, and trace metals present are readily removed with

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[3] Criteria pollutant emissions from biogas firing in a 20 MW power plant based on test data, as referenced in Jenner, Mark, *The BioTown, USA Sourcebook of Biomass Energy*, Indiana State Department of Agriculture & Reynolds, Indiana, April 3, 2006, p. 48.

conventional boiler gas cleanup operations. For purposes of this study, the emissions of VOC and air toxic pollutants from co-firing biomass syngas were conservatively assumed to be neutral (i.e., no net decrease).

5.1.3 Carbon Capture with CO_2 Sequestration

Carbon capture and sequestration (CCS) options for reduction in emissions of CO_2 is a focus area of research by many organizations globally, including the US Department of Energy (DOE). The concept of this mitigation option is to capture a nearly pure stream of CO_2 from a combustion or process source and inject the CO_2 for geologic sequestration. The primary candidates for CO_2 capture are large stationary sources, such as from electric power plants and other large industrial facilities.

The flue gas streams from large stationary combustion sources such as power plants have CO_2 concentrations on the order of 4% to 9% by volume. For successful carbon sequestration, the carbon must be captured and concentrated before injection. The carbon capture step may be enhanced with oxy-fuel combustion. Oxy-fuel combustion uses oxygen instead of air for combustion, producing a flue gas that is mainly H_2O and CO_2 and which is readily captured. This option is still under development. The use of oxy-fuel combustion is being examined by the U.S. DOE, Office of Fossil Energy, National Energy Technology Laboratory (NETL). The use of oxygen in the place of air results in a much lower volume of flue gas, which enhances thermal efficiency, thereby directly lowering CO_2 emissions.

Oxy-fuel combustion requires a source of nearly pure oxygen. There are three primary technologies for oxygen production. First, oxygen can be separated from air using cryogenic distillation, resulting in purities up to 99.9% O_2. Second, vacuum pressure swing adsorption (VPSA) takes advantage of the adsorbent properties of zeolites to produce oxygen in purities around 90-94% O_2. Finally, selective ceramic oxygen transport membranes (OTM) are being developed that can produce very high purity O_2. Currently, all three technologies can produce oxygen within a similar cost range, around \$18 to \$32 per ton O_2 in larger facilities. However, cryogenic distillation and OTM technologies currently have the highest production volume capability, with facilities producing 1000 to 3000 tons O_2 per day. OTM technology is improving, and oxygen production costs will likely drop as the technology matures.

Highly efficient oxy-fuel boilers, with the incorporation of lower cost OTM oxygen generation technology, have the potential to provide significant GHG reductions through carbon capture and storage at more competitive costs. The oxy-fuel technology has the potential to significantly reduce the complexity of CO_2 capture, thus reducing the overall cost of carbon capture and sequestration, while offering increased thermal efficiency and reduced pollutants from the combustion process. However, O_2 production is an energy intensive process, with current technology requiring approximately 200 kWh/ton O_2. The emissions produced indirectly through the production of the process energy would need to be accounted for in this mitigation scenario.

Other current and emerging carbon capture technologies, categorized into four general types, target the separation of CO_2 from gas mixtures containing nitrogen, hydrogen, water vapor and methane associated with the different applications. Table 5-2 shows a matrix of the capture technologies by category (i.e., solvents, membranes, sorbents, and cryogenic distillation), associated with various capture applications.

TABLE 5-2. MATRIX OF CARBON CAPTURE TECHNOLOGIES

Capture Technologies	Capture Applications			
	Process Streams	Flue gas Separation	Oxy-fuel Combustion	Gasification
Solvents	Chemical and physical solvents	Chemical solvents	Biomimetic solvents	Chemical and physical solvents
Membranes	Polymeric, Ceramic, Facilitated transport, and Carbon Contactors			
Sorbents	Zeolites and Activated carbon	Zeolites, Activated carbon, carbonates, and carbon-based sorbents	Zeolites, Activated carbon, Adsorbents for O_2/N_2 separation, Perovskites, and Oxygen chemical looping	Zeolites and Activated carbon
Cryogenic distillation	Ryan-Holmes process	Liquefaction and Hybrid processes	Distillation	Liquefaction and Hybrid processes

Source: IPCC SRCCS, Table 3.1

The choice of a specific capture technology is determined largely by the process conditions under which it operates.

Geologic sequestration of CO_2 involves storage in underground geologic formations, after capture from the power plant or other industrial process exhaust stream. Geologic formations suitable for sequestration include depleted oil and gas reservoirs, deep saline aquifers, and coal seams that cannot be mined.

Another CCS option being researched is mineral carbonation, which effectively combines the capture and sequestration of CO_2 into a single process. Mineral carbonation is the reaction of CO_2 with non-carbonate minerals such as olivine and serpentine to form geologically stable mineral carbonates. Mineral carbonation could be realized in two ways. First, minerals could be mixed and reacted with CO_2 in a process plant. Second, CO_2 could be injected into selected underground mineral deposits for carbonation, similar to geological sequestration.

Mineral carbonation processes will be practical only when two key issues are resolved. First, for sequestration purposes, a fast reaction route that optimizes energy management must be found. Second, issues with respect to the mining and processing activities required for mineral sequestration need to be quantified, especially concerns related to overall economics and environmental impact.

Carbon capture and sequestration as applied to dilute sources of CO_2, such as combustion flue gas streams, was not considered as a viable mitigation option for the detailed analysis.

5.2 GAS-FIRED TURBINE COGENERATION AND COMBINED CYCLE UNITS

Cogeneration and combined cycle power plants utilize the waste heat from the combustion process for enhanced energy generation. Cogeneration and combined cycle plants are inherently more efficient than simple cycle power generation. Table 5-3 presents a summary of the gas-fired turbine cogeneration units that are located in the Bay Area.

TABLE 5-3. GAS-FIRED TURBINE COGENERATION UNITS IN THE BAY AREA

Turbine Size	No of Turbines	% of Total No of Turbines	% of Total Generating Capacity-Weighted (a)
>100 MW	6	3.8	28.7
50 to 100 MW	1	0.6	2.8
10 to 50 MW	65	41.1	63.2
<10 MW	86	54.4	5.2
TOTAL	158	100	100

(a) Based on the MW output per turbine and total MW of generating capacity.

As stated above, a new combined cycle natural gas-fired power plant has been identified by the California Energy Commission as the minimum mitigation technology to be used for electric power generation for use in California.

5.2.1 Use of Biofuels

Gaseous biofuels can theoretically be used as a supplemental fuel for power generation. Infrastructure and/or facilities to generate biogas would be required to implement this option to mitigate GHG emissions from natural gas-fired power generation. Refer to the discussion in Section 5.1.2 for a description of the biofuel options available.

Co-firing of biogas in a turbine would need to be examined for the specific unit under consideration, as the design characteristics and manufacturer’s warranties may be a barrier for biofuel combustion. Another consideration is the potential for higher NO_x emissions from co-firing of synthetic fuels due to the variability of the fuel composition and inability to optimize the gas turbine combustor design for existing sources.

5.2.2 Advanced Gas Turbines

Turbine improvements – mostly in materials – have resulted in turbines capable of reaching 60% efficiency or slightly above. New turbines, such as the GE Frame G and H models are designed for higher efficiency operations. The technology is proven and demonstrated, but expensive. The net improvement is also small, generally only a few percentage points in increased efficiency.

This technology is not a retrofit for existing units, meaning that existing unit efficiencies cannot be greatly increased. Overall efficiency can only be improved through elevated firing temperatures, requiring specialized materials of construction to withstand these conditions. For a retrofit application, this is not a plausible mitigation option because the base machine design is set for a certain temperature range.

For a new source, advanced turbine design may be a viable consideration with efficiencies of up to 60%, NO_x emissions achievable to 10 ppmvd @ 15% O_2 without add-on controls, and at a competitive cost.

5.3 GAS-FIRED TURBINES (SIMPLE CYCLE/PEAKER PLANTS)

The gas-turbines in the Bay Area are nearly all natural gas fired and vary in MW output. Simple cycle natural gas-fired turbines are inherently less efficient than combined cycle (i.e., integrated heat recovery steam generator) or cogeneration (also referred to as combined heat and power), as there is no provision for recovery of waste heat from combustion. Conversion of simple cycle to combined cycle operation would provide an efficiency increase from around 35% for simple cycle operation to around 50% for combined cycle operation. However, most gas turbines are peak load plants, so operation in combined cycle mode at baseload operation is not a viable option. They are required to operate as load-following, rather than baseline operation. For the purposes of the study, it is assumed that conversion of a simple cycle unit to combined cycle or cogeneration is not feasible as a retrofit technology.

5.3.1 Gas Turbines with Hydrogen Supplemental Fuel

It may be possible to use additional hydrogen as a supplemental fuel for existing natural gas fired turbines. As described in Section 5.4 below, hydrogen co-firing only affords reductions in GHG emissions if the CO_2 emissions from the hydrogen production are captured and sequestered.

Turbines can be fired on refinery fuel gas which can contain around 10 percent hydrogen (by volume). The issues associated with firing hydrogen are:

- Hydrogen causes material of construction brittleness for equipment components;
- Flame temperature is much higher; and
- Overall combustion efficiency may change.

One developer was limited by materials of construction and flame temperature to 10-15% hydrogen. The actual emission reduction from firing hydrogen is only reduced if the CO_2 from H_2 production is captured and stored. For this reason, the option of supplemental hydrogen co-firing was not evaluated in detail as a prioritized option for mitigation.

5.3.2 Use of Biofuels

Gaseous biofuels can theoretically be used as a supplemental fuel for power generation. Infrastructure and/or facilities to generate biogas would be required to implement this option to mitigate GHG emissions from natural gas-fired power generation. See discussion in Section 5.1.2 for a description of the biofuel options available.

Liquid biofuels could potentially replace the firing of diesel fuel as back-up in the case of natural gas curtailment. Co-firing of biogas in a turbine would need to be examined for the specific unit under consideration, as the design characteristics and manufacturer’s warranties may be a barrier for biofuel combustion.

5.3.3 Energy Efficiency Improvements

Efficiency improvements for simple cycle natural gas-fired turbine units can be achieved through combustion tuning, air to fuel ratio control, and process optimization. The expected efficiency improvements depend on the condition of the current equipment, with typical efficiency improvements on the order of 0.5-5 percent for non-optimized performance. However, in the Bay Area where NO_x control standards are stringent, only marginal improvements in unit efficiencies can be expected. Therefore, energy efficiency improvements may not prove the most fruitful option for effecting measurable reductions in GHG emissions from existing natural gas-fired combustion turbine units. As mentioned in Section 5.1.1, a cooperative effort between governmental agencies to prioritize dispatch in favor of units with the best environmental profile, taking CO_2 emissions into account, could prove the most beneficial measure to address efficiency in electricity generation dispatch.

5.4 NEW / REPLACEMENT MITGATION TECHNOLOGIES

Although new source or replacement mitigation technologies were not the primary focus of the study, there are numerous technologies that could be applied to electric power generation as new or replacement sources. As these apply for replacement or supplemental capacity across all types of power generation sources, they are discussed here as a separate grouping of technologies.

5.4.1 Renewable Energy Sources

The most common types of renewable energy technologies that could be considered for application in the Bay Area, including:

- Wind energy;
- Solar energy; and
- Geothermal energy.

These renewable sources generally would be considered to replace or supplement existing power or heat sources, rather than as a retrofit technology for mitigating GHG emissions from permitted sources.

Wind Energy: Installation of wind turbines for electricity generation is a proven renewable energy technology. Modern wind turbines are divided into two major categories: horizontal axis turbines and vertical axis turbines. Research is ongoing to improve the efficiency of low wind speed applications to improve the cost effectiveness.

Horizontal axis turbines are the most common turbine configuration used today. They consist of a tall tower, atop which sits a fan-like rotor that faces into or away from the wind, the generator, the controller, and other components. Most horizontal axis turbines built today are two- or three-bladed, although some have fewer or more blades and are the most common turbine type in use today.

Cost of Wind Energy: In the electricity market, wind power is competing with traditional sources of power generation. At today’s average wholesale prices, wind costs around 4.2 cents per kWh in the US, compared with 4 cents for coal, 6.8 cents for natural gas, 9.1 cents for oil and 10 cents for nuclear power, according to Kyle Datta, managing director at the Rocky Mountain Institute, a research group focused on eco-friendly business.

The installed capital cost range for wind turbines is $800 to $3500 per kW, according to the California Energy Commission.[4]

Solar Energy: Solar energy derived from sunlight is a clean, abundant, widespread, and renewable energy source. Various technologies capture this solar energy, concentrate it, store it, and convert it into other useful forms of energy:

- Low-grade thermal energy for residential and commercial heating;
- Medium-grade thermal energy for running some industrial processes;
- High-grade thermal energy for driving turbines to generate electricity;
- Electrical energy, converted directly from sunlight, to provide electricity for all of its myriad applications; and
- Chemical energy in hydrogen (via water splitting using photovoltaic or thermochemical processes to split water), for use in fuel cells and a broad range of electrical, heating, and transportation applications.

Concentrating solar power (CSP) plants produce electric power by converting the sun's energy into high-temperature heat using various mirror configurations. The heat is then channeled through a conventional generator. The plants consist of two parts: one that collects solar energy and converts it to heat, and another that converts heat energy to electricity.

Concentrating solar power systems can be sized for village power (10 kW) or grid-connected applications (up to 100 MW). Some systems use thermal storage during cloudy periods or at night. Others can be combined with natural gas and the resulting hybrid power plants provide high-value, dispatchable power.

Photovoltaic (PV) cells are electricity producing devices made of semiconductor material. Research is being conducted to improve the efficiency and lower production costs of PV technology. Research is ongoing for three materials used in PV - crystalline silicon, thin films, and modules. Crystalline silicon technology is advancing through research on materials, devices,

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[4] http://www.energy.ca.gov/distgen/economics/capital.html

and processes. Key thin- film technologies include amorphous silicon (a-Si), copper indium diselenide (CIS) and its alloys, cadmium telluride (CdTe), and thin films using a multijunction design. Cells are assembled into PV modules, which are optimized to improve performance beyond present limits.

Cost of Solar Energy: The cost to commercial users of photovoltaics ranged between $0.16-0.22/kWh. At present, the high cost of PV modules and equipment (as compared to conventional energy sources) is the primary limiting factor for the technology.

Geothermal Energy: Geothermal energy derives heat from geological sources for creation of electricity, and is an application of renewable energy. Geothermal power plants use steam, heat or hot water from geothermal reservoirs to drive turbine generators that produce electricity. The geothermal water is returned to the reservoir to maintain the pressure and sustain the reservoir supplies. Several types of power plants are in use, tailored to the temperature and pressure of each geothermal reservoir and how much steam is generated by the geothermal water. The power plants have only low levels of CO_2 in the non-condensable gas that is emitted to the air.

5.4.2 Alternative Hydrogen Production

Hydrogen's potential use in fuel and energy applications includes powering vehicles, running turbines or fuel cells to produce electricity, and generating heat and electricity for buildings. Currently, the vast majority of hydrogen is produced from natural gas for use in the petroleum refining industry (see Section 8.3). However, the use of hydrogen as an energy carrier is environmentally attractive, as it only produces water when combusted or used in a fuel cell. This could help eliminate mobile or distributed sources of GHG emissions from the combustion fossil fuels, as the production of hydrogen and the associated GHG emissions would be centralized at large point sources where mitigation would be more cost effective.

Hydrogen can also be produced from renewable energy sources. Water can be hydrolyzed into hydrogen and oxygen gases by electricity. This process can utilize renewable sources of electricity such as wind or solar, which would result in carbon-free hydrogen production. However, hydrogen production by hydrolysis is currently three to six times more expensive than production from natural gas. IGCC, described below, is also used to produce hydrogen from any organic feedstock. The synthesis gas from the IGCC unit is further processed using water-gas shift reactor technology to increase hydrogen and convert carbon monoxide to carbon dioxide.

The state of California has introduced initiatives for the development of a hydrogen fuel infrastructure. In 2004, the Governor signed the California Hydrogen Highway initiative to help develop a network of hydrogen fueling stations throughout the state to support the introduction of hydrogen-powered vehicles to market. As part of the Hydrogen Highway, hydrogen will have to be produced and distributed on a large scale. A detailed examination of the Hydrogen Highway initiative is beyond the scope of this project, however, in the following section some of the possible approaches to additional hydrogen production are given.

5.4.2.1 Integrated Gasification Combined Cycle with CO_2 Sequestration

The Integrated Gasification Combined Cycle (IGCC) generation process integrates a gasification system with a conventional combustion turbine combined cycle power generation unit. The gasification process converts coal, or other solid or liquid feedstock, into a hydrogen-rich gaseous fuel stream (referred to as synthesis gas or syngas). The syngas is then used to power a conventional combustion turbine combined cycle power plant with significantly lower SO_x, PM, mercury, and NO_x emissions.

Geologic carbon sequestration can be combined with this conceptual project by first converting the CO in the syngas stream to CO_2, followed by separation and recovery of the CO_2, together with H_2S. Development of low-cost, advanced CO_2 separation technologies are being investigated, including production of carbon dioxide hydrates, and dry scrubbing processes with regenerable sorbents. An example of this technology is the use of Selexol as the solvent in an acid gas removal unit which removes CO_2 and H_2S from the fuel gas. Selexol is a liquid physical sorbent that does not react chemically with the absorbed gases. The separated CO_2 is condensed to remove water, then compressed for transport via pipeline for sequestration.

There are projects in the planning phase at refineries in the US to implement a carbon capture and sequestration technology to produce hydrogen with significantly reduced CO_2 emissions. Carson Hydrogen Power Project (CHPP) is a joint venture project by BP Alternative Energy and Edison Mission Energy Group. The project includes the construction and commissioning of a 500 MW (nominal) power generation plant using IGCC technology starting with petroleum coke, to fuel the power generation turbines by clean hydrogen product. This is enough energy to power approximately 325,000 households. The CHPP project includes capture, compression, pipeline transport, and permanent sequestration of the carbon dioxide produced in the IGCC process in the nearby offshore oil fields, thus enhancing oil recovery. It is estimated that about 4.4 millions tons per year of CO_2 will be captured and sequestered.

This concept can also be used simply to produce hydrogen, which can then be used for refinery applications. This approach has also been investigated for full scale application.

5.4.2.2 Hydrogen from Nuclear Power

Research sponsored by the Office of Nuclear Energy (ONE) is developing the commercial-scale production of hydrogen using heat from a nuclear energy system. Key research areas include high-temperature thermochemical cycles, high-temperature electrolysis, and reactor/process interface issues.

5.4.2.3 Hydrogen from Renewable Resources

Research sponsored by the Office of Energy Efficiency and Renewable Energy (EERE) is focused on developing advanced technologies for producing hydrogen from domestic renewable energy resources that minimize environmental impacts. Key research areas include electrolysis, thermochemical conversion of biomass, photolytic and fermentative micro-organism systems, photoelectrochemical systems, and high-temperature chemical cycle water splitting.

5.4.3 Fuel Cells

5.4.3.1 Use of Hydrogen Fuel Cells as a Substitute Energy Source

Hydrogen fuel cells can be used as a substitute source of electric power, and then eliminate the need for conventional power generation methods. A hydrogen fuel cell operates like a battery. The chemicals are very simple, just hydrogen and oxygen. The hydrogen and oxygen atoms are joined together to produce water and electricity.

A hydrogen fuel cell consists of two electrodes sandwiched around an electrolyte. Oxygen passes over one electrode and hydrogen over the other, generating electricity, water and heat. Hydrogen is fed into the "anode" of the fuel cell. Oxygen (or air) enters the fuel cell through the cathode.

When excited by a catalyst, the hydrogen atom splits into a proton and an electron, which take different paths to the cathode. The proton passes through the electrolyte. The electrons create a separate current that can be utilized before they return to the cathode, to be reunited with the hydrogen and oxygen in a molecule of water.

Since hydrogen fuel cells rely on chemistry and not combustion, emissions are virtually zero in comparison to the cleanest fuel combustion engines. Hydrogen fuel cells can be made in a vast quantity of sizes. They can be used to produce small amounts of electric power for devices such as personal computers, or be used to produce high voltage powers for electric power stations. The overall energy efficiency of fuel cells meets or exceeds that of other forms of electricity production. The efficiencies can range from 50% to 60% in smaller polymer electrolyte membrane systems for electricity production, and when combined heat and power (CHP) systems are used, total energy efficiencies of 85% can be achieved. This compares to efficiencies of 30%-40% for combined cycle natural gas plants, and up to 60% total efficiency for combined heat and power (CHP) plants (US DOE Energy Efficiency and Renewable Energy).

In California, the California Stationary Fuel Cell Collaborative (CSFCC) promotes the commercialization of fuel cell technologies as a means of reducing or eliminating air pollutants and greenhouse gas emissions, increasing energy efficiency, promoting energy reliability and independence, and helping the state of California move closer to realizing a sustainable energy future. Under the auspices of the Collaborative, private industry and government agencies work together to advance the development of informed public policy; initiate public demonstrations of fuel cells and distributed generation technologies; conduct key studies to further existing knowledge about fuel cell capabilities and the impact of fuel cells and DG technologies; and raise public awareness about these technologies.

A recent Executive Order (EO) requires a report be developed by the end of the year to address the feasibility of a “hydrogen highway” in California and associated fuel cell development and other associated activities over the next five years and beyond. Further, the EO specifically names the Collaborative as a key part of the effort. The initial activity of the Collaborative will be to provide an objective overview to the groups in providing guidance to the process regarding stationary fuel cells. The most notable role would relate to the development of energy stations where stationary fuel cells will be part of the infrastructure. An advisory panel will review the report.

One of the goals of the Collaborative is to implement an inter-organizational policy to utilize fuel cells in government facilities (such as the Cal/EPA Headquarters building in Sacramento) The collaborative is a joint initiative of federal, state and non-governmental organizations interested in the acceleration of stationary fuel cell commercialization in the State of California and beyond. Members represent a group of key government and non-profit organizations interested in combining efforts and resources towards commercialization of stationary fuel cells in California. These organizations are part of a Core Group, focused on its mission to commercialize fuel cells for power generation in California. A key part of the organization is an Industry Advisory Panel that was formed to assure industry participation, advice, and counsel.

5.4.3.2 Fuel Cells as Replacements for Gas Turbines

A new hydrogen fuel cell power plant has been recently installed and began operation in Alameda County to supply power to the Santa Rita jail in Dublin, CA. Construction began on the fuel cell power plant in November 2005 and the one megawatt facility had a total installed cost of $6 million, funded in part with $2.4 million in government grants and incentives and the remainder financed through a 15-year loan provided through the California Energy Commission. The unit was designed by FuelCell Energy, Inc (Danbury, CT) and was assisted by Chevron Energy Solutions. FuelCell Energy has three core fuel cell product offerings—a 300 kW, a 1.5 MW, and a 3.0 MW. The fuel cell also generates waste heat which is captured and used for hot water heating and local comfort heating.

Fuel cells can also used in smaller electrical applications. As an example, as part of its Common Core Power Production (C2P2) project, Concurrent Technologies Corporation (*CTC*) awarded Millennium Cell, Inc. funding to develop an advanced solid boro-hydride fuel module for the 5 kW system, which was constructed and successfully demonstrated under earlier CTC funding. CTC is an independent, nonprofit, applied research and development professional services organization providing innovative management and technology-based solutions.
Millennium Cell, Inc. will design the critical components of the module and CTC will subsequently construct and test system performance within the Fuel Cell Test and Evaluation

Center. The objective of this project is to provide Advanced Power Technology Office (APTO) with advanced and alternative power technologies for military equipment.

5.4.3.3 Fuel Cell Applications for Industrial/Commercial Uses

In some instances, small phosphoric acid fuel cells may provide an option for gas-fired industrial/commercial boilers. Phosphoric Acid Fuel Cells (PAFC) were installed at 30 U.S. Department of Defense (DOD) bases between 1994 and 1997. These fuel cells operate on natural gas, so there will be CO_2 emissions. However, CO_2 emissions are less due to the more efficient operation of the fuel cell, especially with secondary heat recovery. The fuels cells were used in a number of different applications including kitchens, laundries, living quarters (barracks), office buildings, gymnasiums/pools, and as additional general power supply. The objectives of the PAFC Demonstration were to:

- Demonstrate fuel cell capabilities in real world situations;
- Stimulate growth and economies of scale in the fuel cell industry; and
- Determine the role of fuel cells in DoD's long term energy strategy.

The U.S. Army Construction Engineering Research Laboratory (USACERL) was assigned the mission of managing the fuel cell demonstration projects for the DOD. USACERL's specific tasks included developing turnkey PAFC packages, devising site criteria, screening DOD candidate installation sites against selection criteria, evaluating viable applications at each candidate site, coordinating fuel cell site designs, installation and acceptance of the PAFC power plants, and performance monitoring and reporting.

One fuel cell (a model PC25C) was located at the base laundry facility and its adjacent boiler plant. The electrical interface is at a new electrical transformer, which feeds into the base grid. The fuel cell thermal output is used to heat the hot water storage tanks for the laundry. Energy bill savings from the fuel cell prior to installation were estimated at $59,000 per year as shown below:

Electric Savings:	$89,000
Thermal Savings:	<u>$3,000</u>

TOTAL SAVINGS:	$92,000
Natural Gas Cost:	($33,000)
NET SAVINGS:	$59,000

A second fuel cell (also model PC25C) is located at the fuel operation for the US Naval submarine base New London in Groton, CN. The fuel cell is located at the base energy plant (Building 29) which has four boilers, three steam turbine/ generators and a gas turbine. The electrical output of the fuel cell is used as backup and base loading and is connected at a spare breaker in an existing electrical panel. The fuel cell thermal output is used to pre-heat the boiler make-up water resulting in an overall thermal utilization of approximately 90%. The energy savings from the fuel cell were estimated at $98,000 per year as shown below:

Electric Savings:	$132,000
Thermal Savings:	$23,000
TOTAL SAVINGS:	$155,000
Natural Gas Cost:	($57,000)
NET SAVINGS:	$98,000

The fuel cell performance from 9/30/1997 to 3/31/02 included 34,177 hours of operations and a capacity factor of 75%. The average fuel cell output was 178 kW.

There is one cement kiln located in the Bay Area that is a major contributor to overall GHG emissions in the Bay Area District. This kiln is owned and operated by Hanson Permanente and is located in Cupertino, CA.

Emissions of GHG are primarily CO_2 and result from the manufacture of cement clinker. The emissions are dominated by the cement kiln combustion and process emissions as follows:

- CO_2 from limestone calcination reaction. CO_2 is released from the calcination reaction in the cement kiln where limestone is converted to produce clinker. This is the largest source of emissions from the production of cement. The CO_2 released from the calcination reaction itself is concentrated, making this source a potentially attractive candidate for CO_2 capture and sequestration.
- CO_2 from fossil fuel combustion in the cement kiln. Fossil fuel combustion in the cement kiln is the second largest source of CO_2 emissions from the manufacture of cement. In the US, common fossil fuels fired in cement production are coal, petroleum coke, and natural gas.

For the Hanson Permanente Cement Plant in the Bay Area, several fuels are fired in the cement kiln, as shown in the Table 6-1.

TABLE 6-1. FUELS CURRENTLY UTILIZED AT HANSON CEMENT PLANT

Fuel	Annual Throughput	Units of Measure
Coke	7,655	Tons/yr
Natural Gas	2,940,000	Therms/yr
Bituminous Coal	151,534	Tons/yr

6.1 GREENHOUSE GAS MITIGATION TECHNOLOGIES

6.1.1 Pozzolanic Clinker Displacement

Blended cement, using pozzolanic materials to blend with clinker, is a cement product marketed globally. Pozzolanic materials, while not cementitious themselves, react with calcium hydroxide in cement blends to increase the long term strength of the cement. Pozzolanic cement blends of up to 32% by weight have been proposed as project candidates under the Clean Development

Mechanism of the Kyoto Protocol framework. Fly ash is a pozzolanic material that is commonly used in blended cement. The blended material reduces emissions from the cement production operations in three ways:

- Commensurate reduction in the calcination of limestone directly proportional to the amount of clinker displaced by the blended material;
- Reduction in fossil fuel kiln combustion that would have been required for the calcination of limestone; and
- Reduction in consumption of electrical energy.

In California, existing cement standards prevent the use of blended cement, even though it is in widespread use in other countries and even in other states in the US. In addition to the barriers to market acceptance imposed by cement standards, the availability of fly ash is an issue that would need to be addressed to make this option a viable candidate. Fly ash would need to be obtained from neighboring states, or beyond depending upon availability, to make blended cement a viable option. Transportation of fly ash to the Hanson plant site would not only be costly, but have additional environmental impacts that would need to be considered. For purposes of this study, an assumed worse case transportation distance of 600 miles via rail is assumed.

Case Example: Fly Ash Blended Cement

This case example is based on an estimated cement production rate derived from the CO_2 emissions reported from the Hanson plant. The following assumptions were made to derive an estimated cost of emission reductions:

- Existing clinker content of cement currently is 95% on a weight basis;
- Project fly ash replacement to a level of 87% of clinker on a weight basis;
- Fly ash sourced from neighboring state with an assumed transport distance of 600 miles;
- Cost of fly ash is offset by reduction in cost of limestone for clinker.

6.1.2 Alternative Kiln Fuels

GHG emissions from cement production can also be reduced through the use of less carbon intensive fuels for clinker burning in the cement kiln. Biofuels considered carbon neutral have a significant potential for utilization in cement production, with a substantial decrease in CO_2 emissions.

For the Hanson cement plant, the firing of biofuel to replace coal or coke was considered as an alternative to reduce emissions of CO_2. Reportedly, the Hanson plant is evaluating the use of solid biofuels, such as nut shells, to replace or supplement coke at their cement kiln.

The cost effectiveness of replacing a fraction of the coal or coke in the cement kiln with biomass would be more favorable than for the biomass gasification process described in Section 5.1.2. Capital costs would be lower because a gasifier is not needed for the cement kiln case example where solid fuels are being replaced. In addition, the GHG emission reduction potential would likely be higher on a ton/MMBtu as the baseline emissions of firing coal or coke for the cement kiln example are higher than for natural gas firing. This case example was not evaluated in detail because the site is reportedly conducting a separate evaluation of the use of solid biofuels for combustion in the cement kiln.

6.1.3 Kiln CO_2 Emissions Sequestration

In some industrial processes such as cement kilns, chemical reactions lead to the formation of CO_2 in quantities and concentrations that allow direct capture or separation of the CO_2. Cement kiln CO_2 concentrations are higher than typical combustion sources, but lower than from hydrogen production in refineries. Carbon capture and sequestration is discussed in Section 5.1.3.

7.1 LANDFILL GAS RECOVERY (WITH FLARING)

There are several active and inactive sanitary landfills in the Bay Area. The major active landfills are located as shown in Table 7-1.

TABLE 7-1. MAJOR ACTIVE LANDFILLS IN THE BAY AREA

Landfill Name	Location	Tippage (tons/day)	Maximum Total Tonnage In Place	Current Landfill Gas Disposition
TriCities Waste Management	Fremont	2,600	13,500,000	3 proposed IC engines/electricity with flare backup, and 1 proposed new flare
Waste Management of Alameda County	Altamont	11,150	47,100,000	2 gas turbines, 2 engines / electricity with flare backup, plus proposed purification and separation
Republic Services – Vasco Road	Livermore	2,500	23,800,000	Landfill gas flare (71 MMBtu/hr)
ACME Fill Corp	Martinez	1,500	11,100,000	Landfill gas flare plus off-site engines (Central Contra Costa Sanitary District) and microturbines (Bulldog Power)
Allied Waste Landfills – Keller Canyon	Pittsburg	3,500	38,400,000	2 enclosed ground flares, and off-site plant has applied for 2 IC engines (still under review)
West Contra Costa Sanitary Landfill	Richmond	2,500	13,000,000	IC engines/ electricity with flare backup
Redwood Landfill	Novato	2,300	17,100,000	Landfill gas flares (90 and 120 MMBtu/hr)
The Recyclery (Newby Island) and International Disposal Corp of CA	Milpitas	4,000	39,000,000	Off-site IC engines (GRS) and landfill gas flares
Kirby Canyon Landfill	Morgan Hill	2,600	19,840,000	3 proposed IC engines/electricity plus 1 existing flare and 1 proposed

Landfill Name	Location	Tippage (tons/day)	Maximum Total Tonnage In Place	Current Landfill Gas Disposition
				backup flare
Norcal Waste Systems Pacheco Pass Landfill	Gilroy	1,0000	6,200,000	Landfill gas extraction, collection, and flare
Guadalupe Rubbish Disposal (and Gas Recovery Systems, Inc.)	San Jose	3,650	16,400,000	Enclosed landfill gas flare (IC engines by GRS)
Browning Ferris Industries of CA, Inc. Ox Mountain Sanitary Landfill	Half Moon Bay	3,600	22,740,000	3 landfill gas flares, 6 IC engines proposed in off-site plant
Potrero Hills Landfill	Suisan City	4,400	4,430,000	Landfill gas flare
Sonoma County Landfill	Petaluma	2,500	19,590,000	12 IC engines/electricity with flare backup, 1 proposed replacement flare, 1 proposed purification/separation operation
Palo Alto Landfill	Palo Alto	200	5,800,000	Flare

And the primary inactive landfills are shown in Table 7-2.

TABLE 7-2. INACTIVE LANDFILLS IN THE BAY AREA

Landfill Name	Location	Tippage (MM tons/day)	Maximum Total Tonnage In Place	Current Landfill Gas Disposition
Bay Front Park (Marsh Road Landfill)	Menlo Park	Inactive	NA	Off-site IC engines/ electricity with thermal reactor backup, flare
Shoreline	Mountain View	Inactive	12,725,000	2 microturbines plus 3 off-site IC engines (ALZA)/ electricity with three flares for backup
Napa-Vallejo Waste Management Authority (Gas Recovery Systems)	Napa/ American Canyon	Inactive	4,230,000	Landfill gas flare (24 MMBtu/hr) (IC engines by GRS)

Landfill Name	Location	Tippage (MM tons/day)	Maximum Total Tonnage In Place	Current Landfill Gas Disposition
Hillside Landfill	Colma	Inactive	5,000,000	Flare
Brisbane Landfill	Brisbane	Closed	7,000,000 (very old)	Flare
Oyster Bay	San Leandro	Closed	5,700,000	Flare
City of Santa Clara	Santa Clara	Closed	5,500,000	IC engines at San Jose WWRP, flare

The Central Contra Costa Sanitary District Title V operating permit indicates that landfill gas is being burned in a boiler with natural gas and distillate oil and in two incinerators with sewage sludge and natural gas. Landfill gas is supplied from the ACME Fill Corp site in Martinez.

In addition to these large landfills, there are a few smaller active landfills (Pacheco Pass in Gilroy and Clover Flat in Calistoga) and some closed landfills with gas recovery systems (such as Shoreline Amphitheatre/Mountain View, Hellyer Park/San Jose, Turk Island/Union City, Cesar Chavez Park/Berkley, Singleton Road/San Jose, Sunnyvale Landfill/Sunnyvale, Pleasanton Garbage/Pleasanton, and TRC (GBF Pittsburg)). The smaller landfills tend to have flares for burning the landfill gas. The total landfill gas collection rate from these smaller landfills is estimated at about 1500 scfm.

Methane production (or methanosis) results from the biological decomposition of organic wastes in the landfill. The landfill gas can be captured and is sometimes flared with no recovery of the thermal value of the gas. Land fill gas has the following typical composition (on a moisture free basis):

- Methane – 55 vol% typical with a range from 40 to 60 vol%
- Carbon dioxide – 40 vol% typical with a range from 40 to 60 vol%
- Nitrogen – 5 vol% typical with a range from 2 to 5 vol%

Other components of landfill gas include oxygen, ammonia, and hydrogen. Trace quantities of odor causing components, aromatic organics, chlorinated solvents, alcohols, and other mixed hydrocarbons are also present.

Under BAAQMD Regulation 8, Rule 34, a landfill is required to have landfill gas collection and emission control equipment (8-34-301). The rule limits gas leakage from the landfill surface as well as from the landfill gas collection and control systems components.

There is also federal NSPS (40 CFR, Part 60 Subpart WWW0, and federal Emission Guidelines (40 CFR, Part 60 Subpart Cc), and Maximum Achievable Control Technology (MACT) standard for Municipal Solid Waste Landfills (40 CFR 63, Subpart AAAA). See Appendix B for more information on regulations and policies related to the source categories under review. Key differences between these regulations include: (1) the District regulation requires landfill gas collection and control for smaller landfills than the federal regulations; (2) the federal regulation has no landfill gas component leak limits; (3) the District regulation has more stringent emission control requirements for flares.

Gas Collection System Efficiencies

The majority of the landfills under consideration have active gas extraction systems. The efficiency of these systems varies based upon two primary factors: 1) the effectiveness of the operation and maintenance of the system, and 2) the type of cover over the area from which gas is being extracted. Operating sites that have open faces with no cover and gas extraction systems in the area of the open face have much lower efficiencies than systems in areas that are well-covered. One study, based upon cells under varying cover conditions at three large facilities, rated efficiencies of the operating active landfill gas extraction systems as follows (Spokas, et. al, 2005):

TABLE 7-3. EFFICIENCIES OF ACTIVE LANDFILL GAS EXTRACTION

Cover Condition	Efficiency
Operational face, open-no cover	35%
Temporary soil cover	65%
Compacted clay cover	85%
Geosynthetic cover	90%

Clay covers can vary in effectiveness, depending on the locale (frequency and size of rainfall events, potential for freezing) and maintenance of the cover. Using these values, and assuming the sites are operated and maintained to a similar standard, one can calculate the efficiency of the facility based on the final cover types and areas. In general, sites with active gas extraction that are producing energy with engines or turbines have effective clay or geosynthetic covers in place.

7.1.1 Landfill Gas Recovery in IC Engines

This mitigation option entails the utilization of previously flared landfill gas as fuel for IC engine generators to provide power for local use or supply to the grid. This mitigation option is based on the principle of converting a waste stream, i.e., the flared landfill gas, to an energy source for the generation of power. Utilization of the landfill gas for IC engine power generation has a net overall decrease in GHG emissions based on the difference in emissions from a baseline scenario without the project, and the IC engine project itself. The emissions associated with the baseline include:

- Direct emissions from flaring of the landfill gas; and
- Indirect emissions from grid supplied electricity in the pre-project scenario.

The emissions associated with the project itself include:

- Direct emissions from any gas clean-up processes necessary; and
- Direct emissions from combustion of the landfill gas in the IC engine generator(s).

Therefore, the emission reductions associated with the project are based on the decrease in emissions from the recovery of the previously flared landfill gas, and the displacement of electricity from the grid.

Table 7-4 presents the Bay Area landfill facilities that operate with a landfill gas gathering system and IC engine for the production of electricity for sale.

TABLE 7-4. LANDFILLS WITH GAS COLLECTION AND IC ENGINE GENERATION

Landfill Name	Location	IC Engine Type	Power Capacity (MW)
Waste Management of Alameda County	Altamont	Duetz TBG 620 V16 (2)	6.6
TriCities Waste Management	Fremont	Caterpillar Model G3516LE (3 proposed @ 800 kW each)	2.4 (proposed)
West Contra Costa Sanitary Landfill	Richmond	Waukesha GL Series Lean Burn, Model 7042 GL (3 @ 975 kW each)	2.9 (proposed)
Sonoma County Central Disposal Site LFG Power Plant	Petaluma	Lean burn Caterpillar Model 3516 SITA (12)	6.0
Napa-Vallejo Waste Management Authority	Napa/American Canyon	Gas Recovery Systems (GRI) IC engines	
Guadalupe Rubbish Disposal (and Gas Recovery Systems, Inc.)	San Jose	Cooper Superior Rich Burn, Model 8G825 (3), and Waukesha GL Series Lean Burn, Model 7042 GL (1)	2.5
Bay Front Park (Marsh Road Landfill)	Menlo Park	Off-site Cooper Superior Rich Burn, Model 8G825 (4)	2.0
Newby Island I and II Facility	San Jose	Cooper Superior Rich Burn, Model 8G825 (3), and Waukesha GL Series Lean Burn, Model 7042 GL (3)	5.0
Kirby Canyon Landfill	Morgan Hill	Caterpillar Model G3516LE (3 proposed @ 800 kW each)	2.4 (proposed)

Gas Recovery Systems (GRS) purchases landfill gas from the Browning Ferris Industries Newby Island site and then converts that biogas to electricity with their IC engines. GRS currently owns and operates the landfill gas collection system and electric generators at the Newby Island under contract to Browning Ferris Industries, operator of the Newby Island Landfill. GRS has also proposed operating a gas delivery system consisting of compressors, gas drying equipment and a pipeline from Newby Island to the IC engines located at the San Jose/Santa Clara Water Pollution Control Plant. These engines currently burn methane gas created during the wastewater treatment process (digesters). This biogas methane accounts for 30% of the plant's total energy needs. The remaining energy demand is met by purchasing natural gas or electricity from PG&E. GRS also runs engines on landfill gas from the American Canyon Landfill, Marsh Road Landfill, and the Guadalupe Mines Road Landfill.

The IC engines at the Altamont Landfill are operated on landfill gas, liquefied natural gas (LNG) and LNG plant waste gas.

Mitigation options for landfills currently utilizing the landfill gas for electricity generation were not ranked on the priority short list and are not evaluated in this report. As indicated above, the recovery of landfill gas and consumption to generate electricity in an IC engine is one of the mitigation options for flared landfill gas. Significant cleaning of the landfill gas is necessary to maintain proper engine function and meet emissions standards, with water, sulfur compounds, chlorinated compounds, and siloxanes requiring removal prior to combustion. Siloxanes, in particular, can cause glass-like deposits and increased friction in engines, which greatly reduces engine life and can void warranties. Caterpillar and Waukesha engines require siloxane concentrations to be below 25 mg/m^3, while Deutz engines require less than 5 mg/m^3 siloxane content.

7.1.2 Landfill Gas Recovery in Gas Turbines

Gas turbines are also utilized for landfill gas-fired energy production. Table 7-5 lists the facilities in the Bay Area that have gas turbines in place to generate power from landfill gas.

TABLE 7-5. LANDFILLS WITH GAS COLLECTION AND GAS TURBINE GENERATORS

Landfill Name	Location	Turbine Type	Power Capacity (MW)
Waste Management of Alameda County	Altamont	Solar Centaur Model T-4500 (2)	6.6
Central Contra Costa Sanitary District	Martinez		
Shoreline	Mountain View	Ingersoll-Rand Model 70LM microturbines	1.4
Bulldog Power	Martinez	Microturbines	

Gas turbines typically have lower NO_x emissions than IC engine generators and are therefore an attractive alternative for consideration. Lower NO_x emissions from gas turbines may lead to higher N_2O emissions, thus offsetting some of the benefits of low NO_x combustion.

7.1.3 Landfill Gas Utilization as Pipeline Gas or Transportation Fuel

This mitigation option is based on the recovery of previously flared landfill gas and the use of the fuel as a renewable energy source. The recovered methane can be used directly for a local production of pipeline quality gas for energy either on- or off-site. The principle of emission reductions from this option are similar to that for IC engine generation of power in that it represents a recovery of a waste stream as fuel. For landfill gas utilization as pipeline quality natural gas, significant processing of the landfill gas must occur to remove inert constituents, such as CO_2, and other contaminants.

Methane has been recovered from landfill gas using two technologies, pressure swing adsorption (PSA) and polymeric membrane separation. With PSA systems, the raw landfill gas is treated in a carbon bed to remove the impurities. PSA is easier to operate than membrane systems, and can achieve up to 90-92% recovery.

QuestAir Technologies Inc. (QuestAir) is the developer of “fast-cycle” PSA technology. Recently, QuestAir and the City of Vancouver announced that a demonstration project at the Vancouver Landfill Site has begun upgrading landfill gas to methane suitable for injection into the natural gas distribution system or for use as a transportation fuel. The demonstration plant will help the company market its commercially available M-3100 landfill gas upgrading system to municipal landfills around the world. The QuestAir demonstration plant upgrades up to 317,000 cubic feet of landfill gas per day, producing sufficient purified methane to heat approximately 470 suburban homes.

Approximately two to three million tons waste in place will generate 3000 standard cubic feet per minute (scfm) of raw landfill gas. The cost of a PSA treatment system for 3000 scfm raw gas (500 MMBtu/day) is as follows:

- High speed PSA gas purification system skid for $1.4 to 1.7 million.
- Gas cleanup equipment for pipeline quality
- Compressor to pressure recovered gas to 150 psig - $800,000 (or an additional $800,000 up to 500 psig).
- Gas meter station/flow control/gas chromatography/water/H_2S - $500,000
- NG pipeline interconnect - $1.0 million

The total installed investment is $5 to 6 million, although the actual cost is variable and dependent of the landfill gas quality. The PSA technology can work at landfill gas recovery facilities as small as 1000 to1500 scfm raw gas feed.

Landfill gas recovery can be done using polymeric membranes (such as those manufactured by W.R. Grace Co.). The cost for a comparable 3000 scfm membrane recovery system is as follows:

- Membrane system skid mounted - $1-5-1.7 million
- Raw gas chiller with activated carbon siloxane removal - $200,000+
- Meter/flow control/gas chromatography/water/H_2S - $500,000
- Electrical interconnect 4160 and step - $0-1.0 million (for nearby electricity, some utilities will provide some or all of the cost of transformer and interconnect)
- NG pipeline interconnect - $1.0 million.

Therefore, the total capital investment for a membrane system is $6 to 7 million for a 500MMBtu/day system. This was used as the basis to estimate the cost effectiveness of this technology for a case example of 71MMBtu/hr landfill gas previously sent to the flare. The case example assumes that the gas is produced as pipeline quality gas with interconnection with the local natural gas distribution system.

Landfill gas recovery with the generation of a high Btu gas is not very common. Oxygen can be a problem and must be removed down to 0.001 vol% or less for pipeline quality gas. With high recoveries, methane rejection can be high, resulting in a recovery of only 80%. Because the cost to cleanup gas to pipeline quality can be expensive, it may be better to generate a lower Btu gas (approximately 800 Btu/scf) and then use the gas for a local or onsite use. A local use will also eliminate the need for a costly gas interconnect. Use of the gas for transportation fuels would require additional processing or compression for compressed natural gas (CNG) or biodiesel fuel. A small scale gas to liquids process may be utilized for biodiesel fuel production from natural gas.

To estimate the project cost-effectiveness, the baseline emissions for this option would include:

- Direct emissions from flaring of the landfill gas.

The emissions associated with the project itself include:

- Direct emissions from any gas processing processes necessary; and
- Direct emissions from gas pipeline infrastructure required to transport the gas to the local gas supply system, or direct emissions from additional processing to utilize as transportation fuel.

The emission reductions would be the difference between the baseline and project emissions. End use of the produced pipeline quality gas would not be taken into account since the presumption is that this gas would displace other natural gas supply in the Bay Area (i.e., natural gas from other sources would have been used at the end use facility in the absence of the landfill gas recovery project).

7.1.4 Biotic Landfill Covers and Biofiltration

This mitigation option involves a wide range of emerging technologies that all utilize microorganisms in a porous medium, such as soil, compost or other synthetic materials, to oxidize the methane in landfill gas, converting it to cell mass and energy, and releasing CO_2 and water vapor. Landfill gas can be transported through a biofilter actively, using a blower to mix in air and force the gas through an actively-managed compost bed or soil bed. Landfill gas can also be transported passively by allowing it to vent directly from the landfill through a surface layer of biotic media. In either situation, the biological oxidation of landfill gas happens continually, regenerating the sorption capacity of the biofilter. In laboratory studies, the microorganisms have been capable of reducing emissions at a steady rate of 15 mol/day over a square meter surface area for as long as 175 days (DeVisscher, 1999). This indicates a 90% reduction in methane emissions is feasible. In the field, compost beds have been known to reduce odors in experimental periods of over six months. Through field testing and monitoring, methane sinks have been documented (Hilger, et. al., 2003).

Two types of microorganisms are used to oxidize methane: methylotrophs and a subset of methylotrophs, called methanotrophs. Methanotrophs are resilient to a varying environment, becoming inactive during unfavorable conditions, and returning to active growth during favorable conditions. Metabolic activity of methylotrophs and methanotrophs is aerobic, even though the methane is generated anaerobically; uptake of the methane generally occurs naturally at the interface of the aerobic and anaerobic zones in the landfill profile. Other non-methane organic compounds (NMOCs) found in landfill gas, including alcohols, aldehydes, ketones, ethers, esters, organic acids, amines, and thiols, are also biochemically degraded in the landfill or in constructed biofilters.

Optimal temperatures range from 77 °F to 95 °F, depending on the strain (Visvanathan, et. al., 1999; Kjeldsen, et. al., 1997). Since the microorganisms rely on gas diffusion for transport of CH_4 and CO_2 but are active in moist environments, the ideal moisture content is 15% to 20% (Boeck, et. al., 1996; Visvanathan, et. al., 1999). Optimal pH is between 6 and 7 (Sunghoon Park, et. al., 1991). The bacteria are inhibited by excess ammonia due to ammonia/methane substrate competition and colony competition with nitrifying bacteria, which utilize ammonia for energy. The bacteria are also inhibited by phosphorus concentrations greater than 40 mM and copper concentrations greater than 4.3 mM. Application of nitrogen may provide nutrient supply, enhancing CH_4 degradation.

For purposes of this study, two applications of this technology are considered: passive biotic covers and active biofiltration beds.

7.1.4.1 Biotic Landfill Covers

The passive biotic covers involve passively venting the landfill gas through a landfill final cover that is prepared to enhance methane metabolization. These covers are commonly referred to as biotic covers. They are constructed of soil, compost or other porous media, including synthetic materials. Often there is a permeable substrate of gravel or sand beneath the porous media. This substrate layer performs two functions: it drains away excess liquid from the biotic cover and it distributes the gas that is generated in the waste mass to the porous medium. The biotic medium is often “seeded” with the methanotrophs taken from the waste generating the landfill gas. Nutrients, phosphorous, nitrogen, lime and sewage sludge are other additives currently being field tested. Passive biotic covers can be constructed at minimal additional cost, since they constitute an enhancement of the required final cover. Assuming the biotic layer can be constructed at a 25% premium (compared to the traditional two-foot soil cover) and adding costs for a 12-inch gravel distribution layer beneath the biotic medium, separated above and below by a filter geotextile, estimated costs would add a premium of $15,000 to $35,000 per acre to the cost of a traditional landfill final cover. The variation is due to the availability of biotic and substrate materials. Operations and maintenance costs can vary widely, dependent upon the level of monitoring and optimization desired. As with cover construction, the costs are a premium added to the established costs of maintaining a typical landfill final cover.

The literature indicates a potential for 4% to more than 90% reduction in methane emissions compared with directly emitting the gas (Spokas, et. al., 2005; Hilger, et. al., 2003). Performance monitoring would be costly, as well as technically challenging to monitor concentrations accurately. This option would be classified as emerging technology, where applications are still in the field trial stage in the US.

7.1.4.2 Active Biofiltration Bed

The second application discussed in this study involves an active biofiltration bed. A common design runs the discharge piping from the passive gas collection system to a series of biofilter beds; a blower and valves are used to control flow rates and mix in air. The perforated pipes join at a biofilter bed; the perforated piping distributes the gas/air mixture under three feet of soil or compost. The bed may be provided with a controlled source of moisture to ensure optimal conditions for the methanotrophs. At the base of the bed is a layer of sand or gravel and a liquid collection tray. The collection tray catches excess moisture which could be recycled or treated as a byproduct of the system.

For effective treatment, the pipes should be at 0.4 to 1.2 meters depth in the beds. To achieve optimum treatment of the methane, the dispersion through the filtration bed would involve mixing the landfill gas with 10 parts ambient air to 1 part landfill gas. Due to the size of the biofilter bed needed to treat the air/landfill gas mixture, this mitigation process is only reasonable for small, passively venting landfills, for old sites where the methane content of the landfill gas has decreased to less than 30%, or for fugitive emissions from larger sites with active gas collection systems. Sites that are passively vented typically include gas collection trenches or wells that are connected to downstream collector pipes. Without the biofilter, the collector pipes typically discharge directly to the atmosphere or combust the landfill gas with passive flares. The estimated cost of a typical biofilter bed is $1,500 to $3,500 per scfm for a bed that is open to the environment. Enclosed biofiltration beds could run up to $20,000 per scfm. The cost range is due to lower gas flow rates in smaller sites, causing the cost of biofilter beds to be incrementally higher. Operations and maintenance costs vary widely and are a function of the desired level of monitoring and optimization, the desired level of methane conversion, and the increasing use of the technology and future availability of standardized systems.

For active biofiltration systems, literature citations indicate the potential for 10% to almost 100% reduction in methane emissions compared with directly emitting the gas (Hilger, 2003). There is no wide scale usage of this technology as a basis for a more definitive assessment of the costs and potential for reduction.

There are several advantages of using a biofilter as opposed to a flare. A flare emits CO_2 and water vapor, as well as heat, CO, NO_x, SO_x, particulates, and chlorinated hydrocarbons. A biofilter only produces CO_2 and water vapor. There is no fuel needed for heat generation. Biofilters can also degrade most NO_x and SO_x, and have potential to degrade hydrocarbons. There are less safety controls for operation, and there are no start up or shut down procedures. This procedure is a potentially effective option for landfills sites with emission rates too low for flare mitigation.

US policy for reducing greenhouse gas emissions appropriately emphasizes the active collection and oxidation of methane in landfill gas. When energy capture is not economically feasible, flaring is typically recommended. Biotic CH_4 removal systems offer the same conversion to CO_2 as flaring. However, unlike combustion, not every molecule of CH_4 consumed biotically is converted to $CO_{2.}$ As much as 85% (mole/mole) of the CH_4 carbon may be incorporated into biomass and not released to the environment (Borjesson, et. al., 2001). Therefore, biotic conversion of methane offers benefits beyond flaring and even beyond using the landfill gas as fuel to produce energy.

The balance to this significant benefit is that, particularly with passive biotic covers, the system is less controlled and significant amounts of methane may escape the biofilter entirely and vent to the atmosphere. Disadvantages of biofilter technologies include a lack of control and monitoring ability on a passive gas collection system. Some trace volatile organics, such as halogenated compounds, have low degradation rates and may not decompose in the biofilter.

The biofilter size needed for effective mitigation is impractical for large landfill sites that currently use flaring. Although the successful application of this process is well-documented in the laboratory, field size application is not widely established.

7.2 WASTEWATER TREATMENT PLANT DIGESTER GAS WITH FLARE

Anaerobic digestion of municipal wastewater converts carbon in the waste stream to biogas, a foul-smelling, corrosive mixture of methane, carbon dioxide and hydrogen sulfide. The biogas produced in a digester (also known as "digester gas") is actually a mixture of gases, with methane and carbon dioxide making up more than 90 percent of the total. Methane content varies from about 55 percent to 80 percent. Typical digester gas, with a methane concentration of 65 percent, contains about 600 Btu of energy per cubic foot. Biogas typically contains smaller amounts of hydrogen sulfide, nitrogen, hydrogen, methyl mercaptans and oxygen.

There are several wastewater treatment plant digesters in the Bay Area. A representative group of digesters are located as indicated in Table 7-6.

TABLE 7-6. REPRESENTATIVE DIGESTER FACILITIES IN THE BAY AREA

Wastewater Treatment Plant Name	Location	Current Digester Gas Disposition
San Francisco, City & County PUC	San Francisco	IC engines/boilers/ digester gas flares
East Bay Municipal Utility District	Oakland	Hot water boiler (1)/ cogeneration IC engine (3)/digester gas flare
Southeast Treatment Plant	San Francisco	Cogeneration IC engine/flare
San Jose/Santa Clara Water Pollution Control Facility	San Jose	Cogeneration IC engines (16) / digester gas flare (5)
Oro Loma Sanitary District	San Lorenzo	Cogeneration IC engines
South Bayside System Authority	Redwood City	Cogeneration IC engines/boilers
City of Sunnyvale Water Pollution Control	Sunnyvale	IC engines/ electricity with flare backup
Central Contra Costa Sanitary District	Martinez	Boilers (2) and Incinerators (2)
Palo Alto Regional Water Quality Control Plant	Palo Alto	IC engines/ boilers
Fairfield-Suisun Sewer District	Fairfield	Cogeneration IC engines
San Mateo Water Quality Control Plant	San Mateo	Digester flare
City of Santa Rosa Wastewater Treatment Plant	Santa Rosa	IC engines/ electricity with flare backup
Union Sanitary District	Union City	IC engines (2)/ hot water sludge heating boilers (2)/ hot water boiler (1)/ flare (3)

Most Bay Area wastewater treatment plants that use anaerobic digesters burn the gas for heat to maintain digester temperatures, heat building space, or produce electricity with IC engines. After filtering and drying, digester gas is suitable as fuel for an internal combustion engine, which, combined with a generator, can produce electricity. Future applications of digester gas may also include electric power production from gas turbines or fuel cells.

In the Bay Area, most digester gas is currently utilized effectively as a biogas fuel. The residual flared gas can be used as a valuable energy resource for supplying heat, steam, or power. The following mitigation options apply to facilities that flare the digester gas.

7.2.1 Digester Gas Recovery in IC Engines

If unused gas is burned off as waste in a flare, it could be used for fuel in an engine-generator (or possibly fuel cell) to produce electric power. This mitigation option entails the utilization of previously flared digester gas as fuel for IC engine generators to provide power for local use or supply to the grid. This mitigation option is based on the principle of converting a waste stream, i.e., the flared digester gas, to an energy source for the generation of power. Utilization of the digester gas for IC engine power generation has a net overall decrease in GHG emissions based on the difference in emissions from a baseline scenario without the project, and the IC engine project itself. The emissions associated with the baseline include:

- Direct emissions from flaring of the digester gas; and
- Indirect emissions from grid supplied electricity in the pre-project scenario.

The emissions associated with the project itself include:

- Direct emissions from any gas clean-up processes necessary; and
- Direct emissions from combustion of the digester gas in the IC engine generator(s).

Therefore, the emission reductions associated with the project are based on the decrease in emissions from the recovery of the previously flared digester gas, and the displacement of electricity from the grid.

Mitigation options for this source category were not ranked on the priority short list and are not evaluated in this report. As indicated below, the recovery of digester gas and consumption to generate electricity in an IC engine is one of the mitigation options for flared landfill gas.

For digester gas, H_2S concentrations will be an issue. The following H_2S removal technologies could be used to remove H_2S prior to combustion:

- Sulfatreat® or Iron Sponge, which use porous synthetic iron compound pellets to react with H_2S from the gas stream
- Membranes with the ability to selectively separate H_2S from the gas stream
- QuestAir, which uses pressure swing adsorption (PSA) to treat landfill or digester gas

7.2.2 Digester Gas Utilization as Pipeline Gas

This mitigation option is based on the recovery of previously flared digester gas and supply of gas for energy either on- or off-site. The principle of emission reductions from this option are similar to that for IC engine generation of power in that it represents a recovery of a waste stream as fuel. For digester gas utilization as pipeline quality natural gas, significant processing of the digester gas must occur to remove inert constituents, such as CO_2, and other contaminants.

The baseline emissions for this option would include:

- Direct emissions from flaring of the digester gas.

The emissions associated with the project itself include:

- Direct emissions from any gas processing processes necessary; and
- Direct emissions from gas pipeline infrastructure required to transport the gas to the local gas supply system.

The emission reductions would be the difference between the baseline and project emissions. End use of the produced pipeline quality gas would not be taken into account since the presumption is that this gas would displace other natural gas supply in the Bay Area (i.e., natural gas from other sources would have been used at the end use facility in the absence of the digester gas recovery project).

8.1 PETROLEUM REFINERY PROCESS HEATERS

Process heaters are essential to the production of refined petroleum products and as such are used extensively in the five refineries in the Bay Area. A process heater can have from 20 to 100 burners, and is thus a much different combustion device than a boiler. The largest heaters in a refinery are the crude heaters, hydrogen plant heaters, and fluidized catalytic cracking unit heaters.

8.1.1 Ultra-Low Emission Process Heaters

As part of a collaborative development program with the US Department of Energy, an ultra-low-emission burner technology for process heaters has been developed and commercialized. The advanced heater design has the advantage of reducing emissions of NOx, increasing the overall efficiency of the process heater as compared to conventional burner designs, and improving the cost/performance ratio. The ULE heater incorporates three advanced technologies:

- Ultra-low emission (ULE) burners
- A specially designed fire heater with enhanced heat recovery optimized for use with the ULE burner systems.
- An on-line process tube temperature sensing and burner control system to enhance heat transfer, reduce maintenance costs, and increase run lengths.

The ULE burner design was jointly developed and commercialized by TIAX, LLC; ExxonMobil Research and Engineering Company; and Callidus Technologies, Inc (Tulsa, OK). This technology is for new source or replacement application only and is not considered in detail for application to existing permitted sources.

8.1.2 Alternate Fuels for Process Heaters

Most refineries current produce a “refinery fuel gas” that is used extensively as a process heater fuel. This fuel is often higher in hydrogen content than natural gas. The hydrogen use results in a reduced amount of GHG formation. Additional hydrogen may be possible through greater cracking of the petroleum products or through the formation of hydrogen from steam methane formation. If the hydrogen can be produced at the refinery with subsequent carbon capture and sequestration, this hydrogen can be blended with refinery fuel gas and used in the process heaters. Discussions related to the production of hydrogen at a refinery are given in Section 8.3 below.

Biofuels could also be considered as partial replacement fuel for process heaters. Both the use and the associated emissions reductions would be similar in principle to the use of biofuels discussed previously in Section 5.1.2.

8.1.3 Oxy-Fuel Combustion with Carbon Sequestration

Oxy-fuel combustion uses oxygen instead of air for combustion, producing a flue gas that is mainly H_2O and CO_2 and which is readily captured. This option is still under development and not available commercially (see Section 5.1.3).

8.1.4 Energy Efficiency Improvements

Efficiency improvements for refinery process heaters can be achieved through combustion/burner tuning or process optimization programs. The expected efficiency improvements depend on the condition of the current heater burner and combustion air mixing characteristics, but typical efficiency improvements may be on the order of 0.5-5% (see Section 5.1.1). Improvements in energy efficiency for refinery heaters that have not be optimized to minimize NOx emissions may be even higher, but expectations in the Bay Area refineries are at the lower end of the efficiency improvement range.

The five most energy intensive processes in petroleum refining are:

- Atmospheric and vacuum crude distillation
- Fluidized catalytic cracking (FCC)
- Catalytic hydrotreating
- Catalytic reforming
- Alkylation

Each of these processes has a heater, preheater, and/or integrates heat recovery as part of the process. Improvements in efficiency of each of these five refining processes have been evaluated in a desk review study as shown in Table 8-1 below (US Department of Energy, Energy Efficiency and Renewable Energy, September 2006).

TABLE 8-1. POTENTIAL EFFICIENCY IMPROVEMENTS IN REFINING PROCESSES

Refinery Process	Potential Efficiency Improvement Measure	Overall Potential for Efficiency Improvement
Crude Oil Distillation (atmospheric and vacuum)	➢ Control of fouling in the crude preheater train and fired heater ➢ Improved fired heater efficiency ➢ Enhanced heat integration between the atmospheric and vacuum towers ➢ Use of waste heat to run absorption chillers to generate cooler water for the overhead condenser	Up to 45% reduction in fuel consumption
Fluidized Catalytic Cracking Unit	➢ Addition of a power recovery turbine ➢ Conversion of condensing turbine drive to electric motor drive ➢ Improved heat integration ➢ Minimization of other losses, including surface losses	Up to 27% reduction in energy consumption
Catalytic Hydrotreating	➢ Improved preheater performance ➢ Improved catalyst ➢ Improved heat integration ➢ Minimization of other losses, including surface losses	Up to 7% reduction in energy consumption, with an additional savings from technologies in the research and development stage.
Catalytic Reforming	➢ Improved feed and interstage process heater performance ➢ Replace horizontal heat exchangers with vertical plate and frame exchange ➢ Improved equipment efficiency ➢ Minimization of other losses, including surface losses	Up to 4% reduction in energy consumption, and 50 Btu/bbl savings.
Alkylation	➢ Improved compressor efficiency ➢ Improved heat integration ➢ Use of dividing wall column design and other advanced separation technology ➢ Upgraded control system	Up to 68% reduction in energy consumption, with an additional 20% in research and development stage.

8.2 PETROLEUM REFINERY FCCU REGENERATOR

The catalytic cracking process uses a catalyst to aid in the “cracking” of heavier fractions of crude oils or residues into lighter products such as gasoline or LPG. The cracking process deposits coke on the catalyst as a byproduct of the reaction. That coke must be burned off to restore the activity of the catalyst. The coke is continuously burned off in the regenerator. This process vent will be a significant source of CO_2 emissions.

Fluid catalytic cracking units (FCCUs) are operated in two basic modes:

1. Full, or complete, CO burn mode, where essentially all CO is combusted to CO_2 within the regenerator. The exhaust gas typically contains approximately 2% O_2 and less than 1% CO. The hot exhaust gases often pass through a waste heat boiler, operated with or without supplemental fuel, to produce steam prior to exiting through the stack.
2. Partial burn mode, where the regenerator exhaust gas contains less than 1% O_2 and 6-8% CO. The exhaust gases pass through a CO boiler, which completes the combustion of CO to CO_2 external to the FCCU regenerator prior to exiting the stack.

In some cases, the regenerator off-gas may be controlled with a CO Boiler (to control CO and TOC emissions) if operated in a conventional or partial burn mode or with an electrostatic precipitator or scrubber (to control particulate emissions). FCCU catalyst regeneration operations typically recover the waste heat from the process to improve the overall energy efficiency of the refinery.

Of the five refineries in the Bay Area, four refineries have fluidized catalytic cracking units (FCCUs). Table 8-2 below indicates the permitted limits for the quantity of crude oil processed in the FCCU, or the FCCU feed rate. Catalyst regeneration from FCCU results in large quantities of CO_2 liberated as part of the regeneration process.

TABLE 8-2. FCCU OPERATIONS AT BAY AREA REFINERIES

Refinery/Location	FCCU Feed Rate (bbl/day)
Tesoro/Pacheco	75,000
Shell/Martinez	79,500
Valero/Benecia	77,200
Chevron/Richmond	90,000
ConocoPhillips/Rodeo	None (a)

(a) The COP Rodeo refinery has a hydrocracker instead an FCCU.

8.2.1 Carbon Capture and Sequestration

Catalyst regeneration from FCCU results in large quantities of CO_2 liberated as part of the regeneration process. The only identified mitigation options were carbon capture and sequestration (CCS) and firing of biofuel to replace any supplemental fuel firing in the CO boiler. Most CO boilers associated with FCCU catalyst regeneration do not fire supplemental fuels, so the options of supplemental fuel replacement were not investigated.

The application of CCS to the relatively low concentration of CO_2 in the catalyst regeneration process gas stream was not considered further in this study due to the extremely high capital cost requirements and lack of demonstration of the technology as applied to a dilute gas stream in an industrial process. One potential consideration for future applications could be the combination of oxy-combustion with CCS to produce a concentrated CO_2 stream for capture.

8.3 PETROLEUM REFINERY HYDROGEN PRODUCTION

Hydrogen is most generally produced from natural gas. Steam reforming is a catalytic process that involves a reaction between natural gas or other light hydrocarbons and steam. The result is a mixture of hydrogen, carbon monoxide, carbon dioxide and water that is produced in a series of three reactions. The first reforming step catalytically reacts methane with steam to form hydrogen and carbon monoxide in an endothermic reaction. The carbon monoxide is then "shifted" with steam to form additional hydrogen and carbon dioxide in an exothermic reaction. The carbon dioxide is removed using one of several adsorption processes. The methanation step is used to remove all remaining carbon monoxide by exothermically reacting CO with hydrogen to form methane and water. Finally, hydrogen is separated in preparation for its final use. Hydrogen production from steam methane reforming results in a highly concentrated CO_2 process vent stream.

The hydrogen plants in the Bay Area are listed in Table 8-3.

TABLE 8-3. HYDROGEN PLANTS AT BAY AREA REFINERIES

Refinery/Location	Hydrogen Unit No.	Total Hydrogen Production (MMscf/day)
Chevron/Richmond	Hydrogen Manufacturing Plant	180
Valero/Benecia	Hydrogen Manufacturing Plant	141
Shell/Martinez (including unit operated by Air Products)	Hydrogen Plant #1, Hydrogen Plant #2 (AP), Hydrogen Plant #3	208.5
Tesoro/Martinez	Hydrogen Manufacturing Plant	82
ConocoPhillips/Rodeo	Hydrogen Manufacturing Plant	84

As an example, the hydrogen plant at Shell Oil Company’s Martinez Refinery is a steam reforming plant designed and constructed by Air Products. The plant provides approximately 90 million standard cubic feet per day (MMscfd) of hydrogen for Shell's Clean Fuels Projects. The Shell hydrogen plant includes designs by Kinetics Technology International Corporation (KTI) under their alliance with Air Products, with KTI providing the hydrogen plant technology and Air Products supplying the pressure swing adsorption (PSA) cleanup and control systems.

8.3.1 More Efficient Production of Hydrogen from Natural Gas

Within the U.S. Department of Energy, the Offices of Energy Efficiency and Renewable Energy (OEERE) and Fossil Energy (OFE) are working to reduce the cost of producing hydrogen via steam methane reforming. OEERE is focused on distributed hydrogen production from natural gas and bio-derived liquid feedstock and OFE is focused on sub-centralized and centralized hydrogen production. Although hydrogen from natural gas is certainly a viable near-term option, it is not viewed by DOE as a long-term solution because it does not help solve the GHG or energy security issues.

8.3.2 Hydrogen Production with Carbon Capture and Sequestration

The steam methane reforming process generates a more concentrated exhaust gas with higher CO_2 concentrations than natural gas combustion. Carbon capture and sequestration (CCS) options for reduction in emissions of CO_2 is has been discussed above in Section 5.1.3. This discussion would apply to the capture and sequestration of CO_2 from the steam-methane reforming process.

8.4 PETROLEUM REFINERY FLEXICOKER WITH CO BOILER

Flexicokers are a type of fluid coker that can further gasify the coke from the normal fluid coking process. This purge coke is gasified into a low-Btu fuel gas, which is used elsewhere in the refinery, and the residual coke is harder with a higher concentration of metals. There are two flexicokers located in the Bay Area, one at the Tesoro Refinery in Pacheco and one at the Shell Refinery in Martinez. The flexicoker in the Tesoro Refinery is currently being re-commissioned as a delayed coker and will cease to operate as a flexicoker in the near future. A delayed coker does not gasify the purge coke, which is collected and sold as a fuel. If the coke has a low enough concentration of metals, it can be sold for higher value as a material for making graphite anodes in the aluminum smelting industry. Thus, the transition to a delayed coker can potentially result in more marketable by-products from the coking process.

Flexicoker operations at refineries in the Bay Area result in large quantities of carbon monoxide (CO). The CO is usually ducted to a nearby boiler and used as low-Btu fuel gas. The boiler completes the oxidation of CO to CO_2 and may include additional gaseous fuels (such as natural gas or refinery fuel gas) to produce adequate steam and power for the facility demands.

8.4.1 Greenhouse Gas Mitigation Technology

The only identified mitigation option for GHG mitigation is carbon capture and sequestration (CCS). The application of CCS to the low concentration of CO_2 in the catalyst regeneration process gas stream was not considered further in this study due to the extremely high capital cost requirements and lack of demonstration of the technology as applied to a dilute gas stream in an industrial process. One potential consideration for future applications could be the combination of oxy-fuel combustion with CCS to produce a concentrated CO_2 stream for capture.

8.5 PETROLEUM REFINERY FLARING

Flares are predominately utilized as emergency control devices to collect and burn vapor releases from process units, often from safety valves during high pressure upsets. In addition, excess or waste gas is typically sent to a refinery flare.

Refineries normally operate such that total gas production is less than internal fuel demand, with natural gas typically purchased to satisfy the incremental internal fuel demands. When refinery gas production is greater than internal needs, excess gas can be flared, once all other alternatives have been exhausted. Situations that can cause gas production/consumption imbalances that require flaring include:

- Start-up or shutdown of process units or systems;
- Equipment or process system malfunctions;
- Upsets or abnormal conditions in process system(s); and
- Equipment or system depressurizing and purge in preparation for maintenance.

Most refineries have some type of flare gas recovery system to compress and recycle gas sent to the flare header by returning it to the refinery fuel gas system. Such recovery systems can handle moderate flare gas load if there is sufficient fuel gas demand to accept the recovered gas. However, gas compression capacity and fuel gas demands are not usually capable of absorbing extremely high loads from large upsets.

Table 8-4 identifies the flaring sources at refineries in the Bay Area.

TABLE 8-4. FLARING SOURCES AT BAY AREA REFINERIES

Refinery/Location	Flare[a]
Chevron/Richmond	High level flare, LSFO South ISOMAX Flare North ISOMAX Flare FCC Flare Alky-Poly Flare RLOP Flare D&R Flare
Valero/Benecia	Acid gas flare Butane Flare North Flare South Flare
Shell/Martinez (including unit operated by Air Products)	LOP Auxiliary Flare OPCEN Flexigas (FXG) Flare OPCEN Hydrocarbon (HC) Flare DC Area Flare
Tesoro/Pacheco	East Air Flare West Air Flare Emergency Flare Tank 691 Safety Flare North Coker Flare South Coker Flare
ConocoPhillips/Rodeo	C-1 Flare MP-30 Flare

[a] LOP – Light Oil Processing; OPCEN – Operations Central; DC – Delayed Coking.

Flaring of hydrocarbon gases at refineries has become highly regulated. The BAAQMD recently promulgated a rule to regulate refinery flaring emissions, requiring the monitoring of streams routed to the flare. This rule has resulted in a net overall reduction in flared gas from Bay Area refineries. Many refinery flares are equipped with Flare Gas Recovery Compressors (FGRCs), resulting in low levels of flaring except when excess flow occurs to the FGRC (e.g., vent gas flows during an episodic flaring event) or when the vent gases sent to the FGRC are off-spec (e.g., high hydrogen or nitrogen content). As such, the excess or off-spec gases cannot be recovered and routed back to the fuel gas blend drum.

Several of the flare technology manufacturers, including John Zink, Flare Industries, Inc., NAO Flares, and ABB Gas Technology AS are developing technologies to improve flare pilot performance and combustion efficiency. These include flare-igniting systems, which virtually eliminate flare pilots, weatherproof flare pilots, optical pilot monitors, and acoustic flare monitors using an acoustic sensor to detect pilot outages.[5] Of these emerging technologies, flare-

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[5] www.johnzink.com, www.flareindustries.com, www.nao.com, and www.offshore-technology.com.

igniting systems that eliminate pilot gas utilization may be the most promising as a GHG mitigation option. Potential issues with such technology would be related to ignition reliability, as continuous flare pilots are utilized to ensure safe operation of the flare system.

Several flare manufacturers are conducting research to improve the flare burner design. Efforts are focused on improved efficiency, smokeless performance, reduced noise, reduced NO_x emissions, improved pilot reliability and reduced utility (steam/air) consumption.

Another potential reduction measure is enhanced control to reduce the consumption of flare assist utilities, such as steam. Assist utility consumption can be reduced by automating the utility flow (steam and/or air) based on flare gas flow to the flare stack. Control can be either step-wise or modulating. Advantages of reducing the assist utilities during periods of low flare rates are: 1) energy savings due to reduced utility consumption, and 2) reduced flare noise in the case of steam assist flares. Applicability of automated controls with the existing burner tip design would need to be conducted to assess the feasibility of effective control of the assist utility flow.

While these measures may have the potential to incrementally reduce the emissions from flaring operations, the expected net reduction in GHG emissions would be expected to be minimal compared to reductions already achieved in the Bay Area refineries through flare gas flow monitoring and reduction efforts, as well as FGRC system recovery.

8.6 CHEMICAL MANUFACTURING PROCESS HEATERS

General Chemical Corp. in Richmond and Dow Chemical Co. in Pittsburg are the two major chemical manufacturing facilities in the Bay Area. General Chemical operates two heaters with a combined capacity of 31.6 MMBTU/hr. Dow Chemical operates two heaters both rated at 25 MMBTU/hr and equipped with low NOx burners. Dow also has three thermal oxidizers operating as part of their process with a combined rating of 10 MMBTU/hr that burn natural gas, process vents and liquid waste. Additionally they operate three thermal oxidizers as abatement equipment.

8.6.1 Ultra Low Emission Process Heaters

Ultra Low Emissions (ULE) process heaters may be utilized in any energy intensive industry, including chemical manufacturing. The ULE process heater design effectively improves the combustion efficiency, thus resulting in lower fuel consumption and GHG emissions. See discussion in Section 8.1.1 above.

8.6.2 Oxy-Fuel Combustion with Carbon Sequestration

Oxy-fuel combustion uses oxygen instead of air for combustion, producing a flue gas that is mainly H_2O and CO_2 and which is readily captured. This option is still under development and not available commercially. See discussion in Section 5.1.3.

8.6.3 Energy Efficiency Improvements

Efficiency improvements for industrial process heaters can be achieved through combustion/burner tuning or process optimization programs. The expected efficiency improvements depend on the condition of the current heater burner and combustion air mixing characteristics, but typical efficiency improvements may be on the order of 0.5-5%.

8.7 CHEMICAL MANUFACTURING FLARING

Emissions from flaring at chemical manufacturing plants can be reduced through improved monitoring and reporting of gas being sent to the flare (see Section 8.5).

9.1 AUTOMOBILE MANUFACTURING PAINT SPRAY BOOTH

There is one major automobile manufacturing facility in the Bay Area. The paint spray operations at the facility are controlled with thermal oxidizers. There are no control options for reducing GHG emissions that were identified that warrant further consideration. The main GHG emissions are from the thermal oxidation of organic constituents, which results in CO_2 emissions. Although methods such as waste heat recovery, vapor recovery systems, or other means to reduce the emissions of CO_2 could be employed, these were not deemed to represent a significant reduction in emissions relative to the capital cost required. Carbon absorption, which theoretically could be used for VOC control, would have negligible CO_2 emissions. However, carbon absorption would represent a source replacement technology, rather than retrofit, and is not considered for further evaluation.

9.2 JET AIRCRAFT MAINTENANCE FACILITIES PAINT SPRAY BOOTH

There is one major jet aircraft maintenance facility in the Bay Area. This facility operates 16 paint spray booths with a total capacity of 171,575 cfm with no abatement equipment. Similar to automobile manufacturing paint spray booth options discussed in Section 9.1, mitigation options for this source category were not ranked on the priority short list and are not evaluated in this report.

9.3 JET AIRCRAFT MAINTENANCE JET ENGINE TEST STANDS

The jet aircraft maintenance facility operates two Auxiliary Power Unit (APU) test cells rated at 5 MMBtu/hr each and two engine test cells rated at 118 MMBtu/hr each. Both types of test cells burn jet fuel and have no abatement equipment. Jet engine test stands are relatively difficult sources to control. Because the objective is to test the engine as it would be used in actual flight, the addition of controls to the engine itself is not possible. Therefore, mitigation can only occur through the reduction of GHG emissions at the effluent of the jet engine test facility building. As mitigation options would be extremely high cost with relatively low reduction potential, they were not prioritized for detailed evaluation in this report.

9.4 GLASS MANUFACTURING GLASS MELTING FURNACE

The mitigation options for glass manufacturing are aligned with energy efficiency or process optimization improvements.

9.4.1 Energy Efficiency Improvements and Process Optimization

The US DOE's Office of Energy Efficiency and Renewable Energy (OEERE) supports the development of advanced energy-efficient process technologies for the glass manufacturing industry. These include advanced process controls using a combination of sensors that improve product quality, while reducing waste and energy consumption during the manufacturing process. These technologies are in various stages of development. Examples include:

- Advanced Temperature Monitoring System Using Self-validating Sensor Technology – sensor provides accurate temperature readings while continuously monitoring and self-validating it's measuring elements so no element can drift without detection. This product is commercially available.
- Development and Validation of a Coupled Combustion Space/Glass Bath Furnace Simulation – a validated analytical tool to evaluate furnace performance, develop optimal fuel-firing strategies, and improve environmental performance. The model was developed by Argonne National Laboratory and is available for use by the glass industry for analysis of its furnaces
- Measurement and Control of Glass Feedstocks – by measuring the chemical makeup in raw materials and recycled glass cullet using laser-induced breakdown spectroscopy (LIBS), glass manufacturers can quickly detect contaminants and batch non-uniformity. LIBS provides high measurement speeds for high throughput of particles. As a result of repeatable batch formulations entering the furnace, the technology allows for more optimal furnace parameters. Based on a 20% reduction in product defects, energy savings are estimated at 260-520 billion Btu per year. The technology is in the Research and Development phase.
- Technologies offering real-time measurement of furnace parameters and exhaust gas species,- including, tunable diode laser sensors, furnace thermal imaging, and furnace flame image analysis, FTIR exhaust gas analysis, miniature amperometric oxygen sensors. These technologies help in managing the combustion process through proper

burner management and optimization of fuel-air ratio to improve fuel efficiency and reduce emissions.

9.5 GAS-FIRED INDUSTRIAL/COMMERCIAL BOILERS

This source category for gas-fired industrial or commercial boilers would be similar to that discussed in Section 5 for power generation.

9.5.1 Energy Efficiency Improvements

Energy efficiency in commercial and industrial boilers has been studied for emission reduction of other pollutants including nitrogen oxides (NO_x). Techniques for improving overall energy efficiency include:

- Boiler tuning to improve combustion characteristics;
- Air to fuel ratio controls to optimize performance;
- Burner retrofits with advanced mixing, enhanced efficiency burner design; and
- Process optimization through modeling, enhanced process controls, and circulating pump efficiency improvements.

These techniques generally result in modest emission reductions of around 5 to 15 percent.

9.5.2 Use of Biofuels

Biofuel combustion is another potentially viable option for co-firing in industrial or commercial boilers. The infrastructure to enable the transport, storage, and handling of biofuels would need to be taken into consideration, which is site specific.

9.5.3 Cogeneration for Energy Efficiency

Cogeneration, also known as combined heat and power (CHP), is the simultaneous production of electricity and process heat from the same fuel. In these units, the heat produced from the electricity generating process (e.g., from the exhaust systems of gas turbines or from conventional boilers with steam turbines) is captured and used for process steam, furnace applications, hot water heating, space heating, and other thermal needs.

Cogeneration projects have the potential to reduce GHG emissions in two ways:

1. The cogeneration system represents an improvement in overall energy efficiency compared to the separate generation of electricity and steam; and
2. The cogeneration fuel source may replace or displace other more carbon intensive fuel sources, in relation to steam generation, electricity generation, or both.

9.6 ELECTRICAL TRANSMISSION EQUIPMENT MAINTENANCE ACTIVITIES

This area source consists of the breakers and switches used in electrical transmission and distribution that utilize SF_6 as an insulating material. SF_6 was introduced as an alternative to PCB-containing oils, and it has a global warming potential (GWP) of 22200 times that of CO_2 along with a very long residence time in the atmosphere. Pacific Gas and Electric (PG&E) has put an administrative program in place to reduce the fugitive emissions of SF_6 from leaking equipment. This program consists of replacing older equipment with newer versions guaranteed by the manufacturer to have lower leak rates. Additionally, all equipment containing SF_6 has pressure alarms to provide early notification of leaking equipment, which is replaced or repaired immediately. PG&E also reduced the number of SF_6 vendors used by PG&E to one in order to better track consumption.

10.1 EXPECTED PERFORMANCE

The expected GHG emission reduction performance of each of the prioritized mitigation options was evaluated for a typical project application in the Bay Area. The emission reduction performance was quantified as the difference between a baseline (base case), or existing emissions from the source being controlled, and the project emissions from the source after controls are implemented.

10.1.1 Emission Reduction Potential from Mitigation Technology

The projected emission reductions estimate from each mitigation option is summarized in Table 10-1. The assumptions and uncertainties in the estimates are also summarized. The estimated GHG emission reductions are based on a typical facility in the Bay Area. For most options, the baseline case emissions are representative of the existing GHG emissions from the source as provided by BAAQMD in the draft inventory figures. The emissions from the project activity would be the resulting estimated emissions after implementation of the control technology, assuming the same unit throughput or capacity as used in the baseline. The emission reductions are the difference between the baseline and project emissions.[6]

10.2 UNCERTAINTIES AND CHALLENGES TO IMPLEMENTATION

Challenges to implementation, operation and maintenance of GHG mitigation measures were identified and documented. Challenges may include such issues as true demonstrated nature of the mitigation technology, financial ability of the facility to implement the mitigation measure, retrofitting issues, and incentives to ensure that the measures are fully implemented. In addition, the technical risks associated with a project or technology were highlighted and any mitigating measures to reduce these risks identified.

In addition, associated uncertainties in the implementation of the mitigation technologies were identified, taking into account variation based on site-specific influences such as process

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[6] All estimates are presented in short tons CO_2 equivalent emissions per annum. Please note that most international standards would be represented in units of metric tonnes CO_2 equivalent per annum. For purposes of this study to evaluate cost effectiveness of emission reduction options, aligned with other comparable air quality analyses such as BACT, we have presented emissions figures in short tons.

capacity, actual throughput, and configuration and layout based on siting requirements. Any challenges and uncertainties associated with the mitigation options were identified and summarized in Table 10-2.

TABLE 10-1. ESTIMATED GHG EMISSION REDUCTIONS FROM MITIGATION OPTIONS

Mitigation Option	Case Example Capacity	Estimated GHG Emissions, tons CO2e/yr			Assumptions/ Uncertainties
		Baseline Case	Project Emissions	Emission Reduction	
Biofuel (replacing natural gas combustion)	2,150 MMBtu/hr	937,050	843,340	93,700	➢ Replacing 10% of heat input with biogas. ➢ Capacity factor of 85%. ➢ Biogas from agricultural waste is carbon neutral.
Energy Efficiency	2,150 MMBtu/hr	937,050	934,700	2,350	➢ 0.25% efficiency improvement in overall plant wide energy use. ➢ Capacity factor of 85%.
Pozzolanic Clinker Replacement	1,330,710 tons cement/yr	663,700	607,800	55,900	➢ 95% clinker in standard cement product. ➢ 87% clinker in blended cement product. ➢ 3,636,700 lb CO_2/day and 0.525 ton CO_2/ton clinker as basis
Carbon Capture and Sequestration	1330 tons CO_2/day	485,450	97,090	388,360	➢ 80% recovery factor for CO_2 capture and sequestration, accounting for energy consumption and inefficiencies.
Landfill or Digester Gas with IC Engine	71 MMBtu/hr flared gas	66,240	39,680	26,560	➢ Baseline includes emissions from flared gas and from natural gas fired generation to supply an equivalent amount of electricity. ➢ Project emissions include the landfill gas combustion in the IC engine generators.

Mitigation Option	Case Example Capacity	Estimated GHG Emissions, tons CO2e/yr			Assumptions/ Uncertainties
		Baseline Case	Project Emissions	Emission Reduction	
Landfill or Digester Gas with Gas Turbine	71 MMBtu/hr flared gas	70,220	39,680	30,540	➢ Baseline includes emissions from flared gas and from natural gas fired generation to supply an equivalent amount of electricity. ➢ Project emissions include the landfill gas combustion in the gas turbine generators.
Landfill or Digester Gas Recovery as Pipeline Gas	71 MMBtu/hr flared gas	39,680	3,970	35,710	➢ Baseline includes emissions from flared landfill gas. ➢ Project emissions assume 10% of the landfill gas is utilized for gas processing and compression.

TABLE 10-2. CHALLENGES TO IMPLEMENTATION OF MITIGATION OPTIONS

Mitigation Option	Challenges to Implementation
1. Biofuels	➢ Availability and cost of biofuels to replace natural gas. ➢ Transportation, storage, and materials handling requirements dependent on the biofuel type and source of supply. ➢ Biogas cleanup requirements to remove impurities. ➢ Change in overall combustion unit efficiency, which can be minimized by co-firing with natural gas. ➢ Slagging in the boiler cycle and ash handling for the gasifier system would need to be considered. Ash carryover may require soot blowers in the steam generation cycle.
2. Energy Efficiency	➢ Magnitude of energy efficiency improvements are site specific, but not expected to be significant (i.e., performance is optimized at very low NO_x levels). ➢ Permanence of emission reductions from efficiency improvement activities.
3. Pozzolanic Clinker Replacement	➢ Availability and transport distance to source for suitable fly ash is unknown and is likely a significant barrier as coal firing is uncommon in California. ➢ Costs of fly ash, taking into account transportation costs. ➢ Extent of blending possible, depending on existing cement products.
4. Carbon Capture and Sequestration	➢ For combustion sources, lack of demonstrated and commercially available technologies for efficient carbon capture. ➢ Energy and infrastructure requirements for CO_2 injection. ➢ Suitability of the reservoir for long-term storage of CO_2. ➢ Stability of storage in seismic zone.
5. Landfill or Digester Gas with IC Engine	➢ Capacity of landfill gas generation over time. ➢ Quality of landfill gas and suitability for power generation.
6. Landfill or Digester Gas with Gas Turbine	➢ Capacity of landfill gas generation over time. ➢ Quality of landfill gas and suitability for power generation.
7. Landfill or Digester Gas Recovery as Pipeline Gas	➢ Capacity of landfill gas generation over time. ➢ Quality of landfill gas and suitability for cost effective gas processing.

11.1 COST ESTIMATE METHODOLOGY

Cost estimations were derived from referenced sources where possible. The installation cost factors for mitigation technologies follow the EPA Office of Air Quality Planning and Standards' (OAQPS) guidelines. As many technologies are still in development or proving stages, it is often difficult to obtain firm capital costs or operating expenses. In these cases, estimations were made using input from industry experts and costs for similar technologies. The estimates for labor, maintenance, installation, design engineering and other ancillary costs were calculated as a percentage of the equipment capital costs. These percentages were adjusted in some cases based on estimates or knowledge of the relative complexity of maintenance, installation, etc. These cost estimates are indicative only and are used only for comparative purposes for ranking the individual mitigation options. The annualized cost details are provided in Appendix A.

11.1.1 Capital and Operating & Maintenance Cost Estimates

Capital costs were gathered from vendors, manufacturers and end-users when available. Operating costs were calculated using the OAQPS factored estimates for direct and indirect costs. These estimates were adjusted when actual operating costs were known or expert estimates provided results different than the standard OAQPS factors.

The total capital, operating and maintenance, and annualized cost effectiveness estimates are presented in Table 11-1. Note that the annualized costs were derived using a capital recovery factor based on an interest rate of 7% over 15 years for all case examples except carbon capture and sequestration, which used 7% interest over 20 years.

11.1.2 Costing Assumptions and Uncertainties

Assumptions and/or uncertainties in the costs are identified in Table 11-1. The total amount of GHG removed by the technology was also calculated, taking into account any GHG penalties resulting from increased power demand, shipping or other factors. These figures were then used to obtain a cost per ton of GHG removed on an annualized basis.

TABLE 11-1. ESTIMATED COSTS FOR MITIGATION OPTION CASE STUDIES

Mitigation Option	Case Example Capacity	Estimated Cost, US$			Assumptions/ Uncertainties
		Total Capital Cost. $	O&M Cost, $/yr	Cost Effectiveness, $/ton CO2e	
Biofuel (replacing natural gas combustion)	2,150 MMBtu/hr	33,043,000	(2,602,000)	11 ($0.0187/kWh)	➢ 10% of thermal input is generated from biomass. ➢ Capital cost for biomass asification system was based on $900/kW as the average of the range of $900 - $1,300/kW.[7] ➢ Biogas cleanup requirements are assumed at $100/kW.[8] ➢ Some retrofits to the boiler or gas turbine were assumed to burn biogas at 4% of installed equipment costs. ➢ Cost of natural gas at $6/MMBtu and cost of biomass at $40/dry ton, with $10/dry ton transportation upcharge. ➢ Capital recovery at 7% interest over 15 years.
Energy Efficiency	2,150 MMBtu/hr	400,000	(37,000)	3	➢ Engineering judgment for capital and maintenance costs. ➢ Assumes 0.25% overall efficiency improvement, but would depend on the specific source.

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[7] California Energy Commission, *Utilization of Waste Renewable Fuels in Boilers with Minimization of Pollutant Emissions*, November 2005.

[8] California Energy Commission, *Biomass Cofiring with Natural Gas in California*, November 2002.

Mitigation Option	Case Example Capacity	Estimated Cost, US$ Total Capital Cost. $	O&M Cost, $/yr	Cost Effectiveness, $/ton CO2e	Assumptions/ Uncertainties
					➢ Assume level of efficiency can be maintained over time, based on an incremental increase in maintenance costs. ➢ Natural gas at $6/MMBtu. ➢ Capital recovery at 7% interest over 15 years.
Pozzolanic Clinker Replacement	1,330,710 tons cement/hr	4,672,000	146,000	9	➢ Estimate includes fly ash handling, conveying, grinding, dust removal, etc. ➢ Capital costs scaled based on figures in WRI report case study[9]. ➢ Actual fly ash volume assumed based on 95 to 87% clinker content. ➢ Cost of fly ash is offset by reduction in cost of limestone. ➢ Capital recovery at 7% interest over 15 years.
Carbon Capture and Sequestration	1330 tons CO_2/day	96,970,430	3,173,000	32 (capture only)	➢ Capital cost estimate based on average from 2 case studies as referenced in IPCC report.[10] ➢ Costs only include capture of CO_2, and exclude compression, transport and injection for storage. These sequestration costs would be site dependent. ➢ Capital recovery at 7% interest over 20 years.

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[9] World Resources Institute/World Business Council for Sustainable Development, *The Greenhouse Gas Protocol for Project Accounting*, November 2005.

Mitigation Option	Case Example Capacity	Estimated Cost, US$			Assumptions/ Uncertainties
		Total Capital Cost. $	O&M Cost, $/yr	Cost Effectiveness, $/ton CO2e	
Landfill or Digester Gas with IC Engine	71 MMBtu/hr flared gas	17,643,000	(1,451,000)	8 ($0.0049/kWh)	➢ Electricity sold to grid at $0.055/KWh ➢ Landfill gas contains 55% methane. ➢ Capital recovery at 7% interest over 15 years.
Landfill or Digester Gas with Gas Turbine	71 MMBtu/hr flared gas	24,346,000	(1,546,000)	25 ($0.0148/kWh)	➢ Electricity sold to grid at $0.055/KWh ➢ Assumes gas turbine purchase equipment cost is 20% higher than IC engine. ➢ Landfill gas contains 55% methane. ➢ Capital recovery at 7% interest over 15 years.
Landfill or Digester Gas Recovery as Pipeline Gas	71 MMBtu/hr flared gas	23,915,000	(1,631,000)	18	➢ Natural gas sold at $6/MMBtu ➢ 10% of gas is used for energy supply to gas processing operations. ➢ Capital recovery at 7% interest over 15 years.

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[10] Intergovernmental Panel on Climate Change, *IPCC Special Report on Carbon Dioxide Capture and Storage*, 2005.

12.1 IMPACTS ASSESSMENTS

Issues related to environmental, energy, social, and/or economic impacts of each technology, as it would potentially be implemented in the Bay Area, were identified and qualitatively assessed. In addition to issues and negative potential impacts, benefits associated with each measure were addressed, including additional environmental benefits beyond greenhouse gas emission reductions, social/economic benefits, and other potential benefits of the mitigation measure. The negative impacts are weighed against the proposed positive aspects of reducing GHG emissions in Section 13 where the mitigation options are ranked according to their overall impacts.

Each of these mitigation technologies was assessed to identify both adverse and beneficial impacts, with a summary presented in the following subsections.

12.1.1 Energy Impacts

The energy impacts were qualitatively identified and assessed at both the source level and within the project boundary. The project boundary refers to all sources affected by the emission reduction project activity. For example, a mitigation technology requiring biogas as the fuel source would have site level impacts, as well as upstream impacts associated with the production, transport, and storage of biomass.

The overall qualitative energy impact was rated as high, medium, or low impact based on the net energy requirements within the project boundary including upstream impacts. The energy impacts of each abatement option have been ranked in three categories as follows:

Score	Energy Impact of Mitigation Option
3	No adverse energy impacts (low impact)
2	Relatively low adverse energy impacts and respective consequence (medium impact)
1	Significant adverse energy impacts (high impact)

Table 12-1 presents a summary of the energy impacts for each of the mitigation technologies under detailed review. Each mitigation option is given a score based on the impact category listed above.

TABLE 12-1. SUMMARY OF QUALITATIVE ENERGY IMPACTS ASSOCIATED WITH MITIGATION OPTION

Mitigation Technology	Energy Impact Summary	Overall Qualitative Energy Impact
1. Biofuels	➢ Increase in energy requirements at the source to unload, store, and supply biofuels to the power generation source. This energy requirement would be partially offset by the energy reduction from decreased natural gas consumption. ➢ On a life cycle basis, the energy requirements to produce and transport biofuels would need to be compared to the energy requirements to produce and transport natural gas.	2
2. Energy Efficiency	➢ Overall reduction in energy requirements at the source.	3
3. Pozzolanic Clinker Replacement	➢ Energy requirements for transport and handling of fly ash would be similar to lime that is being displaced, assuming that the transportation distances from supply to source are comparable; therefore, no significant net increase in energy requirements for ash handling. ➢ Net decrease in energy for the calcination process proportional to the quantity of clinker being displaced by fly ash.	3
4. Carbon Capture and Sequestration	➢ Significant increase in energy for carbon capture, CO_2 compression and transport, and CO_2 injection.	1

Mitigation Technology	Energy Impact Summary	Overall Qualitative Energy Impact
5. Landfill or Digester Gas with IC Engine	➢ The baseline scenario of flaring the landfill gas can be viewed as wasted energy that would be recovered in the IC engine project. Therefore, the baseline scenario has a higher energy penalty than the project scenario of utilizing the landfill gas. ➢ Within the project boundary, the parasitic load energy requirements to produce electricity from the landfill gas would need to be compared to the energy requirements to produce an equivalent amount of power supplied by the grid. The expectation is that the parasitic load requirements are similar and therefore, there is no net increase in energy requirement.	3
6. Landfill or Digester Gas with Gas Turbine	➢ The baseline scenario of flaring the landfill gas can be viewed as wasted energy that would be recovered in the gas turbine project. Therefore, the baseline scenario has a higher energy penalty than the project scenario of utilizing the landfill gas. ➢ Within the project boundary, the parasitic load energy requirements to produce electricity from the landfill gas would need to be compared to the energy requirements to produce an equivalent amount of power supplied by the grid. The expectation is that the parasitic load requirements are similar and, therefore, there is no net increase in energy requirement.	3
7. Landfill or Digester Gas Recovery as Pipeline Gas	➢ The baseline scenario of flaring the landfill gas can be viewed as wasted energy that would be recovered in the pipeline gas project. Therefore, the baseline scenario has a higher energy penalty than the project scenario of utilizing the landfill gas. ➢ The energy requirements for recovering the methane in landfill gas as pipeline quality gas are higher than the on-site power generation case examples. ➢ Further processing of the gas to produce transportation fuels, e.g., biodiesel or compressed natural gas (CNG), would require significantly more energy to produce.	1

12.1.2 Environmental Impacts

The following section documents the potential environmental impacts of the identified greenhouse gas mitigation technologies in this study, some of which may be adopted by BAAQMD. The impacts are of particular concern with respect to increases in air criteria pollutants, such as NO_x or SO_2, resulting from a mitigation technology.

The environmental impacts include any increases or decreases in air pollutant emissions other than greenhouse gas constituents (which are quantified separately in Section 10). In addition to air quality impacts, any other environmental influences associated with the mitigation option were identified, such as water and solid waste impacts.

The environmental impact of each mitigation option has been ranked in three categories as follows:

Score	Environmental Impact of Mitigation Option
3	No adverse environmental impacts known
2	Environmental impacts can be managed
1	Considerable environmental risk, or risks unknown

Abatement technologies that have no known adverse environmental impact, or a positive environmental outcome, are assigned a score of three. In some instances, there are known environmental impacts, such as utilization of the solid products from mineral carbonation, which can be managed during the process to ensure that both environmental goals and the long-term abatement of CO_2 are jointly achieved. Environmental risks are assigned a score of one where there is considerable risk of irreversible environmental damage, an increase in criteria pollutants within the project boundary, or if the environmental risks are unknown.

Table 12-2 presents a summary of the environmental impacts for each of the mitigation technologies under detailed review. Each mitigation option is given a score based on the impact category listed above.

TABLE 12-2. SUMMARY OF QUALITATIVE ENVIRONMENTAL IMPACTS ASSOCIATED WITH MITIGATION OPTIONS

Mitigation Technology	Environmental Impact Summary	Overall Qualitative Environmental Impact
1. Biofuels	➢ At the source level, the overall environmental impacts will be dependent on the type of biofuel combusted. For combustion of biogas (e.g., from landfill or biodigester), the emissions of criteria pollutants and HAPs would be anticipated to be comparable with natural gas combustion. For combustion of biodiesel or ethanol, the emissions of NO_x may be higher than for natural gas combustion, but SO_2 emissions would be negligible for biofuel combustion. ➢ On a life cycle basis, the environmental impacts associated with the production and transport of biofuels would need to be compared to the environmental requirements to produce and transport natural gas. Air quality impacts would be anticipated to result in higher emissions of criteria pollutants associated with the energy requirements of biofuel production. ➢ Solid waste generation associated with biofuel production would need to be considered. The solid waste impact will be dependent on the type of biofuel produced (e.g., for ethanol production, the solid waste is recovered as an animal feed product but requires additional energy, hence air pollutants, to dry and process the animal feed constituent).	2
2. Energy Efficiency	➢ Overall reduction in air impacts at the source due to reduced fuel combustion to generate an equivalent amount of power.	3
3. Pozzolanic Clinker Replacement	➢ Net decrease in air quality impacts at the source from cement additive due to the overall reduction in energy requirements at the site. This would be partially offset by transportation of fly ash to the site, but expected overall effect is a net reduction in air emissions. ➢ Net decrease in solid waste impacts within the project boundary associated with the fly ash used for cement additive (i.e., it is assumed that the fly ash would have otherwise been landfilled).	2
4. Carbon Capture and Sequestration	➢ Environmental impacts at the source are dependent on the type of carbon capture technology employed, as well as the CO_2 injection energy requirements that would be site specific. Overall, additional energy will be required for both carbon capture and sequestration, resulting in increased emissions of air pollutants at the source.	1
5. Landfill or Digester Gas with IC Engine	➢ Net increase in NO_x emissions at the source for combusting the landfill or digester gas compared to flaring the gas. ➢ Within the project boundary (which includes the grid displacement of electricity produced from the previously	2

Mitigation Technology	Environmental Impact Summary	Overall Qualitative Environmental Impact
	flared gas), the net effect of utilizing the previously flared gas for energy is a reduction in emissions of criteria and air toxic pollutants. The energy supplied to the grid or the site would have been produced from another means (assumed to be natural gas combustion), meaning that the baseline scenario includes both emissions from flaring the landfill or digester gas and emissions from the imported energy being displaced by the project. The project emissions are from the generation of energy from the previously flared landfill or digester gas; therefore, there is a net overall decrease in emissions of all air pollutants.	
6. Landfill or Digester Gas with Gas Turbine	➢ Net decrease in NO_x emissions at the source for combusting the landfill or digester gas compared to flaring the gas. ➢ Within the project boundary (which includes the grid displacement of electricity produced from the previously flared gas), the net effect of utilizing the previously flared gas for energy is a reduction in emissions of criteria and air toxic pollutants. The energy supplied to the grid or the site would have been produced from another means (assumed to be natural gas combustion), meaning that the baseline scenario includes both emissions from flaring the landfill or digester gas and emissions from the imported energy being displaced by the project. The project emissions are from the generation of energy from the previously flared landfill or digester gas; therefore, there is a net overall decrease in emissions of all air pollutants.	3
7. Landfill or Digester Gas Recovery as Pipeline Gas	➢ Recovery of the landfill gas followed by processing to produce pipeline quality gas would significantly reduce the air emissions from combustion at the site. However, this fuel would subsequently be combusted by an end user; thus, the environmental impacts are similar to the options of on-site power generation. ➢ Additional air emissions would result from the processing and compression of the gas. These air quality increases would be incremental to those of the on-site power generation options.	2

Air quality impacts were evaluated as a preliminary indication of the benefits and adverse impacts of the various mitigation options evaluated. The net change in estimated air quality emissions from different scenarios is summarized in the following Tables 12-3 to 12-9.

12.1.2.1 Biomass Co-Firing with Natural Gas

For the case example of biomass gasification and co-firing with natural gas in a steam electric boiler, the comparison of emissions was made for uncontrolled units in both the baseline and the project scenario. Uncontrolled factors were available for biogas combustion; hence, the comparison was made on a comparable basis between the baseline of natural gas-firing and the project activity of biomass co-firing. Table 12-3 presents the baseline, project, and projected change in uncontrolled emissions for criteria and hazardous air pollutants (HAPs).

TABLE 12-3. SUMMARY OF AIR POLLUTANT EMISSION REDUCTIONS FROM BIOMASS CO-FIRED BOILER

Pollutant	Baseline Emissions, tons/yr	Project Emissions, tons/yr	Net Change in Air Emissions, tons/yr
NOx	2.20E+03	2.21E+03	8.71E+00
CO	6.59E+02	5.97E+02	(6.26E+01)
PM (Total)	5.96E+01	7.20E+01	1.23E+01
SO_2	4.71E+00	5.07E+00	3.60E-01
VOC	4.32E+01	4.72E+00	(3.84E+01)
Arsenic	1.57E-03	1.90E-02	1.75E-02
Barium	3.45E-02	1.67E-01	1.33E-01
Beryllium	9.42E-05	9.65E-04	8.71E-04
Cadmium	8.63E-03	1.11E-02	2.42E-03
Chromium	1.10E-02	2.67E-02	1.57E-02
Cobalt	6.59E-04	5.80E-03	5.14E-03
Copper	6.67E-03	4.52E-02	3.86E-02
Manganese	2.20E-03	1.28E+00	1.28E+00
Mercury	2.04E-03	4.64E-03	2.60E-03
Molybdenum	8.63E-03	9.45E-03	8.18E-04
Nickel	1.65E-02	4.12E-02	2.48E-02
Selenium	1.88E-04	2.41E-03	2.22E-03
Vanadium	1.80E-02	1.70E-02	(1.02E-03)
Zinc	2.28E-01	5.41E-01	3.13E-01
Acenaphthene	1.41E-05	7.41E-04	7.27E-04
Acenaphthylene	1.41E-05	4.01E-03	4.00E-03
Benzene	1.65E-02	3.38E+00	3.36E+00
Benzo(a)anthracene	1.41E-05	6.47E-05	5.06E-05
Benzo(b)fluoranthene	1.41E-05	9.28E-05	7.86E-05
Benzo(e)pyrene	9.42E-06	1.06E-05	1.14E-06
Benzo(g,h,i)perylene	9.42E-06	8.29E-05	7.35E-05
Benzo(j,k)fluoranthene	1.41E-05	1.41E-04	1.27E-04
Chrysene	1.41E-05	4.31E-05	2.90E-05
Dibenzo(a,h)anthracene	9.42E-06	1.58E-05	6.34E-06
Fluoranthene	2.35E-05	1.30E-03	1.28E-03
Florene	2.20E-05	2.74E-03	2.72E-03

Pollutant	Baseline Emissions, tons/yr	Project Emissions, tons/yr	Net Change in Air Emissions, tons/yr
Formaldehyde	5.89E-01	4.05E+00	3.46E+00
Indeno(1,2,3,c,d)pyrene	1.41E-05	8.24E-05	6.82E-05
Naphthalene	4.79E-03	8.20E-02	7.72E-02
Phenanthrene	1.33E-04	5.72E-03	5.59E-03
Pyrene	3.92E-05	3.00E-03	2.96E-03
Toluene	2.67E-02	7.60E-01	7.34E-01

Sources: Baseline natural gas emission factors are from AP-42 Table 1.4-1 and Tables 1.4-3 and 1.4-4 for air toxic emission factors. Project emissions for biogas combustion are from Jenner[11] for criteria pollutant emissions from biogas combustion and from AP-42 Wood Residue Combustion in Boilers, Tables 1.6-3 and 1.6-4 for air toxics.

In addition to the combustion emissions at the site, incremental emissions will occur due to the transport of the biomass material to the site. These emissions are estimated in Table 12-4 based on a round-trip transport distance of 400 miles as a worse case scenario.

TABLE 12-4. SUMMARY OF AIR POLLUTANT EMISSIONS FROM TRANSPORT OF BIOMASS TO SITE

Pollutant	Emissions, tons/yr	EF Source
CO_2	4,312	API Compendium Table 4-1 for diesel
CH_4	0.24	API Compendium Table 4-9 for HDDV
N_2O	0.12	API Compendium Table 4-9 for HDDV
ROG	1.85	EMFAC 2002 for model years 1965-2005 (most conservative emission factor set)
CO	8.31	
NO_x	54.7	
PM_{10}	1.02	
SO_x	0.53	

12.1.2.2 Energy Efficiency

The net reduction in air pollutant emissions from the energy efficiency case study is presented in Table 12-5. The basis of the air pollutant reductions is a baseline case of a 2,150 MMBtu/hr natural gas-fired boiler, with a project basis of 0.25% improvement in efficiency.

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[11] Jenner, Mark, *The BioTown, USA Sourcebook of Biomass Energy*, Indiana State Department of Agriculture and Reynolds, Indiana.

TABLE 12-5. SUMMARY OF AIR POLLUTANT EMISSIONS FROM ENERGY EFFICIENCY IMPROVEMENTS

Pollutant	Baseline Emissions, tons/yr	Project Emissions, tons/yr	Net Change in Air Emissions, tons/yr
NO_x	7.85E+02	7.83E+02	(1.96)
CO	6.59E+02	6.58E+02	(1.65)
Lead	3.92E-03	3.91E-03	(9.81E-06)
N_2O	5.02E+00	5.01E+00	(0.01)
PM (Total)	5.96E+01	5.95E+01	(0.15)
PM (Condensable)	4.47E+01	4.46E+01	(0.11)
PM (Filterable)	1.49E+01	1.49E+01	(0.04)
SO_2	4.71E+00	4.70E+00	(0.01)
TOC	8.63E+01	8.61E+01	(0.22)
Methane	1.80E+01	1.80E+01	(0.05)
VOC	4.32E+01	4.31E+01	(0.11)
2-Methylnapthalene	1.88E-04	1.88E-04	(4.71E-07)
3-Methylchloranthrene	1.41E-05	1.41E-05	(3.53E-08)
7,12-Dimethylbenz(a)anthracene	1.26E-04	1.25E-04	(3.14E-07)
Acenaphthene	1.41E-05	1.41E-05	(3.53E-08)
Acenaphthylene	1.41E-05	1.41E-05	(3.53E-08)
Anthracene	1.88E-05	1.88E-05	(4.71E-08)
Benz(a)anthracene	1.41E-05	1.41E-05	(3.53E-08)
Benzene	1.65E-02	1.64E-02	(4.12E-05)
Benzo(a)pyrene	9.42E-06	9.39E-06	(2.35E-08)
Benzo(b)fluoranthene	1.41E-05	1.41E-05	(3.53E-08)
Benzo(g,h,i)perylene	9.42E-06	9.39E-06	(2.35E-08)
Benzo(k)fluoranthene	1.41E-05	1.41E-05	(3.53E-08)
Butane	1.65E+01	1.64E+01	(0.04)
Chrysene	1.41E-05	1.41E-05	(3.53E-08)
Dibenzo(a,h)anthracene	9.42E-06	9.39E-06	(2.35E-08)
Dichlorobenzene	9.42E-03	9.39E-03	(2.35E-05)
Ethane	2.43E+01	2.43E+01	(0.06)
Fluoranthene	2.35E-05	2.35E-05	(5.89E-08)
Fluorene	2.20E-05	2.19E-05	(5.49E-08)
Formaldehyde	5.89E-01	5.87E-01	0.00
Hexane	1.41E+01	1.41E+01	(0.04)
Indeno(1,2,3-cd)pyrene	1.41E-05	1.41E-05	(3.53E-08)
Napthalene	4.79E-03	4.78E-03	(1.20E-05)
Pentane	2.04E+01	2.04E+01	(0.05)
Phenanathrene	1.33E-04	1.33E-04	(3.34E-07)
Propane	1.26E+01	1.25E+01	(0.03)
Pyrene	3.92E-05	3.91E-05	(9.81E-08)
Toluene	2.67E-02	2.66E-02	(6.67E-05)

12.1.2.3 Pozzolanic Clinker Replacement

The net reduction in site non-GHG air emissions from the replacement of clinker content with fly ash would be associated with the commensurate reduction in fuel consumption in the calcination process. This reduction would be partially offset by air emissions increases associated with the transport of fly ash to the site. Table 12-6 presents the estimated air emissions from transport of the fly ash to the site, assuming a 600 mile round trip distance and transport via truck as a worst case scenario for quantifying emissions.

TABLE 12-6. SUMMARY OF AIR POLLUTANT EMISSIONS FROM FLY ASH TRANSPORT TO HANSON PLANT

Pollutant	Emissions (tons/yr)	EF Source
CO_2	4,425	API Compendium Table 4-1 for diesel
CH_4	0.24	API Compendium Table 4-9 for HDDV
N_2O	0.13	API Compendium Table 4-9 for HDDV
ROG	1.90	EMFAC 2002 for model years 1965-2005 (most conservative emission factor set)
CO	8.53	
NO_x	56.18	
PM_{10}	1.05	
SO_x	0.55	

12.1.2.4 Carbon Capture and Sequestration

The carbon capture and sequestration mitigation option would involve energy consumption associated with carbon capture, compression, transport, and injection. The actual energy requirements would be dependent on the location of the injection reservoir and the reservoir depth and pressure characteristics. As this option is not one of the most cost effective options considered in the study, a detailed evaluation of air emissions from the associated operations to transport and sequester the carbon was not conducted.

12.1.2.5 Landfill Gas or Digester Gas with IC Engine

The air pollutant emissions associated with the mitigation option for landfill gas combustion in an IC engine is the difference between flaring the gas in the baseline scenario and combustion in the IC engine as the project-based reduction. The estimated net change in emissions from this mitigation option is presented in Table 12-7. Note that emission factors for combustion of digester gas in an IC engine are not published in AP-42, but would be expected to have the same emissions trends as for landfill gas.

TABLE 12-7. SUMMARY OF AIR POLLUTANT EMISSIONS FROM LANDFILL GAS COMBUSTION IN IC ENGINES

Pollutant	Baseline Emissions from Flaring, tons/yr	Project Emissions from IC Engine, tons/yr	Net Change in Air Emissions, tons/yr
CO	3.21E+02	2.01E+02	(1.20E+02)
NO_x	1.71E+01	1.07E+02	8.98E+01
PM_{10}	7.27E+00	2.05E+01	1.33E+01

12.1.2.6 Landfill Gas or Digester Gas with Gas Turbine

The net change in air emissions from landfill gas and digester gas combustion, respectively, in a gas turbine is presented in Tables 12-8 and 12-9. The net change in air emissions is estimated as the difference between the baseline scenario of flaring the landfill gas and combusting the landfill gas in a gas turbine.

TABLE 12-8. SUMMARY OF AIR POLLUTANT EMISSIONS FROM LANDFILL GAS COMBUSTION IN GAS TURBINE

Pollutant	Baseline Emissions from Flaring, tons/yr	Project Emissions from Turbine, tons/yr	Net Change in Air Emissions, tons/yr
CO	3.21E+02	9.83E+01	(2.22E+02)
NO_x	1.71E+01	3.72E+01	2.01E+01
PM_{10}	7.27E+00	9.41E+00	2.14E+00

TABLE 12-9. SUMMARY OF AIR POLLUTANT EMISSIONS FROM DIGESTER GAS COMBUSTION IN GAS TURBINE

Pollutant	Baseline Emissions from Flaring, tons/yr	Project Emissions from Turbine, tons/yr	Net Change in Air Emissions, tons/yr
CO	3.21E+02	9.83E+01	(2.22E+02)
NO_x	1.71E+01	3.72E+01	2.01E+01
PM_{10}	7.27E+00	9.41E+00	2.14E+00

12.1.3 Social, Economic, and Other Impacts

Social, economic, and other related impacts were also considered for each mitigation option. These impacts included any known or anticipated potential impacts on society or the economy within or outside the Bay Area region. Note that the costs to implement the mitigation options have been addressed in Section 11 and are not included in the economic analysis included in this section.

An overall qualitative ranking score of other impacts for each abatement option is as follows:

Score	Social, Economic, Other Impacts of Mitigation Option
3	No adverse social, economic, other impacts (low impact)
2	One adverse impact or relatively low adverse consequence (medium impact)
1	Significant adverse social, economic, other impacts (high impact)

Table 12-10 presents a summary of the key social, economic, and other impacts that were identified for each of the mitigation options. Each mitigation option is given a score based on the impact category listed above.

TABLE 12-10. SUMMARY OF QUALITATIVE SOCIAL IMPACTS ASSOCIATED WITH MITIGATION OPTIONS

Mitigation Technology	Social/Other Impact Summary	Overall Qualitative Social/Other Impact
1. Biofuels	➢ Overall social impacts associated with the combustion of biofuels are anticipated to be negligible. Biofuel production may have local social impacts associated with production operations, including job creation. ➢ For liquid biofuels, the use of biofuels might be easier because the current liquid fuels infrastructure could be used. This includes blending of biofuels with existing petroleum-based fuels (e.g., transportation fuel blends of 85% ethanol in gasoline or diesel fuel).	3
2. Energy Efficiency	➢ Overall social impacts associated with energy efficiency improvements are anticipated to be negligible to positive.	3
3. Pozzolanic Clinker Replacement	➢ Overall social impacts associated with cement additives are anticipated to be negligible. ➢ Acceptability of blended cement product in the local market may have a perceived negative impact, although	1

Mitigation Technology	Social/Other Impact Summary	Overall Qualitative Social/Other Impact
	blended cements are reportedly of higher quality than unblended cement products. ➢ Availability of fly ash is a potential issue, with delivery costs and impacts from sources in surrounding states a potential issue.	
4. Carbon Capture and Sequestration	➢ Safety impacts or perceptions associated with the long-term storage of CO_2 would need to be addressed. ➢ The construction of carbon capture and sequestration facilities will require major capital expenses. Also, like the facility being planned in Carson, CA or currently operating in Scotland, the facility will need to be located near an existing deep well sequestering location. If enhanced oil production can be accomplished, the sequestering operations will have some type of payback.	1
5. Landfill or Digester Gas with IC Engine	➢ Potential for job creation at landfill or waste water treatment sites associated with the operation and maintenance of IC engine generators. ➢ Noise impacts would be higher at the local site; however, typical landfills and wastewater treatment plants are not located adjacent to residential areas.	3
6. Landfill or Digester Gas with Gas Turbine	➢ Potential for job creation at landfill or waste water treatment sites associated with the operation and maintenance of IC engine generators. ➢ Noise impacts would be higher at the local site; however, typical landfills and wastewater treatment plants are not located adjacent to residential areas.	3
7. Landfill or Digester Gas Recovery as Pipeline Gas	➢ Potential for job creation at the landfill or waste water treatment sites associated with the operation and maintenance of the gas processing operations.	3

12.1.4 Barriers to Implementation

Some of the GHG mitigation options have significant barriers to overcome in order to be considered as viable candidates for implementation in the Bay Area. Table 12-11 presents a summary of the known barriers to implementation of the technology in the Bay Area.

An overall qualitative ranking score of barriers to implementation for each abatement option is as follows:

Score	Social, Economic, Other Impacts of Mitigation Option
3	No known significant barriers to implementation of the technology.
2	Barriers to implementation are minor, and can likely be overcome.
1	Significant barriers to implementation are known to exist. The probability of successful implementation is uncertain.

TABLE 12-11. SUMMARY OF QUALITATIVE RANKING OF BARRIERS TO IMPLEMENTATION OF THE MITIGATION OPTIONS

Mitigation Technology	Barriers to Implementation	Overall Qualitative Ranking of Barriers to Implementation
1. Biofuels	➢ Availability of suitable biomass material. ➢ Production of suitable biomass material from source.	2
2. Energy Efficiency	➢ Limited potential for improvement in energy efficiency from sources optimized to meet low NO_x standards.	2
3. Pozzolanic Clinker Replacement	➢ Acceptability of blended cement in market. ➢ Cement standards in California. ➢ Availability of suitable fly ash for blending.	1
4. Carbon Capture and Sequestration	➢ Suitability of reservoir for long-term sequestration. ➢ Safety implications of sequestration in seismic zone. ➢ Lack of technology demonstration, except for enhanced oil recovery operations.	1
5. Landfill or Digester Gas with IC Engine	➢ Landfill gas quality and production potential over time.	3
6. Landfill or Digester Gas with Gas Turbine	➢ Landfill gas quality and production potential over time.	3
7. Landfill gas quality and production potential over time.	➢ Landfill gas quality and production potential over time. ➢ Suitability of the gas for gas processing operations.	3

12.2 IMPACTS RANKING

The individual impacts categories that are used to rate each of the mitigation options have each been assigned a score, which is then consolidated into an overall impacts score. The three main rating categories for overall impacts have been each assigned a weighting factor.

The scores that are applied to each of the rating categories to derive the overall impacts score are presented below. Each of the category scores (1 to 3) is multiplied by its respective weighting and combined into the Overall Impacts Score. Table 12-12 presents a summary of the impacts ranking for each of the mitigation options evaluated.

Impact	Weighting in final ranking
Energy	15%
Environmental	45%
Social/Other	10%
Barriers to Implementation	30%

TABLE 12-12 MITIGATION OPTION OVERALL IMPACTS SCORES

Mitigation Option	Energy Impacts	Environmental Impacts	Social, Other Impacts	Barriers to Implementation	Overall Impacts Score
	15%	45%	10%	30%	
Biofuels	2	2	3	2	**2.1**
Energy Efficiency	3	3	3	2	**2.7**
Pozzolanic Clinker Replacement	3	2	1	1	**1.8**
Carbon Capture and Sequestration	1	1	1	1	**1**
Landfill or Digester Gas with IC Engine	3	2	3	3	**2.6**
Landfill or Digester Gas with Gas Turbine	3	3	3	3	**3**
Landfill gas quality and production potential over time.	1	2	3	3	**2.3**

13.1 RANKING OF MEASURES

GHG mitigation technologies that have been identified in this project have been assessed using a rating system to yield an overall ranking of the available options. The parameters used to rank the mitigation technologies are:

- Capital cost of mitigation measure;
- Quantity of GHG emission reductions;
- Cost effectiveness of mitigation measure, including capital and operating/maintenance costs; and
- Impacts of mitigation technique.

These parameters are each assigned a value which allows the different mitigation measures to be ranked. The different mitigation methods are compared in an Overall Mitigation Ranking Score. The overall score is structured such that high-scoring mitigation options are the most effective measures for BAAQMD to pursue further, while low-scoring options are low priority for further evaluation.

13.1.1 Capital Cost of Abatement

The capital cost of the mitigation option has been provided in $US where available. The costs have been ranked in three categories as follows:

Score	Cost of Abatement
3	Capital cost of less than US$25 Million
2	Capital cost of between US$25 Million and US$50 Million
1	Capital cost of more than US$50 Million

13.1.2 Amount of CO_2 Abated

A primary concern for BAAQMD is the amount of CO_2 that can be reduced through each mitigation option. The best score of three has been assigned to options which can potentially reduce more than 250,000 ton CO_2 equivalent (t CO_2e) per annum per source.

The amount of CO_2-e of each abatement option has been ranked in three categories as follows:

Score	Abatement Amount in ton CO_2e
3	More than 250,000 tons CO_2e per year
2	Between 50,000 and 250,000 tons CO_2e per year
1	Less than 50,000 tons CO_2e per year

13.1.3 Cost Effectiveness of Mitigation Measure

Another metric used to rank the mitigation measures is the cost effectiveness of the mitigation measures. The cost effectiveness is a function of both the capital cost and the amount of GHG emissions reduced, but also takes into account operating and maintenance costs of the mitigation measure. The cost effectiveness of the mitigation measures were presented previously in Section 11.

The cost effectiveness of each mitigation option has been ranked in three categories as follows:

Score	Cost Effectiveness in $ per ton CO_2e
3	Less than $10 per ton CO_2e
2	Between $10 and $20 per ton CO_2e
1	Greater than $20 per ton CO_2e

13.1.4 Impacts of Mitigation Measure

The overall impacts assessed using the methodology presented in Section 12 takes into account the energy, environmental, social, economic, and other impacts, as well as the commercial demonstration status of the mitigation measure. The consolidated impacts score summarized in Section 12.2 is used in the overall ranking of each mitigation option.

13.2 OVERALL MITIGATION SCORE

The individual categories that are used to rate each of the mitigation options have each been assigned a score, which is then amalgamated into an Overall Mitigation Score. The five main rating categories have been each assigned a weighting. The Feasibility category has been assigned further weightings for each sub-category, which are used to derive the Feasibility score.

The Scores that are applied to each of the rating categories to derive the Overall Mitigation Score are presented below. Each of the category scores (1 to 3) is multiplied by its respective weighting and combined into the Overall Mitigation Score.

Ranking Criteria	Weighting in final ranking
Capital cost of abatement in $US	20%
Abatement amount, t CO_2e	30%
Cost effectiveness, $/t CO_2e	20%
Overall impacts	30%

The overall score of each mitigation option is shown in Table 13.1. As shown, the mitigation scores fell between 1.6 and 2.3. Following is a rank ordered listing of the mitigation options by their overall scores in the evaluation.

- Landfill gas recovery with IC engine (2.3)
- Energy efficiency (2.3)
- Pozzolanic cement replacement (2.3)
- Biofuel combustion (2.0)
- Landfill gas recovery with gas turbine (2.0)
- Landfill gas recovery as pipeline quality gas (2.0)
- Carbon capture and sequestration (1.6)

All options received above a 2 (average) ranking, except the carbon capture and sequestration option.

TABLE 13-1 MITIGATION OPTION SCORES AND OVERALL SCORES

Source Category	Mitigation Option	Capital Cost	Abatement Amount	Cost Effectiveness	Other Impacts	Overall Score
		20%	30%	20%	30%	
➢ NG Steam Boiler ➢ NG Cogeneration ➢ NG Gas Turbine ➢ Cement Kiln Combustion ➢ Refinery FCCU Catalyst Regeneration ➢ Refinery Flexicoker ➢ Refinery Process Heater ➢ Chemical Process Heater	Biofuels	2	2	2	2.1	2.0
➢ NG Steam Boiler ➢ NG Gas Turbine ➢ Refinery Process Heater ➢ Chemical Process Heater	Energy Efficiency	3	1	3	2.7	2.3
➢ Cement Kiln	Pozzolanic Clinker Replacement	3	2	3	1.8	2.3
➢ Refinery Hydrogen Production	Carbon Capture and Sequestration	1	3	1	1	1.6
➢ Landfill Gas with Flaring ➢ Digester Gas with Flaring	Landfill or Digester Gas with IC Engine	3	1	3	2.6	2.3
➢ Landfill Gas with Flaring ➢ Digester Gas with Flaring	Landfill or Digester Gas with Gas Turbine	3	1	1	3	2.0
➢ Landfill Gas with Flaring ➢ Digester Gas with Flaring	Landfill or Digester Gas Recovery as Pipeline Gas	3	1	2	2.3	2.0

14.1 SUMMARY OF RESULTS

Based on the evaluation of mitigation options, the respective measures were ranked in accordance with their overall effectiveness, costs, and impacts. The mitigation measures were rank ordered on a scale of 1 to 3, with 3 being the most favorable score possible. Table 14-1 shows the overall results of the evaluation in order of most favorable to least favorable.

TABLE 14-1. OVERALL RANKING OF MITIGATION OPTIONS

Mitigation Option	Overall Ranking Score	Applicable Source Categories
Landfill or Digester Gas Recovery in IC Engine	2.3	➢ Landfill Gas with Flaring ➢ Digester Gas with Flaring
Energy Efficiency	2.3	➢ NG Steam Boiler ➢ NG Gas Turbine ➢ Refinery Process Heater ➢ Chemical Process Heater
Pozzolanic Cement Replacement	2.3	➢ Cement Kiln
Biofuel Combustion	2.0	➢ NG Steam Boiler ➢ NG Cogeneration ➢ NG Gas Turbine ➢ Cement Kiln Combustion ➢ Refinery FCCU Catalyst Regeneration ➢ Refinery Flexicoker ➢ Refinery Process Heater ➢ Chemical Process Heater
Landfill or Digester Gas Recovery in Gas Turbine	2.0	➢ Landfill Gas with Flaring ➢ Digester Gas with Flaring
Landfill or Digester Gas Recovery as Pipeline Gas	2.0	➢ Landfill Gas with Flaring ➢ Digester Gas with Flaring
Carbon Capture and Storage	1.6	➢ Refinery Hydrogen Production

All of the mitigation options evaluated in detail were ranked at a level above average (i.e., ranking of 2.0 or higher), except the carbon capture and sequestration option for refinery hydrogen production. The above average ranked mitigation options are concluded to have favorable benefits as compared to costs and other adverse impacts. The options with a favorable ranking are described below:

- Landfill gas or digester gas utilization in IC engine for power generation. This option is based on utilizing previously flared landfill or digester gas in an IC engine to produce power for sale to the grid. This option has low uncertainties and barriers, although the quantity and quality of the landfill gas would determine feasibility.
- Energy efficiency improvement in combustion sources across source categories. This option is based on an average 0.25 percent improvement in overall efficiency. The resulting GHG emission reduction is associated with commensurate lowered fuel utilization to produce an equivalent energy output. Uncertainties associated with this option include the extent to which energy efficiency can be improved, which will be highly site specific. Another source of uncertainty is long-term permanence of the emission reduction from efficiency improvements.
- Pozzolanic clinker replacement in cement manufacturing. This is an option to utilize fly ash for blending with the cement to replace a fraction of the clinker content of the cement. This option results in avoided emissions of CO_2 from the calcination reaction and pyrolysis of the clinker being replaced by fly ash. However, barriers to implementation of this option are significant. The acceptability of the blended cement product in the market is a significant issue. In addition, the availability and supply costs and impacts associated with a reliable source of fly ash are unknown. A more promising option for the Hanson plant would likely be biomass co-firing in the cement kiln to displace some of the coal or coke that is being burned. This option was not reviewed in detail because the plant is already investigating the feasibility of biomass co-firing.
- Biofuel combustion to replace a fraction of the natural gas utilized in power generation, industrial and commercial boilers, process heaters, and other potential combustion sources. The option to utilize biofuel is based on gasification of agricultural waste, with subsequent blending of the biogas with natural gas. The emission reductions from the biogas firing are based on avoiding the emissions of the replaced natural gas. Biofuels are typically considered carbon neutral. Uncertainties associated with this option include the source of agricultural waste to be used to generate biogas, requirements for biogas clean-up, capital and operating/maintenance costs associated with the bio-gasification system, and combustion burner modifications required.

- Landfill gas or digest or gas utilization in gas turbine for power generation. This option is based on utilizing the previously flared landfill or digester gas and utilizing the gas for power generation in a gas turbine. This option has the low overall uncertainties associated with application of the technology; however, the actual gas volumes and composition over time would require site specific data collection to confirm the results.
- Landfill gas or digester gas recovery and processing to produce pipeline quality natural gas. This option is based on utilizing the previously flared landfill or digester gas and producing pipeline quality gas for sale. This option is similar to the landfill gas recovery and on-site power generation options, but would require additional energy to process the landfill gas.
- Biofiltration and biotic covers for landfills is another promising option that was not evaluated in detail due to uncertainties in costs and performance of these technologies. However, studies have indicated a high potential for methane oxidation, and even a potential for sequestration in the compost cover.

The last option evaluated that was ranked below average was carbon capture and sequestration for refinery hydrogen production. This option would capture the high concentration CO_2 stream from the hydrogen process and store in an underground formation. The high costs, coupled with uncertainties around the long-term permanence of storage make this option less attractive than the others evaluated.

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15.1 TECHNICAL DOCUMENTS

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15.2 WEBSITES

General Control Technology Information:

United Nations Framework Convention on Climate Change, http://unfccc.int/2860.php

www.netl.doe.gov

www.ieagreen.org/uk

Carbon Sequestration:

www.gulfcoastcarbon.org

http://co2captureandstorage.info/co2db.php4

http://www.beg.utexas.edu/environqlty/co2seq/fieldexperiment.htm

www.cleanenergysystems.com

www.fossil.energy.gov

Hydrogen Production:

http://www.hydrogen.energy.gov/

http://www.eere.energy.gov/RE/hydrogen.html

www.co2captureandstorage.info

Landfill Gas to Energy:

http://www.methanetomarkets.org/

http://www.epa.gov/lmop/

Biomass Combustion:

www.eere.energy.gov/RE/biomass.html

www.nucor.com/enviropages/articles/01-FerroGusaCarajasProject.htm

Appendix A

Summary of GHG Mitigation Cost Estimates

ESTIMATED CAPITAL AND OPERATING COSTS
BIOGAS FOR ELECTRICAL GENERATION
REPLACING NATURAL GAS

CASE EXAMPLE

- Biogas to replace 10% of natural gas firing
- Boiler capacity of 2,150 MMBtu/hr

CAPITAL COSTS		
DIRECT CAPITAL COSTS (DC)		
Installed Equipment Costs (PE)		
Gasifier and gas clean-up equipment ($900/KW^{a})		$21,285,000
Biomass handling equipment ($100/KW^{a})		$2,150,000
	PE Total =	$23,435,000
Direct Installation Costs (DI)		
Direct Installation Costs (included in capital cost)		$0
	DI Total =	$0
	DC Total =	$23,435,000
INDIRECT CAPITAL COSTS (IC)		
Indirect Installation Costs (41% of PE, OAQPS Manual)		$9,608,000
	IC Total =	$9,608,000
	TOTAL CAPITAL INVESTMENT (TCI) = Sum (DC + IC) =	**$33,043,000**
Capital Recovery at 7% interest over 15 years (0.1098*TCI)		**$3,628,000**
OPERATION AND MAINTENANCE (O & M)		
DIRECT ANNUAL COSTS (DA)		
Operating Labor:		
Operator (4 hr/shift, 8760 hrs/yr, $20/hr) + Supervisor (15% of Operator)		$100,740
Maintenance:		
Labor (2 hr/shift, 8760 hrs/yr, $15/hr) + Materials (100% of Labor)		$65,700
Maintenance Materials (1% f TCI)		$330,000
Consumables		
Agricultural waste cost differential with natural gas		($5,646,798)

Cost of natural gas = \$6/MMBtu; Cost of biogas based on \$40/dry ton biomass; 318.98 dry ton/day	
Transportation costs at \$10/dry ton	\$989,635
DA Total =	(\$4,161,000)
INDIRECT ANNUAL COSTS (IA)	
Overhead (60% of maintenance parts & labor costs, OAQPS Manual)	\$237,000
Admin., Property Tax, Insurance (4% of TCI, OAQPS Manual)	\$1,322,000
IA Total =	\$1,559,000
Annual O & M Total =	**(\$2,602,000)**
TOTAL ANNUAL CAPITAL AND O & M COSTS (incldg. Capital Recovery)	**\$1,026,000**
Baseline CO_2 Emissions (tons/yr)	937,044
Annual CO_2 removal (tons)	93,704
Annual cost effectiveness, \$/ton CO_{2e}	**\$11**
Cost of generation	**0.0187**

[a] Installed costs based on report, *Utilization of Waste Renewable Fuels in Boilers with Minimization of Pollutant Emissions*, California Energy Commission, November 2005.

Note: Cost Factors based on OAQPS Control Cost Manual (Ch. 9, 6th Ed., January 2002)

ESTIMATED CAPITAL AND OPERATING COSTS

ENERGY EFFICIENCY

CASE EXAMPLE

- Energy efficiency improvement of 0.25%
- Boiler capacity of 2,150 MMBtu/hr

CAPITAL COSTS

DIRECT CAPITAL COSTS (DC)		
Purchased Equipment Costs (PE)		
Materials Costs		$200,000
	PE Total =	$200,000
Direct Installation Costs (DI)		
	DI Total =	$0
	DC Total =	$200,000
INDIRECT CAPITAL COSTS (IC)		
Energy Audit and Repair		$200,000
	IC Total =	$200,000
	TOTAL CAPITAL INVESTMENT (TCI) = Sum (DC + IC) =	**$400,000**
Capital Recovery at 7% interest over 15 years (0.1098*TCI)		**$44,000**

OPERATION AND MAINTENANCE (O & M)

DIRECT ANNUAL COSTS (DA)		
Maintenance:		
Labor (2 hr/shift, 8760 hrs/yr, $15/hr) + Materials (100% of Labor)		$100,740
Maintenance Materials (4% f TCI)		$16,000
Consumables		
Reduction in natural gas consumption (0.25% efficiency improvement); natural gas at $6/MMBtu		($240,134)
	DA Total =	($123,000)
INDIRECT ANNUAL COSTS (IA)		
Overhead (60% of maintenance parts & labor costs, OAQPS Manual)		$70,000
Admin., Property Tax, Insurance (4% of TCI, OAQPS Manual)		$16,000

IA Total =	$86,000
Annual O & M Total =	**($37,000)**
TOTAL ANNUAL CAPITAL AND O & M COSTS (incldg. Capital Recovery)	**$7,000**
Baseline CO_2 Emissions (tons/yr)	937,044
Annual CO_2 removal (tons) (assumes 0.25% efficiency improvement)	2,343
Annual cost effectiveness, $/ton CO_{2e}	**$3**

Note: Cost Factors based on OAQPS Control Cost Manual (Ch. 9, 6th Ed., January 2002)

ESTIMATED CAPITAL AND OPERATING COSTS

BLENDED CEMENT MANUFACTURING

CAPITAL COSTS	
DIRECT CAPITAL COSTS (DC)	
Installed Equipment Costs (PE)	$3,461,061
PE Total =	$3,461,000
Direct Installation Costs (DI)	
Included in installed cost estimate	$0
DI Total =	$0
DC Total =	$3,461,000
INDIRECT CAPITAL COSTS (IC)	
Indirect Installation Costs (35% of PE, OAQPS Manual)	$1,211,000
IC Total =	$1,211,000
TOTAL CAPITAL INVESTMENT (TCI) = Sum (DC + IC) =	**$4,672,000**
Capital Recovery at 7% interest over 15 years (0.1098*TCI)	**$380,000**
OPERATION AND MAINTENANCE (O & M)	
DIRECT ANNUAL COSTS (DA)	
Operating Labor:	
Operator (1 hr/shift, 8760 hrs/yr, $20/hr) + Supervisor (15% of Operator)	$25,185
Maintenance:	
Labor (2 hr/shift, 8760 hrs/yr, $15/hr) + Materials (100% of Labor)	$65,700
Raw Materials (assume cost of fly ash is equivalent to lime)	$0
DA Total =	$91,000
INDIRECT ANNUAL COSTS (IA)	
Assume no increase in indirect annual costs	$55,000
IA Total =	$55,000

Annual O & M Total =	**$146,000**
TOTAL ANNUAL CAPITAL AND O & M COSTS (incldg. Capital Recovery)	**$526,000**
Baseline CO_2 Emissions from cement production (tons/yr)	663692.00
Annual CO_2 removal assuming X Removal Efficiency (tons)	55900
Annual cost effectiveness, \$/ton CO_{2e}	**$9**

Note: Cost Factors based on OAQPS Control Cost Manual (Ch. 9, 6th Ed., January 2002)

ESTIMATED CAPITAL AND OPERATING COSTS
CARBON CAPTURE AND SEQUESTRATION AT
REFINERY HYDROGEN PLANT
CAPTURE COSTS

CAPITAL COSTS	
DIRECT CAPITAL COSTS (DC)	
Installed Equipment Costs (PE)	$68,773,430
PE Total =	**$68,773,430**
Direct Installation Costs (DI)	
Direct Installation Costs (included in capital estimate)	$0
DI Total =	$0
DC Total =	**$68,773,430**
INDIRECT CAPITAL COSTS (IC)	
Indirect Installation Costs (41% of PE, OAQPS Manual)	$28,197,000
IC Total =	$28,197,000
TOTAL CAPITAL INVESTMENT (TCI) = Sum (DC + IC) =	**$96,970,430**
Capital Recovery at 7% interest over 20 years (0.0944*TCI)	**$9,154,000**
OPERATION AND MAINTENANCE (O & M)	
DIRECT ANNUAL COSTS (DA)	
Operating Labor:	
Operator (4 hr/shift, 8760 hrs/yr, $20/hr) + Supervisor (15% of Operator)	$100,740
Maintenance:	
Labor (2 hr/shift, 8760 hrs/yr, $15/hr) + Materials (100% of Labor)	$131,400
Electricity (7.87 MW/yr hrs/yr @ $0.055/kW-hr)	$433.3
Consumables	$50,000.0
DA Total =	$283,000
INDIRECT ANNUAL COSTS (IA)	
Overhead (60% of maintenance parts & labor costs, OAQPS Manual)	$139,000
Admin., Property Tax, Insurance (4% of TCI, OAQPS Manual)	$2,751,000

IA Total =	$2,890,000
Annual O & M Total =	**$3,173,000**
TOTAL ANNUAL CAPITAL AND O & M COSTS (incldg. Capital Recovery)	**$12,327,000**
Baseline CO_2 Emissions from hydrogen process (tons/yr)	485,450
Annual CO_2 removal assuming X Removal Efficiency (tons)	388,360
Annual cost effectiveness, $/ton CO_{2e}	**$32**

Note: Cost Factors based on OAQPS Control Cost Manual (Ch. 9, 6th Ed., January 2002)

ESTIMATED CAPITAL AND OPERATING COSTS
LANDFILL GAS UTILIZATION
IN IC ENGINE GENERATORS

CAPITAL COSTS	
DIRECT CAPITAL COSTS (DC)	
Purchased Equipment Costs (PE)	
IC Generator ($1300/kW per USEPA 430-B-96-0004)	$9,236,621
Assume capture system already in place	
PE Total =	$9,237,000
Direct Installation Costs (DI)	
Direct Installation Costs (56% of PE, OAQPS Manual)	$5,173,000
DI Total =	$5,173,000
DC Total =	$14,410,000
INDIRECT CAPITAL COSTS (IC)	
Indirect Installation Costs (35% of PE, OAQPS Manual)	$3,233,000
IC Total =	$3,233,000
TOTAL CAPITAL INVESTMENT (TCI) = Sum (DC + IC) =	**$17,643,000**
Capital Recovery at 7% interest over 20 years (0.1098*TCI)	**$1,665,000**
OPERATION AND MAINTENANCE (O & M)	
DIRECT ANNUAL COSTS (DA)	
Operating Labor:	
Operator (4 hr/shift, 8760 hrs/yr, $20/hr) + Supervisor (15% of Operator)	$100,740
Maintenance:	
Labor (2 hr/shift, 8760 hrs/yr, $15/hr) + Materials (100% of Labor)	$65,700
Electricity sales to customers across grid ($0.055/KWh)	($2,423,053)

	DA Total =	($2,257,000)
INDIRECT ANNUAL COSTS (IA)		
Overhead (60% of maintenance parts & labor costs, OAQPS Manual)		$100,000
Admin., Property Tax, Insurance (4% of TCI, OAQPS Manual)		$706,000
	IA Total =	$806,000
	Annual O & M Total =	**($1,451,000)**
TOTAL ANNUAL CAPITAL AND O & M COSTS (incldg. Capital Recovery)		**$214,000**
Baseline CO_2/methaneEmissions assuming flaring (tons/yr)		39,682
Baseline CO2 emissions from engines using pipeline quality natural gas		26,553
Total Baseline (tons/yr)		66,235
Project Emissions from Engines using landfill gas		39,682
Annual CO_2/methane reduction (tons/yr)		26,553
Annual cost effectiveness, $/ton CO_{2e}		**$8**
Cost of generation		**$0.0049**

Note: Cost Factors based on OAQPS Control Cost Manual (Ch. 9, 6th Ed., January 2002)

ESTIMATED CAPITAL AND OPERATING COSTS
LANDFILL GAS UTILIZATION
IN GAS TURBINE GENERATORS

CAPITAL COSTS	
DIRECT CAPITAL COSTS (DC)	
Purchased Equipment Costs (PE)	
Gas Turbine Generator (assume 20% higher than IC engine)	$12,746,537
Assume capture system already in place	
PE Total =	$12,747,000
Direct Installation Costs (DI)	
Direct Installation Costs (56% of PE, OAQPS Manual)	$7,138,000
DI Total =	$7,138,000
DC Total =	$19,885,000
INDIRECT CAPITAL COSTS (IC)	
Indirect Installation Costs (35% of PE, OAQPS Manual)	$4,461,000
IC Total =	$4,461,000
TOTAL CAPITAL INVESTMENT (TCI) = Sum (DC + IC) =	**$24,346,000**
Capital Recovery at 7% interest over 20 years (0.1098*TCI)	**$2,298,000**
OPERATION AND MAINTENANCE (O & M)	
DIRECT ANNUAL COSTS (DA)	
Operating Labor:	
Operator (4 hr/shift, 8760 hrs/yr, $20/hr) + Supervisor (15% of Operator)	$100,740
Maintenance:	
Labor (2 hr/shift, 8760 hrs/yr, $15/hr) + Materials (100% of Labor)	$65,700
Electricity sales to customers across grid ($0.055/KWh)	($2,786,510)

DA Total =	($2,620,000)
INDIRECT ANNUAL COSTS (IA)	
Overhead (60% of maintenance parts & labor costs, OAQPS Manual)	$100,000
Admin., Property Tax, Insurance (4% of TCI, OAQPS Manual)	$974,000
IA Total =	$1,074,000
Annual O & M Total =	**($1,546,000)**
TOTAL ANNUAL CAPITAL AND O & M COSTS (incldg. Capital Recovery)	**$752,000**
Baseline CO_2/methaneEmissions assuming flaring (tons/yr)	39,682
Baseline CO2 emissions from engines using pipeline quality natural gas	30,536
Total Baseline (tons/yr)	70,218
Project Emissions from Engines using landfill gas	39,682
Annual CO_2/methane reduction (tons/yr)	30,536
Annual cost effectiveness, $/ton CO_{2e}	**$25**
Cost of generation	**$0.0148**

Note: Cost Factors based on OAQPS Control Cost Manual (Ch. 9, 6th Ed., January 2002)

ESTIMATED CAPITAL AND OPERATING COSTS
BIOGAS FOR ELECTRICAL GENERATION
REPLACING NATURAL GAS

CAPITAL COSTS		
DIRECT CAPITAL COSTS (DC)		
Installed Equipment Costs (PE)		
Gasifier and gas clean-up equipment ($900/KW[a])		$21,285,000
Biomass handling equipment ($100/KW[a])		$2,150,000
	PE Total =	$23,435,000
Direct Installation Costs (DI)		
Direct Installation Costs (included in capital cost)		$0
	DI Total =	$0
	DC Total =	$23,435,000
INDIRECT CAPITAL COSTS (IC)		
Indirect Installation Costs (41% of PE, OAQPS Manual)		$9,608,000
	IC Total =	$9,608,000
	TOTAL CAPITAL INVESTMENT (TCI) = Sum (DC + IC) =	**$33,043,000**
Capital Recovery at 7% interest over 15 years (0.1098*TCI)		**$3,628,000**
OPERATION AND MAINTENANCE (O & M)		
DIRECT ANNUAL COSTS (DA)		
Operating Labor:		
Operator (4 hr/shift, 8760 hrs/yr, $20/hr) + Supervisor (15% of Operator)		$100,740
Maintenance:		
Labor (2 hr/shift, 8760 hrs/yr, $15/hr) + Materials (100% of Labor)		$65,700
Maintenance Materials (1% f TCI)		$330,000
Consumables		
Agricultural waste cost differential with natural gas		($5,646,798)
Cost of natural gas = $6/MMBtu; Cost of biogas based on $40/dry ton biomass; 318.98 dry ton/day		
Transportation costs at $10/dry ton		$989,635
	DA Total =	($4,161,000)
INDIRECT ANNUAL COSTS (IA)		
Overhead (60% of maintenance parts & labor costs, OAQPS Manual)		$237,000
Admin., Property Tax, Insurance (4% of TCI, OAQPS Manual)		$1,322,000
	IA Total =	$1,559,000
	Annual O & M Total =	**($2,602,000)**
TOTAL ANNUAL CAPITAL AND O & M COSTS (incldg. Capital		**$1,026,000**

Recovery)	
Baseline CO_2 Emissions (tons/yr)	937,044
Annual CO_2 removal (tons)	93,704
Annual cost effectiveness, \$/ton CO_{2e}	**\$11**
Cost of generation	**0.0187**

[a] Installed costs based on report, *Utilization of Waste Renewable Fuels in Boilers with Minimizaiton of Pollutant Emissions*, California Energy Commission, November 2005.

Note: Cost Factors based on OAQPS Control Cost Manual (Ch. 9, 6th Ed., January 2002)

Appendix B

Supporting Policy Information

Supporting Policy Information

B.1 EXISTING BAAQMD AIR RULES AND BACT

Although the agency does not regulate GHG emissions, they do regulate criteria pollutants and air toxics. The District's ozone precursor control strategy has resulted in extensive utilization of clean burning natural gas fuel in the Bay Area power plant sector, largely electric steam generating boilers and cogeneration gas turbine systems. Extensive utilization of natural gas as a clean fuel has been accomplished by stringent NO_x control rules, such as Regulation 9, Rule 11 for the large installed base of older electric generating steam boilers, and Best Available Control Technology (BACT) for the newly installed generation of cogeneration systems. As such, most major stationary combustion sources firing natural gas already have relatively low carbon intensity profile, with about half the emissions of CO_2 as compared to coal firing.

The BAAQMD has determined BACT technologies for some of the source categories above. BACT is defined in District Regulation 2, Rule 2, Section 206 as follows:

> "2-2-206 Best Available Control Technology (BACT): For any source or modified source, except cargo carriers, the more stringent of:
>
> - 206.1 The most effective emission control device or technique which has been successfully utilized for the type of equipment comprising such a source; or
> - 206.2 The most stringent emission limitation achieved by an emission control device or technique for the type of equipment comprising such a source; or
> - 206.3 Any emission control device or technique determined to be technologically feasible and cost-effective by the APCO; or
> - 206.4 The most effective emission control limitation for the type of equipment comprising such a source which the EPA states, prior to or during the public comment period, is contained in an approved implementation plan of any state, unless the applicant demonstrates to the satisfaction of the APCO that such limitations are not achievable. Under no circumstances shall the emission control

> required be less stringent than the emission control required by any applicable provision of federal, state or District laws, rules or regulations."

The Air Pollution Control Officer (APCO) shall periodically publish and update a BACT Workbook specifying the requirements for commonly permitted sources. BACT will be determined for a source by using the workbook as a guidance document or, on a case-by-case basis, using the most stringent definition of this Section 2-2-206. In the BACT determination tables, the following terms are used:

- "Not Applicable": For example, the pollutant in question is not a problem for the source category under consideration.
- "No Determination": No BACT determination has been made to date for the source category or BACT category under consideration.
- "Not Specified": A BACT determination has been made but no specific emissions limitation has been set or the detailed equipment/process technology has not been specified.

B.2 GAS FIRED STEAM ELECTRIC BOILERS

B.2.1 BAAQMD BACT Determination

The following BACT determination has been made for gas-fired steam boilers $\geq$33.5 MMBtu/hr to <50 MMBtu/hr heat input:

POLLUTANT	BACT	TYPICAL TECHNOLOGY
Precursor Organic Compound (POC)	1. No determination 2. Not specified	1. No determination 2. Good combustion practice
Nitrogen Oxides (NOx)	1. 9 ppmv @ 3% O_2 Dry 2. 25 ppmv @ 3% O_2 Dry	1. Low NO_x Burners + Flue Gas Recirculation + Selective Catalytic Reduction 2. Low NO_x Burners + Flue Gas Recirculation
Sulfur Dioxide (SO_2)	1. Natural Gas or Treated Refinery Gas Fuel w/ $\leq$.50 ppmv Hydrogen Sulfide and $\leq$100 ppmv Total Reduced Sulfur 2. Natural Gas or Treated Refinery Gas Fuel w/ $\leq$100 ppmv Total Reduced Sulfur	1. Fuel Selection 2. Fuel Selection
Carbon Monoxide (CO)	1. No determination 2. 100 ppmv @ 3% O_2 Dry	1. No determination 2. Good Combustion Practice

POLLUTANT	BACT	TYPICAL TECHNOLOGY
Particulate Matter (PM_{10})	1. No determination 2. Natural Gas or Treated Refinery Gas Fuel	1. No determination 2. Fuel Section
Non-Precursor Organic Compound (NPOC)	1. Not applicable 2. Not applicable	1. Not applicable 2. Not applicable

1. Technologically Feasible/ Cost Effective
2. Achieved in Practice

The BACT determination for NO_x is 20/25 ppmvd @ 3% O_2 and for CO is 100 ppmvd @ 3 % O_2 regardless of fuel type. However, emergency backup fuel oil w/ $\leq$ 0.05 wt. % sulfur may be permitted to emit up to 60 NO_x ppmvd @ 3% O_2 and 100 ppmvd CO @ 3 % O_2 during natural gas curtailment.

The following BACT determination has been made for gas-fired steam boilers $\geq$50 MMBtu/hr heat input:

POLLUTANT	BACT	TYPICAL TECHNOLOGY
Precursor Organic Compound (POC)	1. No determination 2. Not specified	1. No determination 2. Good Combustion Practice (GCP)
Nitrogen Oxides (NOx)	1. 7 ppmv @ 3% O_2, Dry 2. 9 ppmv @ 3% O_2, Dry	1. Selective Catalytic Reduction (SCR) + Low NO_x Burners (LNB) + Flue Gas Recirculation (FGR) 2. Ultra Low NO_x Burners (ULNB) + FGR
Sulfur Dioxide (SO_2)	1. Natural Gas or Treated Refinery Gas Fuel w/ <50 ppmv Hydrogen Sulfide and <100 ppmv Total Reduced Sulfur 2. Natural Gas or Treated Refinery Gas Fuel w/ <100 ppmv Total Reduced Sulfur	1. Fuel Selection 2. Fuel Selection
Carbon Monoxide (CO)	1. 10 ppmv @ 3% O_2 Dry 2. 50 ppmv @ 3% O_2 Dry	1. Oxidation Catalyst 2. Good Combustion Practice in Con-junction with SCR System or Ultra Low NO_x Burners and FGR
Particulate Matter (PM_{10})	1. No determination 2. Natural Gas or Treated Refinery Gas Fuel	1. No determination 2. Fuel Selection
Non-Precursor Organic Compound (NPOC)	1. Not applicable 2. Not applicable	1. Not applicable 2. Not applicable

1. Technologically Feasible/ Cost Effective
2. Achieved in Practice

The cost-effectiveness evaluations were based on emissions from firing primary fuels but not emergency backup fuels. The BACT limits above apply to all fuels except for emergency backup fuel oil used during natural gas curtailment. For emergency backup fuel oil, BACT is as follows:

1. For NO_x and CO (achieved using LNB+ FGR+ SCR and GCP) is 25 ppmvd NO_x @ 3% O_2; 100 ppmvd CO @ 3% $O_{2,}$ and 5 ppmvd NH_3 @ 3% O_2; BACT
2. For NO_x and CO (achieved using ULNB+ FGR and GCP) is 40 ppmvd NO_x @ 3% O_2 and 100 ppmvd CO @ 3% O_2; BACT
3. For SO_2 and PM_{10} is the use of low sulfur fuel with < 0.05 wt. % S; and BACT (2) for POC is GCP.

The BACT CO limit does not apply to boilers smaller than 250 MM BTU/hour unless an oxidation catalyst is found to be cost effective or is necessary for TBACT or POC Control.

B.2.2 San Francisco Energy Plan

Energy supply and demand has been examined intensely in the last several years, especially in San Francisco. In December 2002, San Francisco adopted an Electricity Resource Plan called for the development of 107 Megawatts (MWs) of load reduction through load management and efficiency measures. The load shifting included 72 MWs of small-scale distributed generation such as fuel cells.

A summary of resources identified this electricity resource portfolio in 2005 and 2012 is as follows (The table is in megawatts, based on maximum capacity installed and achieved.):*

Resource	Year-2005	Year-2012
New load shifting in SF	NA**	NA**
New demand reduction in SF	23	107
New renewables in SF	10	50
New cogeneration in SF if needed	100	100
New imports to SF (from "green" sources)	350	350
Existing imports to SF	640	640
Existing Potrero Power Plant (peaking only)	0-363	0-363
Existing Hunters Point Power Plant	0	0
Proposed Potrero Power Plant Unit 7	0	0
Total capacity with existing Potrero plant	1486	1610
Total capacity without existing Potrero plant	1123	1247

* Capacity projections for each resource are City staff draft projections. The sum of these projections exceeds projected peak SF demand projections, even demand projections that do not reflect maximum practical conservation, efficiency, and load shifting. The Hunters Point plant can close without any expansion of the Potrero plant.

** Not available in the City staff's March 2002 draft Plan. The City's next draft of the Plan, to be presented to the Board of Supervisors, should include projections reflecting the maximum practical load shifting in San Francisco.

The City and County of San Francisco has mandated that fossil fuel generation should be minimized (Ordinance No. 86-04). The Power Plant Ordinance requires plans for "all practical transmission, conservation, efficiency, and renewable alternatives to fossil fuel generation in the City and County of San Francisco."

B.3 GAS FIRED TURBINE COGENERATION OR COMBINED CYCLE UNIT

B.3.1 BAAQMD BACT Determination

The following BACT determination has been made for combined cycle gas turbines greater than or equal to 2.0 MW but less than 40 MW:

POLLUTANT	BACT	TYPICAL TECHNOLOGY
Precursor Organic Compound (POC)	1. No determination 2. 2.0 ppmv, Dry @ 15%O_2	1. No determination 2. Oxidation Catalyst
Nitrogen Oxides (NOx)	1. 2.5 ppmv, Dry @ 15%O_2 (achieved in practice for >12 MW) 2. 5.0 ppmv, Dry @ 15%O_2	1. SCR + Water or Steam Injection; or SCONOx 2. SCR + Water or Steam Injection
Sulfur Dioxide (SO_2)	1. Natural Gas Fuel 2. Natural Gas Fuel	1. Fuel Selection 2. Fuel Selection
Carbon Monoxide (CO)	1. No determination 2. 6.0 ppmv, Dry @15% O_2	1. No determination 2. Oxidation Catalyst
Particulate Matter (PM_{10})	1. Natural Gas Fuel 2. Natural Gas Fuel	1. Fuel Selection 2. Fuel Selection
Non-Precursor Organic Compound (NPOC)	1. Not applicable 2. Not applicable	1. Not applicable 2. Not applicable

1. Technologically Feasible/ Cost Effective
2. Achieved in Practice

And the following BACT determination has been made for combined cycle gas turbines greater than or equal to 40 MW:

POLLUTANT	BACT	TYPICAL TECHNOLOGY
Precursor Organic Compound (POC)	1. No determination 2. 2.0 ppm, Dry @ 15%O_2	1. No determination 2. Oxidation Catalyst, or Efficient Dry Low-NOx Combustors [a,b,e,f,i]
Nitrogen Oxides (NOx)	1. 2.0 ppm, Dry @ 15% O_2 2. 2.5 ppm, Dry @ 15% O_2 (2.0 ppm achieved in practice for 50 MW LM6000 combined cycle unit.)	1. SCR+ Low NOx Combustors, or Water or Steam Injection, or a SCONOX System 2. SCR+ Dry Low-NOx Combustors
Sulfur Dioxide (SO_2)	1. No determination 2. Natural Gas Fuel (sulfur content not to exceed 1.0 grain/100 scf)	1. No determination 2. Exclusive use of PUC-regulated grade natural gas
Carbon Monoxide (CO)	1. No determination 2. 4.0 ppm, Dry @15% O_2 [g,i]	1. No determination 2. Oxidation Catalyst
Particulate Matter (PM_{10})	1. No determination 2. Natural Gas Fuel (sulfur content not to exceed 1.0 grain/100 scf)	1. No determination 2. Exclusive use of PUC-regulated grade natural gas
Non-Precursor Organic Compound (NPOC)	1. Not applicable 2. Not applicable	1. Not applicable 2. Not applicable

1. Technologically Feasible/ Cost Effective
2. Achieved in Practice

B.4 GAS FIRED TURBINE COGENERATION OR COMBINED CYCLE UNIT

B.4.1 BAAQMD BACT Determination

The following BACT determination has been made for simple cycle gas turbines less than 2.0 MW:

POLLUTANT	BACT	TYPICAL TECHNOLOGY
Precursor Organic Compound (POC)	1. No determination 2. 5.0 ppmv, Dry @ 15%O_2	1. No determination 2. Catalytic Combustor
Nitrogen Oxides (NOx)	1. 5.0 ppmv, Dry @ 15% O_2 2. 9.0 ppmv, Dry @ 15%O_2	1. Catalytic Combustor, or High-Temperature SCR + Combustion Modifications 2. Combustion Modifications (e.g. dry low-NOx combustors)
Sulfur Dioxide (SO_2)	1. Natural Gas Fuel 2. Natural Gas Fuel	1. Fuel Selection 2. Fuel Selection
Carbon Monoxide (CO)	1. No determination 2. 10 ppmv, Dry @15% O_2	1. No determination 2. Catalytic Combustor

POLLUTANT	BACT	TYPICAL TECHNOLOGY
Particulate Matter (PM_{10})	1. Natural Gas Fuel 2. Natural Gas Fuel	1. Fuel Selection 2. Fuel Selection
Non-Precursor Organic Compound (NPOC)	1. Not applicable 2. Not applicable	1. Not applicable 2. Not applicable

1. Technologically Feasible/ Cost Effective
2. Achieved in Practice

And, the following BACT determination has been made for simple cycle gas turbines greater than or equal to 2.0 MW but less than 40 MW:

POLLUTANT	BACT	TYPICAL TECHNOLOGY
Precursor Organic Compound (POC)	1. 2.0 ppmv, Dry @ 15%O_2 [a] 2. 2.0 ppmv, Dry @ 15%O_2 [b]	1. Oxidation Catalyst 2. Oxidation Catalyst
Nitrogen Oxides (NOx)	1. < 5.0 ppmv, Dry @ 15%O_2 2. 5.0 ppmv, Dry @ 15%O_2	1. Dry Low NOx Combustor and High Temperature SCR 2. High Temperature SCR + Water or Steam Injection
Sulfur Dioxide (SO_2)	1. Natural Gas Fuel 2. Natural Gas Fuel	1. Fuel Selection 2. Fuel Selection
Carbon Monoxide (CO)	1. 6.0 ppmv, Dry @ 15%O_2 2. 10 ppmv, Dry @15% O_2	1. Oxidation Catalyst 2. Oxidation Catalyst
Particulate Matter (PM_{10})	1. Natural Gas Fuel 2. Natural Gas Fuel	1. Fuel Selection 2. Fuel Selection
Non-Precursor Organic Compound (NPOC)	1. Not applicable 2. Not applicable	1. Not applicable 2. Not applicable

1. Technologically Feasible/ Cost Effective
2. Achieved in Practice

And finally, the following BACT determination has been made for simple cycle gas turbines greater than or equal to 40 MW:

POLLUTANT	BACT	TYPICAL TECHNOLOGY
Precursor Organic Compound (POC)	1. No determination 2. 2.0 ppmv, Dry @ 15%O_2	1. No determination 2. Oxidation Catalyst
Nitrogen Oxides (NOx)	1. No determination 2. 2.5 ppmv, Dry @ 15%O_2	1. No determination 2. High Temperature SCR + Water or Steam Injection
Sulfur Dioxide (SO_2)	1. Natural Gas Fuel 2. Natural Gas Fuel	1. Exclusive use of CPUC-regulated grade natural gas 2. Exclusive use of CPUC-regulated grade natural gas
Carbon Monoxide (CO)	1. No determiantion 2. 6.0 ppmv, Dry @15% O_2	1. No determination 2. Oxidation Catalyst

POLLUTANT	BACT	TYPICAL TECHNOLOGY
Particulate Matter (PM$_{10}$)	1. Natural Gas Fuel 2. Natural Gas Fuel	1. Exclusive use of CPUC-regulated grade natural gas 2. Exclusive use of CPUC-regulated grade natural gas
Non-Precursor Organic Compound (NPOC)	1. Not applicable 2. Not applicable	1. Not applicable 2. Not applicable

1. Technologically Feasible/ Cost Effective
2. Achieved in Practice

As can be seen above the implementation of BACT technologies includes the selection of fuels for the turbines.

B.5 CEMENT MANUFACTURE

B.5.1 BAAQMD BACT Determination

The BAAQMD has determined the follow as BACT for cement kilns:

POLLUTANT	BACT	TYPICAL TECHNOLOGY
Precursor Organic Compound (POC)	1. No determination 2. No determination	1. No determination 2. No determination
Nitrogen Oxides (NOx)	1. 0.9 lb NO$_x$/ton clinker produced 2. 1.8 lb NO$_x$/ton clinker produced	1. Precalciner/Kiln System w/ Combustion Modifications + Low NO$_x$ Burner + Cyanuric Acid Injection 2. Precalciner/Kiln System w/ Combustion Modifications + Low NO$_x$ Burner
Sulfur Dioxide (SO$_2$)	1. No determination 2. Not selected	1. No determination 2. In Situ Limestone Capture
Carbon Monoxide (CO)	1. No determination 2. No determination	1. No determination 2. No determination
Particulate Matter (PM$_{10}$)	1. $\leq$0.006 gr/dscf 2. $\leq$0.01 gr/dscf	1. Baghouse 2. Baghouse
Non-Precursor Organic Compound (NPOC)	1. Not applicable 2. Not applicable	1. Not applicable 2. Not applicable

1. Technologically Feasible/ Cost Effective
2. Achieved in Practice

B.6 LANDFILL GAS RECOVERY

B.6.1 BAAQMD BACT Determination, NSPS and NESHAP

The BAAQMD has determination that the BACT for landfill gas gathering is horizontal and vertical gas collection lines vented to internal combustion (IC) engine or enclosed flare. This may include a BAAQMD approved design and operation. As shown in the above table, landfill gas recovery is a routine operation in the Bay Area.

The agency has further determined that BACT for a flare on a landfill gas collection system is as follows:

POLLUTANT	BACT	TYPICAL TECHNOLOGY
Precursor Organic Compound (POC)	1. No determination 2. Ground level, enclosed, >0.6 sec. retention time at >1400°F, auto combustion air control, automatic shut-off gas valve and automatic re-start system	1. No determination 2. BAAQMD approved design and operation
Nitrogen Oxides (NOx)	1. <0.06 lb/MMBtu 2. 0.06 lb/MMBtu	1. Not specified 2. Not specified
Sulfur Dioxide (SO_2)	1. Scrubbing and/or carbon adsorption for hydrogen sulfide removal 2. No determination	1. BAAQMD approved design and operation 2. No determination
Carbon Monoxide (CO_	1. No determination 2. Same as for POC above [b]	1. Not applicable 2. BAAQMD approved design and operation
Particulate Matter (PM_{10})	1. Not selected 2. Not selected	1. Fuel Gas Filter 2. Knockout Vessel
Non-Precursor Organic Compound (NPOC)	1. Not applicable 2. Not applicable	1. Not applicable 2. Not applicable

1. Technologically Feasible/ Cost Effective
2. Achieved in Practice

[NSPS for Landfills]

[NESHAP for Landfills]

The BAAQMD made the following BACT determination based on information in the memorandum entitled *"BACT Guideline for the Vasco Road Sanitary Landfill's Proposed Gas*

Turbine (Application #19620, Plant #5095)" dated 6/17/99 from B. Young to W. deBoisblanc, Director of Permit Services:

POLLUTANT	BACT	TYPICAL TECHNOLOGY
Precursor Organic Compound (POC)	No determination	Not applicable
Nitrogen Oxides (NOx)	25 ppmv @15% O_2	Water or steam injection, or low-NOx turbine design
Sulfur Dioxide (SO_2)	150 ppmv sulfur limit as H_2S	Fuel Selection
Carbon Monoxide (CO)	200 ppmv @15% O_2	Good Combustion Practice
Particulate Matter (PM_{10})	Fuel Gas Pretreatment	Strainer, filter, gas/liquid separator, or equivalent particulate removal device
Non-Precursor Organic Compound (NPOC)	No determination	Not applicable

The BACT determination was based on those technologies that were currently achieved in practice.

Another option for the IC engines is termed “Silent Camp” as coined by ERDC-CERL researchers to describe a system concept whereby a diesel generator is coupled with an electrolyzer, hydrogen storage system, and fuel cell to form an integrated package to silently power loads. If the diesel generators are lightly loaded, the efficiency of the generators is very low. By feeding excess power from the generators to an electrolyzer, the generators run at higher efficiency with improved operation (less maintenance). The electrolyzer in turn splits water into hydrogen and oxygen, and the hydrogen can be stored and utilized in a fuel cell to power loads. The “Silent Camp” concept has been endorsed by the military, who deploy 750 kW and larger generators in the field.

The BAAQMD made the following BACT determination for landfill gas recovery systems with IC engines (>250 HP output):

POLLUTANT	BACT	TYPICAL TECHNOLOGY
Precursor Organic Compound (POC)	1. 0.6 g/bhp-hr 2. 1.0 g/bhp-hr	1. Not specified 2. Lean burn technology

POLLUTANT	BACT	TYPICAL TECHNOLOGY
Nitrogen Oxides (NOx)	1. 1.0 g/bhp-hr 2. 1.25 g/bhp-hr	1. Not specified 2. Lean burn technology
Sulfur Dioxide (SO_2)	1. Not specified 2. 0.3 g/bhp-hr	1. Fuel gas treatment w/ $\geq$80% H_2S Removal 2. Addition of iron salts to digester sludge to remove H_2S
Carbon Monoxide (CO)	1. 2.1 g/bhp-hr 2. 2.65 g/bhp-hr	1. Not specified 2. Lean burn technology
Particualte Matter (PM_{10})	1. No determination 2. Not specified	1. Not specified 2. Lean gas pretreatment[a]
Non-Precursor Organic Compound (NPOC)	1. Not applicable 2. Not applicable	1. Not applicable 2. Not applicabe

1. Technologically Feasible/ Cost Effective
2. Achieved in Practice

The BACT determination was based on those technologies that were either considered technologically feasible/cost effective or were achieved in practice.

B.6.2 Landfill Gas Recovery in Gas Turbines

The BAAQMD made the following BACT determination based on information in the memorandum entitled *"BACT Guideline for the Vasco Road Sanitary Landfill's Proposed Gas Turbine (Application #19620, Plant #5095)"* dated 6/17/99 from B. Young to W. deBoisblanc, Director of Permit Services:

POLLUTANT	BACT	TYPICAL TECHNOLOGY
Precursor Organic Compound (POC)	No determination	Not applicable
Nitrogen Oxides (NO_x)	25 ppmv @15% O_2	Water or steam injection, or low-NOx turbine design
Sulfur Dioxide (SO_2)	150 ppmv sulfur limit as H_2S	Fuel Selection
Carbon Monoxide (CO)	200 ppmv @15% O_2	Good Combustion Practice
Particulate Matter (PM_{10})	Fuel Gas Pretreatment	Strainer, filter, gas/liquid separator, or equivalent particulate removal device

POLLUTANT	BACT	TYPICAL TECHNOLOGY
Non-Precursor Organic Compound (NPOC)	No determination	Not applicable

The BACT determination was based on those technologies that were currently achieved in practice.

B.7 DIGESTER GAS WITH FLARING

B.7.1 BAAQMD BACT Determination

The agency has determined that BACT for a flare on a digester gas collection system is as follows:

POLLUTANT	BACT	TYPICAL TECHNOLOGY
Precursor Organic Compound (POC)	1. No determination 2. Ground level, enclosed, $\geq$0.6 sec. retention time at $\geq 1400^{o}$F, auto combustion air control, automatic shut-off gas valve and automatic re-start system	1. No determination 2. BAAQMD approved design and operation
Nitrogen Oxides (NOx)	1. $\leq$0.06 lb/MMBtu 2. 0.06 lb/MMBtu	1. Not specified 2. Not specified
Sulfur Dioxide (SO_2)	1. Scrubbing and/or carbon adsorption for hydrogen sulfide removal 2. No determination	1. BAAQMD approved design and operation 2. No determination
Carbon Monoxide (CO)	1. No determination 2. Same as for POC above [b]	1. Not applicable 2. BAAQMD approved design and operation
Particulate Matter (PM_{10})	1. Not specified 2. Not specified	1. Fuel Gas Filter 2. Knockout Vessel
Non-Precursor Organic Compound (NPOC)	1. Not applicable 2. Not applicable	1. Not applicable 2. Not applicable

1. Technologically Feasible/ Cost Effective

2. Achieved in Practice

The BAAQMD has made a determination that BACT for digester operation includes the collection and venting of gases to an internal combustion engine or boiler. In addition, digester gas should be treatment w/ >80% H_2S removal or the addition of iron salts to digester sludge to remove H_2S. Furthermore, the BAAQMD made the following BACT determination for digester gas recovery systems with IC engines (>250 HP output):

POLLUTANT	BACT	TYPICAL TECHNOLOGY
Precursor Organic Compound (POC)	1. 0.6 g/bhp-hr 2. 1.0 g/bhp-hr	1. Not specified 2. Lean burn technology
Nitrogen Oxides (NO_x)	1. 1.0 g/bhp-hr 2. 1.25 g/bhp-hr	1. Not specified 2. Lean burn technology
Sulfur Dioxide (SO_2)	1. None specified 2. 0.3 g/bhp-hr	1. Fuel gas treatment w/ $\geq$80% H_2S Removal 2. Addition of iron salts to digester sludge to remove H_2S
Carbon Monoxide (CO)	1. 2.1 g/bhp-hr 2. 2.65 g/bhp-hr	1. Not specified 2. Lean burn technology
Particulate Matter (PM_{10})	1. No determination 2. Not specified	1. Not specified 2. Lean gas pretreatment
Non-Precursor Organic Compound (NPOC)	1. Not applicable 2. Not applicable	1. Not applicable 2. Not applicable

1. Technologically Feasible/ Cost Effective
2. Achieved in Practice

The BACT determination was based on those technologies that were either considered technologically feasible/cost effective or were achieved in practice.

B.8 PROCESS REFINERY HEATERS

B.8.1 BAAQMD BACT Determination

The agency has determined that BACT for a **r**efinery process heater with natural or induced draft with an input heat capacity greater than or equal to 5 MMBtu/hr to less than 50 MMBtu/hr is as follows:

POLLUTANT	BACT	TYPICAL TECHNOLOGY
Precursor Organic Compound	1. No determination 2. Not specified	1. No determination 2. Good Combustion Practice

POLLUTANT	BACT	TYPICAL TECHNOLOGY
(POC)		
Nitrogen Oxides (NOx)	1. 10 ppmv @ 3% O_2 Dry 2. 25 ppmv @ 3% O_2 Dry	1. Selective Catalytic Reduction (SCR) + Low NO_x Burners 2. Low NO_x Burners; or Low NO_x Burners + Selective Non-Catalytic Reduction (SNCR)
Sulfur Dioxide (SO_2)	1. Natural Gas or Treated Refinery Gas Fuel w/ ≤50 ppmv Hydrogen Sulfide and ≤100 ppmv Total Reduced Sulfur 2. Natural Gas or Treated` Refinery Gas Fuel w/ ≤100 ppmv Total Reduced Sulfur	1. Fuel Selection 2. Fuel Selection
Carbon Monoxide (CO)	1. No determination 2. 50 ppmv @ 3% O_2 Dry	1. No determination 2. Good Combustion Practice
Particulate Matter (PM_{10})	1. No determination 2. Natural Gas or Treated Refinery Gas Fuel	1. No determination 2. Fuel Selection
Non-Precursor Organic Compound (NPOC)	1. Not applicable 2. Not applicable	1. Not applicable 2. Not applicable

1. Technologically Feasible/ Cost Effective

2. Achieved in Practice

And BACT for a **r**efinery process heater with forced draft with an input heat capacity greater than or equal to 5 MMBtu/hr to less than 50 MMBtu/hr is as follows:

POLLUTANT	BACT	TYPICAL TECHNOLOGY
Precursor Organic Compound (POC)	1. No determination 2. Not specified	1. No determination 2. Good Combustion Practice
Nitrogen Oxides (NOx)	1. 10 ppmv @ 3% O_2 Dry 2. 20 ppmv @ 3% O_2 Dry	1. Selective Catalytic Reduction (SCR) + Low NO_x Burners 2. Low NO_x Burners; + Flue Gas Recirculation; or Low NO_x Burners + Selective Non-Catalytic Reduction (SNCR); or Selective Catalytic Reduction(SCR)
Sulfur Dioxide (SO_2)	1. Natural Gas or Treated Refinery Gas Fuel w/ ≤50 ppmv Hydrogen Sulfide and ≤100 ppmv Total Reduced Sulfur 2. Natural Gas or Treated` Refinery Gas Fuel w/ ≤100 ppmv Total Reduced Sulfur	1. Fuel Selection 2. Fuel Selection
Carbon Monoxide (CO)	1. No determination 2. 50 ppmv @ 3% O_2 Dry	1. No determination 2.Good Combustion Practice
Particulate Matter (PM_{10})	1. No determination 2. Natural Gas or Treated Refinery Gas Fuel	1. No determination 2. Fuel Selection

POLLUTANT	BACT	TYPICAL TECHNOLOGY
Non-Precursor Organic Compound (NPOC)	1. Not applicable 2. Not applicable	1. Not applicable 2. Not applicable

1. Technologically Feasible/ Cost Effective

2. Achieved in Practice

And BACT for any **r**efinery process heater with an input heat capacity greater than or equal to 50 MMBtu/hr is as follows:

POLLUTANT	BACT	TYPICAL TECHNOLOGY
Precursor Organic Compound (POC)	1. No determination 2. Not specified	1. No determination 2. Good Combustion Practice
Nitrogen Oxides (NOx)	1. No determination 2.10 ppmv @ 3% O_2 Dry	1. No determination 2. Selective Catalytic Reduction (SCR) + Low NO_x Burners
Sulfur Dioxide (SO_2)	1. Natural Gas or Treated Refinery Gas Fuel w/ ≤50 ppmv Hydrogen Sulfide and ≤100 ppmv Total Reduced Sulfur[a] 2. Natural Gas or Treated` Refinery Gas Fuel w/ ≤100 ppmv Total Reduced Sulfur[a]	1. Fuel Selection 2. Fuel Selection[a]
Carbon Monoxide (CO)	1. No determination 2. 50 ppmv @ 3% O_2 Dry[a,f]	1. No determination 2. Good Combustion Practice in Conjunction w/ Selective Catalytic Reduction (SCR) System[a]
Particulate Matter (PM_{10})	1. No determination 2. Natural Gas or Treated Refinery Gas Fuel[a,b]	1. No determination 2.Fuel Selection[a,b]
Non-Precursor Organic Compound (NPOC)	1. Not applicable 2. Not applicable	1. Not applicable 2. Not applicable

1. Technologically Feasible/ Cost Effective

2. Achieved in Practice

B.9 FCCU CATALYST REGENERATION

B.9.1 BAAQMD BACT Determination

The BAAQMD has determined the follow as BACT for a fluidized catalytic cracking unit:

POLLUTANT	BACT	TYPICAL TECHNOLOGY
Precursor Organic Compound (POC)	1. Not determined 2. Waste heat boiler w/ >0.5 sec. retention time at >1600°F	1. Not determined 2. BAAQMD approved design and operation
Nitrogen Oxides (NOx)	1. No determination 2. No determination	1. No determination 2. No determination
Sulfur Dioxide (SO_2)	1. Not applicable 2. Not specified	1. No determination 2. FCCU Feed Desulfurization (Feed Hydrotreater) or $DeSO_x$ Catalyst (Additive to FCCU Catalyst)
Carbon Monoxide (CO)	1. Not determined 2. Waste heat boiler w/ >0.5 sec. retention time at >1600°F	1. Not applicable 2. BAAQMD approved design and operation
Particulate Matter (PM_{10})	1. No determination 2. Not specified	1. No determination 2. Multi-cyclone and Electrostatic Precipitator
Non-Precursor Organic Compound (NPOC)	1. Not applicable 2. Not applicable	1. Not applicable 2. Not applicable

1. Technologically Feasible/ Cost Effective

2. Achieved in Practice

And the following BACT determinations have been made for the CO boiler:

POLLUTANT	BACT	TYPICAL TECHNOLOGY
Precursor Organic Compound (POC)	1. Not determined 2. Not specified	1. Not determined 2. Minimum Furnace Gas bypassing + Good Combustion Practice
Nitrogen Oxides (NOx)	1. Not specified 2. 80 ppm @ 3% O_2, Dry	1. Selective Catalytic Reduction (SCR) + Flue Gas Recirculation + Technologies listed below 2. Low NOx Burners + Reduced Air Preheat + Natural Gas or Treated Refinery Gas as Supplemental Fuel
Sulfur Dioxide (SO_2)	1. Natural gas or Treated	1. Fuel Selection

POLLUTANT	BACT	TYPICAL TECHNOLOGY
	Refinery Gas Fuel w/ $\leq$50 ppm as H_2S as Supplemental Fuel 2. Natural gas or Treated Refinery Gas Fuel w/ $\leq$100 ppm as H_2S as Supplemental Fuel	2. Fuel Selection
Carbon Monoxide (CO)	1. No determination 2. 100 ppm @ 3% O_2, Dry[c]	1. Not determined 2. Minimum Furnace Gas Bypassing + Good Combustion Practice
Particulate Matter (PM_{10})	1. No determination 2. Not specified	1. No determination 2. Electrostatic Precipitator
Non-Precursor Organic Compound (NPOC)	1. Not applicable 2. Not applicable	1. Not applicable 2. Not applicable

1. Technologically Feasible/ Cost Effective

2. Achieved in Practice

B.10 PETROLEUM REFINERY FLEXICOKER

B.10.1 BAAQMD BACT Determination

And the following BACT determination has been made for the CO boiler associated with the flexicoker:

POLLUTANT	BACT	TYPICAL TECHNOLOGY
Precursor Organic Compound (POC)	1. No determination 2. Not specified	1. No determination 2. Minimum Furnace Gas bypassing + Good Combustion Practice
Nitrogen Oxides (NOx)	1. Not specified 2. 80 ppm @ 3% O_2, Dry	1. Selective Catalytic Reduction (SCR) + Flue Gas Recirculation + Technologies listed below 2. Low NOx Burners + Reduced Air Preheat + Natural Gas or Treated Refinery Gas as Supplemental Fuel
Sulfur Dioxide (SO_2)	1. Natural gas or Treated Refinery Gas Fuel w/ $\leq$50 ppm as H_2S as Supplemental Fuel 2. Natural gas or Treated Refinery Gas Fuel w/ $\leq$100 ppm as H_2S as Supplemental Fuel	1. Fuel Selection 2. Fuel Selection

POLLUTANT	BACT	TYPICAL TECHNOLOGY
Carbon Monoxide (CO)	1. No determination 2. 100 ppm @ 3% O_2, Dry	1. No determination 2. Minimum Furnace Gas Bypassing + Good Combustion Practice
Particulate Matter (PM_{10})	1. No determination 2. Not specified	1. No determinatin 2. Electrostatic Precipitator
Non-Precursor Organic Compound (NPOC)	1. Not applicable 2. Not applicable	1. Not applicable 2. Not applicable

1. Technologically Feasible/ Cost Effective

2. Achieved in Practice

B.11 AUTOMOBILE MANUFACTURING

B.11.1 BAAQMD BACT Determinations

The BAAQMD has determined BACT for paint spray booths and drying ovens used for the coating of motor vehicles in an assembly plant. The air rules of rmanually operated paint spray booths

- POC and NPOC: Coating w/ VOC content less than and transfer efficiency greater than that required by Reg. 8, Rule 13, and emissions controlled to overall capture/ destruction efficiency $\geq$60%[a,T]
- POC and NPOC: A BAAQMD approved collection system vented to carbon adsorber or afterburner

For a auto assembly line paint spray boothes with automatic spray zones, the BAAQMD air rules are:

- POC and NPOC: Coating w/ VOC content less than and transfer efficiency greater than that required by Reg. 8, Rule 13, and emissions controlled to overall capture/ destruction efficiency $\geq$60%
- POC and NPOC: Coating w/ VOC content and transfer efficiency complying w/ Reg. 8, Rule 13[a,T]
- POC and NPOC: A BAAQMD approved collection system vented to carbon adsorber or afterburner

- POC and NPOC: Low VOC Coatings and Solvents

In all cases particulate matter from the paint spray booths are to be controlled with dry filters or waterwash systems that are properly maintained.

The BACT determination for topcoat, primer, sealer or elpo ovens for the coating of motor vehicles are the same as the automatic paint spray booths.

B.12 COMMERCIAL AND INDUSTRIAL BOILERS

B.12.1 BAAQMD BACT Determinations

The BAAQMD has determined the following BACT for gas-fired industrial and commercial boilers:

For boilers from greater than or equal to 5 MM Btu/hr to less than 33.5 MM Btu/hr:

POLLUTANT	BACT	TYPICAL TECHNOLOGY
Precursor Organic Compound (POC)	1. No determination 2. Not specified	1. No determination 2. Good Combustion Practice
Nitrogen Oxides (NOx)	1. 20 ppmv @ 3% O_2 Dry 2. 20 ppmv @ 3% O_2 Dry, for Firetube Boilers 25 ppmv @ 3% O_2 Dry, for Watertube Boilers	1. Low NO_x Burners + Flue Gas Recirculation 2. Low NO_x Burners + Flue Gas Recirculation
Sulfur Dioxide (SO_2)	1. Natural Gas or Treated Refinery Gas Fuel w/ <u><</u>.50 ppmv Hydrogen Sulfide and <u><</u>100 ppmv Total Reduced Sulfur 2. Natural Gas or Treated Refinery Gas Fuel w/ <u><</u>100 ppmv Total Reduced Sulfur	1. Fuel Selection 2. Fuel Selection[c]
Carbon Monoxide (CO)	1. 50 ppmv @ 3% O_2 Dry 2. 50 ppmv @ 3% O_2 Dry, for Firetube Boilers[f] 100 ppmv @ 3% O_2 Dry, for Watertube Boilers	1. Good Combustion Practice 2. Good Combustion Practice
Particulate Matter (PM_{10})	1. No determination 2. Natural Gas or Treated Refinery Gas Fuel	1. No determination 2. Fuel Selection
Non-Precursor Organic Compound (NPOC)	1. Not applicable 2. Not applicable	1. Not applicable 2. Not applicable

1. Technologically Feasible/ Cost Effective
2. Achieved in Practice