Energy Research and Development Division
FINAL PROJECT REPORT

MICROTURBINE-BASED CHP FOR THERMAL OXIDIZERS

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PREFACE

The California Energy Commission Energy Research and Development Division supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

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This report *Microturbine Based Combined Heat and Power for Thermal Oxidizers* is the final report for the project Microturbine-Based CHP for Thermal Oxidizers (Energy Commission Contract Number PIER-07-007) conducted by CMC-Engineering with assistance from Altex Technologies Corporations. The information from this project contributes to Energy Research and Development Division's Industrial/Agricultural/Water End Use Energy Efficiency program.

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ABSTRACT

The widespread application of small (less than 250 kilowatts) distributed generation systems in California depends on the availability of packaged combined heat and power systems that are low in cost, have low emissions, and are highly efficient. The market for these systems can be divided into two areas: (1) small- to medium-size industries that have high and constant thermal and power needs; and (2) commercial installations.

This project explored a novel installation of the recuperated microturbine package integrated with a thermal oxidizer. Thermal oxidizers are used in various design configurations to destroy volatile organic compounds at temperatures ranging from 800 to 1,800 degrees Fahrenheit emitted from more than 50 industrial processes. Thermal oxidizers are air pollution control devices and are considered as parasitic loads that do not add to the efficiency of the manufacturing processes. Waste heat can be recovered efficiently and at low cost by exhausting microturbines directly into industrial furnaces. The development of low-cost, clean, microturbine-based distributed generation integrated with large industrial burners addresses the industrial market for small-scale, process-integrated distributed generation.

This project demonstrated that energy could be produced with lower costs and lower air emissions by integrating a recuperated microturbine package with a thermal oxidizer. For California ratepayers, this translates into cost savings for utility bills and increased health benefits, along with lower healthcare costs due to decreased air pollution.

Keywords: Power generation, microturbines, microturbine generator, low exhaust emissions, combined heat and power (CHP), thermal oxidizer, regenerative thermal oxidizer, volatile organic compounds (VOC), incinerators

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The widespread application of small (less than 250 kilowatts) distributed generation (DG) systems in California depends on the availability of packaged combined heat and power (CHP) systems that are low in cost, have low emissions, and are highly efficient. The market for these systems can be divided into two areas: (1) small- to medium-size industries that have high and constant thermal and power needs; and (2) commercial installations.

Project Purpose

The primary goal of this project was demonstrating the application of a microturbine-based combined heat and power (CHP) technology with waste heat recovery in a thermal oxidizer. A thermal oxidizer (TO) is an industrial furnace designed to incinerate volatile organic compounds (VOCs) and hazardous air pollutants at high temperature. A microturbine is a compact gas turbine that provides shaft power to an asynchronous generator. A microturbine can typically generate up to 250 kilowatts (kW) of grid-quality power when interfaced with a power converter with an efficiency of about 30 percent when not in CHP configuration. Efficiency increases to 70 to 85 percent when the microturbine is in CHP mode. By exhausting microturbines directly into industrial furnaces and boilers, the waste heat is recovered very efficiently and at low cost.

The objectives of the project were:

- Identifying and securing a host site for demonstrating the microturbine-based CHP technology with a thermal oxidizer.
- Evaluating all design and operational aspects of the selected thermal oxidizer when operating in combination with the microturbine in a CHP configuration.
- Preparing all field drawings for the installation as they related to the final configuration of purchased microturbine equipment.
- Designing, developing, and testing a low-emission combustor to replace the existing microturbine combustor supplied by the microturbine's original equipment manufacturer (OEM). A low-emission combustor produces low nitrogen oxide (NOx) emissions.
- Securing all system components for preliminary assembly and readiness testing.
- Assembling the simple cycle microturbine, installing the equipment, and performing checkout tests in the field to fully commission the system.
- Performing field tests to document the system's efficiency and emissions and to confirm that the project's performance objectives were attained.

Project Results

The project team secured Momentive Specialty Chemicals in Fremont, California as the host site and finalized a field test agreement with them. They were willing to participate because of the economic benefits of inexpensive onsite distributed generation. They were also interested in recovering fuel energy combined with the incineration of a gaseous waste stream containing VOCs that would otherwise be hazardous to public health if released to the atmosphere.

The requirement to replace the combustor was based on the host site's emission compliance needs triggered automatically by modifications to existing equipment that would normally require no net increase in emissions. The host site also needed to meet 2007 California Air Resources Board (CARB) emission limits for CHP systems that require meeting 0.07 pounds per megawatt hour (lb/MWh) for NOx and and 0.7 lb/MWh for carbon monoxide (CO) under CHP conditions.

The host site required that original OEM- supplied equipment be installed for the CHP demonstration. Therefore, the developed combustor was ultimately not used as this would have voided the warranties on the OEM, and equipment requirements would have made it difficult to secure the host site's participation in the project. Instead, a newer upgraded combustor was installed to provide an added measure of emissions performance and reliability.

The microturbine was delivered to the host site after several additional upgrades. Installation drawings were prepared and the CHP assembly was commissioned in the field with full operational status. A test plan was drafted and field tests were conducted to document the energy efficiency of the CHP system and emissions before and after the CHP retrofit. These field tests demonstrated compliance with the Bay Area Air Quality Management District's emission limits and the attainment of energy efficiency objectives established for the project.

This design offered the following benefits:

- Reduced energy costs from operating the thermal oxidizers and lower air emission compliance costs for regulated industries.
- Lower maintenance and capital costs for waste treatment processes.
- Return on capital that offsets the investment for air pollution control equipment.
- Conventional benefits of onsite power and CHP, including a net reduction of carbon dioxide (CO_2) emissions due to associated energy efficiency gains and reduced power purchases.

Performance tests of microturbine-based CHP for thermal oxidizer furnaces demonstrated:

- VOC destruction in the CHP system greater than 99 percent.
- Overall power conversion efficiency of 95 percent.
- NOx and CO emissions in compliance with the CARB 2007 standards of 0.07 lb/MWh and 0.10 lb/MWh, respectively.
- Compliance with Bay Area Air Quality Management District permit conditions.

- CO_2 emission reductions of 75 lb/MWh compared with central power plants.

The market penetration for CHP integrated with TO furnaces in California is estimated at 10 to 15 MW. For each of the estimated 150 feasible installations in California, the generation of electricity can be accomplished with a net power conversion efficiency of 80 to 90 percent, resulting in fuel savings compared to a central station modern power plant with an efficiency of 45 percent. On a site-by-site basis, this could result in about 50 to 57 million British thermal units (Btu) per hour (MMBtu/hr) of natural gas savings or about 0.4 to 0.46 quadrillion Btu per year statewide. The annual savings to a host facility are estimated at $44,147 per year where CHP retrofit is feasible, which represents a significant reduction in the operating cost of these VOC air pollution control devices.

Project Benefits

The fuel savings that could be realized from installing facilities that integrate CHP and TO furnaces in California would help reduce emissions of nitrogen oxides, carbon monoxide, and volatile organic compounds. Reducing these hazardous air pollutants would improve air quality, reduce health effects from air pollution, and contribute to attaining California Air Resources Board objectives.

CHAPTER 1:
Introduction

1.1 Background

PIER has supported demonstrations of low-cost, clean microturbine-based distributed generation (DG) integrated with large industrial burners, as a way to address the industrial market for small-scale process-integrated combined heat and power (CHP). By exhausting microturbines directly into industrial furnaces and boilers, the waste heat is recovered very efficiently and at low cost. With this project, PIER has pursued a novel installation of microturbine integrated with a thermal oxidizer (TO). The project, proposed by CMC-Engineering, was awarded in 2008 and culminated with the installation of a CHP system at the host site. TOs and volatile organic compounds (VOC) recovery furnaces are used in more than fifty industries as air pollution control devices for destruction of VOCs and hazardous air pollutants (HAPs) in contaminated air and process tail gases. The use of CHP integrated with TO furnaces and HAPs incinerating boilers reduces the cost of operating these devices while providing the site with the benefits of lower cost onsite power generation. This demonstration of the microturbine CHP with TO will also broaden the visibility and acceptance of self-generation integrated with conventional industrial furnaces.

The attractiveness of selecting TOs as the thermal sink for this CHP can be summarized as follows:

- It reduces the energy cost of operating the TOs and thus significantly lowers air emission compliance cost for regulated industries.
- It lowers maintenance and capital costs for waste treatment processes that result in the release of VOCs.
- It provides industry with a return on capital that offsets the investment for air pollution control equipment.
- It provides the conventional benefits that come with onsite power and CHP, including a net reduction of CO_2 emissions due to associated energy efficiency gains and reduced power purchase.

1.2 Project Goals and Objectives

Table 1 summarizes the technical and performance goals of this project. The CHP system can boost overall conversion of microturbine fuel to useful energy (electricity + thermal) to a minimum of 92 percent (15 percent for the power generation plus 77 percent from the 90 percent recovery by the TO of the remaining 85 percent left in the exhaust). Emissions from the CHP assembly, measured at the stack of the TO furnace, would comply with local Air District emissions. If applicable, microturbine emissions would comply with California Air Resources Board (CARB) 2007 emission standards.

Table 1: CHP Technical and Performance Goals of Microturbine with TO

Parameter	Simple Cycle 100kWe MTG	1200 scfm TO	CHP	Facilitating Technologies
Efficiency (conversion to electricity for MTG and conversion to heat for TO)	15% HHV w/o CHP 92% w/CHP	90%	92%(1)	Conversion to electricity for MTG; Conversion to heat for TO; Conversion to combined power and heat for CHP-TO
Natural gas use, 1000 cft/hr	2.4	2.4	3.1	Onsite power generation is added at about 7,000 Btu/kWh
NOx emissions	0.343 lb/MWh	0.01 lb/MMBtu	0.01 lb/MMBtu	MTG NOx does not add noticeably to overall TO emissions. CHP credited emissions in compliance at 0.056 lb/MWh
CO emissions	18 lb/MWh	0.01 lb/MMBtu	0.01 lb/MMBtu	High CO emissions are burned in the TO. Overall CO emissions from TO remain unaffected

(1) TOs can have efficiencies exceeding 90% due to significant heat recovery by preheating VOC stream Source: CMC-Engineering

The specific objectives of this project were to:

- Secure agreements with the selected demonstration host facility and related air permits from the Air Permit Administrator to retrofit a simple cycle microturbine equipped with a low-NOx combustor on a TO furnace
- Engineer, design, fabricate and install a 100 kWe microturbine in a CHP configuration with the TO equipment and with the existing burner
- Demonstrate overall CHP efficiency in excess of 90 percent, exceeding the current efficiency of the TO while providing the site with revenue from reduced power purchase
- Demonstrate compliance with applicable Air District regulations and, with CARB 2007 emission standards
- Demonstrate added energy (fuel and electricity) savings in excess of 10 and 30 percent respectively associated with improved TO operation with microturbine waste heat recovery in the TO and savings in power usage

1.3 Project Approach

The approach followed by the project team was to first focus on securing a host site for the demonstration. This process was made lengthy and difficult by the fact that all facilities generally operate with only one TO furnace. Thus, any modifications to the furnace would require system shutdown causing interruptions in the manufacturing process. The project team was ultimately successful in securing a host facility at the Momentive Specialty Chemicals in Fremont, CA. Also, during the site search process, the team discovered that each site required a tailored approach to CHP retrofit, dictated by the type of TO furnace, type of VOC emissions treated, type of manufacturing process, access for placement of microturbine-TO system interface, and type of burner used in the TO furnace. While the search for a suitable site was ongoing, the project team addressed engineering designs for CHP systems on types of TOs; procured a microturbine, designed and fabricated a low NOx silo combustor, and performed various modifications and upgrades to the microturbine equipment for ultimate deployment to the selected site. A silo combustor is one that is located externally to the microturbine housing in contrast to a convention annular combustor that is located within the microturbine housing. Once the site was secured, installation drawings were prepared; final assembly of the microturbine took place at the laboratory prior to shipment to the site; additional assembly was performed at the site with some key activities performed by Momentive under match funds. Subsequently, the air emissions and operating permits were obtained and the installation of the CHP system was completed. Prior to testing, the microturbine operation was checked out and field commissioned as ready and functional. Operating instructions and a brief training in the operation of the microturbine and CHP was completed at the site prior to testing. Finally, performance tests were undertaken and CHP efficiency and emissions were measured according to developed and Energy Commission-approved test plan.

The following chapters describe the accomplishments achieved in each of the project tasks defined in the project Scope of Work.

CHAPTER 2:
Site Selection and Coordination Agreements

2.1 Goal and Objectives

The goal of this task was to secure all necessary signed agreements, schedules and field retrofit contracts with the demonstration host site, detailing roles and responsibilities of all parties involved. The agreement with the host site was to include provisions regarding ownership, rights, and liabilities relative to the microturbine package and all associated materials.

The specific objectives of this task included the following:

- Contact potential host sites, make onsite presentations of project
- Initiate discussions with the host site management and obtain needed engineering and layout data for site retrofit evaluation
- Draft field test agreement and move the process through evaluation and approval
- Perform engineering and economic analyses of proposed installation
- Perform all coordination tasks between CMC-Engineering, subcontractor, and equipment vendors

This chapter discusses the selected host site process and the final selection of Momentive Specialty Chemicals (also referred to as host site, Momentive, or MSC) as the demonstration site for the CHP for TO project.

2.2 Approach to Site Selection Process

The project team sought potential host sites in the South Coast and San Francisco Bay Area Air Quality Districts (SCAQMD and BAAQMD), focusing principally on the surface coating, electronics, waste water treatment, and chemical manufacturing industries. The project team sought participation from a total of nineteen sites before securing the final host site for the demonstration. The project team started with a list of potential candidates suggested by AHM Associates.

The initial focus was to locate a thermal oxidizer facility in Southern California to support the interests of the Southern California Gas Company, which provided match funds for the project. A total of nineteen companies were contacted, as listed below. The first six companies were located in Southern California. Out of these, CMC-Engineering visited only Steelscape, a manufacturer of steel coating coils. The other companies were visited by the AHM Associate representative based in Southern California. A total of three separate visits were made to Steelscape because the site expressed an interest in the project and a formal presentation was made, including a detailed site visit and proposal.

- Steelscape, Rancho Cucamonga

- Falcom Foam, Los Angeles
- American Racing Wheel, Rancho Dominguez
- Marko Foam, Los Angeles
- Interplastic Thermoset Resin Division, Hawthorne
- Erecycling, Paramount

Following the final decision by Steelscape not to participate in the project, the focus for site selection was switched to Northern California to facilitate more direct involvement by CMC-Engineering. Thirteen sites were contacted by telephone. These sites are listed below. Of these, sites visits were performed at Hitachi, Perkin Elmer, and Hexion Specialty Chemicals following an initial expression of interest. The project team finally reached an agreement with Hexion, now formally part of the Momentive Corporation, located in Fremont, CA.

- Hitachi Global Storage Technologies, San Jose
- Perkin Elmer - Optoelectronics, Santa Clara
- Hayward Waste Water Treatment Plant, Hayward
- City of Petaluma – Dept of Water Resources, Petaluma
- West County Wastewater District, Richmond
- City of Burlingame, Burlingame
- Wedemeyer Bakery, South San Francisco
- San Jose Mercury News, San Jose
- US Foam, Inc. , San Jose
- Hexion Specialty Chemicals, Fremont
- Stericycle, Inc. , San Leandro
- Beyer Health Care Pharmaceuticals, Emeryville
- Ball Metal Beverage Container Corp, Fairfield

The selection process indicated that the engineering approach of integrating a DG system in CHP configuration with a TO furnace , incinerator, or boiler would vary from site to site as the VOC treatment used were very site specific. Furthermore, the application of a novel CHP system with one of these VOC incinerating devices was seen as potentially risky to the manufacturing process, as these TO furnaces do not normally have backup equipment and are normally left running constantly preventing temporary shutdowns for CHP retrofit. In many cases, these risks were perceived to outweigh the potential energy saving benefits of onsite power generation at very low cost to the user coupled with significant incentives in the form of heavily subsidized capital investment.

In order to diminish the perception of risk and improve future host site participation in these PIER projects, it is recommended that PIER undertake a more segmented program focusing first on the commercial development of a new CHP technology and new applications. Once these technologies are fully developed on a commercial scale, they can be warranted and industry acceptance and field applications should become more readily attained. The commercial development of new technologies often requires key development stages that can clearly document the applicability, reliance, and benefits to the users prior to financial commitment by the host facilities.

2.3 Momentive Specialty Chemicals

The Momentive Specialty Chemicals in Fremont, California manufactures formaldehyde based resins that are used in the fabrication of plywood sheets. At the time of the initial contact, the plant was operating at 50 percent capacity due to the slump in the new housing market. Manufacturing of plywood resins involves the manufacturing of formaldehyde. As a consequence, formaldehyde and related chemicals are emitted from the distillation column where methanol is made to react with water over a steam heated catalyst to form formaldehyde. Along with the formaldehyde, hydrogen and VOCs are also generated. The combined waste stream (tail gas) is void of air and free of solid impurities (such as catalyst dust). The stream is at low <100 F temperature because the reaction temperature in the column is fairly low.

2.3.1 Description of Thermal Oxidizer Furnace

The site uses a Nebraska boiler rated at 800 Bohp (about 30 MMBtu/hr). The boiler normally operates at a peak firing rate of 22 MMBtu/hr producing all the steam needed by the plant. The boiler is fitted with one natural gas-fired burner and two specially designed tail gas burners. The boiler generates 125 psig to 150 psig steam that first passes through a bottoming cycle steam turbine to produce about 300 kW of power used within the plant. Low pressure steam leaves the steam turbine and is then used in the formaldehyde reactor. Tail gas from the reactor is incinerated in the Nebraska boiler accomplishing the destruction of VOCs present in the tail gas and recovering the heating value to produce steam with no added natural gas fuel needed

Natural gas for the boiler is used only for startup and to reach furnace operating temperatures conducive to the destruction of VOCs. The natural gas is then shut off and the burner firing is switched to tail gas only. The burners are specifically designed to operate solely with low heating value tail gas. The tail gas is produced in sufficient quantity to supply all the fuel required by the boiler. The Nebraska boiler is certified as an air pollution control device and is thus not subject to air emission regulation such as NOx or CO limits. As indicated in the Appendix, air permit regulations imposed by the BAAQMD for the retrofit of a microturbine-based CHP was based on new limits imposed on the TO furnace stack. These limits included NOx and CO that were not part of the operating permit prior to the installation of the CHP system.

Figure 1 shows the Nebraska boiler with the combustion air blower and boiler stack located on the left of the photo. Figure 2 shows the side of the building with the large combustion air blower on the right and the down pipe that sends the VOC laden tail gas to the boiler furnace for incineration and heat recovery.

Figure 1: Nebraska VOC Heat Recovery Boiler

View of Nebraska VOC Heat Recovery Boiler at Momentive Specialty Chemical in Fremont, California
Photo Credit: CMC-Engineering

Figure 2: Combustion Air Blower and VOC Supply Line to Nebraska Boiler

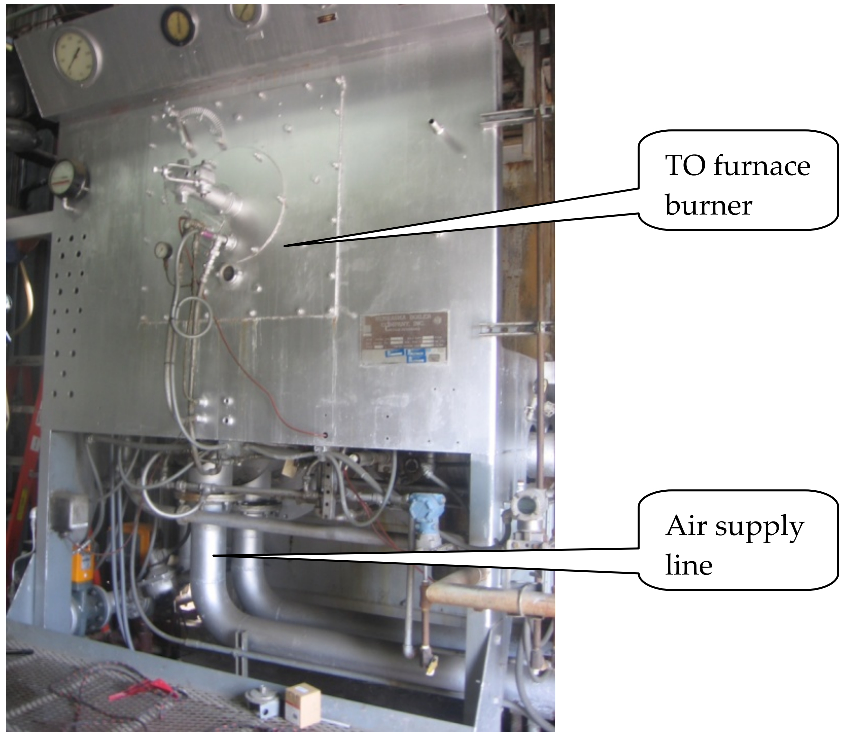
View of Combustion Air Blower and VOC Supply Line to Nebraska Boiler at Momentive Specialty Chemical in Fremont, California
Photo Credit: CMC-Engineering

Figure 3 illustrates the two combustion air pipes that supply air to two separate burners used for combustion of the tail gas. Behind the lower pipe, not visible, are the pipes that supply tail gas to the two tail gas burners. Figure 4 shows the lower air supply line and the VOC stream pipe to the furnace burners.

Figure 3: Burner Air Supply Line Inside Boiler Building

Burner Air Supply Lines Inside Boiler Building at Momentive Specialty Chemical in Fremont, California
Photo Credit: CMC-Engineering

Figure 4: Burner Front and Air and VOC Supply Lines



View of the Burner Front and Air and VOC
Supply Lines at Momentive Specialty Services
in Fremont, California
Photo Credit: CMC-Engineering

2.3.2 Volatile Organic Compounds Process Data

Table 2 shows the composition of the VOC tail gas stream, averaged from data obtained from laboratory analyses of two supplied samples. As indicated, the principal combustible component in the tail gas is hydrogen at nearly 23 percent concentration on a volumetric basis. This is followed by nearly 1 percent CO and lesser concentrations of methanol, methyformate and dimethyl maleate byproducts of the formaldehyde process. The calculated molecural weight of the gas is 22.76 lb/lbmole and its high heating value (HHV) is 1,566 Btu/lbm (85.9 Btu/scft), corresponding to a total heat input to the Nebraska furnace of 14.26 MMBtu/hr (HHV) or 12.17 MMBtu/hr of a low heating value basis (LHV). The total flowrate of the VOC laden tail gas can vary based on business conditions, but it was reported to CMC-Engineering at about 2,766 scft/min. Because of the low heating value of the stream, this would not be a suitable engine fuel as the gas compression work would be too excessive. Furthermore, since there is no oxygen in the tail gas, this stream could not provide the combustion air needed by the microturbine. Table 3 shows the calculations of the the combustion byproducts of this tail gas in the Nebraska furnace. The amount of oxygen needed to burn all the hydrogen and VOCs in the tail gas defines the amount of combustion air needed by the Nebraska furnace burner to incinerate all the VOC s and burn all the hydrogen. The 21,340 SCFH of oxygen requirements correspond to about 4,400 scfm of combustion air that is supplied by the combustion air blower shown in Figure 2.

2.3.3 Combined Heat and Power Application

The CHP options for this project were discussed with the Energy Commission review panel for the second CPR meeting/conference. During that meeting, CMC-Engineering explained that the microturbine selection and method of interface with the process will depend on the configuration of the site, access to the VOC burner, and the composition of the VOC stream. Because the VOC stream has a very low heating value with no oxygen content, and because the VOC components can create fouling of the microturbine compressor and combustor, the only available option was to run the microturbine on natural gas and recover the waste heat from the microturbine into the VOC incineration furnace. The waste heat from the microturbine would then serve to generate more steam for the process and reduce the quantity of supplemental natural gas that is occasionally used. This would give a CHP efficiency of greater than 80 percent, depending on the boiler efficiency. In addition, Momentive Specialty Chemicals also requires 90-140 F water to keep the feedstock from crystallizing and ensure easy pumping into the distillation column. Utilization of low temperature waste heat will increase efficiency of the CHP system to well above 90 percent.

Therefore, the project proposed installing a recuperated 100 kWe Elliott microturbine with waste heat recovery unit (HRU). The exhaust from the Elliott unit would then be ducted to the Nebraska furnace windbox for heat recover. The general configuration is as shown in Figure 5. This will reduce the amount of power used by the combustion air blower as the microturbine supplies 580 scfm or about 13 percent of the total air needs. The exhaust from the microturbine would be 580 F when the heat recovery unit (HRU) used to make hot water is bypassed. When hot water is needed by the site, the recuperated microturbine will be able to generate about 60 gpm of 140 F in addition to 190 F exhaust to the TO boiler furnace. The HRU cannot be fully bypassed without risking overheating the HRU. This is because some hot 580 F microturbine exhaust will leak into the HRU causing possible damage to the heat exchanger. Therefore, some heat recovery via the water circulation loop will always be necessary during CHP operation.

Table 2: Composition of VOC Stream

		VOC Stream Composition (%vol)						MMBtu/hr	
Composition		Sample no. 1	Sample no. 2	Avg	State	MW	lb/hr	HHV	LHV
Hydrogen	H2	22.65	22.97	0.228	gas	2	196.5	12.082	10.14
Oxygen	O2	0.06	0.23	0.001	gas	32	19.8	0.000	0.000
Carbon Monoxide	CO	1.18	0.94	0.011	gas	30	137.1	0.556	0.556
Carbon Dioxide	CO2	4.1	4.20	0.041	gas	44	89.5	0.000	0.000
Water	H2O	1.55	1.53	0.015	liq	18	119.4	0.000	0.000
Methanol	CH3OH	0.13	0.12	0.001	liq	32	17.2	0.168	0.149
Methylformate	C2H4O2	0.35	0.39	0.004	gas	60	95.4	1.300	1.185
Dymethyl Maleate	C6H8O4	0.04	0.01	0.000	liq	144	14.3	0.158	0.144
Balance Nitrogen	N2	69.94	69.62	0.698	gas	28	8415.5	0.000	0.000
	TOTAL			1.000			9104.67	14.26	12.17
	MW					22.76			
High Heating Value HHV (Btu/cft)				85.9	calculated				
Low Heating Value LHV (Btu/cft)				73.3	calculated				

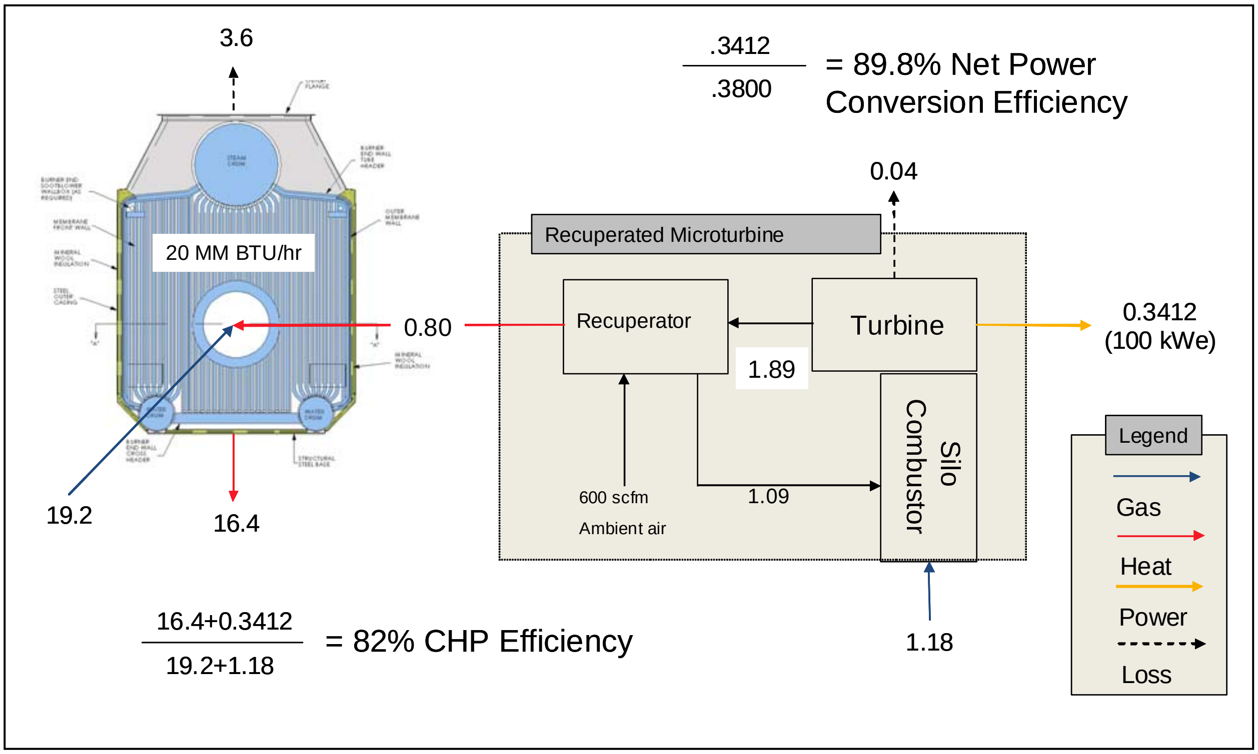
Source: CMC-Engineering

Table 3: Combustion Calculations of the VOC Stream in Nebraska VOC Recovery Boiler

		SCFH	O2	N2	Total		CO2	H2O	N2	TOTAL
VOC Waste Stream	H2	37,865	18,932	71,222	90,154			37,865	71,222	109,086
Composition	O2	238	(238)	(896)	(1,134)				(896)	(896)
	CO	1,761	880	3,312	4,193			1,761	4,193	5,953
	CO2	6,889		-	-		6,889			6,889
	H2O	2,556		-	-			2,556		2,556
	CH3OH	208	311	1,171	1,482		208	415	1,171	1,793
	C2H4O2	613	1,226	4,612	5,838		1,226	1,226	4,612	7,064
	C6H8O4	38	230	863	1,093		230	153	863	1,246
	Bal N2	115,833		115,833	115,833				115,833	115,833
	TOTAL	166,000	21,341	196,118	217,459		8,552	43,975	196,998	249,525

Source: CMC-Engineering

Figure 5: Configuration for CHP Application



Configuration for the CHP application at Momentive Specialty Chemicals located in a Fremont, California
Source: CMC-Engineering

CHAPTER 3:
Engineer and Design System

3.1 Goal and Objectives

The goal of the system engineering task was to evaluate the configuration, layout, and equipment for CHP applications on thermal oxidizers (TO). The specific objectives were to:

- Prepare a list of performance objectives in synch with the project goals and overall objectives as described in Table 1 and consistent with the operational attributes of the CHP system
- Perform an engineering analysis of the silo combustor design characteristics and operating requirements with the higher required firing rates associated with simple cycle microturbine configuration
- Analyze the NOx and CO performance impacts on the existing TO burner with preheated engine exhaust vitiated air requirements for upgrade
- Prepare a detailed system components, arts, and specifications
- Prepare a detailed configuration design of equipment to be fabricated and assembly drawings

3.2 Approach to System Engineering

The system engineering effort performed under this project was initiated prior to the final selection of the host site. Therefore, system engineering evaluated all possible configurations for CHP retrofit to the major types of TO furnaces and VOC-contaminated waste streams being treated. This required an analysis of the types of equipment used for TOs and selection of the applicable CHP assembly that would comply with key site specific factors that influence the selection of the type of microturbine and the configuration of the CHP system

The selection of the power generation equipment focused on the use of an Elliott TA-100 microturbine (now manufactured by Capstone Turbine Company). This project evaluated the use of the Elliott TA-100 microturbine in either its original recuperated configuration supplied by Elliott or in a simple cycle configuration with a modifications to the annular combustor to convert it to a lean premixed silo combustor. The lean premixed silo combustor was considered necessary to meet ultra low NOx emissions for compliance with CARB 2007 emission limits for CHP. The simple-cycle microturbines in CHP for TOs offers the advantages of lower cost compared to their recuperated counterparts and results in about double the amount of heat that can be utilized in the TO. This is beneficial to the operation of the TO, especially for larger, greater than 10,000 scfm recuperative or regenerative type TOs. However, the selection of the microturbine type, such as, recuperated or simple cycle, is as much influenced by the requirements of the host site and process conditions as by the need to meet ultra low emissions.

While searching for a host site, the project team also learned some important factors affecting the applicability of CHP system for TO, mostly regenerative or recuperative thermal oxidizers (RTOs). These key factors can be listed as follows:

1. the type of RTO, namely regenerative or recuperative affecting access to the burner and burner type;
2. the size of the RTO, namely the volume of VOC –contaminated air being processed;
3. the chemical and physical characteristics of the VOCs in the air stream; and
4. the typical operating duty of RTOs.

Consistent among all CHP option is the requirement to not increase the volume of VOC-contaminated air being treated by the RTO, as this would add to the fuel requirements and in-turn offset the benefits of the CHP installation. Since RTOs are essentially pollution control devices, their energy use and operating costs increase with increase in the volume of process gas that must be processed.

3.3 Impact of TO Furnace Type on CHP Application

Recuperative RTOs have the likelihood of operating with burners that can be more readily accessed. Furthermore, some are equipped with their own ambient air supply independent of the VOC-contaminated air stream being treated in the RTO. This type of RTO design permits the use of a microturbine that can draw ambient air for its operation without adding additional volume to the RTO. Ambient air intake for the microturbine is much preferred as microturbines are not very suitable to dirty or contaminated compressor air intake streams.

CHP applications on regenerative type RTOs do not have ready access to the burner area. This will preclude in most cases the use of a prepackaged microturbine-burner assembly of the type evaluated for industrial boilers. Furthermore, many of these RTOs use VOC-contaminated air within the RTO furnace to supply combustion air for the burner-injected fuel. Thus, these systems do not have independent ambient air for combustion of the fuel. Lack of easy access to the burners dictates that the microturbine generator has to be placed away from the burner and would thus be free standing. Also, the existing RTO burner would not need to be replaced. Alternatively, industrial boiler used to burn VOC-laden process gases can utilize either conventional recuperated microturbines or integrated simple cycle-burner assemblies that can replace existing boiler burners.

In order to prevent any increase in the total volume of air being treated by the RTO, these CHP systems must be able to utilize a slip stream from the incoming VOC-contaminated air for air intake to the microturbine. In this arrangement, a distinction had to be made between type and concentration of VOCs as not to interfere with the operation of the microturbine. Certain VOCs, such as aldehydes and resins from paint spray boots or silicate-chlorinated organic compounds from the semiconductor manufacturing operations, for example, would not be suitable for microturbine air intake unless the air stream is first scrubbed and filtered at considerable expense. Therefore, the analysis considered two types of CHP installations, one in which the VOC-contaminated air intake to the microturbine is suitable for microturbine operation and the other when potential erosion and deposits on the impeller blades of the air compressors would cause premature engine failure. In the latter case the microturbine has to operate with ambient air and heat recovery must then be accomplished with an air-air heat exchanger to be placed in the RTO inlet air duct.

The other site specific factors affecting the configuration of the CHP retrofit on an RTO are the volume throughput that the RTO processes and its duty cycle. RTOs come in several different sizes, each processing a given volume of VOC-contaminated air, because the thermal efficiencies of RTOs are mostly greater than 90 percent. These systems use small quantities of natural gas fuel to maintain operating temperatures in the RTO furnace. Operating temperatures can also vary between 1,200 and 1,800 F and are mostly in the 1,500 F range. Burner firing capacities can be as low as 4 MMBtu/hr for RTOs that process VOC-contaminated air throughputs as large as 20,000 scfm. Because the simple cycle microturbine utilizes 2.2 MMBtu/hr (LHV) and delivers 1.8 MMBtu/hr (LHV) to the RTO in a CHP configuration, it is important that the waste heat does not exceed the heat required by the RTO to maintain operating temperatures.

Momentive Specialty Chemicals, the host site, used a packaged, single burner, industrial water tube boiler that is fired entirely with process gas, following initial warm-up with natural gas, with a derated capacity of about 22 MMBtu/hr. As discussed in Chapter 2, the process tail gas contains about 24 percent hydrogen and small less than one percent concentration of VOCs from the production of resins in the manufacture of wood products. In this arrangement, the CHP options would include the use of a conventional recuperated microturbine operated with ambient air (as the process gas is not suitable for ingestion in the air compressor) and exhausting to the boiler windbox for waste heat recovery. The host site would be able to increase boiler steam output by approximately 2.5 percent as well as reduce combustion air blower power requirements. As indicated above, the CHP installation would also permit the utilization of some waste heat from the microturbine for co-production of hot water also used in the plant process, thus adding to the overall efficiency of the CHP configuration

Table 4 summarizes the supplemental firing rate of the RTO burner when a 100 kW simple-cycle microturbine is used for CHP applications on RTOs. These guidelines were developed based on a 90 percent efficient RTO for various operating volumes of VOC-contaminated air and varying concentrations of VOCs in the air used by the microturbine. As indicated, when the VOC-contaminated air volume treated by the RTO is less than 10,000 scfm, the waste heat delivered by the 100 kW microturbine equals or exceeds the heat required by the RTO burner. Without supplementary firing, the RTO would not be able to cycle in firing rate to accommodate varying amounts of VOCs directed from the process. Therefore, the most desirable applications for this type of CHP assembly should most likely target RTOs with a throughput capacity of 10,000 scfm or more and with VOC concentrations less than 50 ppm.

Table 4: Supplementary Firing for RTO Burner with 100 kW Simple Cycle Microturbine

VOC, ppm \ scfm	5,000	10,000	15,000	20,000
20	Only recuperated microturbine, less than 100 kW (for example, Capstone C-65)	0	1.0	1.84
50		0	0.84	1.72
100		Only recuperated microturbine	0.64	1.45
200			0.21	0.90

Source: CMC-Engineering

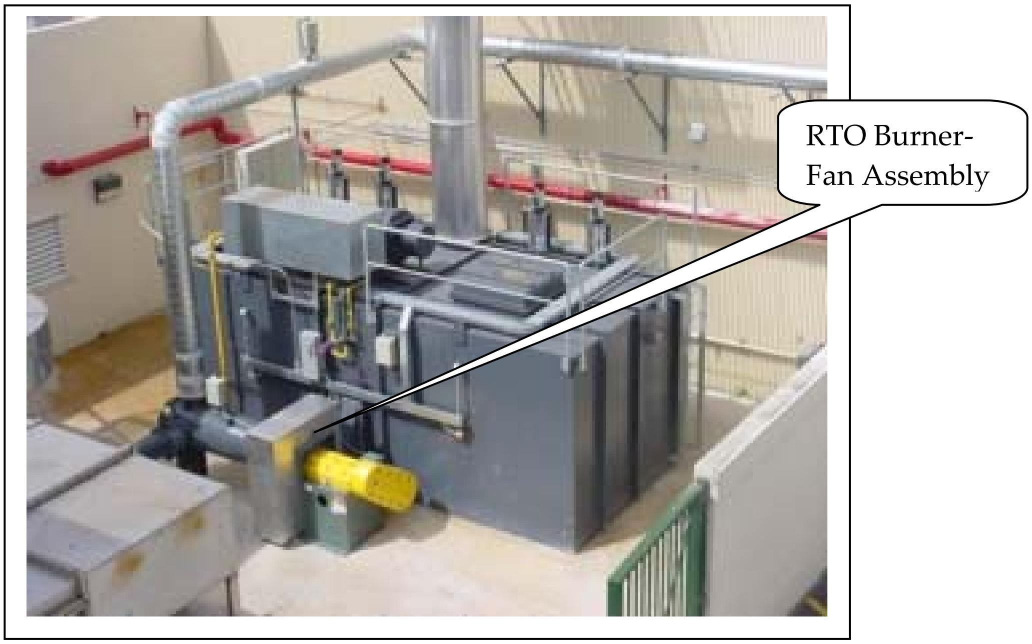
Finally, industrial manufacturing sites that generate VOC in their processes and thus operate VOC controls to comply with air permit regulations generally have only one RTO. These RTOs tend to operate round the clock, 24x7x365, to accommodate round the clock manufacturing. These units tend to stay on even when VOC are not being generated because shutting down these units would necessitate considerable amount of fuel to re-heat the furnace back to operating temperatures. These operating requirements tend to be challenging to bypass to allow the retrofit of the CHP system to the RTO.

In general, TOs consist of a system fan, motor, heat exchanger, modulating burner, fuel train, ceramic-lined reactor, fresh air start-up valves, system controls, temperature recorder, first-out shutdown detector and exhaust stack. The system has a weatherproof, ceramic-lined steel outer skin with access doors that allow service to all internal parts. Boilers include burners and combustion air blower. Heat transfer to the tubes takes place within the furnace to produce steam or hot water. Sections, 3.3.1 through 3.3.3, briefly describe the two main types of RTOs and boilers and how they can influence the engineering approach in the application of a microturbine for the efficient cogeneration of electrical power.

3.3.1 Recuperative Thermal Oxidizers

Recuperative thermal oxidizers, shown on the right side of Figure 6 typically use shell and tube heat exchangers made of metal to exchange heat between the exhaust of the oxidizer and the incoming inlet stream for preheating. This technology is typically implemented in applications where the inlet stream is at 25 percent of the lower explosion limit (LEL). Process gas with VOC contaminants enters the Twin Bed RTO through an inlet manifold. A flow control valve directs this gas into an energy recovery chamber, which preheats the process stream. The process gas and contaminants are progressively heated in the stoneware bed as they move toward the combustion chamber.

Figure 6: Recuperative RTO



Recuperative RTO with ready access to existing burner and fresh air-supply fan used at Electronic Manufacturing Plant
Photo Credit: Anquil Environmental Systems web site at http://www.anguil.com/prregthe.php.

The VOCs are then oxidized, releasing energy in the second stoneware bed. The stoneware bed is heated and the gas is cooled so that the outlet gas temperature is only slightly higher than the inlet temperature. The flow control valve switches and alternates the stoneware beds so each is in inlet and outlet mode. If the process gas contains enough VOCs, the energy released from their combustion allows self-sustained operation. For example, at 95 percent thermal energy recovery, the outlet temperature may be only 77° (25°) higher than the inlet process gas temperature. Programmable Logic Controller (PLC)-based electronics automatically control all aspects of the RTO operation from start-up to shutdown so that minimal operator interface is required.

An important design feature of the recuperative RTO is the location and operation of the existing burner. These burners are normally supplied with fresh air from outside rather than utilizing the process air for supporting fuel combustion. Figure 6 shows the available access to the burner and fan assembly on a recuperative type TO. Although the use of fresh air adds to the amount of air that must be treated in the thermal oxidizer, the high efficiency of these systems compensate for this with an overall minimal impact on operating cost. The availability of the burner with its fresh air supply is consistent with the use of a simple-cycle microturbine and burner assembly that can be used in place of the current burner in an application similar to that used under the Energy Commission project 500-03-037.

3.3.2 Regenerative Thermal Oxidizers

Regenerative thermal oxidizers also implement heat recovery to lower operating costs. They use ceramic heat exchanger media to achieve heat recovery efficiencies of 85 percent to 95 percent. These RTO types use at least two beds of ceramic media for heat recovery. One bed of ceramic media will be used as the outlet bed where heat will be deposited from the high temperature, oxidized gas stream prior to being exhausted to atmosphere. After 1 to 2 minutes, the system flow will switch direction and enter through the preheated ceramic bed that was previously used as the outlet. In this manner, the incoming gas stream is preheated minimizing or possibly eliminating any need for natural gas. The oxidized gas stream will exhaust through the ceramic bed that previously was used as the inlet. This cycle will occur continuously to achieve the high levels of heat recovery.

For CHP application, the type of burner and access conditions will influence the suitable engineering approach in the retrofit of the power generation equipment and choice of burner. Figure 7 and Figure 8 show photos of types of Regenerative RTOs. The burner air supply in these types of RTOs exclusively comes from the air available in the VOC-laden gas stream, therefore there is no external supply of fresh combustion air that would be most suitable for microturbine air intake. Furthermore, the burners are located in the middle of the furnace and have difficult access. For these types of RTOs, the engineering analysis specifies a free standing microturbine without replacement of the existing burner.

Figure 7: Large Regenerative Type RTO

Source: Photo Credit: Anquil Environmental Systems web site at http://www.anguil.com/prregthe.php.

Figure 8: Typical Location of Burner in Regenerative RTO

Source: Photo Credit: CMC-Engineering

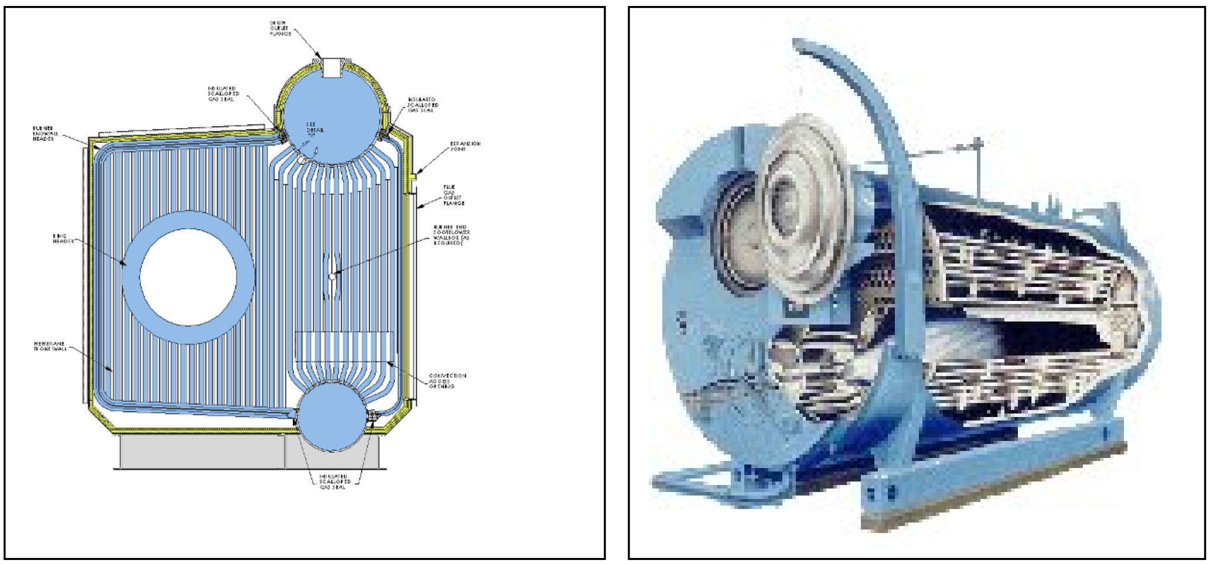
3.3.3 Steam Generators as Process Gas Incinerators

In the case of packaged boilers, such as single burner steam boilers illustrated in Figure 9, used to incinerate process gases containing VOCs, the CHP configuration would allow both simple-cycle and recuperated microturbine designs. The simple-cycle microturbine would be applicable to either stand alone or physically integrated with the boiler burner into one assembly. The standalone microturbine would also be in its conventional recuperated design, which would allow for lower natural gas consumption by the microturbine with lower power requirements for gas compression to the turbine operating pressure. Selection of the recuperated design has the advantage for plant operation in that it provides greater operating practice and thus acceptance by the management.

Finally, the engineering evaluation dealt with compliance with applicable emission regulations. These typically mean compliance with NOx and CO emissions as measured at the microturbine exhaust and at the TO or boiler stack. Emissions measured at the microturbine exhaust are the result of the combustion process that takes place in the microturbine combustor. Emissions at the TO stack are the combined contribution of emissions and emission controls that take place in the microturbine and in the TO furnace where additional fuel is combusted. For TO, however, the principal air permit regulation concerns the destruction efficiency of the VOCs present in the contaminated air being treated by the TO. As discussed later in the available options for a microturbine integrated with an RTO, VOC destruction can occur in the TO furnace alone, as is normally accomplished, or in both the microturbine and TO furnace.

Industrial boilers burning entirely process tail gas contaminated with VOCs are normally exempt from regulations concerning criteria pollutants such as NOx and CO emissions. This is the case for Momentive Specialty Chemicals, the selected host site for the demonstration, which uses a water tube boiler to recover the fuel value of tail gas while accomplishing VOC treatment as an air pollution control device. Because the boiler is categorized as an air pollution control device, it is exempt from NOx and CO emission limits normally applied to industrial steam boilers.

Figure 9: Water Tube and Fire Tube Boilers

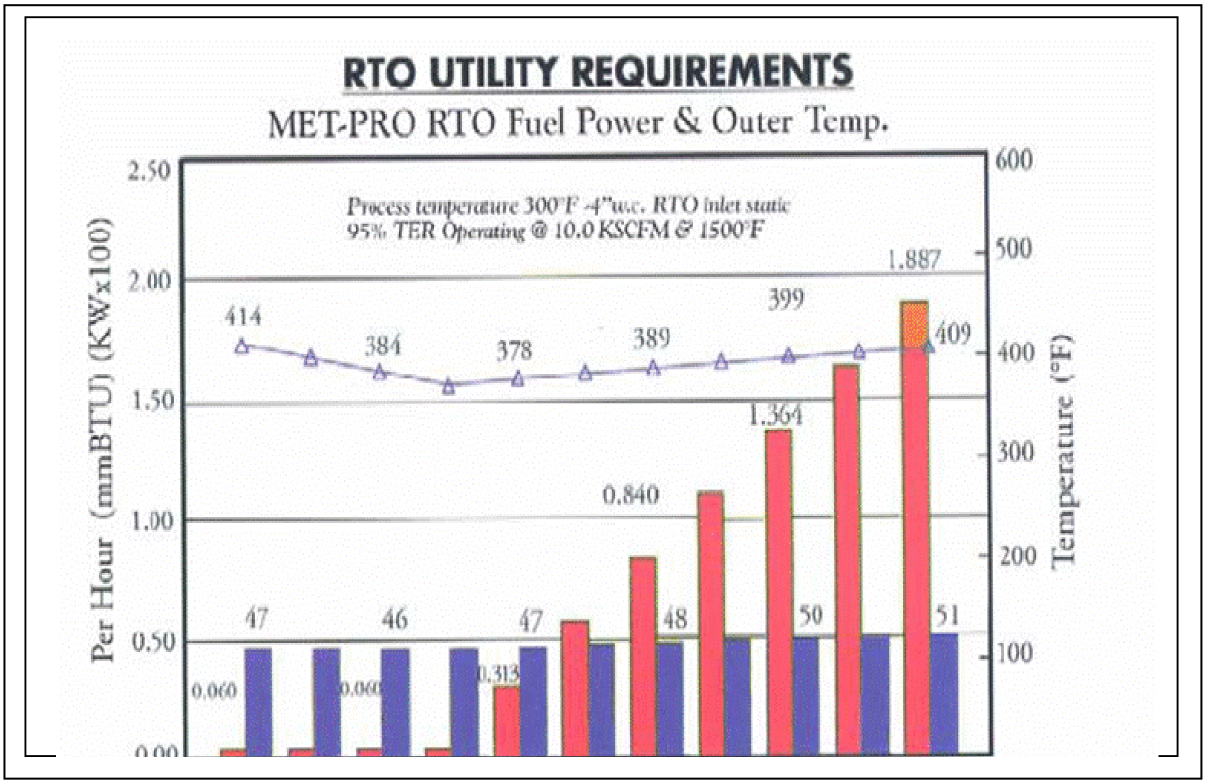


Water tube and fire tube boilers types also used for incinerating VOC-laden process gases
Source: CMC-Engineering

3.3.4 Effect of VOC Type and Quantity on CHP Applications

RTOs treat a variety of VOC streams depending on the industry, size of the plant, and a variety of process conditions. All these affect the type of CHP assembly that is most feasible and the operating conditions that are conducive to the performance goals established in the project. Figure 10 illustrates how the fuel and electricity consumption of an RTO that treats 10,000 scfm of VOC contaminated air to a temperature of 1,500 F would vary based on the concentration of VOC present in the air. A burn rate of about 50 lb/hr of benzene (C_6H_6) in 10,000 scfm corresponds approximately to 0.045 percent (450 ppm) concentration by volume. At these elevated concentrations, the amount of fuel required by the RTO to maintain operating temperature is only 0.85 MMBtu/hr. This firing rate is significantly lower than the 1.8 MMBtu/hr (LHV) heat available in the exhaust of a 100 kW simple cycle microturbine. Therefore, for these types of applications, a smaller recuperated microturbine would be more appropriate. When the VOC concentration is less than 50 ppm, or about 5 lb/hr, the heat required from the burner increases to about the heat available in the microturbine exhaust. Under these conditions, the microturbine would be able to provide all the fuel energy for the system and no additional burner would be necessary with the exception of a backup burner just in case the microturbine is down for maintenance or repair.

Figure 10: Fuel and Electricity Requirements as a Function of VOC Loading – VOC as Benzene



Source: Met-Pro CorporaTION, Indianapolis, IN

Typically, VOC concentrations are on the order of 0-100 ppm unless activated carbon is used upstream of the RTO to concentrated the VOC prior to incineration. Because VOCs are tied to the manufacturing processes, these concentrations can also vary over time. For example, in the semiconductor manufacturing process, that includes photolithography, VOC concentrations can be as low as zero for a period of several hours and then spike to a maximum ppm level of 50ppm. Table 5 lists the approximate firing rates of the RTO burner for different air flow rates and VOC concentration in the contaminated air. The data consider benzene as the VOC in the air stream. The Table shows that as much as 3.6 MMBtu firing rate is required for RTOs that treat 20,000 scfm. However, the firing rate is less than 1 MMBtu/hr when the treated air is 5,000 scfm.

Table 6 shows the amount of fuel required by an RTO when 100 kW CHP is used with a simple-cycle microturbine. As indicated, the simple cycle microturbine CHP is not applicable to RTOs that treat less than 10,000 scfm of VOC contaminated air, even with the lowest VOC concentration. This is because the burner requirements are well below the amount of waste heat in the turbine exhaust of the simple cycle microturbine. For these RTOs, only smaller recuperated microturbines, such as Capstone 65, are most suitable since their turbine exhaust contains less the 0.5 MMBtu/hr sensible heat. When the VOC concentration is greater than 100 ppm, simple-cycle CHP is applicable for contaminated air flow rates in excess of 10,000 scfm. The most optimum application for simple-cycle microturbines in CHP is for RTOs that treat 15,000 scfm or more VOC contaminated air.

Table 5: RTO Fuel Requirements with Varying VOC Concentration

VOC, ppm \ scfm	5,000	10,000	15,000	20,000
20	0.92	1.84	2.76	3.64
50	0.88	1.76	2.64	3.52
100	0.81	1.63	2.44	3.25
200	0.68	1.35	2.03	2.70

Source: CMC-Engineering

Table 6: Supplemental Burner Requirements for 100 kW Simple-Cycle Microturbine in CHP, MMBtu/hr

<table>
<tr><th>VOC, ppm \ scfm</th><th>5,000</th><th>10,000</th><th>15,000</th><th>20,000</th></tr>
<tr><td>20</td><td rowspan="4">Only recuperated microturbine
(for example, Capstone C-65)</td><td>0</td><td>1.0</td><td>1.84</td></tr>
<tr><td>50</td><td>0</td><td>0.84</td><td>1.72</td></tr>
<tr><td>100</td><td rowspan="2">Only recuperated microturbine</td><td>0.64</td><td>1.45</td></tr>
<tr><td>200</td><td>0.21</td><td>0.90</td></tr>
</table>

Source: CMC-Engineering

3.4 Engineering Analysis of Microturbine Combustor Design and Operation

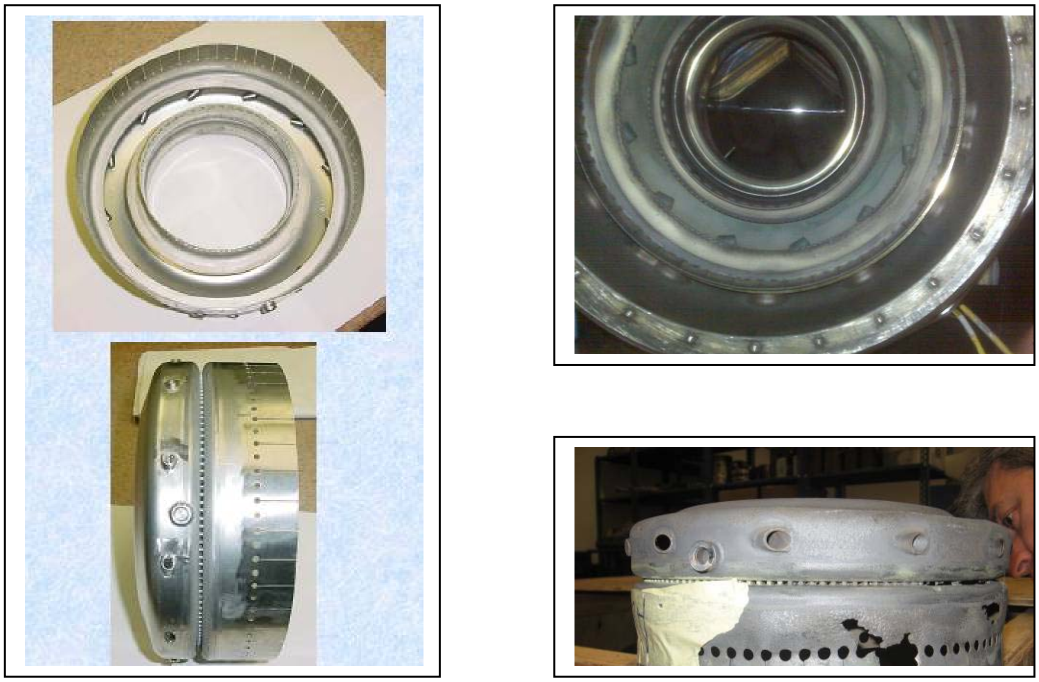
The engineering approach for the retrofit of a 100 kW Elliott microturbine to the RTO included the evaluation of three possible approaches based on the type of RTO or boiler furnace, its capacity, and the amount and type of VOC in the treated air. The three basic configurations of the CHP system are:

- Simple-cycle (unrecuperated) 100 kW Elliott microturbine integrated with RTO replacement burner with firing capacity of the original burner and turndown capacity to provide supplemental heat when in CHP operation
- Simple-cycle (unrecuperated) 100 kW microturbine free standing with exhaust integrated with the incoming air stream to the RTO to allow for RTO designs that do not provide easy access to TO burner.
- Recuperated 100 kW microturbine package free standing with exhaust ducted to RTO or boiler furnace with independent controls

The commercially available Elliott TA-100 microturbines come in recuperated design, offered by the new ownership of the company, Capstone Microturbines. Thus the project proceeded to procure a low-cost, used, 100 kW recuperated TA-100. Chapter 5 describes the purchased microturbine equipment, modifications made to that equipment, and fabrications of other equipment. With the purchased recuperate microturbine in the shop, the project evaluated modifications to the microturbine to convert the design to a simple cycle (unrecuperated) configuration and with a new low NOx silo combustor that would reduce emissions sufficiently to attain CARB 2007 levels. Although a similar approach was used by CMC-Engineering in a previous Energy Commission PIER project 500-03-037, these modifications were never done on a recuperated design. However, because the impact of CARB 2007 compliance and the requirements of the site process conditions and applicable CHP configuration, work was initiated on the development of a low NOx silo combustor and modified turbine housing for application on a simple cycle or recuperated microturbine.

All TA-100 incorporate an annular combustor shown in Figure 11. The combustor operates with a rich-burning first stage highlighted by the 18 fuel injectors, followed by the addition of the remaining combustion air through annular holes located immediately downstream of the first stage and slots at the trailing edge of the combustor. At lower firing rates, for power output of 80 kW, the combustor design operated successfully for the most part. However, at higher firing rates corresponding to 100 kW, the temperature in the combustor exceeded the Inconel steel temperature limits and many of the combustors failed as shown on the right of Figure 13, with catastrophic engine consequences.

Figure 11 Elliott TA-100 Annular Combustor



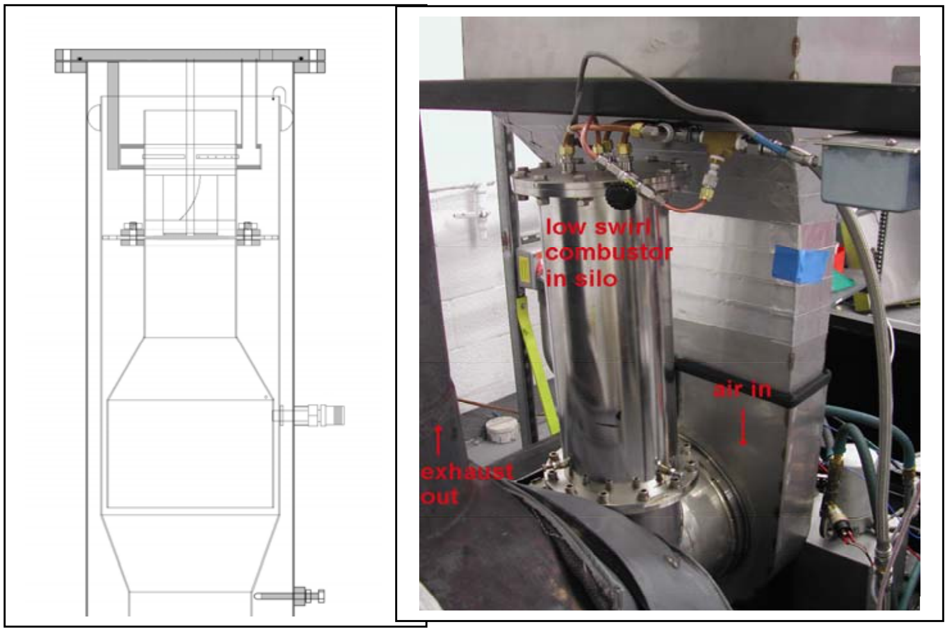
Photograph on the left in this figure shows an annular combustor used in an Elliott TA-100 annular combustor. Photographs on the right show failed combustor due to temperature exceeding limits.
Photo Credit: CMC-Engineering

Consequently, the use of the simple cycle microturbine would have to rely on the replacement of the annular combustor with a fully premixed lean combustor, in which the design was first implemented under Energy Commission project 500-03-037. Figure12 illustrates the schematic of the CMC-Engineering combustor and its implementation on a simple cycle microturbine. The retrofit of the silo combustor requires a new turbine housing, shown in Figure 13, and scroll section, drafted from the original combustor eliminating the duel combustion sections and the annular fuel injectors. Chapter 4 presents the development of a silo combustor for this project based on this experience. The following sections discuss the engineering analysis related to the design and operating conditions of the new combustor as it relates to the emission requirements and potential treatment of combustion air laden with VOCs.

3.4.1 Control of Criteria Emissions from the Microturbine

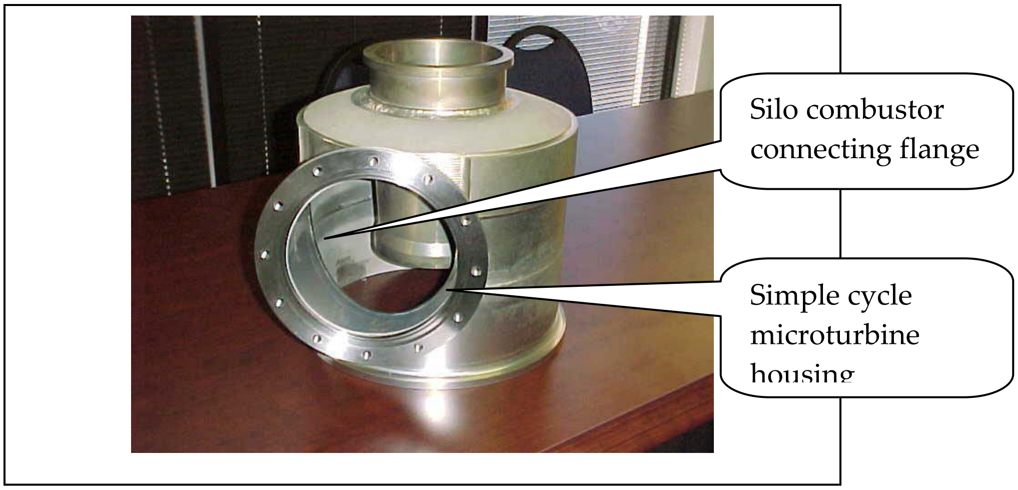
One of the design requirements for the new combustor is the ability to meet NOx and CO emission limits. Table 7 shows the emission targets for compliance with CARB 2007 CHP limits. Figure 14 shows that the TA 100 with an annular combustor exceeds these emissions. Therefore, the engineering analysis included evaluations of low NOx options for the microturbine based on prior experience attained under Energy Commission project 500-03-037.

Figure 12: Silo Combustor Configuration for Simple Cycle Elliott Microturbine



This figure illustrates the schematic of the combustor and its implementation on an Elliott 80 kW simple cycle microturbine.
Photo Credit: CMC-Engineering

Figure 13: Modified Turbine Housing



Modified turbine housing necessary for converting Elliott recuperated microturbine to simple cycle

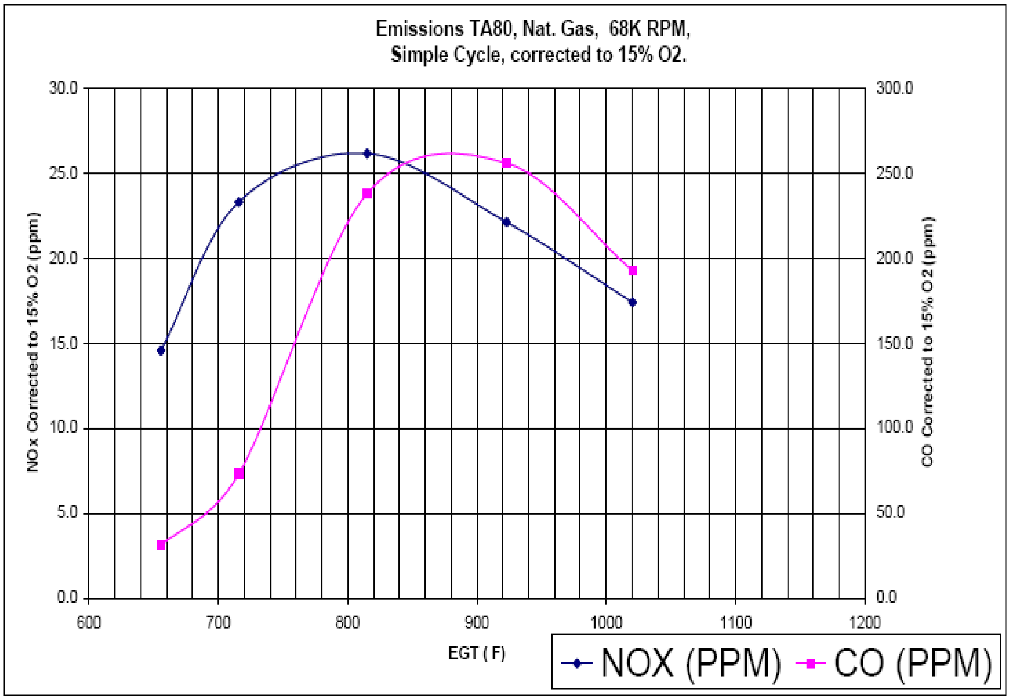
Photo Credit: CMC-Engineering

Figure 14: NOx and CO Emissions

Emission Test Data

Engine S/N: 00-J002-80
Date: 2005/7/26
Fuel Type: CNG
Speed: 68K Rpm
Liner # 800343A

Power (KW)	EGT Deg. (F)	O2 (%)	CO (PPM)	NOX (PPM)	CxHy %	NO/NO2	CO (PPM) Corrected to 15% O2	NOX (PPM) Corrected to 15% O2
0.5	655.7	17.9	16	7.5		6.6/0.8	31.1	14.6
20.8	716	17.4	43	13.7		12/1.7	73.1	23.3
40.5	815.3	16.9	162	17.8		16.5/1.1	238.1	26.2
60.6	923	16.3	199	17.2		16.5/0.5	255.8	22.1
75.7	1020.2	15.8	166	15		13.8/1.3	192.6	17.4



Data of NOx and CO Emissions from Elliott TA-100 Microturbine equipped with annular partial oxidation combustor
Source: Elliott Energy Systems (EES)

Table 7: CARB 2007 CHP Emission Limits

Emissions	Target Limit
NOx, ppm @ 15% O_2	4.33
CO, ppm @ 15% O_2	10.16
HC, ppm @ 15% O_2	3.55

Laboratory tests of the final silo combustor configuration show both NOx and CO levels are in compliance with CARB 2007
Source: CMC-Engineering

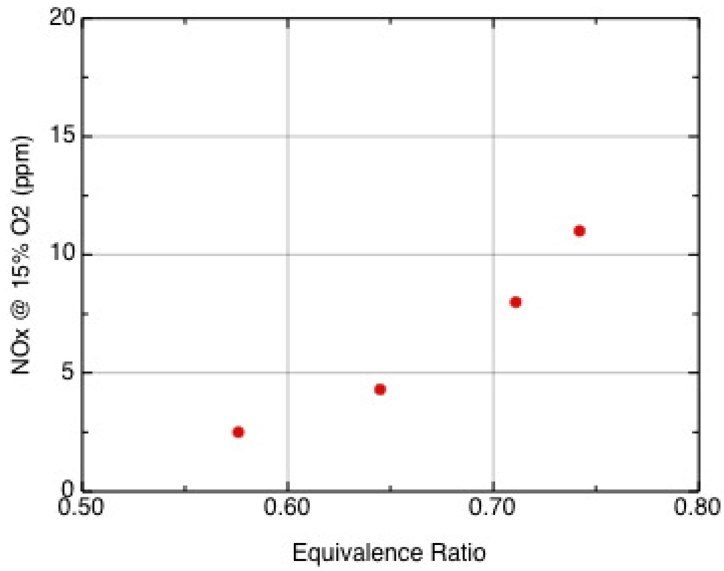
The level of NOx in the exhaust is function of the equivalence ratio (defined as the actual fuel /air ratio divided by the theoretical fuel-air ratio) in the primary combustion zone, fuel air mixing and residence time. The equivalence ratio is dictated by the target NO_x and CO emissions and combustion stability required at engine design load as well as during light-off and part loads. Figure 15 illustrates laboratory test results of NO_x versus equivalence ratio for the combustor. These data, which are representative of most fully premixed combustors, indicate that for a sub 5 ppm NO_x performance at full load the primary combustion zone would have to be at an equivalence ratio of less than 0.65 in each fuel burning zones in the combustor. Because of the ability to stabilize the flame at lower equivalence ratios with this design, the project team selected a design equivalence ratio of 0.58 which would indicate an expected NO_x performance of about 3 ppm corrected to 15 percent O_2. This level of NOx is sufficient to meet the CARB 2007 NOx emission limit of 0.07 lb/MWh, which translate to 4.33 ppm as indicated in Table 7 for the assembly considered for the RTO where overall CHP efficiency will exceed 90 percent.

The combustor would require a pilot gas line which would be able to supply a small quantity of the total fuel and support flame stability with some diffusion burning to address potential light-off and combustion stability at extreme lean conditions. Therefore, the function of the pilot fuel was to promote reliable and vibration-free light-off and combustion stability as engine part firing rate which occurs from light-off to full engine rating. At full firing rate, the combustor would have to operate without the pilot assistance to achieve lowest NOx potential. This is possible if combustion stability is achieved at maximum heat release rate without pilot.

Additional engineering and design work was performed on the microturbine combustor to increase its firing rate compatible with the 100 kW power output. For this power output, the firing rate in the combustor, for a simple cycle configuration, would have to be approximately 2.6 MMBtu/hr HHV (High Heating Value Basis). This compares to the 1.86 MMBtu/hr used for the silo combustor developed under the PIER project 500-03-037. In the case of a recuperated engine, the firing rate would actually be approximately 1.3 MMBtu/hr (about half of the simple cycle microturbine). However, because of the preheated compressed air, the increase in volumetric flow rate would require a larger combustor so that air velocities and pressure drop would remain within design limits.

This evaluation led to the redesign of the new silo combustor based on two-stage lean-lean configuration that could maintain low NOx emissions with increased firing rate compatible with the higher power output of the microturbine for simple cycle configuration, or higher volumetric air flow for the recuperated configuration. This led to the development and fabrication of a new combustor, a departure for the design shown in Figure 12. The development and fabrication of this combustor are described in more detail in Chapter 4.

Figure 15: Laboratory Test Results of Ultra Lean Combustor



Source: CMC-Engineering

3.4.2 Impact of Microturbine Emissions on TO Furnace Emissions

Another engineering evaluation focused on of the impact of the microturbine emissions TO furnace emissions because increases following CHP retrofit at the site could impact local operating permits for regulated emissions measured at the TO stack. Local air permit conditions can impose limits on NOx and CO emissions and on the destruction efficiency of the VOCs in the contaminated air. Table 8 lists the emissions from the microturbine, reported in molar concentrations of ppm at standard 15 percent O_2. For reference, NOx emissions from the modified Elliott TA-100 with the low NOx combustor are compared to emissions from a commercial microturbine, Capstone C-65. These emissions are then converted to TO stack concentration for a TO furnace that treats 20,000 scfm of VOC-contaminated air. The 20,000 scfm volume of VOC-contaminated air is approximately 15 times the volume of exhaust from the microturbine.

In this example, the TO has a regulated NOx limit of 28 ppm, corrected to 3 percent O_2. The actual concentration in the TO stack is about 1.5 ppm because the RTO stack has a diluted oxygen concentration, for example, more than 20 percent. Therefore, in either the modified TA-100 or the Capstone C65, the NOx in the microturbine exhaust contributes less than 1 ppm to the overall NOx measured in the TO stack. Therefore, the impact on compliance for NOx emissions of adding a microturbine exhaust to the RTO processed air is deemed low.

Any CO emissions from the microturbine should have an insignificant impact of CO emissions from the TO furnace. This is because the CO is expected to be oxidized to CO_2 at the operating temperatures found in all TO furnaces. In fact, CO has an activation energy that is much lower than that of any other VOC compound being incinerated because the molecule is already partially oxidized. Therefore, CO is rapidly oxidized to CO_2 at temperatures of 1,200 F and above.

Table 8: Impact of NOx Emissions from Microturbine on RTO Emissions

	Capstone 65 kW	Modified Elliott TA-100 100 kW
NOx from microturbine, ppm @15% O_2	4.0	3.0
NOx from microturbine converted to RTO stack exhaust, ppm @3% O_2	0.14	0.15
Total RTO emissions with CHP, ppm @ 3% O_2	28.4	28.1

Source: CMC-Engineering

3.4.3 Hazardous Air Emissions

The engineering analysis included an evaluation of the important effect on VOC destruction rates applicable to all TO furnaces, and consequently on the application of CHP to TO furnaces. In general, the percent destruction efficiency for total VOCs is set by the air district and can vary from 99 to 99.99 percent, depending on the toxicity of the HAPs or VOCs in the processed gas or contaminated air stream. Confirmation of this destruction efficiency in the TO is often based on the level of hydrocarbons and CO measured in the TO stack. For some VOCs, gas chromatography (GC) using flame ionization detection (FID) is used to measure the stack concentration of the actual compounds entering the TO.

The RTO operating temperature is generally based on the type of VOC being treated and its toxicity level. Table 9 lists the operating temperatures of the TO for some selected VOC compounds. Benzene (C_6H_6) and carbon tetrachloride (CCl_4), for example, are solvents that are typically used in surface treatment. Methyl ethyl ketone (MEK) is often found in the exhaust of paint spray booths. Cyanide is a toxic compound associated with some secondary metal treating furnaces. In some industries, metal-bearing VOC solvents are used in the process and escape in treating furnaces to become polluting VOCs. For example, the electronics and semiconductor manufacturing industry have silicate-based chlorinated solvents. Silicon-bearing reactants (such as silane, tetraethylorthosilicate, dichlorosilane, trichlorosilane, silicon tetrachloride and others) are used with or without nitrogen-and oxygen-containing gases (such as ammonia or nitrous oxide) in deposition processes for manufacturing of semiconductors.

For most VOC-laden air streams that use TOs for emission control and incineration of HAPs, the operating temperature of the RTO furnace is generally 1,500 F. The VOC-contaminated air stream to the RTO can either be at ambient temperature or at some elevated temperature if the last step in the manufacturing process consists of heat treating furnaces or ovens.

Table 9: Furnace Temperature for 99% Destruction of Selected VOCs

VOC	Without Catalyst F	With Catalyst F
Benzene	1460	480
Carbon Tetrachloride	1430	610
MEK	1780	600
Cyanide	1800	500

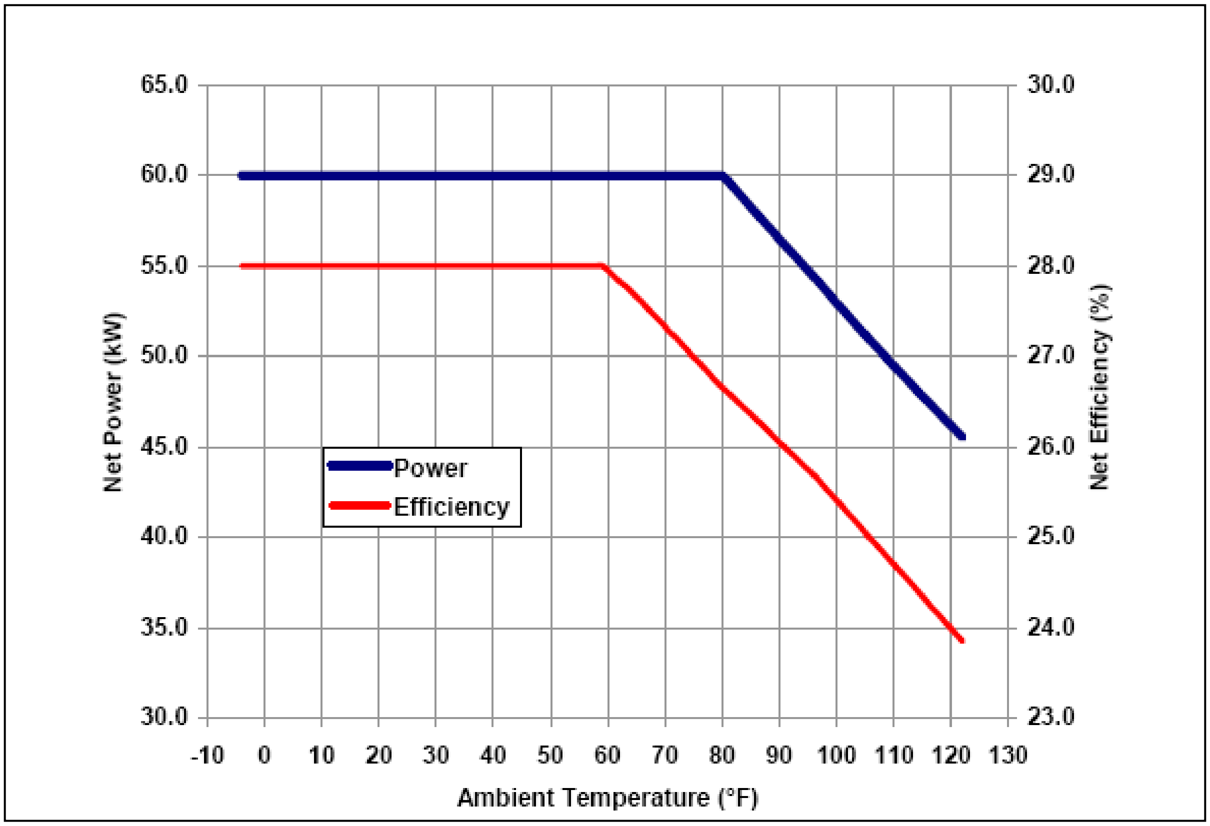
Source: CMC-Engineering

The engineering analysis of microturbine-based CHP ahead of a TO included the evaluation of VOC destruction that will occur in the microturbine combustor, in the case where a process slip stream could be used to supply air to the microturbine thus keeping the overall TO treatment volume unchanged. This was necessary in retrofit cases where the air input to the microturbine would be taken directly for the incoming VOC-contaminated air stream. This is necessary in cases where the amount of gas being treated in the RTO cannot be increased as this would add to the fuel requirements for the RTO and offset some of the efficiency gains with CHP. Also, this approach is only a viable consideration when (1) the VOC concentrations are low (generally less than 50 ppm), (2) the temperature of the air stream entering the RTO is near ambient conditions, and (3) the VOCs are compatible with high speed microturbine operation (for example, they do not foul air filter or the impeller blades of the air compressor).

The low microturbine inlet temperatures are necessary to maintain rated power output on the microturbine**.** Figure 16 illustrates how rate power output and efficiency of the engine diminishes with the temperature of the air entering the air compressor. Therefore, it is desirable to operate with a TO incoming steam at or near ambient temperature. This is more likely for diluted air streams that do not originate from heat treating equipment, such as ovens and furnaces. There are several VOCs that can foul air filter and impeller blades on the air compressor side of the engine. Among those most threatening are the ketones used in paint spry boots and resins used in wood treating processes.

Computational analysis of the VOC destruction that occurs in the microturbine combustor and turbine inlet was undertaken to determine the destruction efficiency and contribution of heat release rate on the fuel needs of the microturbine. The equations that define the residual concentration of unburned VOC (C_a) at selected temperatures (T) and residence time (t) from an initial concentration of C_{a0} are defined by the following three equations, where A, E, and R are the pre-exponential frequency factor (1/sec), activation energy (cal/mole), and universal gas constant (1.987 cal/mole-K), respectively.

Figure 16: Effect of Air Intake Temperature on Microturbine Power Output and Efficiency - Capstone 60



Increase in the temperature of air entering the microturbine reduces its power output and efficiency
Source: Elliott Energy Systems (EES)

Values for A and E were then selected from available literature for selected VOC compounds listed in Table 10[1]

[1] Castaldini, C. Disposal of Hazardous Wastes in Industrial Boilers, Pollution Control Review, Noyes Publications, Library of Congress Catalog Card No. 85-25847, June 1984

Theodore, L. and J Reynolds. Hazardous Waste Incineration, John Riley and Sons Publishers, 1987

$$\frac{dC_A}{dt} = -kC_A$$

$$\ln \frac{C_A}{C_{A_0}} = -k\Delta t$$

The rate constant is defined by the Arrehenius rate expression:

$$k = Ae^{-E/RT}$$

Table 10: Arrhenius Rate Expression Constants for Selected VOCs

VOC	Formula	A (1/sec)	E (Kcal/g-mole)	Temperature, F needed for 99.99% Destruction at 1 sec
1,2- dichloroethane	$C_2H_2Cl_2$	4.82×10^{11}	45.6	NA
Toluene	C_7H_8	2.28×10^{13}	56.5	1,327
Benzene	C_6H_6	7.43×10^{21}	95.9	1351
Chlorobenzene	C_6H_5Cl	1.34×10^{17}	76.6	1408
Ethanol	C_2H_6O	5.37×10^{11}	48.1	13.07
Ethylene	$C2H_4$	1.37×10^{12}	50.8	1328
Pentachlorobyphenyl	C_6HCl_5	1.10×10^{16}	10.0	NA
Acrylonitrile	C_3H_3N	2.18×10^{12}	52.1	NA
Xylene	C_8H_{10}	4.8×10^{12}	75.0	NA
Ethane	C_2H_6	5.65×10^{14}	52.1	1,401

Source: CMC-Engineering

Table 11 and Table 12 summarize the kinetics calculation data for the destruction efficiency of two common VOC compounds found in metal surface coating applications, each subjected to the thermal environment of the combustor a power turbine diffuser. As indicated the 1,2 DCE compound will have a destruction efficiency exceeding four nines (99.99 percent), whereas acrylonitrile will not quite reach a destruction of two nines (99 percent). TO performance requirements are typically set at >99 percent efficiency. Thus, the microturbine environment will not be sufficient to incinerate all VOC to meet the TO regulations. However, since the exhaust of the microturbine in a CHP configuration will enter the TO at the host facility, added incineration efficiency of the VOC first treated by the microturbine will occur. Figure 17 illustrates this increase in destruction efficiency for selected VOCs. As indicated, the overall VOC destruction efficiency for a CHP with a TO furnace will exceeds 6 nines (99.9999 percent) VOC destruction performance in all cases.

Table 11: 1, 2 Dichloroethylene Destruction Efficiency in Microturbine

	t (sec)	T (F)	T (K)	k (1/sec)	O2 (%)	O2	ppm remaining	Destruction
Combustor	0.02	2000	1367	10144	21	0.002559	**1.74E-03**	**99.9965%**
Diffuser	0.09	1425	1047	29.14452	16	0.00195	**1.53E-03**	**99.9969%**

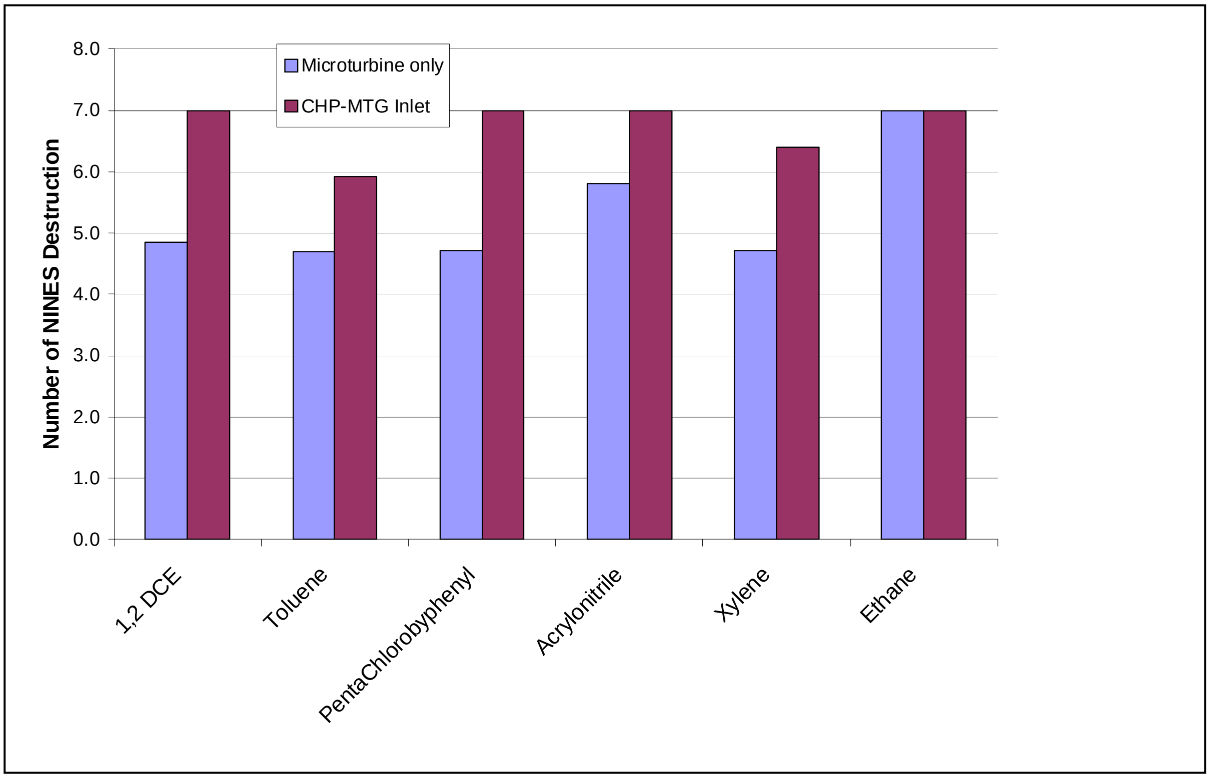
Source: CMC-Engineering

Table 12: Acrylonitrile Destruction Efficiency in Microturbine

	t (sec)	T (F)	T (K)	k (1/sec)	O2 (%)	O2	ppm remaining	Destruction
Combustor	0.200	1850	1283	8321	21	0.002559	**7.07E-01**	**98.59%**
Diffuser	0.05	1500	1089	97	16	0.00195	**6.98E-01**	**98.60%**

Source: CMC-Engineering

Figure 17: VOC Destruction for Selected Compounds with Microturbine and RTO Treatment in CHP Configuration

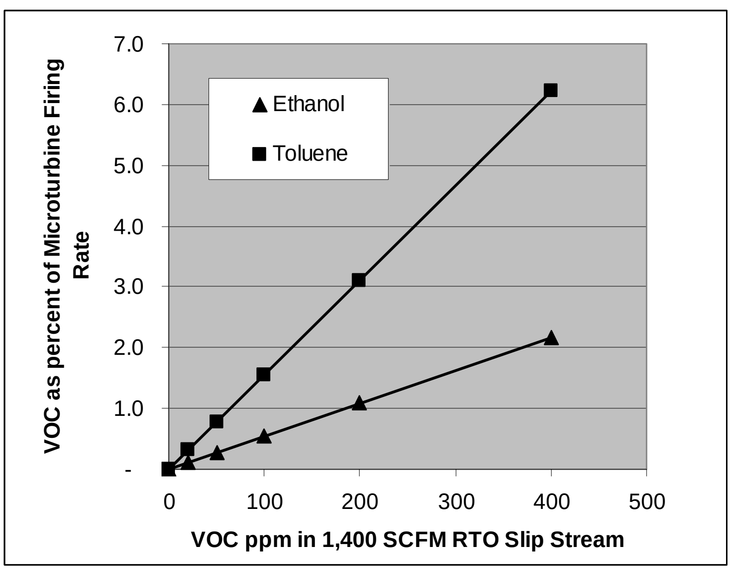


CHP assembly with microturbine and TO exceeds all destruction performance requirements for TO furnaces
Source: CMC-Engineering

For VOC-laden air streams suitable as air supply for the microturbine, the combustion of VOCs in the combustor can reduce the amount of natural gas needed by the microturbine. Figure 18 shows the calculated contribution from the incineration of two selected VOCs to the total heat required by the 100 kW simple cycle microturbine. The TA-100 operating in simple cycle will require about 2.6 MMBtu/hr of natural gas and intakes approximately 1,400 scfm of air. When the combustion air intake contains some combustible VOCs, the heat generated by the incineration of these VOCs will reduce the microturbine demand on natural gas. The data in Figure 18 is also an indication of the percent reduction in natural gas that would result with varying concentrations of these two selected VOCs entering the microturbine combustor with the compressed air. Ethanol has a much lower heating value than toluene, thus the effect on the microturbine fuel gas requirements are significantly lower than in the case of toluene. However, for concentrations of 100 ppm and above, the microturbine fuel control valve has to respond to restrict gas flow to maintain the set point of turbine inlet temperature of about 1,700 F. In the TA-100 power electronics (PE) and control software, needed to maintain rated power output. In most cases, this will occur automatically by modulation of fuel control valves based on load demand.

In several TO processes, the inlet VOC concentration can vary from zero to peak levels over several periodic cycles. These cycles are dictated by the upstream industrial processes that can intermittently use chemicals. Therefore, contrary to typical microturbine operation where the fuel control valve reaches a constant percent-open setting and remains at that setting all the time, the CHP-TO application may entail routine changes in fuel control valve settings as the VOC concentration changes with upstream process conditions.

Figure 18: Heat Input Contribution of VOC to Microturbine Firing Rate



VOCs entering the microturbine compressor with air reduce the amount of natural gas needed to make power
Source: CMC-Engineering

3.5 CHP Process Evaluations for Thermal Oxidizers

The CHP configuration based on either a simple-cycle TA-100 microturbine or a recuperated microturbine for integration with TOs will vary according to several site-related factors. These can be listed as follows:

1. Type of RTO, regenerative or recuperative, influencing the access to the existing RTO burner and method of air supply for RTO burner operation.
2. Type of industrial boiler used to incinerate VOC-laden gas stream, its operating heat load profile and type of VOCs in the process gas.
3. Processing capacity of the RTO measured in standard cubic feet per minute (scfm) of VOC-contaminated air, influencing the amount of heat required to maintain the RTO operating temperature.
4. Types and concentration of VOCs influencing the application of microturbine with VOC-contaminated air supply.

As indicated in Table 6 in Section 3.2, the 100 kW simple-cycle CHP is applicable to TOs with an operating VOC-contaminated air throughput of greater than 10,000 scfm and preferably a low, 50 ppm or lower, concentration of VOCs. The 100 kW microturbine has a turbine exhaust of about 1,400 scfm and a temperature of about 1,100 F when operating in simple-cycle mode. The low heating value (LHV) of the simple-cycle microturbine exhaust is approximately 2.2 MMBtu/hr. If the microturbine operates with ambient air instead of a slip stream from the VOC-contaminated air, the 1,400 scfm would be added to the RTO process, corresponding to a 14 percent increase in 10,000 scfm capacity TO. In this configuration, the TO would be required to use an additional 0.728 MMBtu/hr of fuel to raise the temperature of the microturbine exhaust from 1,100 F to the TO operating temperature of 1,500 F. When the TO operates with a firing rate of1.35 to 1.86 MMBtu/hr, the additional 0.728 MMBtu/hr fuel required to raise the microturbine exhaust temperature to the TO operating temperature of 1,500 F would be a significant increase, defeating the efficiency improvement objectives of the project. Therefore, the project team considered three possible CHP configurations for the types of TOs furnace used specifically for the selected host site. Table 13 summarizes the applicable CHP configurations as dictated by site conditions. The following sections provide detailed discussions of each CHP configuration and associated CHP process data.

3.5.1 System Engineering Analysis – Configuration A

Configuration A considers the retrofit of a recuperative RTO that is currently operating with a 2-4.5MMBtu/hr burner with either its own fresh near ambient temperature air supply air supply and with low concentrations of VOCs that do not to harm the microturbine with excessive deposits on the air-intake filter or compressor impeller. This site will allow for the retrofit of a CHP assembly that consists of a simple-cycle microturbine closely integrated with a replacement low emission burner. This approach is similar to that implemented in the Energy Commission project 500-03-037 for industrial boilers. Figure 19 illustrates the process schematic for this CHP configuration. Table 14 describes the process streams.

Table 13: Applicable CHP Configuration for Selected RTOs

Type	CHP Configuration	Furnace Type and VOC Type
A	Integrated microturbine-burner with compressor air intake connected to VOC contaminated air stream, replacing existing RTO burner	Recuperative RTO or boiler furnace with access to existing burner and with VOC types suitable to microturbine intake air or own fresh air intake
B	Free-standing simple-cycle microturbine with compressor air intake connected to VOC contaminated air stream and with turbine exhaust back to inlet to RTO	Regenerative RTO with no easy access to existing burner and with VOC types suitable to microturbine intake air
C	Free standing simple-cycle microturbine with ambient air intake and exhausting to heat exchanger in the RTO inlet air stream for preheat of VOC-laded stream	Regenerative RTO with no easy access to existing burner and with VOC types unsuitable to microturbine intake air
D	Free-standing recuperated microturbine with ambient air for compressor intake and with microturbine exhaust ducted to boiler windbox for heat recovery	Industrial packaged boiler with single burner and burner windbox with heat input greater than 5 MMBtu/hr.

Source: CMC-Engineering

Table 15 shows the energy and mass balance for this CHP configuration. In this application, the CHP utilizes a 100 kW simple-cycle microturbine with a low emission burner assembly designed for packaged industrial and commercial boilers. The heating value attributed to the VOC is 0.18 MMBtu/hr based on 30 ppm styrene in a 10,000 scfm. The microturbine would utilize 2.17 MMBtu/hr low heating value (LHV) of natural gas of which 1.8 MMBtu/hr will be used to displace fuel for the RTO burner and reduce its fuel consumption to 2.02 MMBtu/hr (LHV). Table 16 summarizes the CHP efficiency and compares it with an existing regenerative RTO operating with an efficiency of 90 percent. In both cases, the thermal efficiencies of the RTO take into consideration the available heat from the combustion of the VOCs. As indicated, the CHP will boost efficiency by 1 percent for the same RTO conditions. Moreover, the CHP will provide least cost 100 kW of electrical power at a cost of less than $0.25/kWh with a $7.0/MMBtu price for natural gas.

Figure 19: CHP-RTO Arrangement -Configuration A

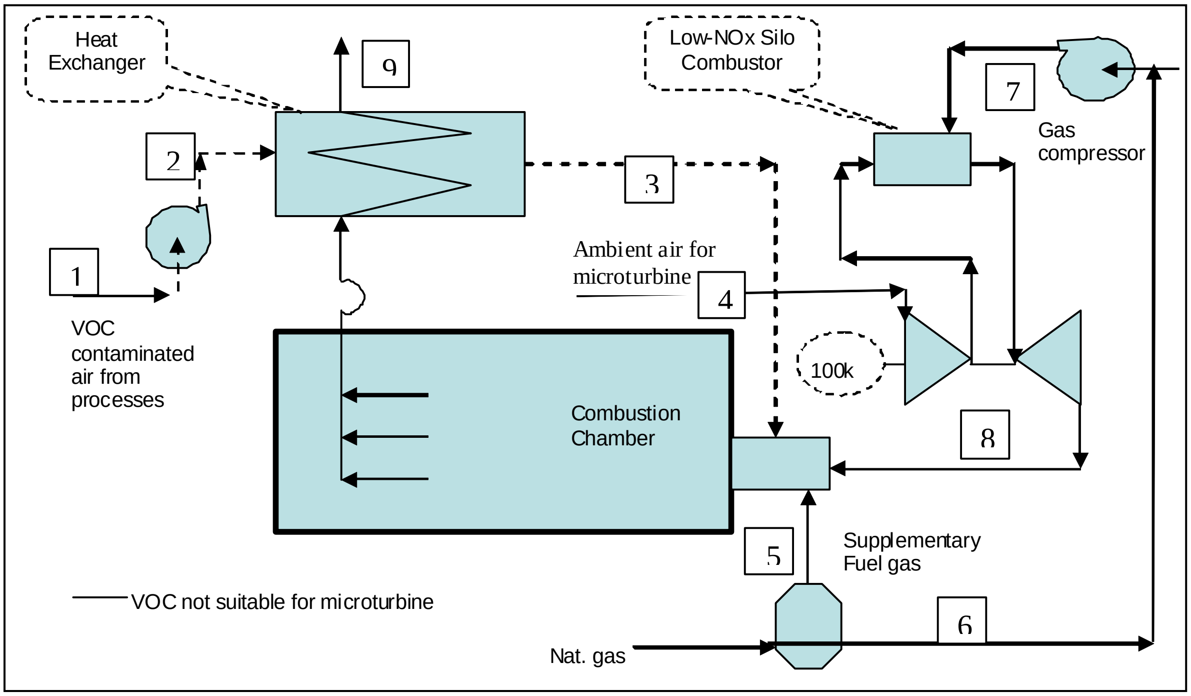


Diagram of CHP installation for RTOs that can utilize burners with independent combustion air supply
Source: CMC-Engineering

Table 14: Description of Process Streams

Location	Description of process flow type
1	VOC contaminated air stream
2	VOC stream to RTO recuperator (HEX)
3	VOC stream to RTO burner
4	Microturbine compressor inlet air
5	Natural gas flow to RTO burner
6	Natural gas flow to microturbine fuel compressor
7	Natural gas to microturbine silo combustor
8	Microturbine exhaust
9	RTO stack

Source: CMC-Engineering

Table 15: Energy and Mass Balance - 10,000 SCFM Styrene Plant - Configuration A

	1	2	3	4	5	6	7	8	9
Mass flow, klb/hr	46.8	46.8	46.8	6.79	0.184	0.11	0.11	6.91	53.8
Pressure, psia	14.7	15.0	14.7	14.7	14.7	14.7	94.7	14.7	14.7
VOC, lb/hr as C	0.18[1]	0.18	0.18	0	0	0	0	0	0
Energy, MMBtu/hr	0.0029	0.0029	0.0029	0	2.02	2.17	2.17	1.8	0.04
Temperature, F	70	70	660	70	70	60	80	1,100	200

MMBtu as LHV: 1. 30 ppm as carbon; 2. Microturbine fuel based on simple cycle microturbine efficiency
Source: CMC-Engineering

Table 16: Energy and Mass Balance

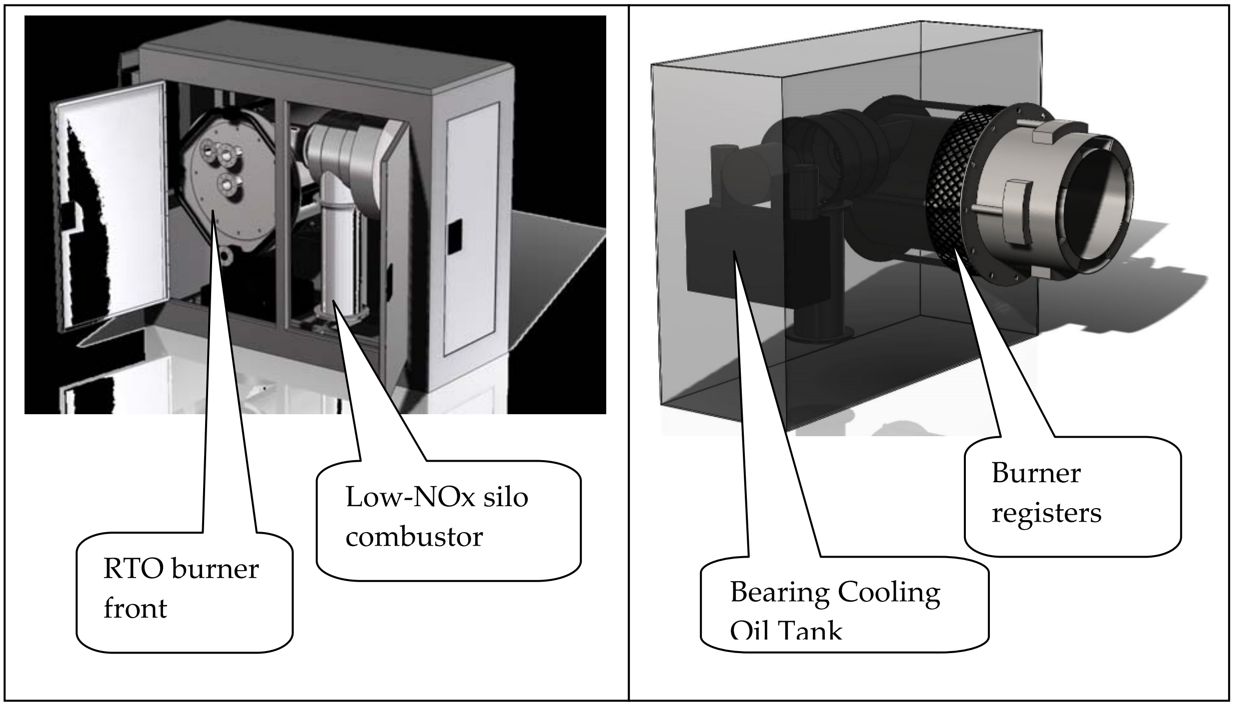
Energy Input, MMBtu/hr	**With CHP**	**Without CHP**
• Microturbine	2.17	0
• RTO	2.02(4.0-1.8-0.18)	4.00 (3.82+0.18)
• Total	4.19	4.0
Energy Output and Recovery	With CHP	Without CHP
• TO Thermal Recovery	3.47	3.60
• Electrical Energy, MMBtu/hr	0.34	0
• Total	3.81	3.60
Power Conversion Efficiency	100%	0
Overall Efficiency	95.0	94.0

This table summarizes the CHP efficiency and compares it with an existing regenerative RTO operating with an efficiency of 90 percent.
Source: CMC-Engineering

Figure 20 shows a preliminary assembly of the integrated microturbine-burner package engineered for this CHP configuration. This configuration is applicable to both recuperative RTOs and industrial packaged boilers incinerating HAPs.

Figure 21 shows how the project team envisions the installation of the integrated microturbine-burner CHP assembly on an RTO where burner size, access, and available footprint are compatible with this installation. The assembly in Figure 21 would replace the existing RTO burner (Figure 20) or boiler burner (Figure 22) with one that is especially adapted to take high temperature 1,100 F microturbine exhaust and produce a stable, low NOx flame. The burner will have a rated firing capacity that is the same as the existing burner even though the microturbine may supply as much as one half of the total required heat input for a 4 MMBtu/hr capacity. This is because the burner would have to function even when the microturbine is down for repair or routing maintenance.

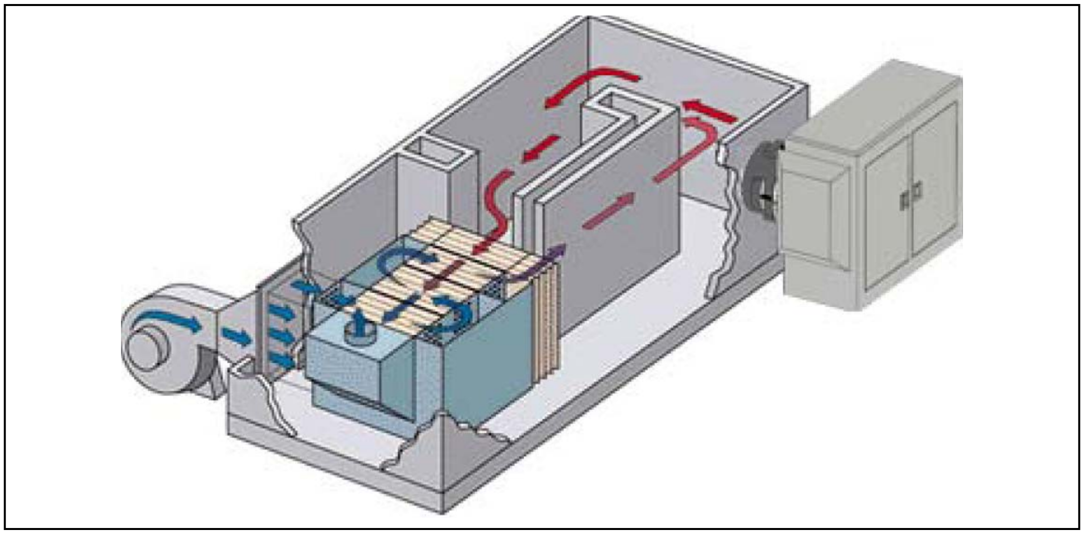
Figure 20: Simple Cycle Microturbine Integrated with RTO Burner into One Assembly – Rear View (left), Front View (right)



Source: CMC-Engineering

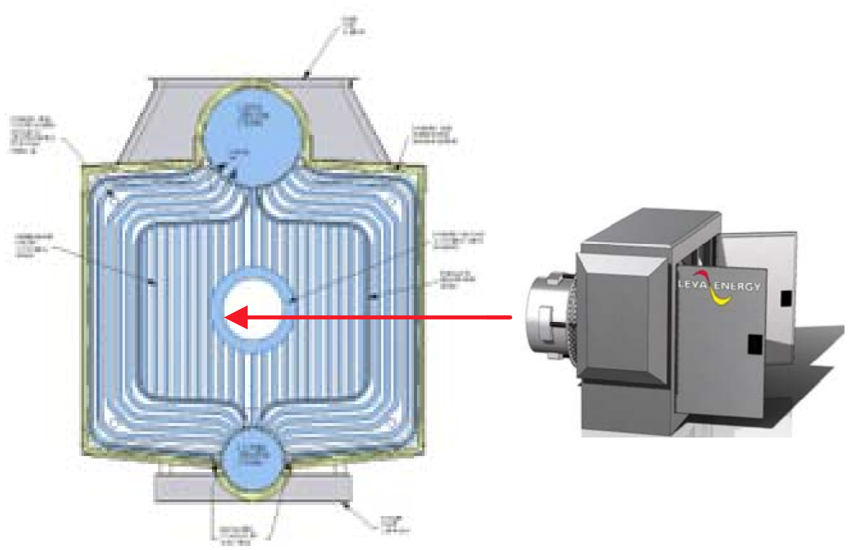
Configuration of a simple cycle microturbine in compact assembly package as replacement of RTO burner
Source: CMC-Engineering

Figure 21: Integrated Microturbine-Burner for Retrofit (Not to Scale)



This diagram shows what the project team envisions with the installation of the integrated microturbine-burner CHP assembly for the retrofitted regenerative RTO with fresh air supply.
Source: Anquil Environmental Systems web site at http://www.anguil.com/prregthe.php.

Figure 22: VOC Boiler Furnace CHP Integration



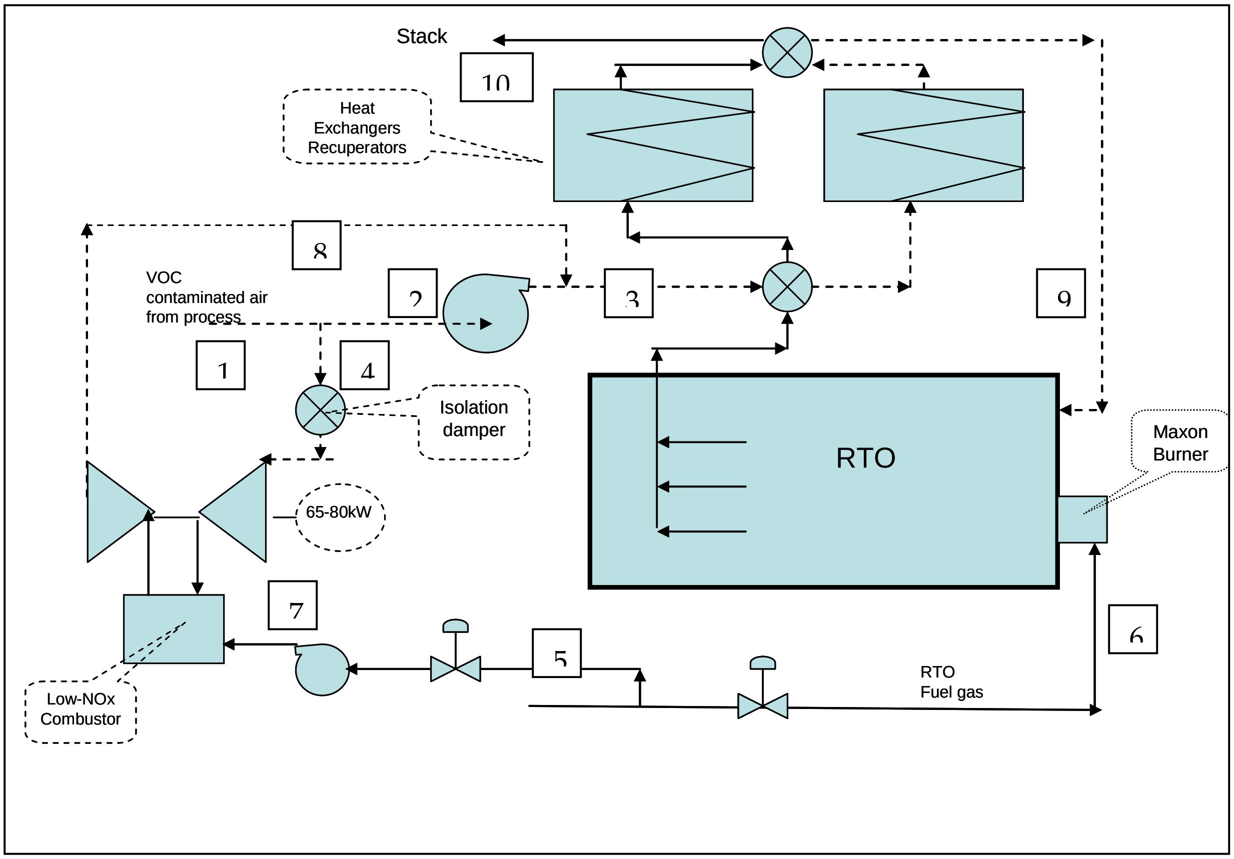
Replacement of boiler burner with integrated microturbine-burner assembly
Source: CMC-Engineering

3.5.2 System Engineering Analysis – Configuration B

Configuration B considers a recuperative RTO with no easy access to the burner that has no fresh air for combustion of the fuel but instead uses the incoming VOC-contaminated air to support combustion of the fuel. The burner can operate intermittently as additional heat is needed to maintain operating temperature. These systems are obviously designed to minimize the amount of total air stream that has to be heated in the RTO. At this site, the simple cycle microturbine will have to be located in its own cabinet and will not include a replacement burner for the RTO. Instead, the engine will take VOC-contaminated process air to supply the air intake to the engine, provided the VOCs are compatible with safe engine operation and the temperature of the process stream is near ambient conditions. The exhaust of the microturbine can then be re-directed back to the process air duct to the inlet of the RTO so not to increase the amount of process air being treated by the RTO.

Figure 23 illustrates the process flow diagram for the CHP-RTO under this configuration. Table17 describes the process streams. As indicated, the microturbine air intake will consist of a slip stream of approximately 1,400 scfm taken from the VOC-contaminated stream to the RTO, ahead of the fan. The slip stream will require a bypass damper that can be used to isolate the engine when not in operation. Table 18 and Table 19 summarize the energy and mass balance and the anticipated CHP efficiency of this CHP configuration compared with an existing RTO thermal efficiency. Also in this case, the thermal efficiency of the RTO takes into consideration the available heat from the combustion of the VOCs. The only difference between Configuration B and A is that the slip stream to the microturbine is returned to the VOC-stream at 1,100 F with that portion of the VOC incinerated in the microturbine silo combustor.

Figure 23: CHP RTO Arrangement - Configuration B



Description of the CHP process applicable to RTO with VOC contaminated air stream suitable for combustion air to microturbine
Source: CMC-Engineering

Table 17: Description of Process Streams- Configuration B

Location	Description of process flow type
1	VOC contaminated air stream
2	VOC stream to fan inlet to RTO recuperator (HEX)
3	VOC stream fan discharge to RTO
4	VOC-contaminated slip stream to microturbine
5	Natural gas flow to microturbine fuel compressor
6	Natural gas flow to RTO burner
7	Compressed natural gas flow to microturbine silo combustor

8	Microturbine exhaust
9	Preheated VOC- stream to RTO
10	Treated VOC stream and combustion byproducts to atmosphere

Source: CMC-Engineering

Table 18: Energy and Mass Balance - 10,000 scfm Styrene Plant - Configuration B

	1	2	3	4	5	6	7	8	9	10
Mass flow, klb/hr	46.8	40.0	46.8	6.79	0.11	0.184	0.11	6.91	46.8	53
Pressure, psia	14.7	15.0	15.0	14.7	14.7	14.7	100	15.0	14.7	14.7
VOC, lb/hr as C	0.18[1]	0.18	0.18							0
Energy, MMBtu/hr	0.0029	0.025	0.025	.004	2.216	2.17	2.216	1.80	0.025	0.04
Temperature, F	70	70	660	70	70	60	60	1100	660	200

MMBtu as LHV: 1. 30 ppm as carbon; 2. Microturbine fuel based on simple cycle microturbine efficiency
Source: CMC-Engineering

Table 19: Energy Balances around System Boundaries - Configuration B

Energy Input, MMBtu/hr	**With CHP**	**Without CHP**
• Microturbine	2.17	0
• TO	2.02 (4.0-1.8-0.18)	4.00(3.82+0.18)
• Total	4.19	4.00
Energy Output and Recovery	With CHP	Without CHP
• TO Thermal Recovery	3.47	3.60
• Electrical Energy, MMBtu/hr	0.34	0
• Total	3.81	3.60
Power Conversion Efficiency	100%	0
Overall Efficiency	95.0	94.0

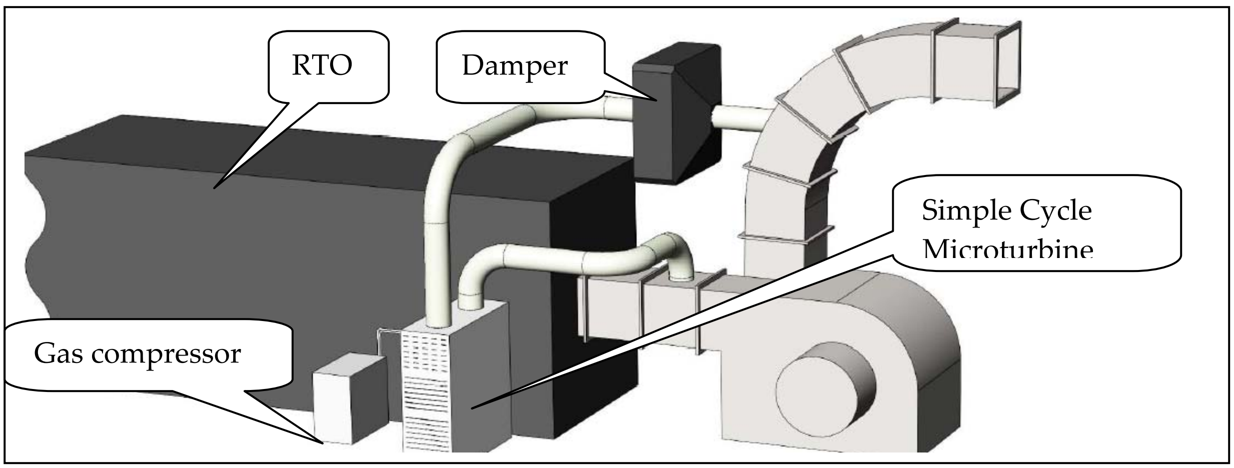
Source: CMC-Engineering

As indicated, the overall efficiencies of both configurations are equal as all the heat from the microturbine is recovered at the RTO operating efficiency of 94 percent. The advantage of the CHP installation, of course is the additional generation of 100 kWnet of electrical power at 100 percent efficiency (gross power) as the output value of the energy is set at 3,412 Btu/kWh, or 0.341 MMBtu/hr. This indicates that by integrating a simple cycle microturbine with an RTO the additional 0.34 MMBtu/hr used in the CHP is nearly all converted to electricity.

Some parasitic losses, associated with the energy used by the gas compressor and the inverter in the power electronics, reduce the net power conversion efficiency in all cases to less than 100 percent.

Figure 24 illustrates the schematic of this CHP configuration. This schematic was generated for a potential host site that used a large metal treating oven in the steel coating industry. As indicated, the simple-cycle microturbine is housed separately from the RTO burner and is free-standing near the VOC-contaminated duct. A rendering of the cabinet housing the microturbine is shown in Figure 25. This microturbine location near the fan and VOC stream duct allows for a short slip stream circular duct to serve the microturbine intake and its exhaust streams. A butterfly isolation damper and connecting flange allows for isolation of the microturbine for routine maintenance and repair. Both ducts were attached to the turbine inlet and outlet flanges. The hot exhaust duct from the microturbine was insulated with standard foam insulation and aluminum covering.

Figure 24: Configuration B Equipment Depiction



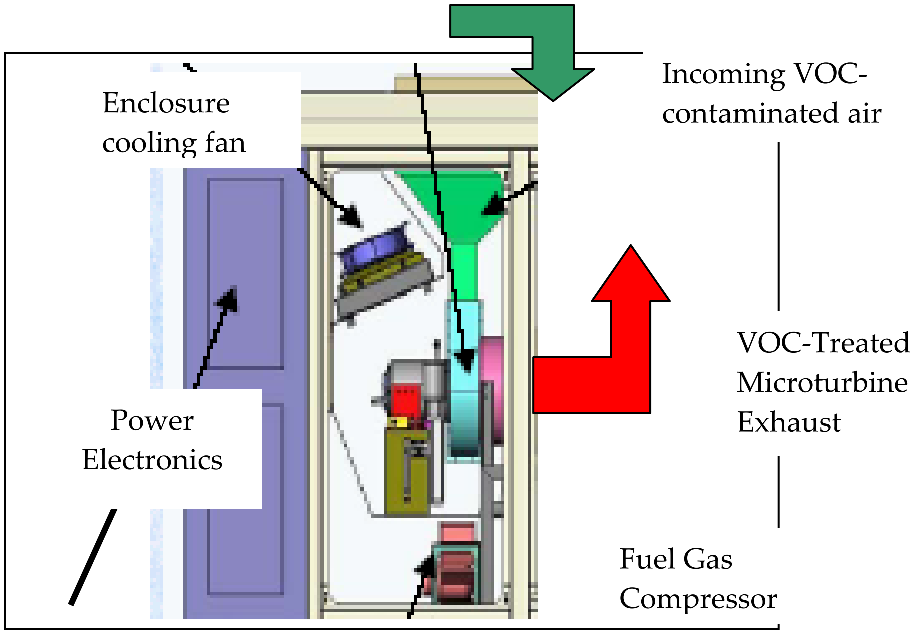
Source: CMC-Engineering

This figure describes how a CHP assembly would appear with a free standing simple-cycle microturbine that uses VOC-contaminated air with hot exhaust reintroduced to the RTO
Source: CMC-Engineering

3.5.3 System Engineering Analysis – Configuration C

Configuration C considers the case where the VOCs are not compatible with the safe operation of the microturbine. This is due to the sticking properties of certain VOCs such as aldehydes found in the paint processes and other surface coating operations. Therefore, the microturbine is instead supplied with filtered ambient air and the high-temperature exhaust from the microturbine is used in an air-air heat exchanger that is placed in the process air intake to the RTO. In this approach there is no contact of the VOCs with engine components and the amount of processed air to the RTO is unaltered. Figure 26 illustrates the process schematic for this CHP configuration and Table 20 describes the key process streams.

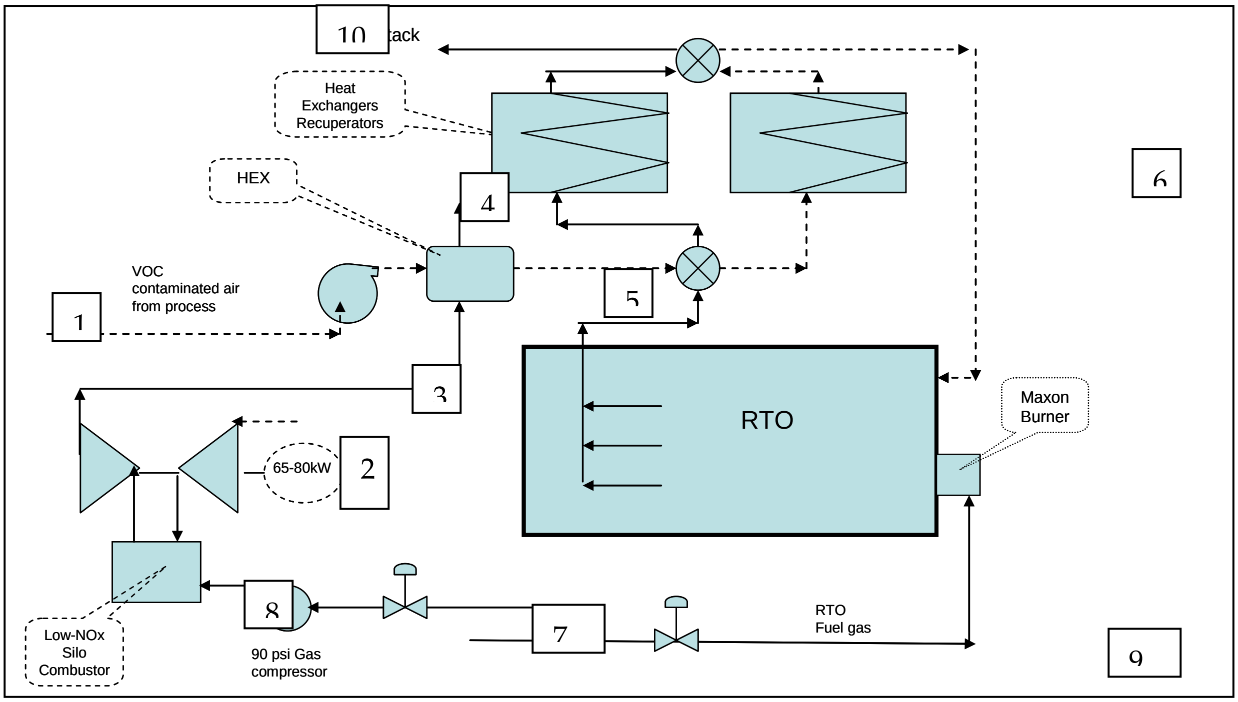
Figure 25: Free-Standing Microturbine with Connecting Ducts to RTO



Description of a reconfiguration of recuperated TA-100 into simple cycle in stand-alone cabinet
Source: Elliott Energy Systems

Table 21 summarizes the energy and mass balance. Some of the thermal energy from the microturbine exhaust is transferred to the VOC-contaminated stream, raising the temperature from ambient to about 180. Because the heat exchanger is not as efficient as the direct mixing of hot microturbine exhaust with the VOC stream as in Configuration B, this CHP configuration would be no greater in overall efficiency than the current RTO system. Out of the 1.8 MMBtu/hr of energy available in the microturbine exhaust, only 1.25 would be recovered and used in the RTO, or 70 percent. Therefore, the power conversion efficiency would be reduced to 70 percent based on the heat exchanger efficiency limitations.

Figure 26: CHP-RTO Arrangement - Configuration C



Description of CHP system with independent heat exchanger for microturbine waste heat recovery into RTO

Source: CMC-Engineering

Table 20: Description of Process Streams- Configuration C

Location	Description of process flow type
1	VOC contaminated air stream
2	Ambient air intake to the microturbine
3	Microturbine exhaust
4	Microturbine exhaust after heat exchanger (HEX)
5	VOC contaminated air stream after heat exchanger (HEX)
6	VOC contaminated stream to RTO
7	Natural gas flow to microturbine gas compressor
8	Natural gas from gas compressor
9	Natural gas to RTO burner
10	Treated VOC stream and combustion byproducts to atmosphere

Description of key process condition applicable to Figure 26
Source: CMC-Engineering

Table 21: Energy and Mass Balance - 10,000 scfm Styrene Plant - Configuration C

	1	2	3	4	5	6	7	8	9	10
Mass flow, klb/hr	46.8	6.79	6.91	6.79	46.8	46.8	0.11	0.11	46.8	53
Pressure, psia	14.7	14.7	15.0	14.7	15.0	15.0	14.7	100	14.7	14.7
VOC, lb/hr as C	0.18[1]				0.18	0.18				0
Energy, MMBtu/hr	0.029		1.8	0.58		15.3	2.20	2.20	1.6	0.04
Temperature, F	70	70	1100	400	180	1350	60	1100	70	200

MMBtu as LHV: 1. 30 ppm as carbon; 2. Microturbine fuel based on simple cycle microturbine efficiency. Process data applicable to CHP configuration C described in Figure 26

Source: CMC-Engineering

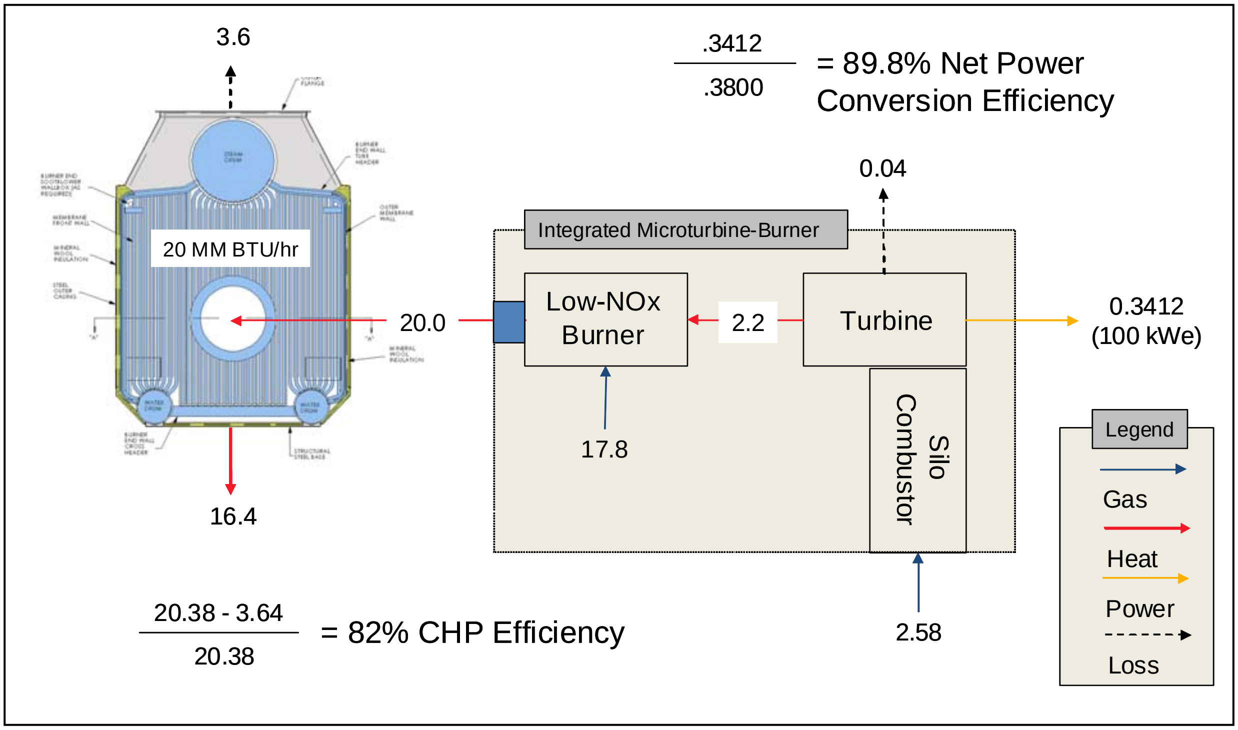
3.5.4 System Engineering Analysis – Configuration D

The selection of the Momentive Specialty Chemicals for the host site for this project has defined the final configuration of the CHP assembly that will be feasible from a technical point of view and acceptable to the host staff. Momentive operates a 20 MMBtu/hr water tube boiler that is fired with 100 percent process gas with the exception of natural gas for startup. Figure 27 and Figure 28 illustrate the boiler, process gas feed line and burner front. The steam from the boiler is used for the chemical process. Some of the steam is used to generate power in a 500 kW steam turbine in a topping cycle. The site also uses 90F hot water for the process.

The Momentive site offers two available options for CHP retrofit using the 100 kW Elliott microturbine. These are illustrated in Figure 27 and Figure 28. Figure 27 shows the use of the microturbine converted to simple cycle and integrated into one assembly under the label Integrated Microturbine-Burner. All the numbers are in MMBtu/hr with the exception of efficiency and kW output. The heat input required by the simple cycle engine would be approximately 2.58 MMBtu/hr of which 2.20 MMBtu/hr would be unused by the engine and delivered to the burner. The additional energy of 17.8 MMBtu/hr to the burner would be provided by the process gas and any additional natural gas depending on the operational demand for steam. The total heat input to the boiler would then be a combined 20 MMBtu/hr, or the design rate for the boiler which operates at an efficiency of 82 percent. The overall CHP efficiency would also approach 82 percent.

Figure 28 shows the use of the recuperated microturbine. The overall heat demands are the same to the boiler and microturbine. The difference is in the lower amount of gas needed by the engine (1.18 MMBtu/hr) and the lower amount of heat delivered to the boiler (0.80 MMBtu/hr) since the microturbine exhaust is at the lower temperature of 560F compared to an exhaust temperature of 1,050F. The overall efficiency of the system remains the same at about 82 percent. Based on this analysis, the site has requested the use of a conventional recuperated microturbine which will not require significantly invasive hardware changes to the boiler and a much longer down time to execute the retrofit of the integrated microturbine-burner system.

Figure 27: CHP Configuration D1 - Simple Cycle Microturbine Integrated with Low Btu Burner

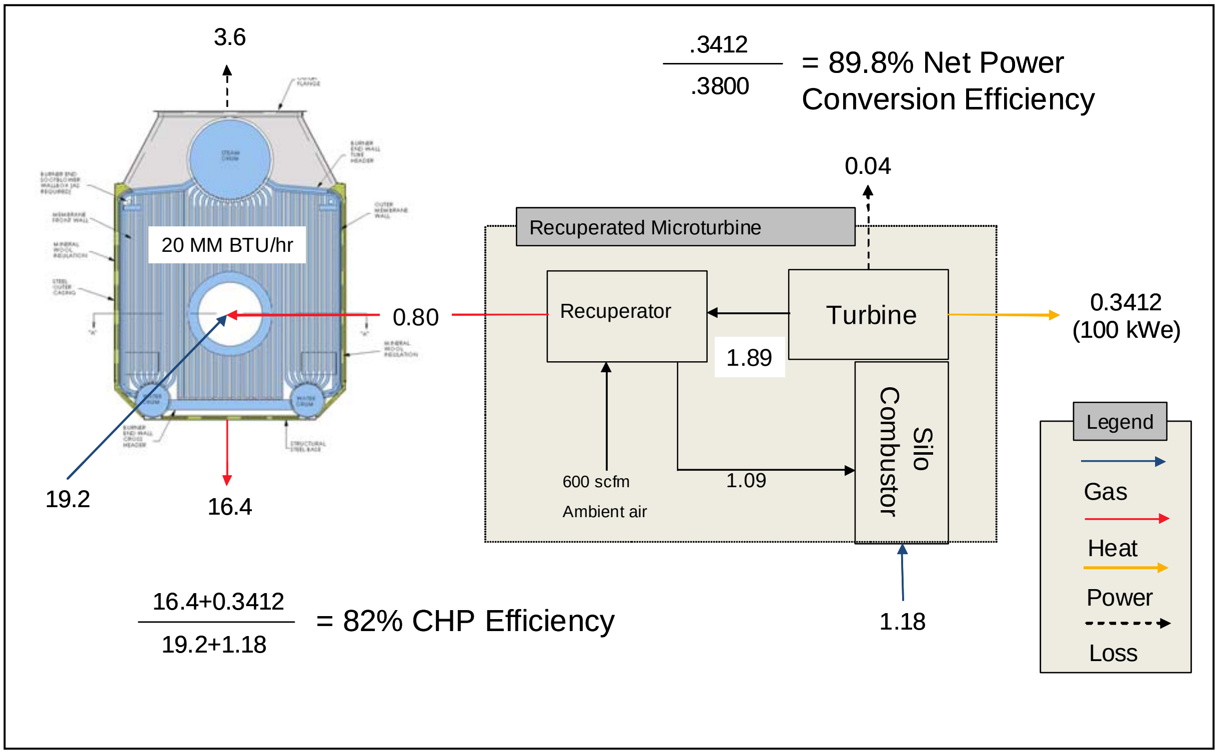


Description of process for CHP retrofit using a simple cycle microturbine interfaced with a TO boiler furnace

Source: CMC-Engineering

Table 22 and Table 23 summarize the process information on the VOC-laden gas starting with composition and combustion air requirements by the boiler when operating at 100 percent VOC gas. These data are specific to the Momentive host facility and to the final CHP configuration considered for the project. As indicated, the process gas has a high heating value (HHV) of 86 Btu/scft. The volume provides about 14 MMBtu/hr of heat input to the boiler. The 23 percent hydrogen content makes the gas easier to burn in a specially designed low Btu burner. Table 23 shows the amount of air remaining in the microturbine exhaust. As indicated, the air in the microturbine exhaust, (1,280 scfm) accounts for about 66 percent of the air needed by the boiler for burning the process gas

Figure 28: Configuration D2- Recuperated Microturbine with Ducted Exhaust Gas



Description of process for CHP retrofit using a recuperated microturbine interfaced with a TO boiler furnace

Source: CMC-Engineering

Table 22: Composition of VOC Stream

Composition		VOC Stream Composition (%vol)						MMBtu/hr	
		Sample no. 1	Sample no. 2	Avg	State	MW	lb/hr	HHV	LHV
Hydrogen	H2	22.65	22.97	0.228	gas	2	196.5	12.082	10.14
Oxygen	O2	0.06	0.23	0.001	gas	32	19.8	0.000	0.000
Carbon Monoxide	CO	1.18	0.94	0.011	gas	30	137.1	0.556	0.556
Carbon Dioxide	CO2	4.1	4.20	0.041	gas	44	89.5	0.000	0.000
Water	H2O	1.55	1.53	0.015	liq	18	119.4	0.000	0.000
Methanol	CH3OH	0.13	0.12	0.001	liq	32	17.2	0.168	0.149
Methylformate	C2H4O2	0.35	0.39	0.004	gas	60	95.4	1.300	1.185
Dymethyl Maleate	C6H8O4	0.04	0.01	0.000	liq	144	14.3	0.158	0.144
Balance Nitrogen	N2	69.94	69.62	0.698	gas	28	8415.5	0.000	0.000
	TOTAL			1.000			9104.67	14.26	12.17
	MW					22.76			
High Heating Value HHV (Btu/cft)				85.9	calculated				
Low Heating Value LHV (Btu/cft)				73.3	calculated				

Description of actual VOC gas stream for the Momentive host site prior to field test
Source: CMC-Engineering

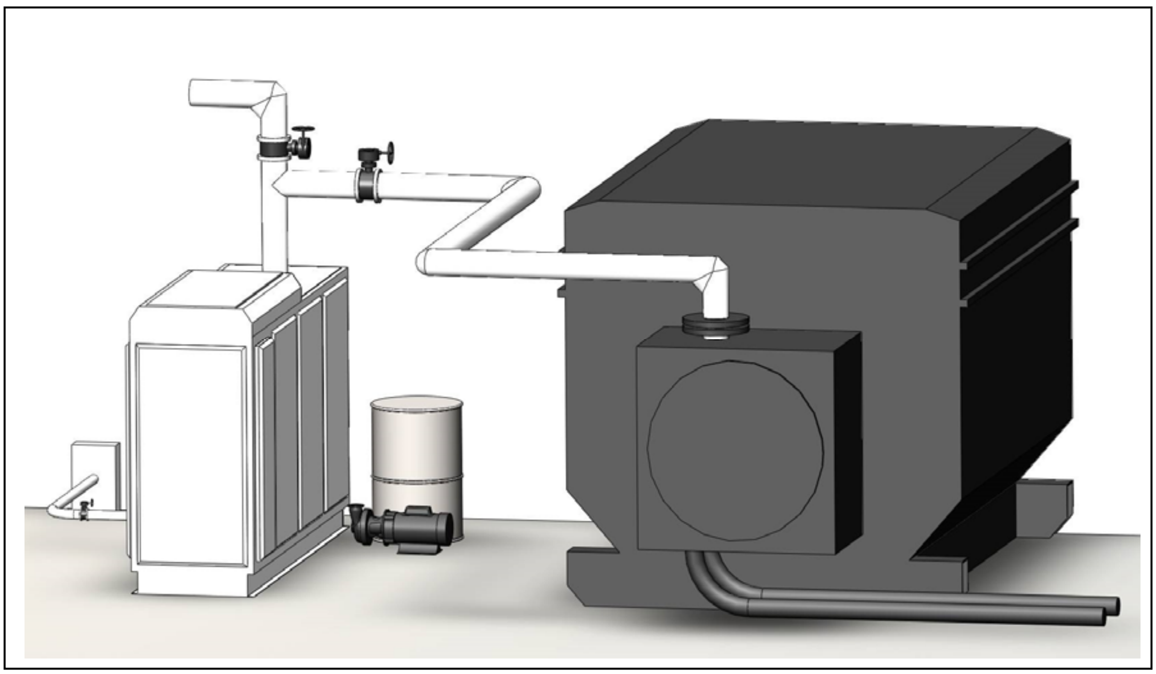
Table 23: Combustion Calculations of the VOC Stream in Nebraska VOC Recovery Boiler

		SCFH	O2	N2	Total		CO2	H2O	N2	TOTAL
VOC Waste Stream	H2	37,865	18,932	71,222	90,154			37,865	71,222	109,086
Composition	O2	238	(238)	(896)	(1,134)				(896)	(896)
	CO	1,761	880	3,312	4,193			1,761	4,193	5,953
	CO2	6,889		-	-		6,889			6,889
	H2O	2,556		-	-			2,556		2,556
	CH3OH	208	311	1,171	1,482		208	415	1,171	1,793
	C2H4O2	613	1,226	4,612	5,838		1,226	1,226	4,612	7,064
	C6H8O4	38	230	863	1,093		230	153	863	1,246
	Bal N2	115,833		115,833	115,833				115,833	115,833
	TOTAL	166,000	21,341	196,118	217,459		8,552	43,975	196,998	249,525

Combustion calculation specific to CHP arrangement for CHP interfaced with TO boiler furnace specific to Momentive host site
Source: CMC-Engineering

Figure 29 shows a preliminary drawing of the arrangement of CHP components that was used to describe the process to the host site.

Figure 29: Field Construction Drawing



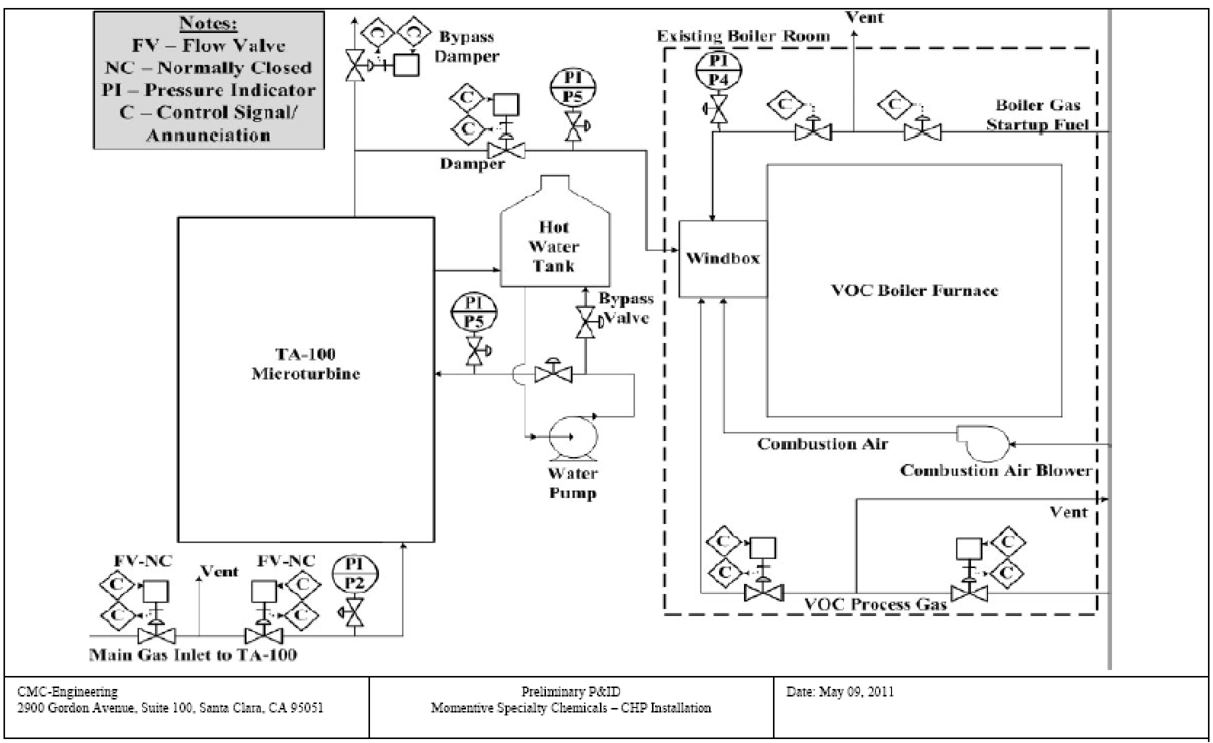
Pictorial view of CHP arrangement based on stand-alone recuperated microturbine with exhaust interfaced with TO boiler furnace
Source: CMC-Engineering

The figure shows the current boiler furnace where the formaldehyde process gas is being incinerated for energy recovery. After startup on natural gas, the boiler uses 100 percent process gas for the steam generation that is used in the catalytic reaction process. The figure shows the piping transporting the process gas and the combustion air that goes to the boiler.

The CHP arrangement locates the microturbine near the TO boiler furnace. The exhaust from the recuperated TA-100 microturbine is hooked up to the windbox or burners air intake. A bypass will allow for the engine to exhaust the gas to the atmosphere during initial startup and when the boiler is not in operation. Isolation dampers in the connecting ductwork will isolate the microturbine from the boiler whenever the microturbine is not in operation. The heat exchanger on the back of the microturbine (exit of the recuperator) can then be used to generate hot water whenever it is needed by the pant to prevent crystallization of the product. A water pump with manual valve was needed to secure the water heating loop. The natural gas will be regulated to a maximum of 5 psig with a pressure regulator and will have a gas meter and manual shutoff ball valve.

Figure 30 shows the piping and instrumentation drawing (P&ID) for the installation. The drawing highlights the three principal process interface requirements, namely the gas fuel for the microturbine, the microturbine exhaust connection to the windbox, and the water connection for the TA-100 hot water boiler.

Figure 30: Preliminary P&ID for CHP Installation at Momentive Specialty Chemical



Source: CMC-Engineering

For the microturbine installation, the parts are related to the four major systems: (a) natural gas hookup; (b) connection to the hot water generation loop; (c) connection of the microturbine exhaust to the boiler windbox; and (d) electrical connection to the utility service panel. Parts needed for the modifications to the boiler will be limited to the connecting flange for the windbox with a fitted thermocouple to monitor engine operation. In addition, it may be necessary to control the excess air level in the furnace to ensure safe combustion for the burner when the microturbine air is added to the windbox. This may require an O2 trim loop with oxygen sensor located in the boiler stack. Combustion air blower would also need to modulate to account for the microturbine operation. All parts, including fitting and sensors, were installed according to the installation manual that was provided to the host site. With the exception of the microturbine, these parts and system components were provided by Momentive Specialty Chemicals as part of the match contribution to the project, bringing the overall match contribution to levels above those planned for the project. This included the fuel and operation support necessary during the performance of the field tests and installation.

CHAPTER 4:
Combustor Testing, Development and Fabrication

4.1 Goal and Objectives

The objective in this task was to develop and fabricate low-NOx silo combustor for the microturbine to be retrofitted and integrated with the TO burner and a CHP assembly for the host site. The low-NOx silo combustor was to be patterned to the PIER developed combustor and was to be adapted to the operating conditions relative to the selected demonstration site. The objective was to include an evaluation of the need for more laboratory development work necessary to evaluate the performance of the combustor with VOC contaminated air stream if necessary under the CHP configuration designed for the specific host site.

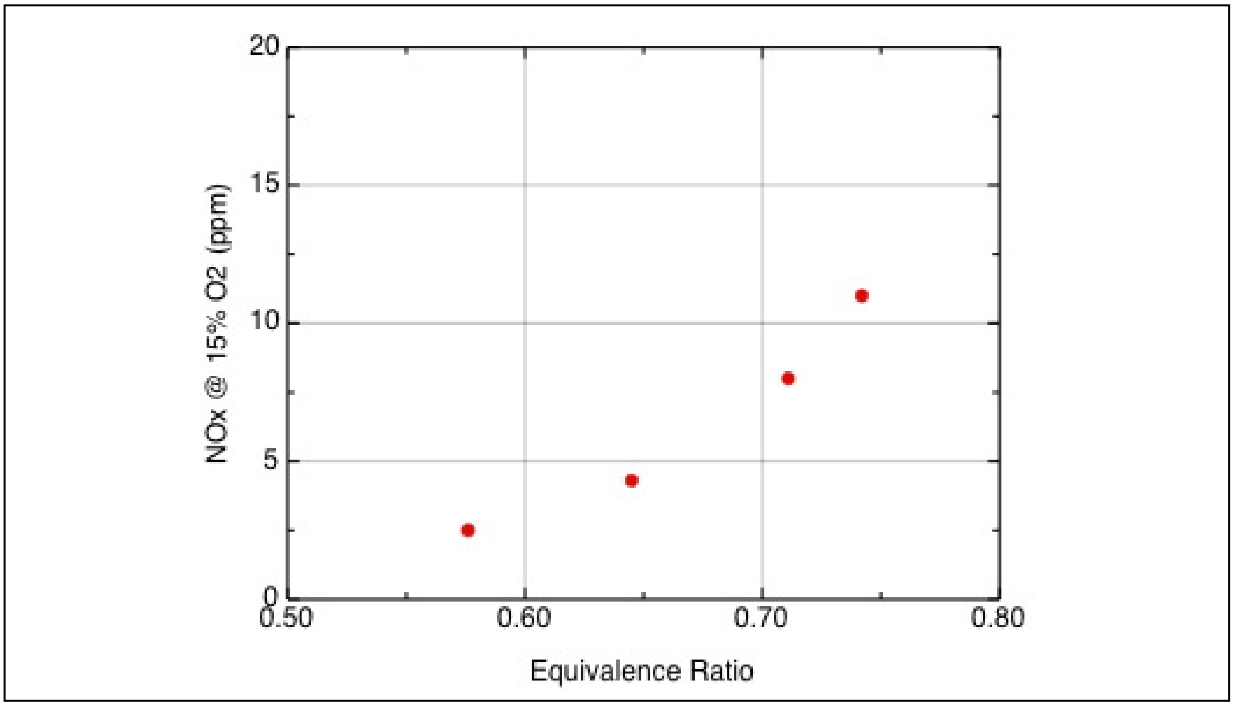
The design and permit conditions of the field demonstration site influence the type of combustor that is best applicable to the CHP installation. For example, if the host site requires a long-term warranty on the microturbine, the application of a novel silo combustor would not be possible because the microturbine could not be warranted based on the associated operational risks of this new technology. In addition, if air emissions limits on the TO or boiler are such that a low NOx combustor would result in an unnecessary operational risk to the installation, then the field installation may preclude the use of a new replacement combustor.

4.2 Approach to Combustor Development

Table 7 in Chapter 3 lists the emission performance goals of the silo combustor that are necessary for the TA-100 Elliott microturbine to meet the CARB 2007 emission limits. Figure 17 also shows that the TA-100 original combustor is not capable of meeting these emission limits with the original equipment manufacturer (OEM) annular combustor. Therefore, modifications to the engine were considered to replace this OEM combustor for application on either the simple cycle design or in a recuperated design (with compressor air preheat) according to the final CHP configuration selected for the demonstration host site. To that end, the project evaluated the application of a low NOx silo combustor that was utilized in a previous Energy Commission project under contract 500-03-037 and a new design under development with concurrent Energy Commission projects for microturbine integrated with burners for boilers. In advance of finalizing the site for the field demonstration, the project team pursued the latter approach in preparation for the possible need to modify the engine to guarantee lower NOx emissions. Final decision of the configuration of the microturbine, selection of silo combustor, and field CHP configuration were influenced by the host site requirements for participation and by the air permit levels issued by the local Air Quality Agency.

One of the critical design requirements for the new combustor is the equivalence ratio (defined as the actual fuel /air ratio divided by the theoretical fuel-air ratio) in the primary combustion zone. The equivalence ratio is dictated by the target NO_x and CO emissions and combustion stability required at engine design load as well as during light-off and part loads. Figure 31 illustrates laboratory test results of NO_x versus equivalence ratio for the combustor. These data, which are representative of most fully premixed combustors, indicate that for a sub 5 ppm NO_x performance at full load the primary combustion zone would have to be at an equivalence ratio of less than 0.65. Because of the ability to stabilize the flame at lower equivalence ratios with this design, the project team selected a design equivalence ratio of 0.58 which would indicate an expected NO_x performance of about 3 ppm corrected to 15 percent O_2. This level of NOx is sufficient to meet the CARB 2007 NOx emission limit of 0.07 lb/MWh, which translate to 4.33 ppm for the assembly being considered for the RTO where overall CHP efficiency will exceed 90 percent.

Figure 31: NOx Emissions versus Flame Equivalence Ratio in Lean Premixed Combustors



Controlling flame equivalence ration is necessary for ultra low NOx emissions in premixed air-fuel combustor
Source: CMC-Engineering

However, lean premixed combustors that operate at very low NOx emissions can result in excessive unburned fuel, manifested as CO emissions. When lean limits are approached, CO emissions can increase exponentially. Efficient mixing of fuel and air and increasing the residence time of the combustion products (for example, increasing the volume of the combustor) can mitigate some of these CO emissions by extending the lean limits of flammability. However, these conditions are difficult to achieve in practice. Increasing residence time can have a negative effect on the formation of NOx, as illustrated in Figure 32. Therefore, by reducing CO in the burnout zone NOx could increase thus negating the benefit of enlarging the combustor. Residence time increase has to occur in the flame zone after the dilution air is added and the peak flame temperature has been reduced. This would prevent the added formation of NOx while trying to reduce CO.

As indicated, the projected initially evaluated upgrading the design of the combustor developed under PIER project 500-03-037 to a higher firing capacity and with reduced CO emissions. This combustor uses a single-stage fully premixed design that is very effective in reducing NOx but can result in excessive CO emissions (unburned fuel) which can cause non-compliance for TOs due to the use of CO in calculating the destruction efficiency of the VOCs. A second approach was also evaluated that looked at a new design based on a 2-stage premixed system that can achieve as low NOx emissions and the single stage design but can provide better CO emission performance. The following two sections discuss the development of a silo combustor for the modification of the TA-100 recuperated microturbine to simple cycle.

Figure 32: Effect of Residence Time on NOx in Premixed Lean Flames

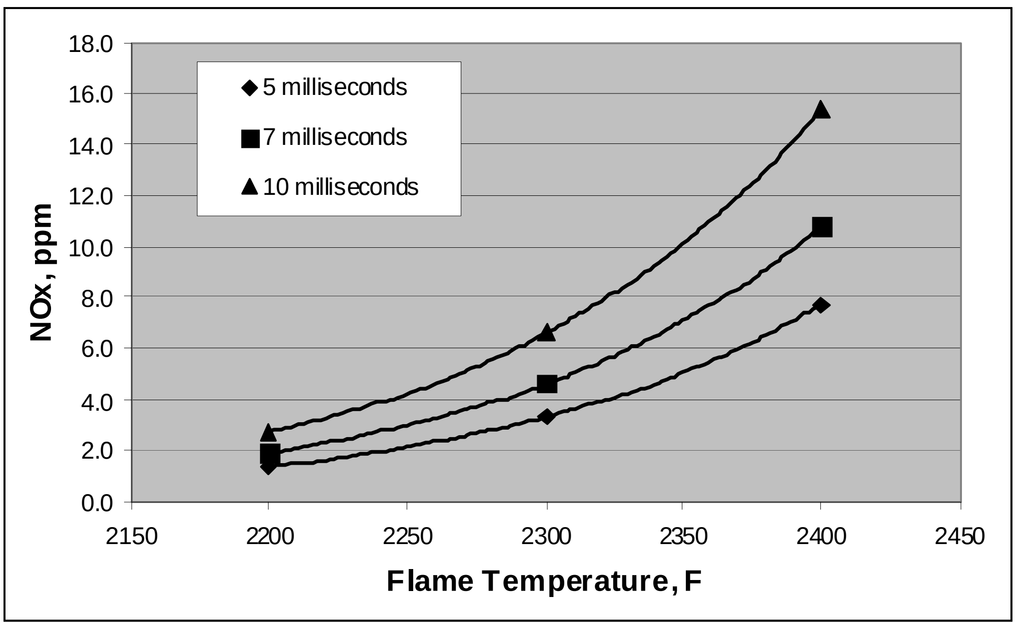


Figure describes tradeoff between reducing CO versus increase in NOx by increasing residence time
Source: CMC-Engineering

The development and testing of these combustors was undertaken in the Altex combustion laboratory, in part using match funds made available to the project. Figure 33 illustrates the combustion test rig. The combustors were fitted to the forefront of the rig and exhausted in a heat exchanger fitted with water cooling to remove excess heat prior to exhausting to the atmosphere. To monitor all important temperatures, both K and R thermocouples were utilized. In addition, flows were monitored by calibrated rotometers and orifice meters. Pressures at various locations were monitored by manometers. To monitor emissions, sample gases were extracted from the exhaust using a cooled stainless steel probe. The sample then flowed through a heated line, to avoid condensation, to a filter and desiccant trap to remove moisture ahead of the emissions monitors. The calibrated emissions monitors used are shown in Figure 34. Emissions were measured with a state-of-the-art continuous emission monitors listed in Table 23. These are standard monitors typically used to certify that combustion equipment meets permitted standards. Before each test, these monitors were calibrated, using applicable gas standards.

Figure 33: Combustor Test Rig

Picture of Combustor installed at the Altex facility located in Sunnyvale, California
Photo Credit: Altex Technologies Corporation

Figure 34: Continuous Emission Monitors

Calibrated emission monitors used during combustor testing at the Altex facility in Sunnyvale, California
Photo Credit: Altex Technologies Corporation

Table 24: Specifications of Continuous Emission Monitors

Measurement Parameter	**Analyzer Manufacturer**	**Measurement Principle**	**Ranges**
NO/NOx	Thermo Environmental	Chemi-luminescence	0-2.5, 20, 25, 200, 580, 1000, 2500, 10000ppm
CO	Thermo Environmental	Gas filter correlation	0-1, 2, 5, 10, 20, 50, 100, 200, 500, 1000ppm
O2	California Analytical Instruments	Galvanic Fuel Cell	0-5, 10, 25%
CO2	California Analytical Instruments	Flame Ionization Detector (FID)	0-5, 15, 20%
Total Hydrocarbons	MSA/Baseline	Flame Ionization Detector (FID)	0-10, 20, 50, 100, 200, 500, 1000ppm

The following two sections describe the combustor development for each of these two combustor approaches.

4.3 Development of Silo Combustor

Two silo combustor designs were evaluated for this effort. The first design was an upgraded version of the single-stage fully premixed silo combustor that was used under the PIER project 500-03-037 for an industrial boiler application. That combustor was rated for a, 80 kW gross power output. Therefore, the design required an upgrade to increase power to 100 kW generator power output. In addition, the combustor design required improved mixing and greater exhaust gas residence time to better control CO emissions. This latter requirement was necessary in this project because the combustor would have to operate without added burner firing in some TO applications that would not require any supplementary firing to maintain furnace temperatures in the range of 1,200 to 1,500 F. The second combustor was based on a developing design that will likely be used in integrated burner-microturbine assemblies. This design is being investigated in part under match funds provided by the US DOE and the Energy Commission PIER program and hardware provided by the Southern California Gas Company (SCG). The decision to add this combustor to the TO project was the improved results attained with CO emissions which would alleviate the concern for small TO units without supplementary firing.

The selection of the Momentive Specialty Chemicals for the host site secured the final requirements of the microturbine configuration and the selection of the final combustor design that would satisfy the management at the host facility and secure their participation. The CHP application at the MSC site necessitated the retrofit of a commercially available TA-100 recuperated 100 kW Elliott microturbine. This microturbine would use the original equipment manufacturer (OEM) annular combustor because of its commercial status. The exhaust of the microturbine would be ducted to an existing boiler windbox equipped with a specially designed burner capable of burning 100 percent waste process gas containing about 20 percent hydrogen and several hundred ppm VOCs from the manufacturing of formaldehyde based resins. The air permit on the boiler at the MSC site is also such that NOx emissions compliance would not be affected by the microturbine even with the original combustor. The MSC site required the use of the microturbine with the original combustor. This decision was in part made to lower the perceived operational risk associated with a new combustor technology.

4.3.1 Single-Stage Silo Combustor

The first approach that was evaluated focused on the upgrade of the silo combustor developed under the PIER project 500-03-037. That combustor utilized a one-stage fully premixed design with pilot assist for ignition and flame stabilization. That combustor was demonstrated to achieve CARB 2007 emissions, albeit with excessively high CO emissions. However, because of its application on industrial boilers, also burning natural gas, and because of the operating requirement that mandated that the microturbine would fire only when the burner was also firing, CO emissions were maintained at or below the levels mandated in the boiler emission limits. Another important feature of that combustor was its firing rate design which was at 80 kW, whereas the new combustor would require a nearly 30 percent increase in firing rate to accommodate the higher generating capacity of the 100 kW microturbine.

Figure 35 illustrates the schematic of the original combustor and its implementation on the microturbine that was achieved under the PIER 500-03-037 project. To address potential light-off and combustion stability issues in the final combustor design, the combustor was equipped with a pilot gas line which would be able to supply a small quantity of the total fuel and support flame stability with some diffusion burning. Therefore, the function of the pilot fuel was to promote reliable and vibration-free light-off and combustion stability as engine part firing rate which occurs from light-off to full engine rating. This period of increased firing rate from the light-off condition to full firing rate takes place over an approximately two minute period. From there on, the microturbine operates at full power. At full firing rate, the combustor would have to operate without the pilot assistance to achieve lowest NOx potential. This is possible if combustion stability is achieved at maximum heat release rate without the pilot.

Figure 35: Silo Combustor Configuration for Simple Cycle Elliott Microturbine

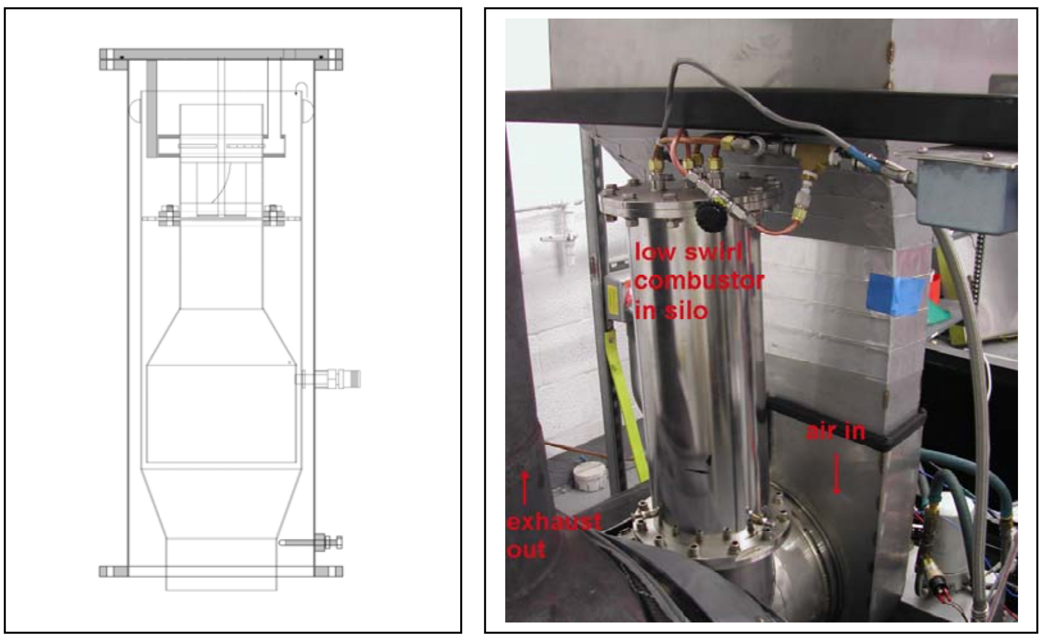


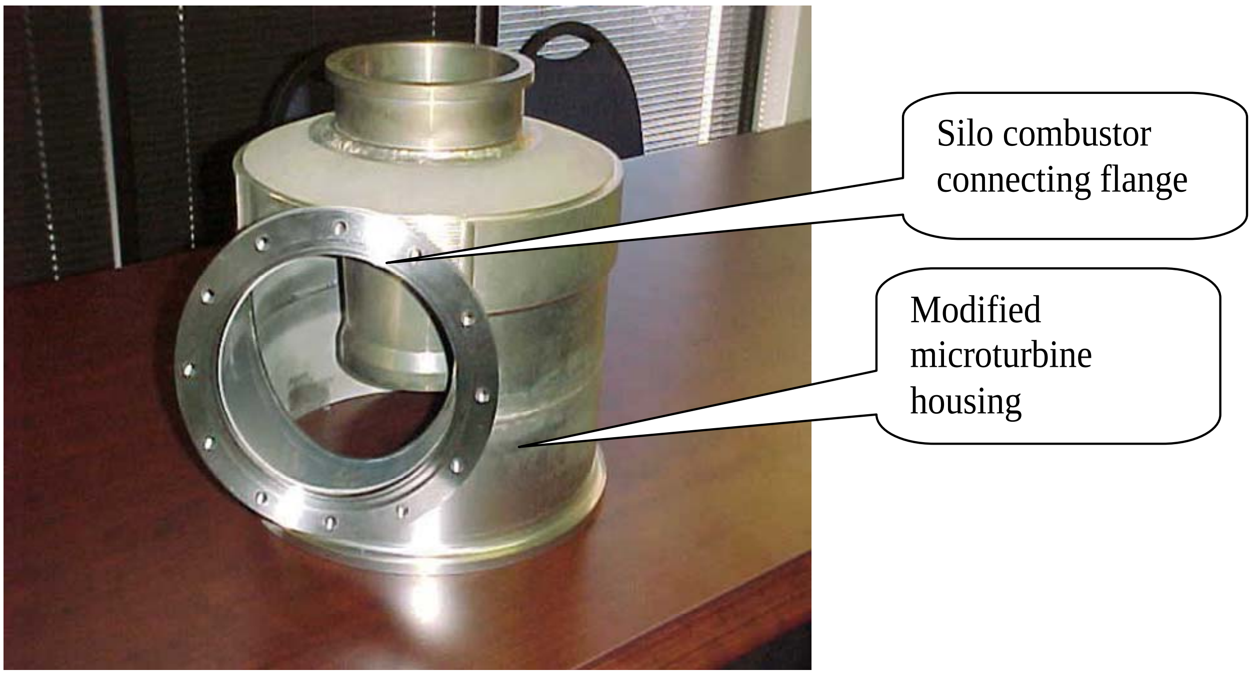
Figure shows design and testing of a low NOx silo combustor developed for 80 kW simple cycle microturbine

Source: CMC-Engineering

The retrofit of the silo combustor requires a new turbine housing, shown in Figure 36, and scroll section, drafted from the original combustor eliminating the duel combustion sections and the annular fuel injectors.

Fitting any silo combustor configuration to the microturbine housing required removing the engine from its cabinet and exposing the housing to implement modifications that would result in a flange that would secure the outside combustor to the housing, Figure 36. Therefore, the project team secured a special engine removal tool designed specifically for this task. Figure 37 illustrates the rail system that is part of the engine removal tool. The rail is then fitted with a small crane that can lift the engine without colliding with other parts in the engine cabinet.

Figure 36: Modified Housing Necessary for Application of Single-Stage Silo Combustor



Modification of turbine housing necessary for external silo combustor interface

Source: CMC-Engineering

Figure 37: Removal of the TA-100 Microturbine Replacement of Annular Combustor

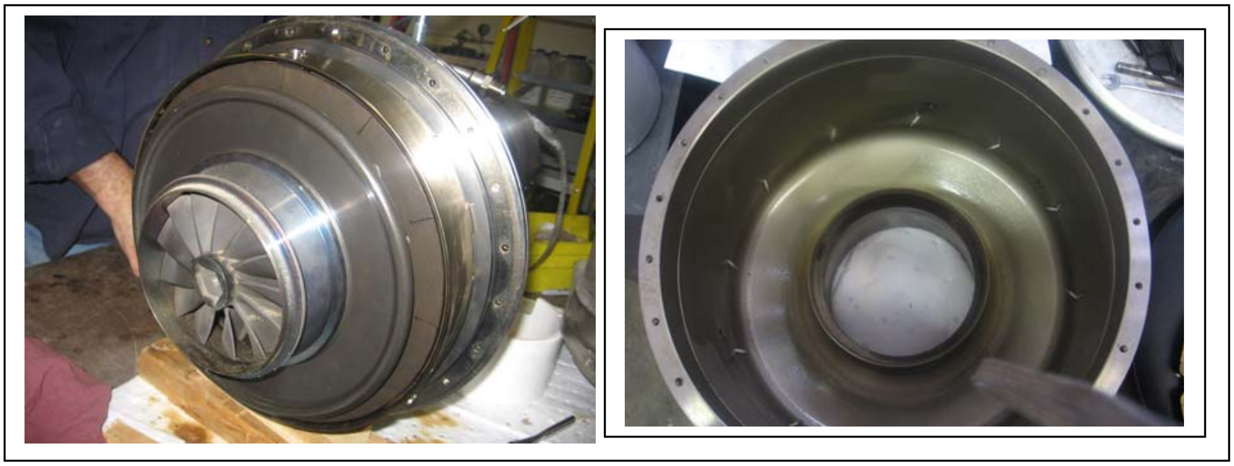


Figure shows removal of engine for access to turbine housing

Source: CMC-Engineering

Figure 38: Removing the Engine with Engine Removal Tool

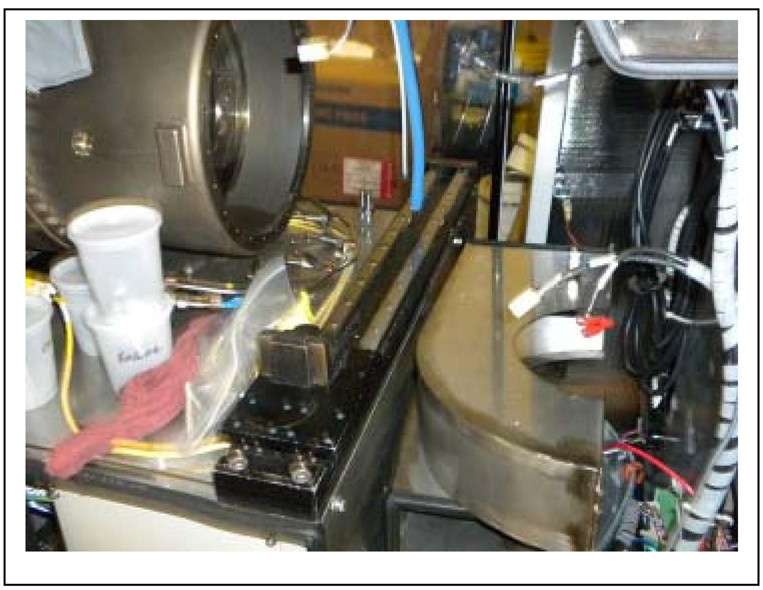


Figure shows engine removal system based on removal tool supplied by CMC-Engineering
Source: CMC-Engineering

Because of the requirements to increase power output from 80 to 100 kW net, for example, increasing the firing rate from about 2.1 to 2.6 MMBtu/hr, the dimensions of the silo combustor would have to be changed to accommodate the higher firing rate while maintaining the flame equivalence ratio in the range required for NOx compliance and reduced CO emissions. A process flow analysis was performed with the intent of achieving the following conditions:

- Increase air flow to flame zone to maintain 0.58 equivalence ratio in the flame
- Reduced flame zone bypass cross-sectional air (between liner and housing)
- Increased exhaust gas residence time at high temperature (before turbine inlet)
- Reduced and delayed cooling of the combustion byproducts to promote CO burnout
- Increase diameter of fuel injection area for greater fuel flow through extended fuel injection spokes
- Extended liner and combustor housing dimensions to accommodate higher flow and residence time

Figures 39 to Figure 43 illustrate the calculated dimensions for the upgraded combustor. These design changes retained the key process conditions in the flame to achieve the NOx performance of less than 0.35 ppm @ 15 percent O2, while reducing the level CO emissions by providing more controlled mixing of dilution air and greater residence time before turbine inlet. These design changes would have resulted in a silo combustor with approximately 0.5 inches increased diameter and 2.75 inches longer. The increase in length was limited by the amount of head space available in the cabinet for placement of the silo combustor.

Figure 39: One-Stage Lean Premixed Silo Combustor with Extended Length for CO Burnout

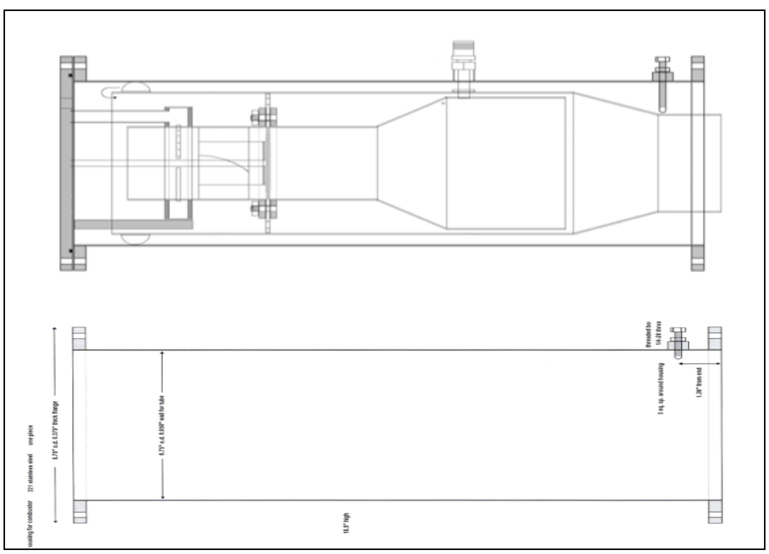


Figure shows how to modify single-stage combustor for better CO burnout

Source: CMC-Engineering

Figure 40: Increased Dimension of Combustor Liner

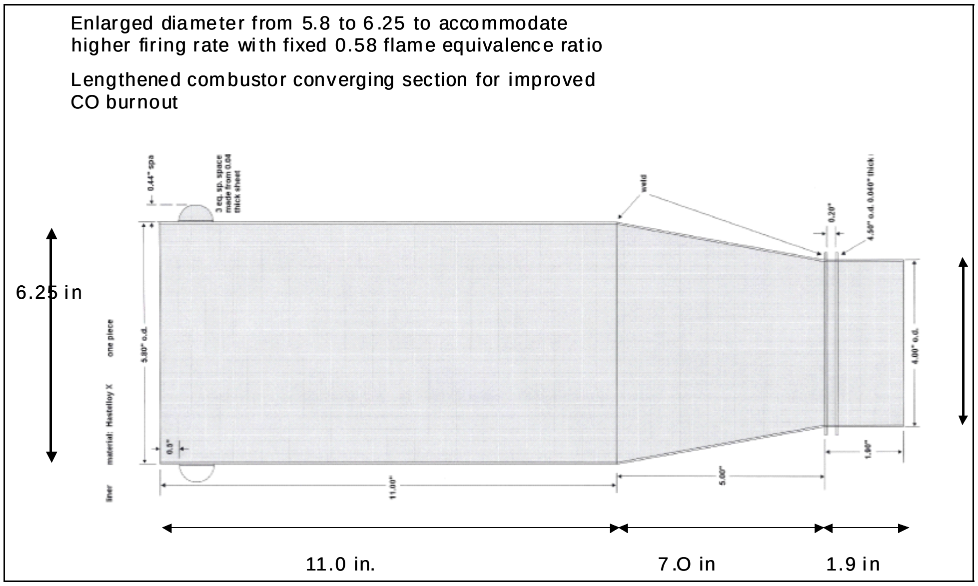


Figure shows the planned changes to combustor liner to fit extended combustor length
Source: CMC-Engineering

Figure 41: Upgraded Dimensions of Combustor Swirler Section

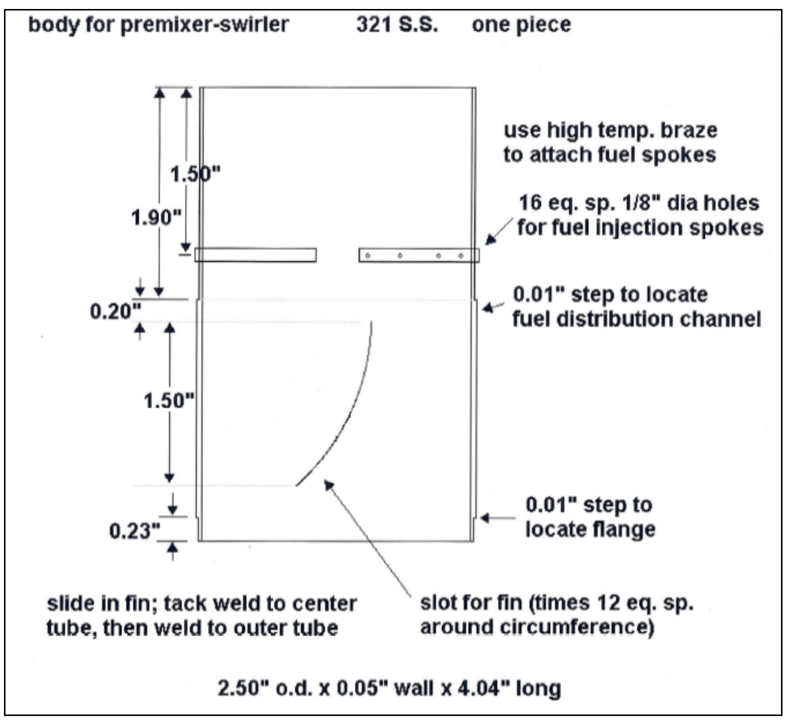


Figure shows the revised dimensions of flame holding section of silo combustor

Source: CMC-Engineering

Figure 42: Increased Diameter of Fuel Injection Spokes

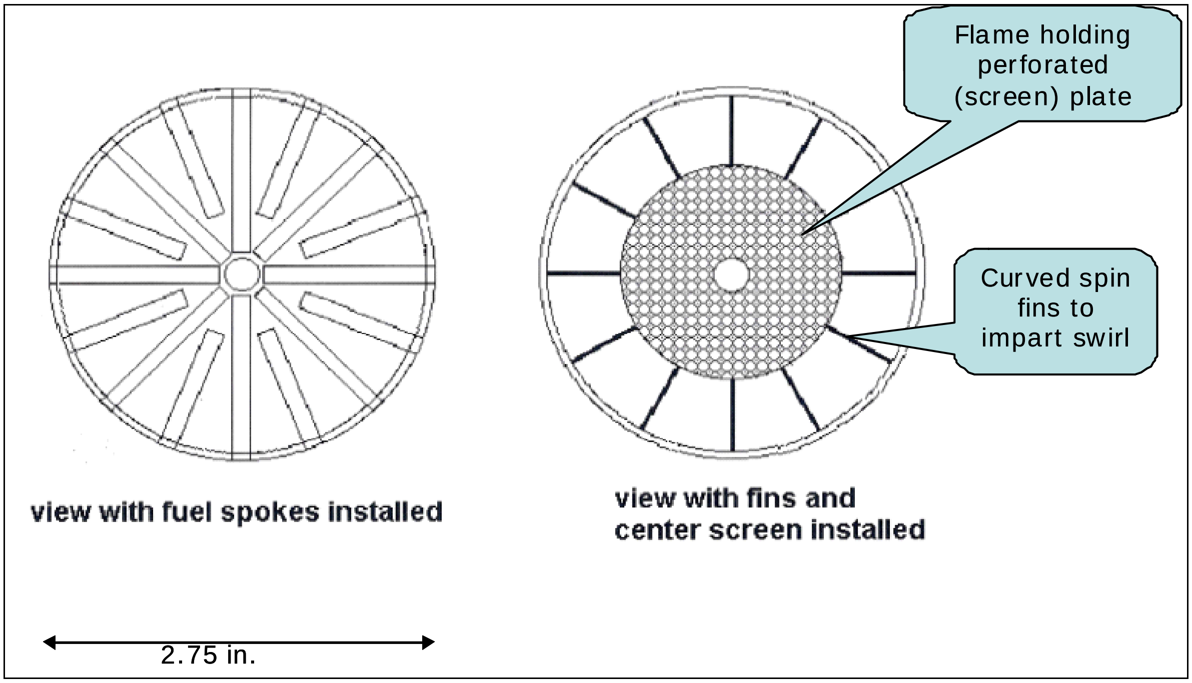


Figure shows the increase in fuel delivery spokes for higher firing rate

Source: CMC-Engineering

Figure 43: Increased Dimensions of Lame Exit Shroud

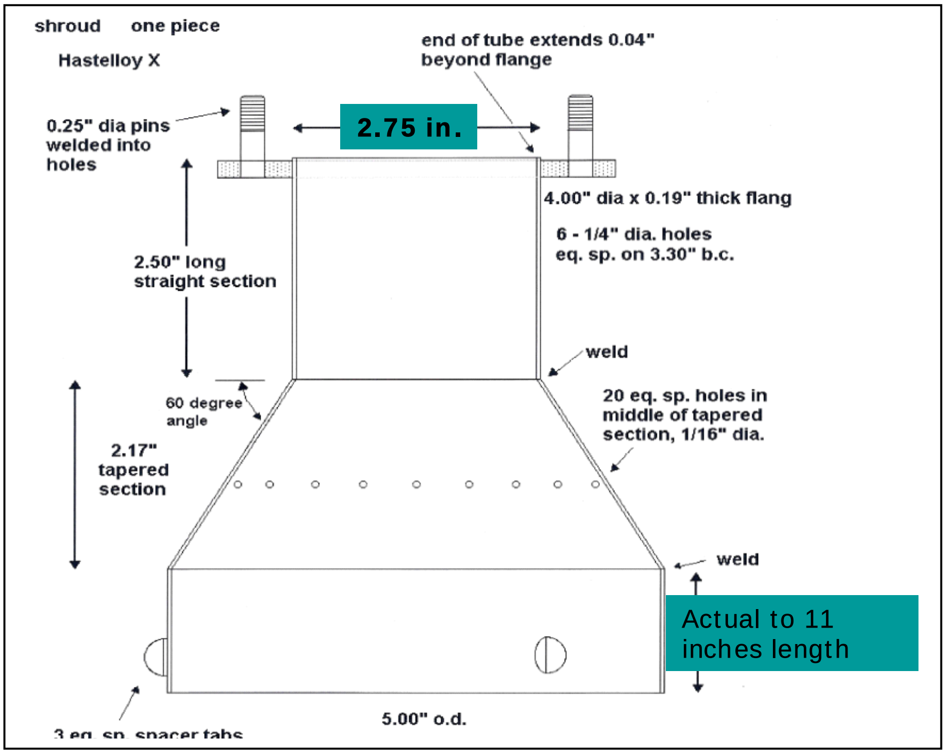


Figure shows additional dimension changes necessary to accommodate higher firing rate for 100 kW combustor

Source: CMC-Engineering

4.3.2 Two-Stage Lean Premixed Silo Combustor

In order to provide greater flexibility on the simultaneous control of NOx and CO emissions, Altex suggested a two-stage silo combustor that also operates in lean premixed conditions. Preliminary results under co-current projects had demonstrated significant promise for controls of both NOx and CO. Bench-scale results are shown in Figure 44 and Figure 45. By splitting the fuel injection in two stages, the peak flame temperatures can be controlled while also allowing the second stage combustion zone to combust any CO produced in the first stage. This allows the first stage to operate at very lean low temperature conditions which are beneficial not only from a NOx suppression point of view but also to protect fabrication materials.

Figure 46 shows a 3-D depiction of the combustor in its bench-scale testing configuration with the first stage in blue color on the left. This air cooling channel is consistent with gas turbine practice. The inside liner, that separates the compressor discharge air channel used for bypass cooling from the main combustion zone, and the first cyclonic designed zone are fabricated of Inconel 625, which has excellent heat and oxidation resistance. Further protection would require the use of Haynes 230 high temperature steel which is much more expensive. Similar alloys are utilized in commercial gas turbine combustors that face even higher temperatures because of operation near stoichiometric conditions in primary combustion zones. Therefore, the durability of the test article that uses lower temperature fuel rich and fuel lean zones should be good.

Figure 44: NOx Emissions Performance as a Function of First Stage Stoichiometry for the Two-Stage Lean Premixed Silo Combustor

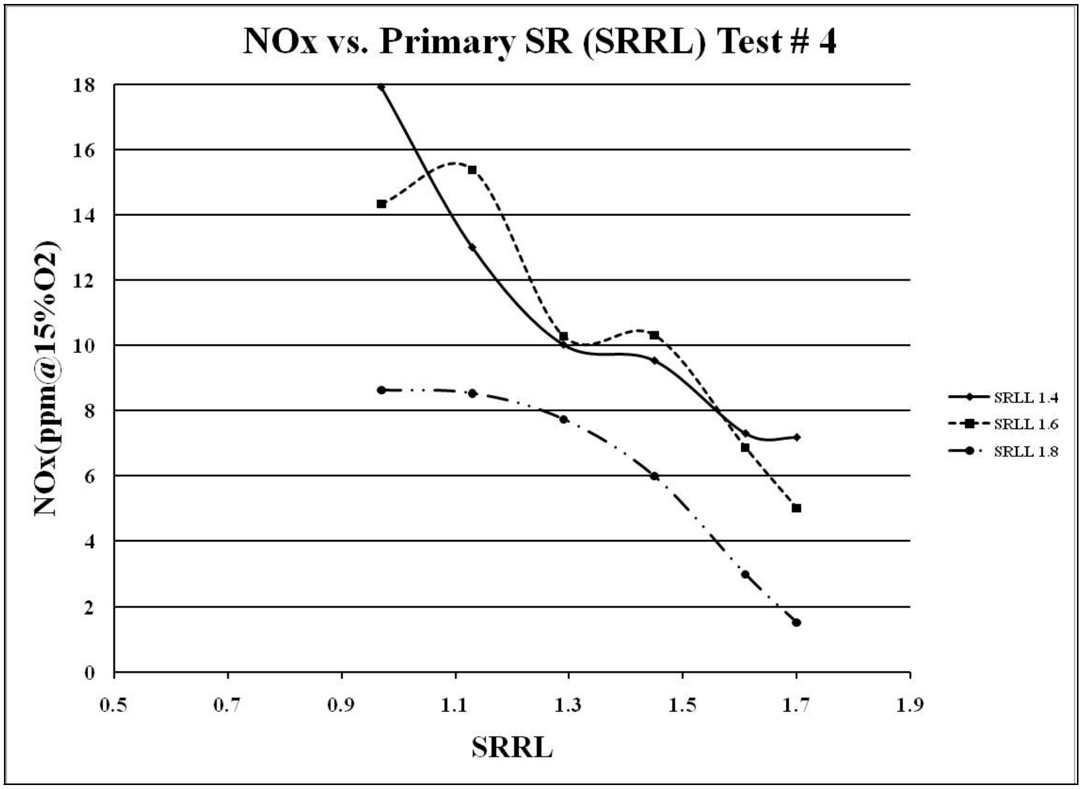


Figure shows CARB 2007 attainment for NOx Emissions with two-Stage Silo Combustor
Source: Altex Technologies Corporation

Figure 45: CO Emissions as a Function of First Stage Stoichiometry with Two-Stage Lean Premixed Combustor

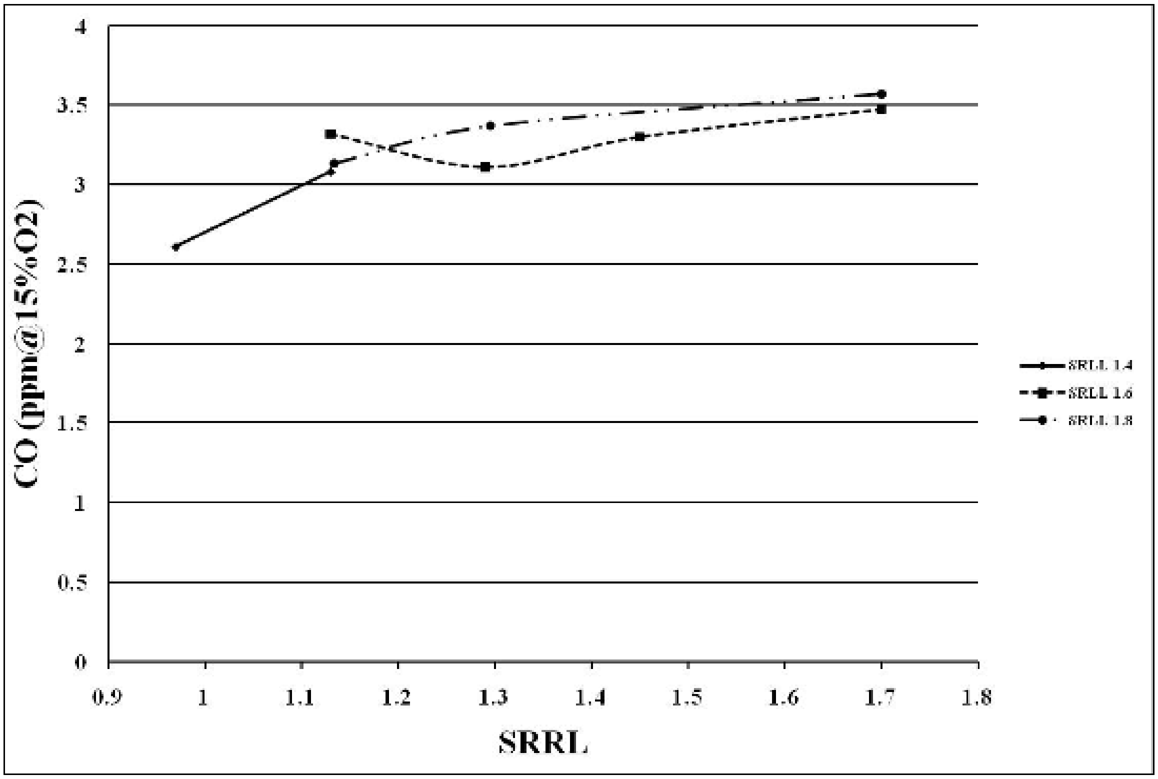
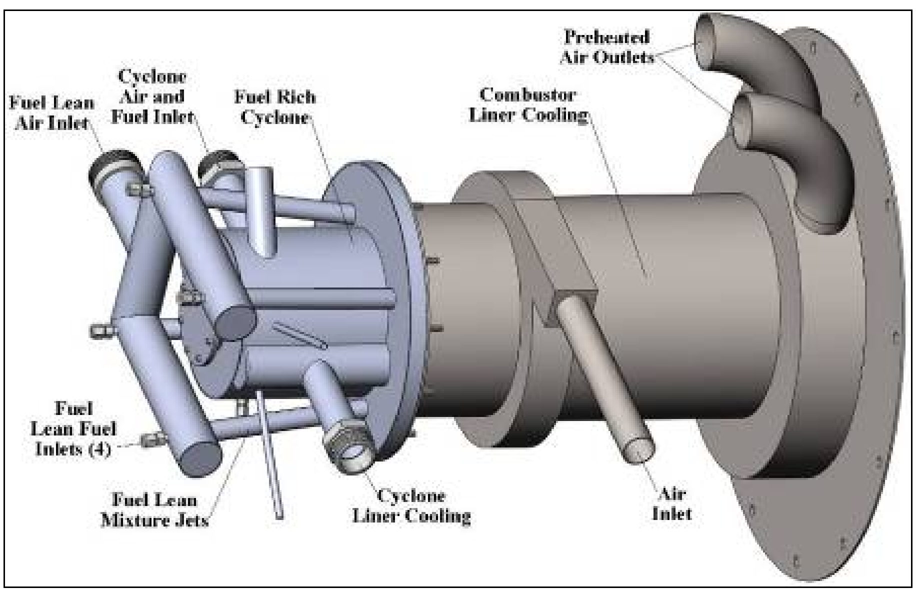


Figure shows attainment of CARB 2007 CO emission limits with two-stage lean premixed silo combustor
Source: Altex Technologies Corporation

Figure 46: Two-Stage Silo Configuration



Representation of the Two-Stage Combustor Selected for development
Source: Altex Technologies Corporation

A picture of the back end and exit plane of the first-stage cyclone burner is given in Figure 47, showing the tangential cyclone fuel/air entry port. Fuel and air mixing is facilitated by a 0.953cm diameter fuel supply tube with 32 holes of 0.16cm placed on the axis of the 3.175cm diameter air entry tube. For the four fuel lean jets, shown as the inwardly angled tubes surrounding the cyclone chamber in Figure 48, fuel/air mixing is facilitated by 0.635cm diameter fuel supply tubes with eight holes of 0.16cm placed on the axis of 3.17cm diameter air entry tubes.

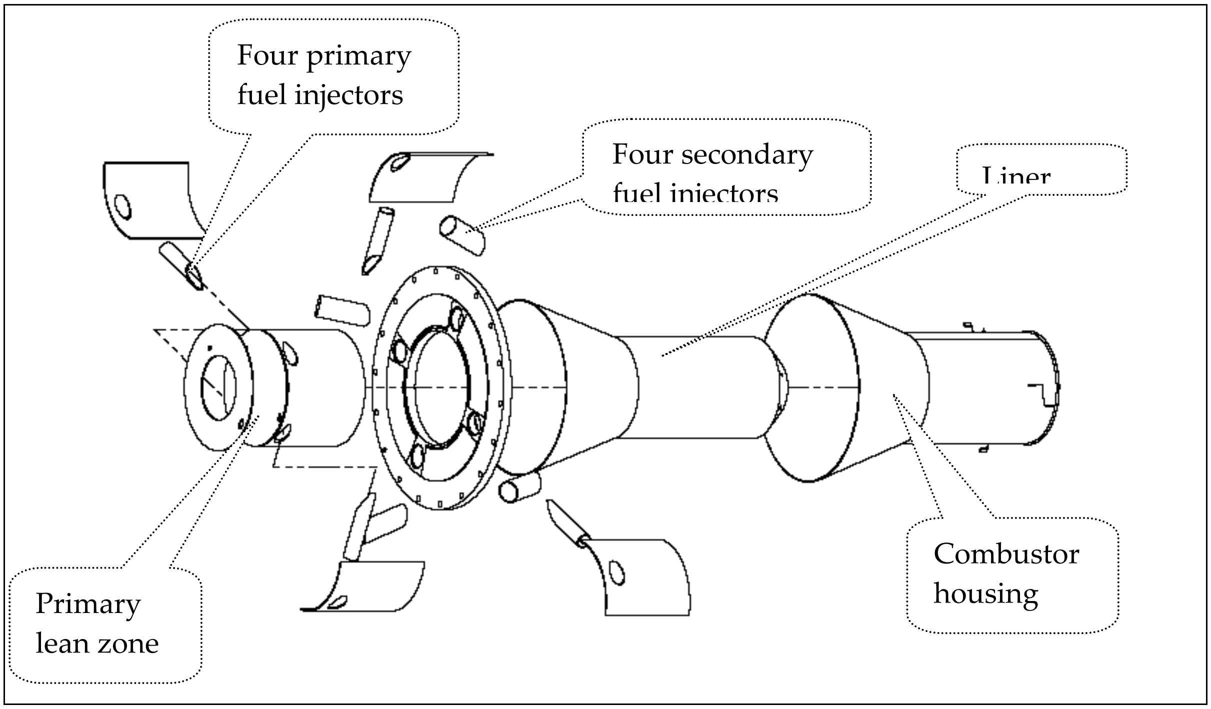
Figure 47: Cyclonic Air and Fuel

First stage section with cyclonic air and fuel injection (Left: Front View; Right Exit View)
Photo Credit: Altex Technologies Corporation

Because of the good results achieved with this configuration and because of the ongoing development and testing under separate programs, CMC-Engineering and Altex decided to pursue this design for the CHP-TO project. Figures 48 to Figure 51 illustrate the fabrication drawings for the combustor. As in the laboratory test unit, the fabrication unit used four tangential injectors for the lean primary zone. This zone is full premixed with external air cooling from the compressor discharge. Fluent™ modeling suggested that the temperature of the metal in the primary zone will be well below the metallurgical limit of the material. However, to be certain, the project used the highest temperature resistance material available on the market. Selection of the material was performed by CMC-Engineering and Haynes-230 steel was procured from Haynes International, located in Indiana. Fabrication of the combustor took place at the Huffman Welding Company in Menlo Park, California.

Final utilization of the low NOx silo combustor was based on acceptance by the host site and applicable permit requirements. As indicated, MSC opted to use of the engine as provided by the Original Equipment Manufacturer (OEM) to ensure least operation risk. This option was available only under the permit conditions that allow the site to operate the VOC-burning boiler with existing emission levels. These levels were guaranteed by the project team, as all indications showed that the microturbine will add about 1 ppm NOx to the overall emission level currently produced in the boiler with a new silo combustor or less than 5 ppm with a modified annular combustor.

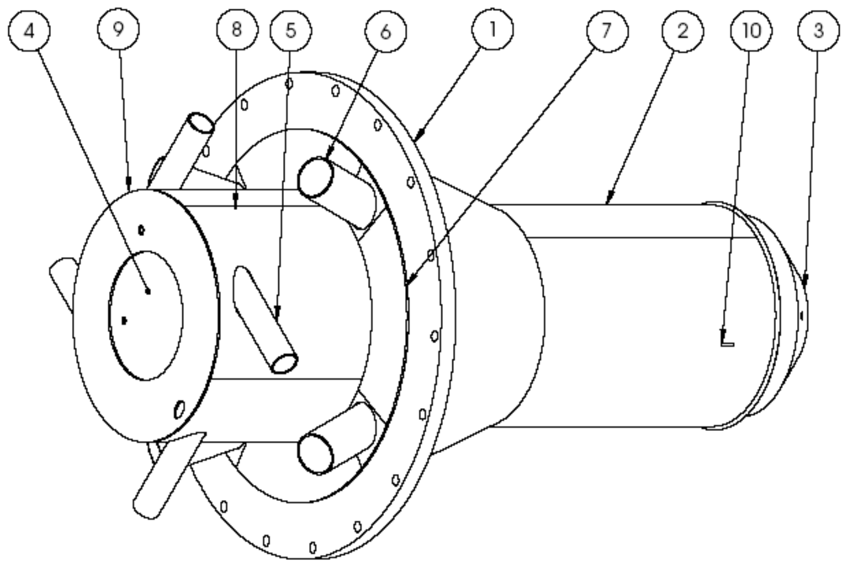
Figure 48: View of Silo Combustor Components Welding Configuration



Source: Altex Technologies Corporation

Figure 49: Silo Combustor Fabrication Drawing and Component List

ITEM NO.	PART NUMBER	DESCRIPTION	QTY.	Material
1	Silo Combustor main flange	3/4 x 17" dia	1	Haynes 230
2	airflow director 2 bottom	0.08 x 41.25 x 17.64	1	321 SS
3	Silo Combustor 5 bottom	0.08 x 38.58 x 19.12	1	Haynes 230
4	Silo Combustor 5 top	0.08 x 8.16 dia + 0.08 x 25.64 x 6.08	1	Haynes 230
5	primary jet 3	1" O.D. x 0.065 w.t. x 5.25	4	Haynes 230
6	secondary jet 3	1.5" O.D. x 0.065 w.t. x 3.5	4	Haynes 230
7	main silo flange air jacket lid	0.08 x 6.24 x 5.26	4	321 SS
8	air jacket top cylinder pie	0.08 x 6.85 x 6.49	4	321 SS
9	air jacket top cap	0.08 x 8.71 dia	1	321 SS
10	air jacket stand off	0.08 x 0.31 x 0.50	3	321 SS



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Notes

Drawn By:	David Arft 5/25/2011
Drawing:	Silo Combustor 5
Revision:	1 Scale: 1:4
Page:	1 OF 3

Figure shows list of components for combustor fabrication
Source: Altex Technologies Corporation

Figure 50: Silo Combustor Fabrication Drawing - Side Views

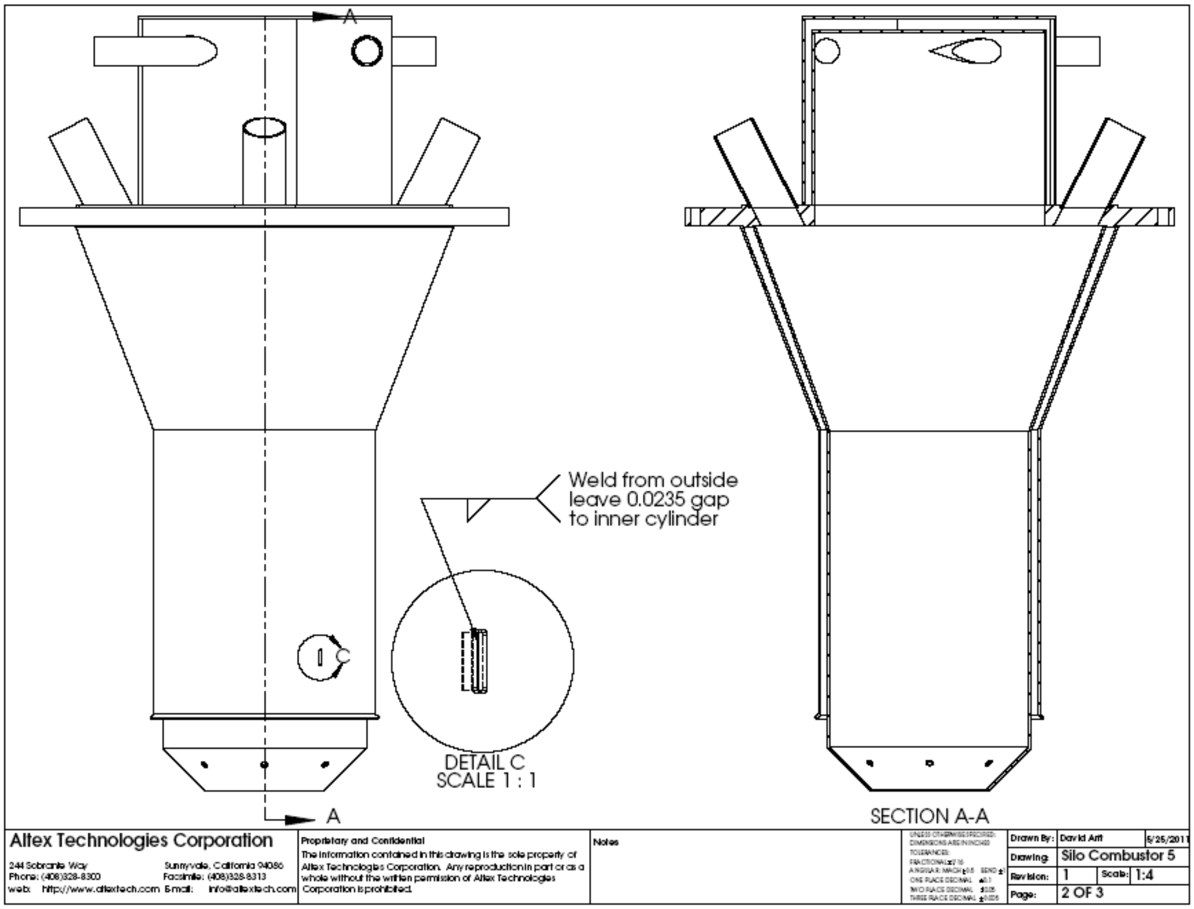
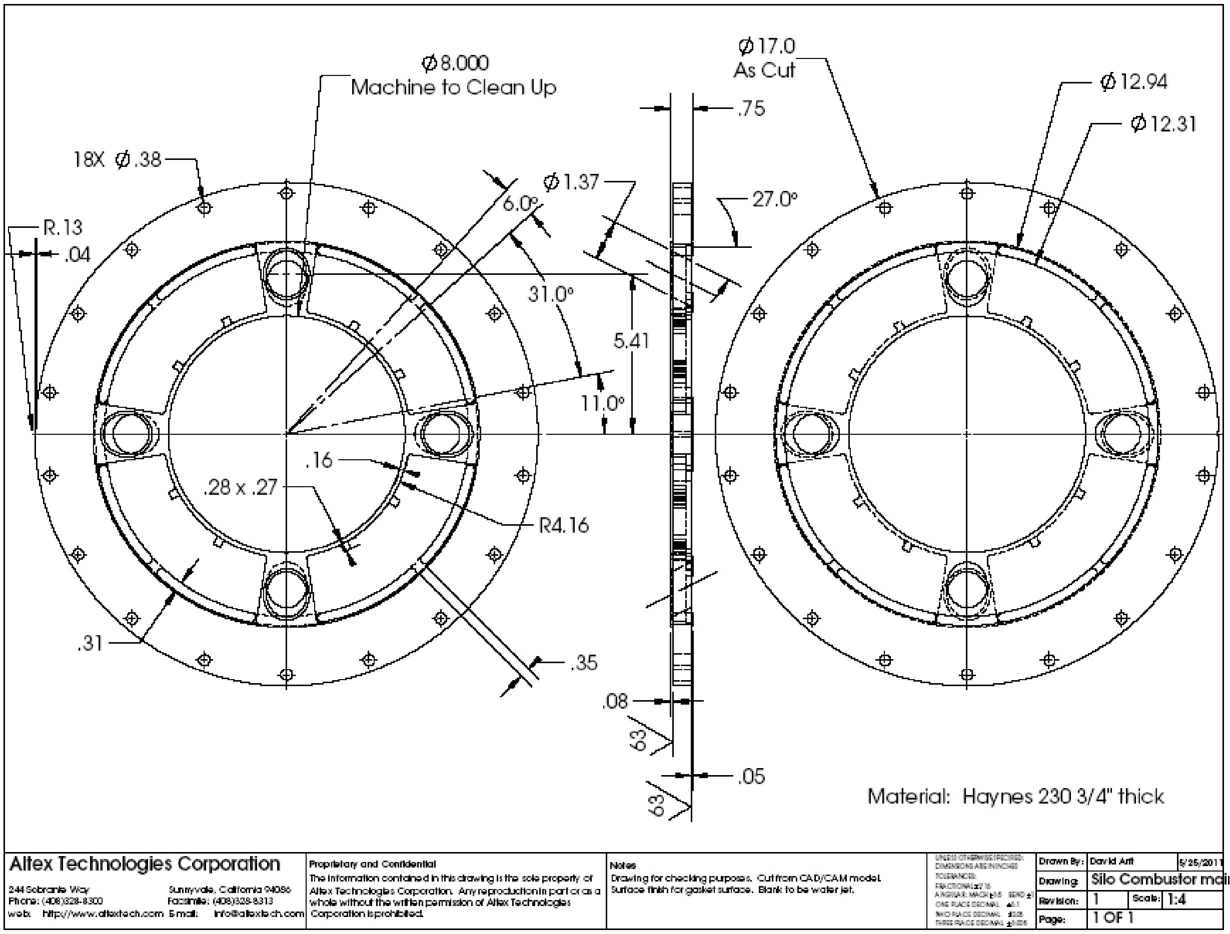


Figure shows the side view and cutout of two-stage silo combustor

Source: Altex Technologies Corporation

Figure 51: Top Flange Detail



Fabrication drawings detail of connecting flanges

Source: Altex Technologies Corporation

CHAPTER 5: Purchase and Fabricate Systems Components

5.1 Goal and Objectives

The goal of this task was to secure all the system components for preliminary assembly and testing prior to shipment of the microturbine and auxiliary equipment to the host site for installation. Attainment of this goal entailed achieving the following objective: (1) preparing and releasing purchase orders (PO); (2) completing the purchase of all the CHP equipment; and (3) securing support of Elliott Engineering Systems (EES) field test engineering to implement engine modifications and upgrades, along with arranging for the assembly site. The components included a parts list developed after the Field Test Agreement (FTA) was reached with the site on respective responsibilities for the procurement and fabrication of these components.

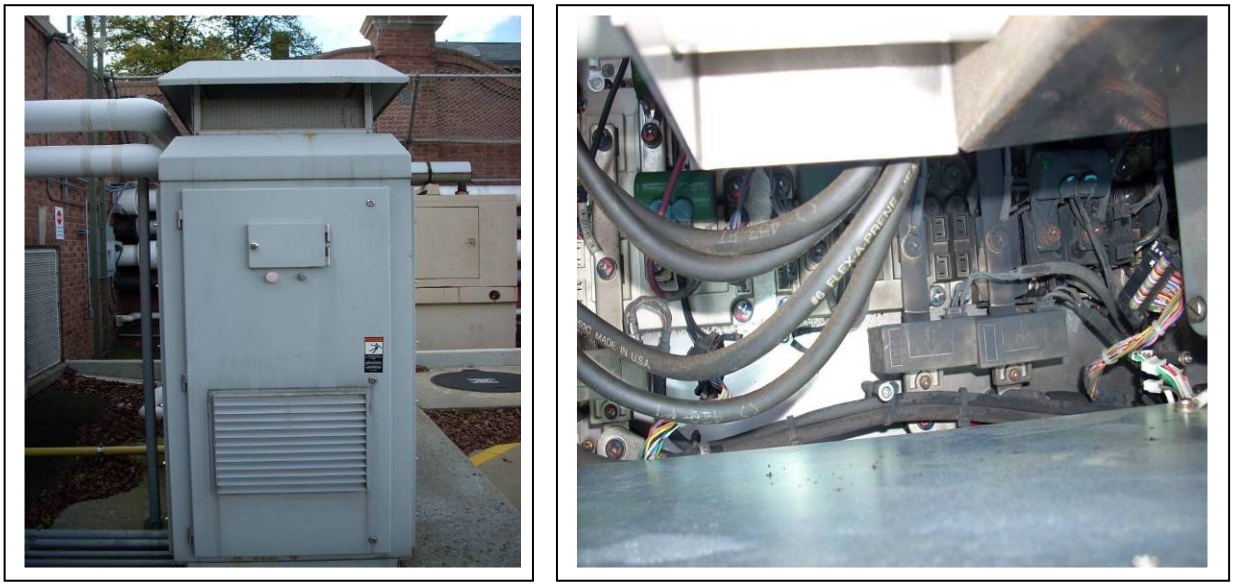
The following sections describe the microturbine equipment procured for the project; the work that was performed to upgrade and modify the microturbine for the project needs and the preparation of parts list for the installation at the selected host facility.

5.2 Purchase of TA-100 Microturbine

During late 2009, CMC-Engineering held conference calls with the management and sales personnel at the Capstone Microturbine Company in Southern California with the intent to explore using a simple cycle Elliott TA-100 microturbine manufactured by Elliott Energy Systems (EES) for the project. Because of the recent acquisition of the EES Company by Capstone, the management had not formulated their plans on how to proceed with the manufacture and planned upgrades of the EES TA-100 product line. Furthermore, Capstone informed CMC-Engineering that they had not planned on offering simple cycle versions of the TA-100 and therefore could not offer such equipment to CMC-Engineering. Pricing for a new recuperated TA-100 microturbine was likely to be double the level of match funds available to the project.

Following this discussion with Capstone, CMC-Engineering with the help of an EES field service engineer identified a handful of facilities in the U.S that desired to sell their used TA-100. Figure 52 illustrates the TA-100 located at the Johnson and Johnson (also referred to as JNJ) facility in New Jersey. On the right of the picture was an area of the power electronics cabinet, which had suffered some apparent damage and would likely require some hardware upgrade to the Integrated Gate Bi-Polar Transistors (IGBTs) of the power electronics supplied by Ebara/Densan of Japan.

Figure 52: TA-100 Microturbine at JNJ Site



TA-100 Microturbine inspected at Johnson and Johnson facility located in New Jersey (left) and identified repair needs in power electronics (right)
Source: CMC-Engineering

Following the field inspections and recommendations from the EES field service engineer on the cost of the repair, CMC-Engineering proceeded with the purchase of the TA-100 microturbine shown in Figure 52. The purchase was finalized in December 2009 and the unit was arranged for shipment to California. All purchase and shipping costs were provided by the match funds available to the project. Figure 53 shows an initial inspection of the engine compartment following the placement of the engine in the storage facility at Altex located in Sunnyvale, California.

5.2.1 Repairs and Upgrades of TA-100 Microturbine

The field and laboratory inspection of the engine confirmed that some upgrades were necessary to bring the microturbine to the most recent standards in hardware and software. Therefore, CMC-Engineering secured field service and parts for the initial upgrade of the system. The EES field service engineer performed the initial repairs as shown in Figure 54 and a more recent software package was uploaded in the power electronics, bringing the unit to most recent operational standards.

Figure 53: TA-100 Microturbine

Inspection of microturbine at the Altex Facility
located in Sunnyvale, California
Photo Credit: CMC-Engineering

Figure 54: Repairs and System Upgrades

Repairs and system upgrades were performed at the Altex facility located in Sunnyvale, California.
Photo Credit: CMC-Engineering

The final check of the TA-100 included a preliminary fire test in the Altex Facility. The tests included spinning the engine without generating power (crank mode) to check the rotational integrity of the engine rotor and bearings, the light-off of the engine to determine reliability of the ignitor system, and generator function by spinning the engine to full rotational speed and then generate power. For this test, the equipment was set up with a gas supply system that include six large high pressure natural gas bottles as shown in the top of Figure 55 and a load bank made available to the project under match funds. The bottom two photos in Figure 55 illustrate the power generated on the power electronics panel and on the load bank. As shown, the generation was limited to 80 kWe because the project team felt that it would be safer to limit turbine inlet temperature and load on the generator to a lower level than the manufacturer power rating until a more detailed operational test would be performed prior to shipping the engine to the eventual host site. In summary, these initial tests indicated that the engine was in good operating conditions; however, some inspection of the engine internals were necessary and, if necessary, replace the thrust bearing connecting the engine to the generator to ensure readiness of the engine for field installation after significant downtime.

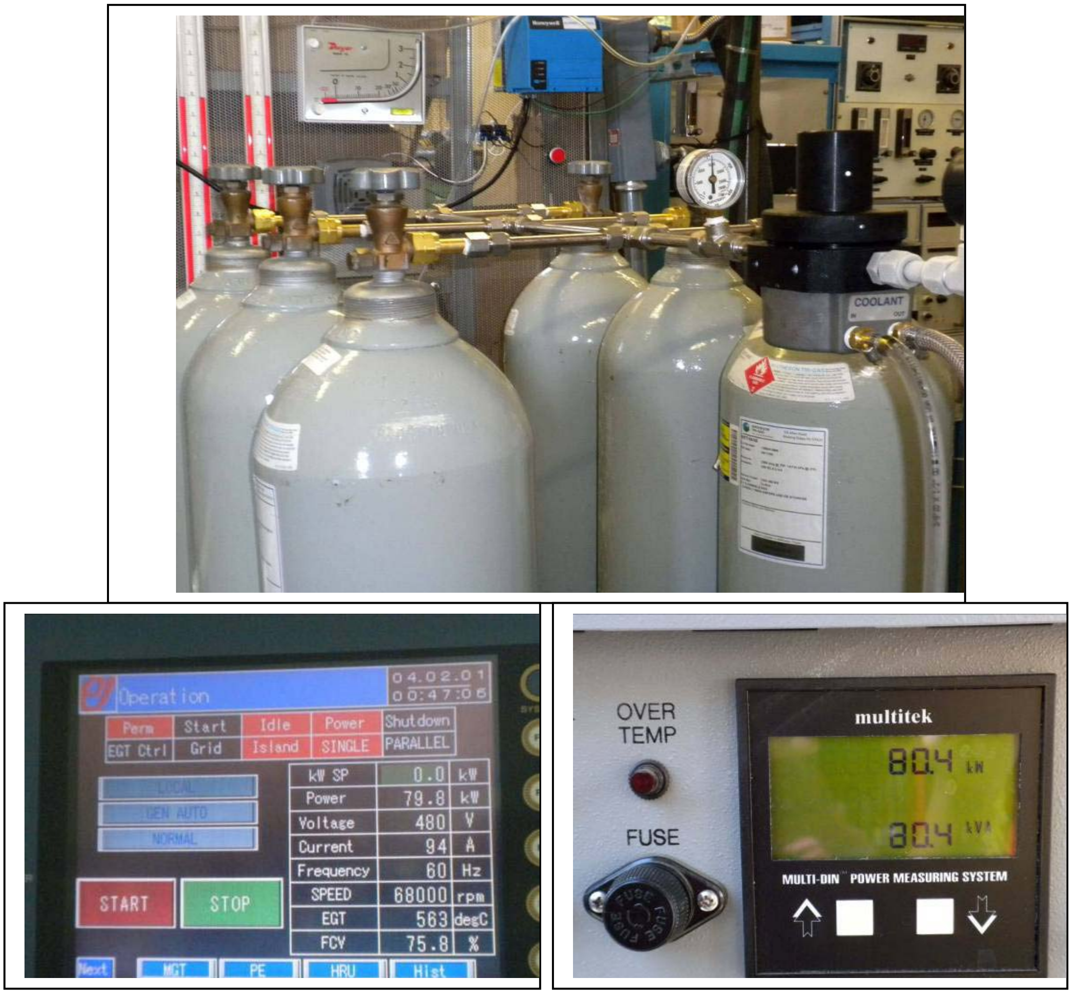
From the initial purchase order executed in November 2009 to June 2011, the project focused on securing a host site; modifying the microturbine to simple cycle; and fabricating the low NOx combustor that would be adaptable to a simple-cycle microturbine and usable for converting the TA-100 to a CARB 2007 compliant engine. Because the host site was finalized more than eighteen (18) months after these initial inspection tests were performed, further testing were scheduled as part of the fabrication, and assembly tasks but ahead of the shipment of the microturbine to the host site. These tests were performed in July and August 2011 with the assistance of the Elliott field service engineer. Section 5.2.4 presents the results of these final equipment readiness checks and upgrades.

5.2.2 Microturbine Inspection and Modifications

While the search for the host facility continued, inspections of the bearings and rotor on the engine occurred to ensure the lack of deposits and the possible presence of wear on the bearing. An engine removal tool was leased from the European Power Systems (EPS) company in Italy. The tool is necessary to remove the engine and take it apart for inspection. Figure 56 illustrates the installation of the removal tool with the engine already taken out. Figure 57 shows the turbine housing free from the engine in the cabinet and the microturbine on the shop floor.

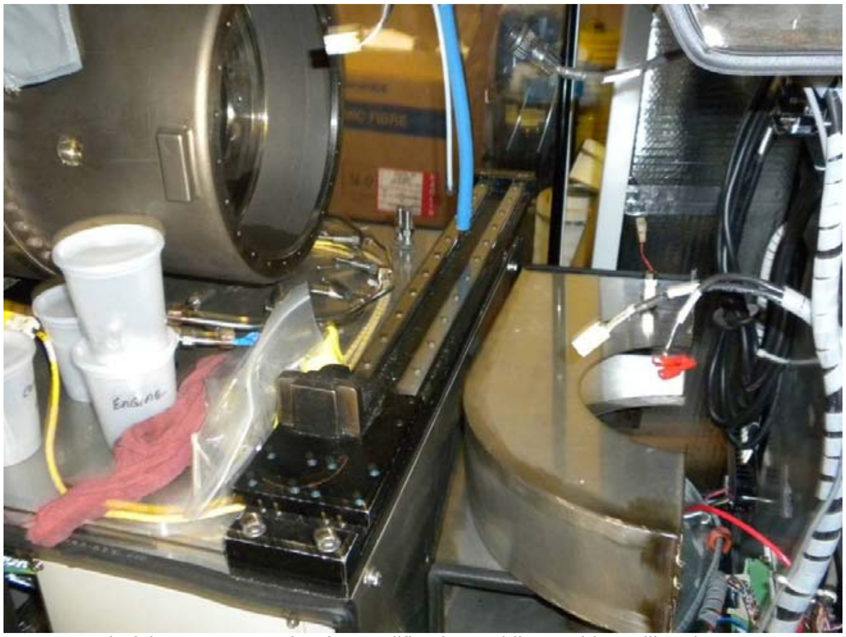
CMC-Engineering proceeded to take the engine apart to access various components of the engine including the combustion liner, the engine rotor and principally the two rotor bearings. Figure 58 shows various views of the engine being taken apart. Shown on the right of Figure 59 are the exposed combustion liner and the high temperature turbine blades. Figure 60 shows the two engine bearings, which were found free of wear. These inspections were necessary because the JNJ engine was not in operation for a period of two years after the power electronics was damaged.

Figure 55: Gas Supply Arrangement (top) with PE Display (bottom left) and Load Bank Power Usage (bottom right)



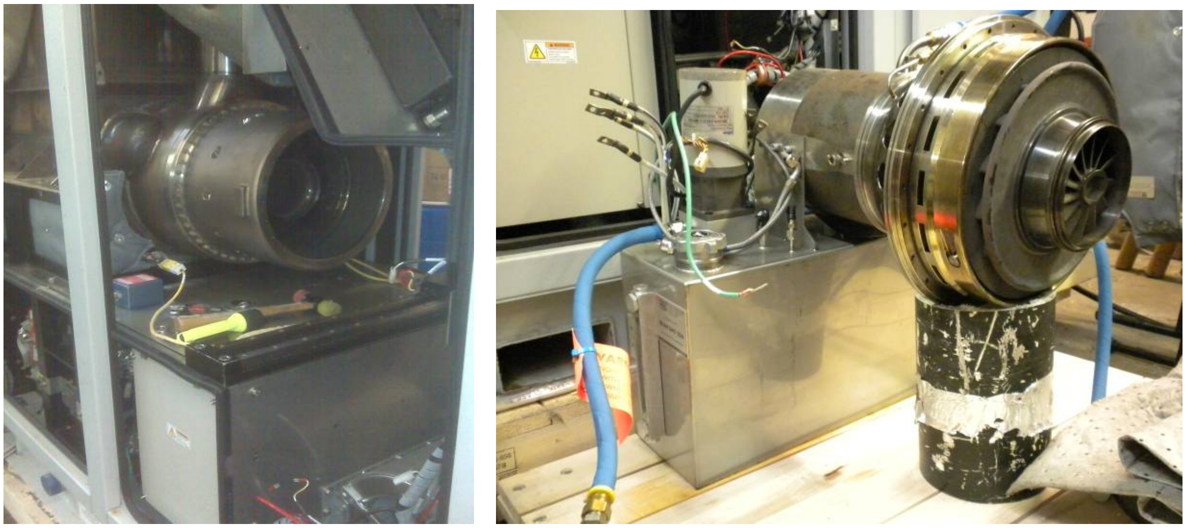
Preliminary fire test of the TA-100 at the Altex facility located in Sunnyvale, California
Photo Credit: CMC-Engineering

Figure 56: Engine Removal Tool Being Used to Remove Engine for Modifications



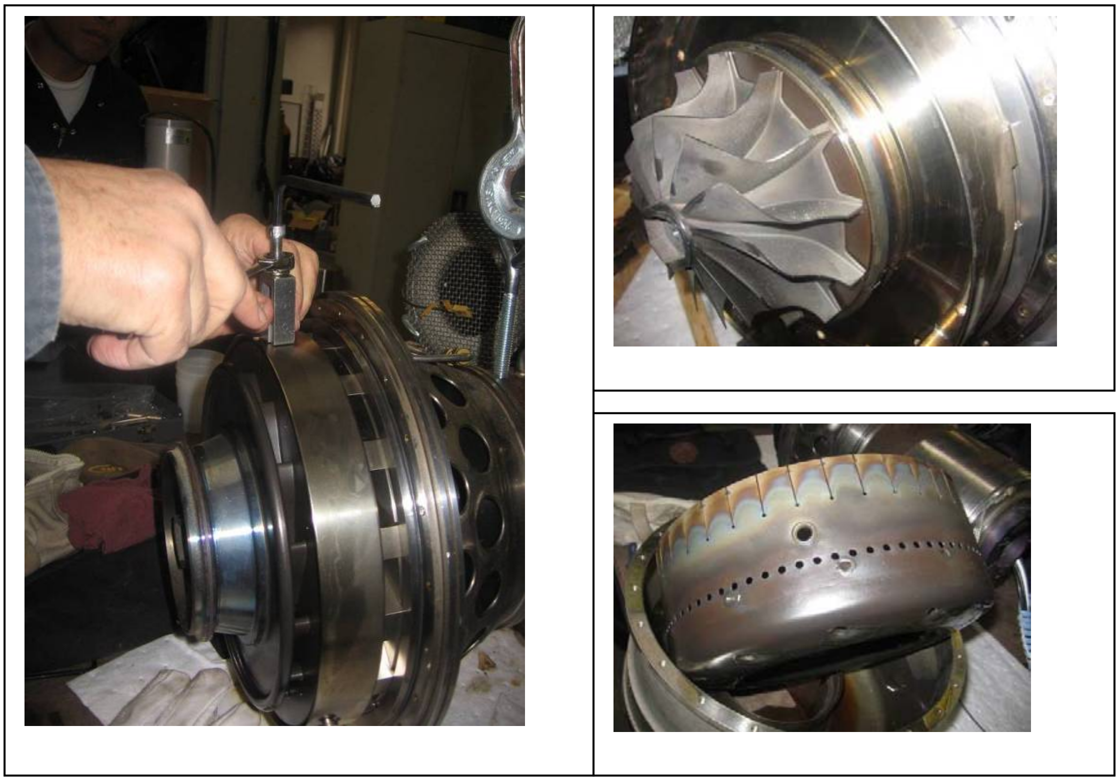
Removal of the TA-100 engine for modifications while machine still at the Altex facility located in Sunnyvale, California
Photo Credit: CMC-Engineering

Figure 57: Turbine Housing with Engine Removed (left) and Turbine on Shop Floor



Removal of turbine housing while the TA-100 was still located at the Altex facility located in Sunnyvale, California.
Photo Credit: CMC-Engineering

Figure 58: Engine Taking Microturbine Apart (left) for Rotor Replacement (top right) and Combustor Replacement (bottom right)



Repairs and modifications to TA-100 while machine was still located at the Altex facility located in Sunnyvale, California.
Photo Credit: CMC-Engineering

Figure 59: Engine Bearings Inspection – Main Bearing (Left), Thrust Bearing (Right)

Bearing inspections of the machine while the TA-100 was still located at the Altex facility

located in Sunnyvale, California.
Photo Credit: CMC-Engineering

5.2.3 Combustor Development and Fabrication

Part of the fabrication effort included a new silo combustor that is designed to meet the CARB 2007 emission NOx limits of 4.33 ppm corrected to 15 percent O_2 that corresponds to the 0.07 lb/MWh for CHP systems with an efficiency of 80 percent minimum. The silo combustor was designed based on the two-stage lean-lean premixed design that has been proven in the laboratory for simple cycle microturbines. The application to the simple cycle microturbines is based on combustor temperature inlet of 460 F, compared to the over 900 F for recuperated microturbines. The two stage lean-lean configuration allows for the peak flame temperature to be moderated in each stage while providing the combustion stability necessary to maintain reliable light off and combustion throughout the range in engine speed up to full power output. The first stage is critical in the design because of the cyclonic fuel injection configuration provides the strong turbulence necessary to ignite the second stage that operate at extremely low equivalence ratio. An important design feature of this first stage is the cooling necessary to maintain the metal temperatures well below the metallurgical limits. To provide additional material safety for all hot temperature components, the project procured the most temperature resistant steel, Haynes 230, from Haynes International.

Following final design of the combustor, CMC-Engineering issued purchase orders (POs) for the procurement of high temperature Haynes 230 steel from Haynes International and for fabrication of the combustor at the Huffman Welding Works. The quantity of steel ordered exceeded the amount needed for one combustor; therefore, CMC-Engineering and Altex are in the process of fabricating two additional combustors for two boiler CHP projects. All the material was delivered and Huffman proceeded with the cutting and fabrication of sheet and fuel injection tubes for each component of the combustor.

Figures 60 to 62 show the various components being fabricated at the Huffman Welding Works in Menlo Park California. The same welding shop was also utilized to fabricate the silo combustors for all other Energy Commission projects, including the steam injection combustor that replaced the existing combustors in both the Elliott and Gergho Industry & Engineering (GI&E) microturbines. Figure 61 shows the eight fuel and air injector pipes, four sets for each of the two combustion stages. The tapered end pipes are designed to further impart tangential spin to the air and fuel in the first stage. Figure 62 shows the fabricated first stage housing and combustor liner. The exit plane of the combustor is fitted with cooling holes designed to provide additional targeted air for CO burnout and cooling to the turbine inlet gas and to the metal. The diameter of the cooling holes can be adjusted (enlarged) if necessary to achieve intended effect.

Figure 62 shows the top plate for the silo combustor. This too is fabricated with Haynes 230 steel, though it is not exposed to the high temperature flames. The four inner holes are bored at an angle and will be fitted with the secondary fuel injection tubes that support the second stage combustion, downstream of the first cyclonic stage.

Figure 60: Fabricated Silo Combustor Components

Silo combustor components fabricated at Huffman Welding Works located in Menlo Park, California.
Photo Credit: CMC-Engineering

Figure 61: Fabricated First and Second Stage Liners

First and second stage liners fabricated at Huffman Welding Works located in Menlo Park, California.
Photo Credit: CMC-Engineering

Figure 63 shows the fabricated top section of the combustor with the primary combustion zone equipped with the four tangential gas injectors. The second stage liner is fitted to the bottom of this top section and the entire unit is then enclosed in the combustor housing.

Figure 62: Fabricated Combustor Top Plate

Combustor top plate fabricated at Huffman Welding Works
located in Menlo Park, California.
Photo Credit: CMC-Engineering

Figure 63: Fabricated Combustor Top Section

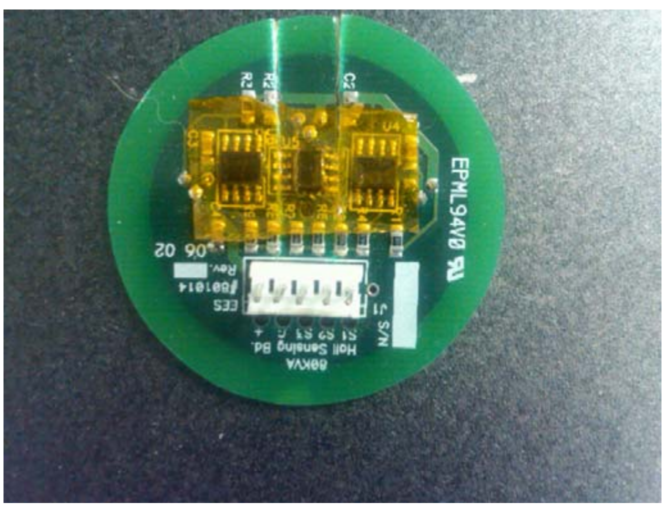
Combustor top section fabricated at Huffman Welding Works located in Menlo Park, California.
Photo Credit: CMC-Engineering

Though this fabrication work for the silo combustor had already started, the final agreements with the host site directed the scope to the use of a conventional recuperated Elliott TA-100 microturbine, not a compact experimental simple cycle design. Consequently, the project team replaced the annular combustor of the Elliott design with a modified one that used larger secondary cooling holes to impart greater staging effect and lower peak flame temperature.

5.2.4 Final Microturbine Equipment Upgrades and Inspection

As indicated in Section 5.2.2, the project team had to evaluate the engine readiness for shipment to the Momentive host site. This is because the engine was stored for a long period of time while the site search continued. Therefore, CMC-Engineering arranged for the Elliott field service engineer to travel to the Altex laboratory for testing of the engine and load the most recent operating software for the TA-100. These second series of engine crank revealed that the engine speed sensor shown in Figure 64 was not working properly. The engine speed sensor sends rpm data to the engine control board so that speed and fuel requirements (opening on fuel control valve) are regulated to maintain proper turbine inlet temperature. Damage to the board and connector also occurred during the removal of the engine to take measurement of the turbine housing for fitting the silo combustor. Removal of the engine took place with the engine removal tool, especially designed for this function. However the tight space may have contributed to the some damage to the connector and to the electronics. After several tries, it was agreed to replace the sensor. A second visit by the field test engineer was necessary to obtain a new sensor and to reinstall it. A total of three sensors were used before the team found one that worked. After that repair, additional hardware problems were encountered in the engine control board which showed software corruption.

Figure 64: Replace Engine Speed Sensor



Engine speed sensor found in the TA-100 during the second series of inspections.
Photo Credit: CMC-Engineering

With that repair completed, the tests continued to the next phase of engine light off and speed ramp to final power generation. However, further problems were revealed. These were attributed to the critical the engine control board. The field service engineer reinstalled the software with accurate engine operational settings that control speed and fuel while monitoring critical engine operation. However, the engine control board seemed to have been corrupted because, once the data was loaded into memory, the fuel control valve settings that determined the rate at which the fuel valve has to open to maintain proper speed increase were corrupted and showed random setting inconsistent with those loaded into memory.

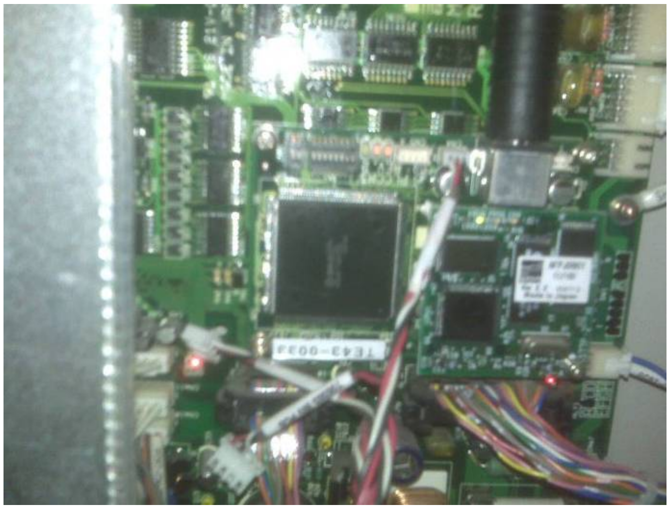
With the assistance of the Elliott service engineer, the project team contacted several sources for the replacement of the engine control board, illustrated in Figure 65. For competitive reasons, we were not able to secure a purchase from Capstone, the current owner of the Elliott microturbine product line. After further contact with the Densan in Japan, the manufacturer of the Power electronics for Elliott and now Capstone, we were able to talk to a Power Electronics engineer who suggested additional checks on the engine control board. The final fix to the problem was revealed by the removal of the daughter board, which reset the memory so it could take the new engine settings. After this final fix, the engine was diagnosed to be ready for the final two operational checks.

Figure 66 illustrates the test setup for the final operational tests. As indicated, the engine was again run with bottled methane gas, shown on the left, because the Altex laboratory lacks the 480 volts power supply. The compressor was disconnected so that gas could be channeled directly to the solenoid valves and fuel control valve, as shown in Figure 67. A laptop was then used to record engine operating data.

Figure 68 illustrates the engine operating profile during light-off. The green line represents the opening of the fuel control valve which feeds gas to the engine combustor. The red line represents the temperature increase measured at the turbine exit, also known as Exhaust Gas Temperature (EGT). A smooth temperature increase is a good indication of proper engine operation. The blue line indicates the increase in engine speed (rpm). This also indicates proper operation of speed and fuel coordination. Figure 69 illustrates that the engine was taken to full 68,000 rpm with an EGT of 510 C (950 F) and generating 62.5 kW. Small steps in the fuel control valve coincide with added load on the load bank. As the load is increased in small steps, the fuel control valve opens a bit more to accommodate that power generation requirement.

Figure 70 shows that the engine was taken up to a maximum of 72.1 kW of gross generating power with an EGT of 560 C (1,040 F). The maximum power output was limited by the 80 kW size of the load bank available for these tests. This EGT is considered high for only 73 kW. The EGT is a reflection of the turbine inlet temperature. Excessively high turbine inlet temperature can cause damage to the engine. This can be due in part to the insufficient air flow to the combustor. Therefore, inspection of air filters and any other blockage will be made prior to the shipment of all equipment to the site. The light-off tests were repeated four times with light off success and smooth engine operation to ensure repeatability.

Figure 65: Engine Control Board



Engine control board with pin connection to engine speed control board
found in the TA-100 during testing at the Altex facility located in Sunnyvale, California.

Photo Credit: CMC-Engineering

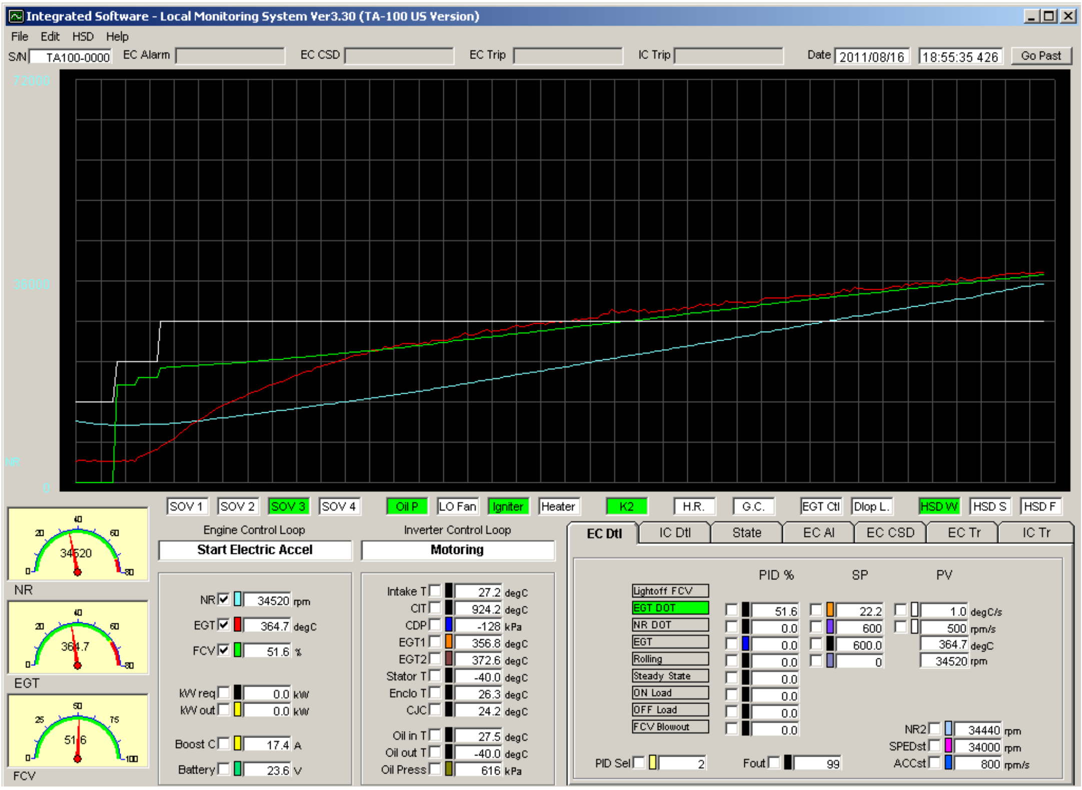
Figure 66: Equipment Setup for Engine Readiness Tests

Equipment setup for engine readiness tests conducted in August 2011 at
the Altex facility located in Sunnyvale, California.
Photo Credit: CMC-Engineering

Figure 67: Gas Connection Bypassing Gas Compressor

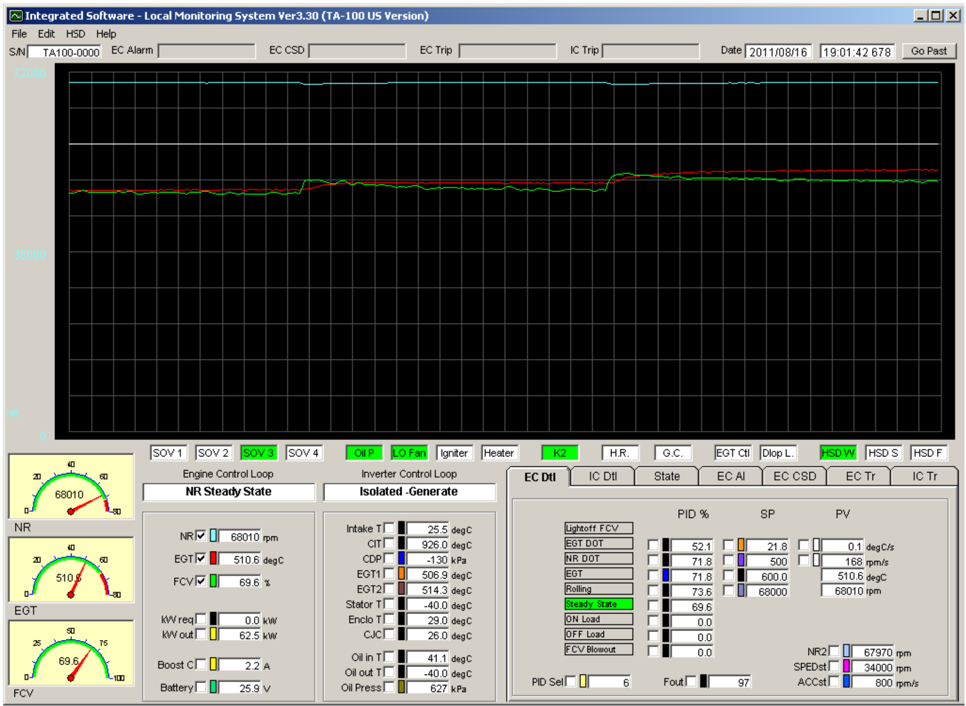
Gas connection bypassing the gas compressor in the TA-100 during testing
the Altex facility located in Sunnyvale, California.
Photo Credit: CMC-Engineering

Figure 68: Engine Operation during Light-off



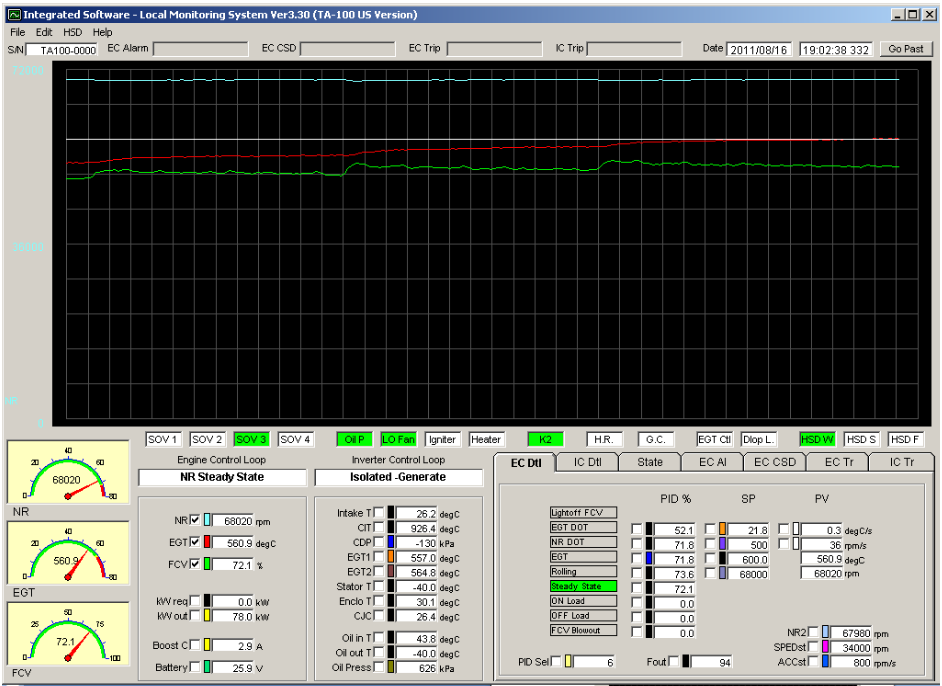
View of the recorded engine data during light-off from a laptop while testing of theTA-100 at the Altex facility Sunnyvale, California (green shows fuel control valve; indicates turbine exit temperature; blue indicates turbine speed; and grey indicates kW.
Source: CMC-Engineering

Figure 69: Power Output at 62.5 kW



View of the recorded data from a laptop showing that the TA-100 engine was taken to full 68,000 rpm (blue line) with an EGT of 510 C (950 F) (red line) and generating 62.5 kW (gray line) during testing at the Altex facility in Sunnyvale, California.
Source: CMC-Engineering

Figure 70: Engine at 72.1 kW Gross Power Output



View of the recorded data from a laptop showing that the TA-100 engine was taken up to a maximum of 72.1 kW of gross generating power (gray line) with an EGT of 560 C (1,040 F) (red line) during testing at the Altex facility in Sunnyvale, California.
Source: CMC-Engineering

Inspection of the gas compressor indicated that the unit required maintenance and it should be subject to tests. Operation of the gas compressor needs 480 volts supply during startup until the engine reaches self-sustained speed of 35,000 rpm at which time the microturbine can supply the transformer with its own power. Therefore, light off requires 480 volts grid power for gas compressor operation. At the time, the Altex laboratory had yet to install the 240 to 480 volts transformer and therefore, the gas compressor operation could not be checked during these tests. A new series of tests was then scheduled just ahead of the planned transfer of the microturbine to the host site.

Following additional measurements on the gas compressor, the project consultant and field engineer decided to retrofit the gas compressor with a variable frequency drive (VFD) controller to allow variable speed and improved operation at peak firing rate for the engine. Figure 71 shows the purchased Allen Bradley VFD.

Figure 71: Variable Frequency Drive

Picture of the newly purchased variable frequency drive from Buckles-Smith for the gas compressor of the TA-100
Photo Credit: CMC-Engineering

5.3 List of Component Parts

This section highlights the key components and parts list necessary for the installation of the CHP system at the Momentive Specialty Chemicals Plant in Fremont, California. As indicated, the site requested the installation of a recuperative TA-100 equipped with a HRU for the co-production of hot water. Additional waste heat recovery will be accomplished in the water tube furnace where VOC destruction of the process off gases will take place. With this CHP configuration, the overall CHP efficiency will exceed 90 percent. Actual efficiency will depend on the use of the heat recovery unit (HRU) where 140 F hot water is co-produced.

Because the TA-100 is in a recuperated configuration, it will have an exhaust temperature of 560 F, instead of the 1050 F of the simple cycle microturbine. This was an important requirement for ensuring that the planned CHP configuration was consistent with the TO furnace burner operation. Lower microturbine exhaust temperature was necessary because the water tube TO furnace burns a process gas with 22 percent hydrogen content. Any excessive temperature in the windbox could result in premature combustion of the hydrogen, bringing combustion closer to the burner front and possibly causing high temperature damage to burner components. The request for co-production of hot water for their process also dictated the use of the recuperated microturbine. The co-generation of hot water provided additional incentive for the site since Momentive was originally using a separate fire tube boiler, which is only for generating hot water. With hot water co-produced by the microturbine, the site can avoid the cost of burner replacement on the fire tube boiler for emission compliance under the Bay Area Air Quality Management District (BAAQMD) rules.

5.3.1 Microturbine Supplied Parts

The microturbine is a self-contained TA-100 unit with specifications shown in Figure 71. The microturbine has a power output rating of 105 kW gross, 95 kW net at ISO conditions (60 F and 1 atmosphere). The fuel gas compressor uses about 5.5 kW of power. The engine consumes 22 scfm of natural gas fed to the compressor at pressure less than 5 psig and raised to a pressure of 80-90 psig. This requires a step down regulator for the gas line for the project host site, since gas is available at the site at 50 psig. When in operation, the HRU that produces hot water will drop microturbine exhaust temperature from 560 F exiting the recuperator to 190 F in the exhaust. This remaining thermal energy will be recovered in the TO furnace via an insulated 14 inch-diameter duct system flanged to the turbine exhaust and connected to the VOC furnace combustion air blower intake.

With agreement from the host site, the location for the microturbine was selected to be outside of the VOC-furnace and boiler house. This was acceptable because the Elliott microturbine is designed for outdoor installation. The site also agreed to fabrication of a cement pad that is required for bolting the equipment in place.

Figure 72: TA-100 Microturbine Spécifications

TA100 CHP Specifications

Performance:
Electrical Output

Output (@ ISO)	100 kW net 105 kW gross
Maximum Block Loading	100%
Minimum Load	0kW
Efficiency*	29% (+/- 1) LHV
THD	< 3%
Voltage Regulation	+/- 2%

Fuel Consumption (ISO Rated Power)

Natural Gas:	22 SCFM/ 0.62 m^3/min (940 BTU/ SCF)
362 kW (@ 1,235,000 Btu/ hr.) LHV	
Heat Rate	12,355 BTU/ kWh

Thermal Output (Hot water)
172 kW / 587,000 Btu/ hr.

Water Inlet Temp	120°F / 49°C
Water Outlet Temp	140°F / 60°C
Flow	60 GPM/ 3.8 L/s
Total System Efficiency*	>75%

* Not Including Gas Compressor

Engine

Manufacturer	Elliott Energy Systems
Model	TA-100 CHP
Type	Recuperated Gas Turbine
Pressure Ratio	4 to 1

Cooling System

Alternator	Oil Cooled
Power Electronics	Air Cooled
Enclosure	2,400 CFM/ 1.13 m^3/s

Exhaust System

Outlet Size	10" Diameter
Max. Back Pressure	5" water column 1.2 kPa
Exhaust Gas Flow	1,500 SCFM 0.71 Nm^3/s

Fuel

Fuel Type	Natural Gas
Pressure Required	0.5 - 5 PSIG 3.4 - 34.5 kPa

Oil System

Oil Type	Mobil SHC 824
Capacity	5 US gal. (19 L)
Oil Filter	Spin On Type, 3 Micron

* All figures at ISO 59°F/ 15°C unless otherwise noted.

Emissions, Natural Gas (Typical)

CO:	20 PPM @ 15% O_2 25.4 mg/MJ 25.0 mg/m^3@ 15% O_2 0.77 lbs/ MWhr 0.243 grams /bhp hr 0.059 lbs /MMBTU
NOx:	22 PPM @ 15% O_2 48.7 mg/MJ 45 mg/m^3@ 15% O_2 1.48 lbs/ MWhr 0.467 grams /bhp hr 0.113 lbs /MMBTU

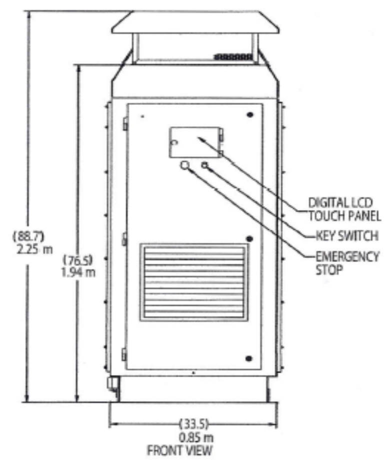
Exhaust Gas Temperature

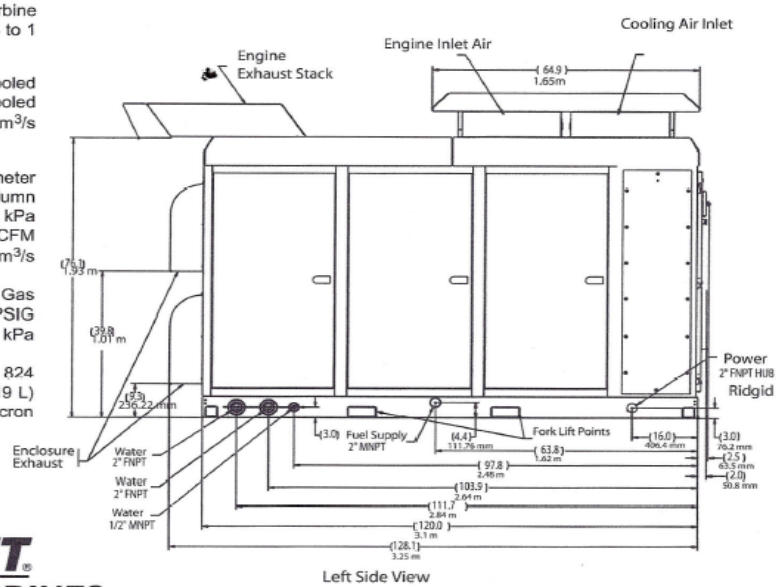
Heat Recovery Mode	180°F/ 82°C
Full HRU Bypass	560°F/ 293°C

Batteries 24VDC min.
Two 12 volt, Group 27, lead acid, maintenance free - 105Ah nominal

Total Weight with Enclosure:

Indoor:	4,100 lb./ 1,860 kg
Outdoor:	4,500 lb./ 2,040 kg





ELLIOTT MICROTURBINES

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The specifications in this catalogue are subject to change without prior notice.

Source: Elliott Microturbines

Agreements were also reached on the supply and fabrication of installation components with further clarification needed on remaining issues. Overall, Momentive agreed to the following:

1. Finalizing the location of the engine as it affects maintenance and length of the exhaust duct
2. Routing natural gas supply to the microturbine from existing high pressure line
3. Installing conduit for the power cable from the microturbine to electrical service panel
4. Placement of a high voltage breaker between the microturbine and the 480 VAC, 250 AMP electrical service panel
5. Locating the hot water tanks to store hot water generated by the Heat Recovery (HRU) located at the back end of the microturbine
6. Make the hot water connection for recirculation of 60 gallons per minute (gpm) of water to maintain a minimum of 140 F temperature in storage tank
7. Design and fabricate the exhaust and flange to install on engine exhaust to bolt the exhaust duct to engine exhaust
8. Routing microturbine exhaust to the combustion air blower inlet using 500F rated insulated duct
9. Determining the need for and exhaust gas bypass valve to allow microturbine exhaust to be routed to the atmosphere
10. Obtaining additional process information to validate safe VOC-furnace operation with microturbine exhaust and need for improved controls on combustion air blower
11. Retrofit remote monitoring capability for the microturbine to allow offsite recording of power produced and to assist Momentive in long-term maintenance
12. Determining the need to replace, and if required, replace the existing combustion air blower to increase inlet air temperature rating when HRU is bypassed.

On item 1, Momentive agreed to pipe natural gas from their high pressure (50 psig) natural gas to the microturbine for a supply requirement of about 20 scfm at a maximum pressure of 5 psig. This required a 4-inch pipe supply line and a step-down pressure regulator. The existing gas supply station is approximately 50 ft from the planned location of the microturbine.

On item 2, Momentive agreed to procure the conduit and 200–amp power cord to connect power to the 250-AMP service panel. CMC-Engineering field service will connect the electrical components during the commissioning process. Details of the panel will be supplied to the Elliott field engineer to ensure compatibility during the planned September 9 weekend, as the panel would have to be wired for 3-phase with ground in addition to the AMP rating.

On items 3 and 4, Momentive agreed to purchase the breaker and the electrical cable. The electrical cable will be 2/0 containing 4 wires for three phase and neutral and one additional 1/0 wire for the ground. The cable will be rated for 600 volts and the breaker will be rated for 300 AMP disconnect. CMC-Engineering supervised the installation of the system in proximity to the microturbine to meet applicable electrical codes.

On items 5 and 6, Momentive agreed to fabricate and install a hot water tank that was used to maintain the product resin from solidifying. The piping included a circulating pump to maintain the tank at 140 F.

On items 7 and 8, CMC-Engineering agreed to fabricate the connecting flange and provide the drawings for the microturbine exhaust and specify the insulating requirements and Momentive will fabricate the ductwork. Figure 73 and Figure 74 show the fabricated connecting.

Figure 73: Fabricated Connecting Flange - Side View

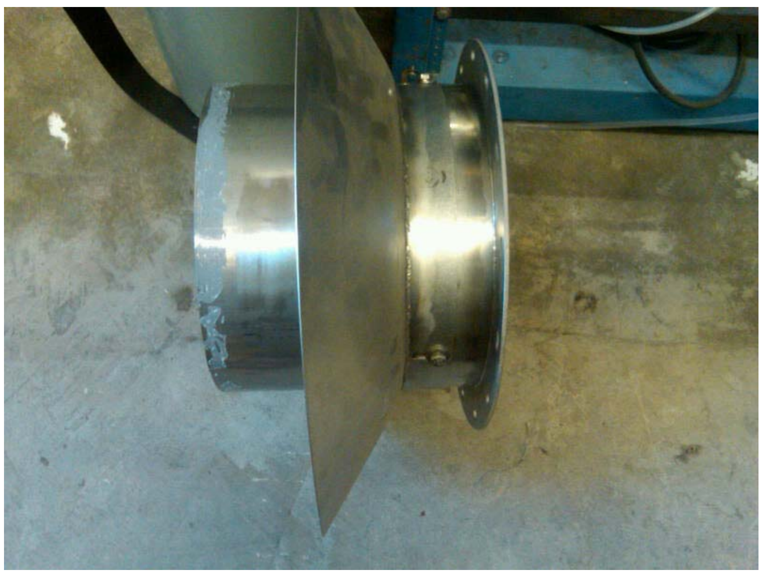


Figure shows the completed fabrication of connecting exhaust flange

Source: CMC-Engineering

Figure 74: Fabricated Connecting Flange - Top View

Figure shows the top view of the fabricated connecting flange

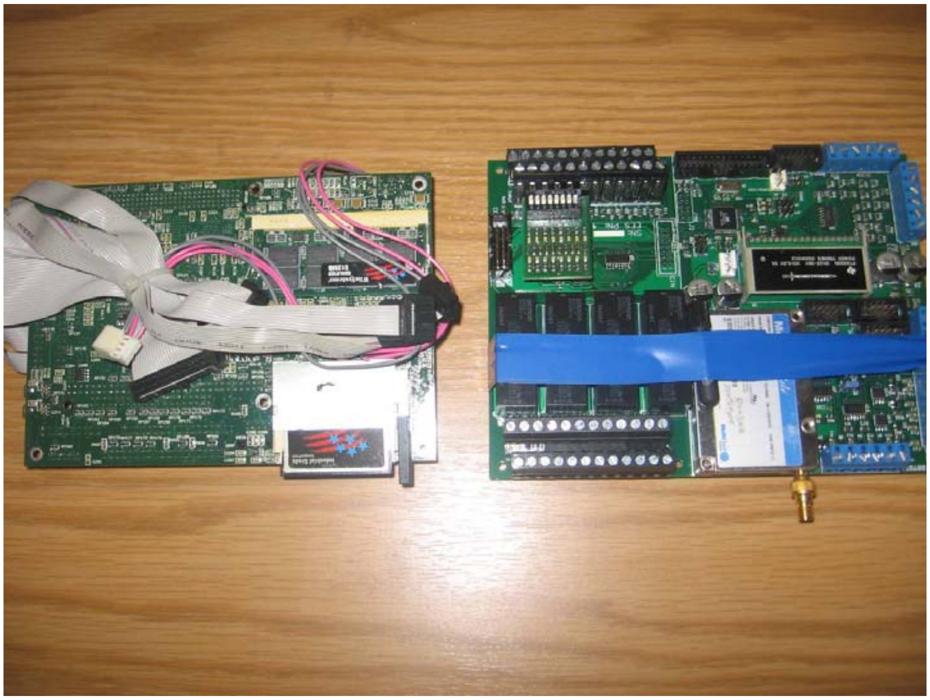
Source: CMC-Engineering

On items 9 and 10, CMC-Engineering made measurements on the combustion air blower intake and VOC furnace stack gas excess oxygen to determine the any resistance to the flow of microturbine exhaust. These measurements were made during a visit from our field test engineer. Draft measurements at the combustion air flow intake indicated 2 inches of water negative pressure when the blower in on. Also measurements at the VOC furnace stack indicated excess oxygen (O_2) near zero percent. This is rather unusual in conventional furnace burner operation, as the excess O_2 is normally 2-3 percent minimum. However, because the process waste gas does not contain any carbon and is mostly hydrogen, no unburned carbon can be produced even at very low excess O_2 conditions. In fact, preliminary measurements of carbon monoxide (CO) show low emissions as expected.

On the items 11, CMC-Engineering agreed to procure the Ethernet boards for monitoring the microturbine operation from offsite locations, for example, from any computer or mobile device connected to the internet. Figure 31 shows the boards at the CMC-Engineering office. These boards will be installed during the final assembly work before the microturbine is shipped to the host site for installation.

On item 12, the robustness of the existing combustion air blower continues to be evaluated for the purpose of determining if the inlet temperature is too high for the design specifications of the blower and its current conditions. This analysis is necessary because the temperature of the air intake to the blower will rise with the addition of microturbine exhaust.

Figure 75: Procured Ethernet Boards for Remote Monitoring



Ethernet cards supplied by CMC-Engineering

Photo by CMC-Engineering

5.3.2 Additional Parts and Components

Table 25 shows how the operation of the combustion air blower and furnace burner will change with the conversion to CHP operation for the VOC-furnace. Originally, the blower has to supply about 1,948 standard cubic feet per minute (SCFM) of air at ambient temperature (60 F), calculated with burner operating at 15 percent excess combustion air (to be confirmed with planned stack measurements). When the operation is switched to CHP, the blower combustion air flow will come from both the microturbine (1,280 SCFM) and the ambient air (688 SCFM) to satisfy the combustion air needs of the VOC furnace. However, the total flow will increase to 2,220 SCFM (1,280 + 1,550), due to the added ballast from the microturbine. In addition, the mixed ambient and microturbine air will produce and increase in temperature at the inlet to the blower. The temperature rise will be a function of how much hot water is also cogenerated. When the HRU in the microturbine cabinet is not bypassed (hot water is being produced at full capacity of 60 gpm, 140 F), the microturbine exhaust will be at 190 F. When the HRU is fully bypassed, the microturbine exhaust will be at 560 F. Under the first operating scenario (hot water being produced, the mixed turbine exhaust and ambient air will have a temperature of about 137 F. This is sufficiently low to not require replacement of the existing blower. However, when no hot water is being produced, the blower inlet temperature will rise to a 327 F, possibly affecting the need for combustor blower replacement. Therefore, it was imperative to coordinate with Momentive on the actual use of hot water during CHP operation. Momentive did agree to replace the blower during the installation process

Since the power on the blower increases with an increase in air flow and temperature, as shown below:

$$Increase in Blower Motor Hp = \frac{Q_A}{Q_B} x \frac{T_A}{T_B}$$

Where Q is the flow and T is the temperature of the blower inlet air and subscript A and B refer to after and before the CHP installation. The power on the blower will increase by the ratio of 2,238/1,948x598/520, or 32 percent when the HRU is on (hot water is being generated) and 2,238/1,948x787/520, or 74 percent when the HRU is off (no hot water is generated. This analysis indicates that the combustion air blower will require replacement.

The analysis was expanded to assist Momentive in developing specifications for a replacement combustion air blower that would have the added capacity to handle the exhaust gas from the microturbine. Table 25 also lists all the possible scenarios for blower flow rate and back pressure that the blower would have to handle. The first operating scenario is with the VOC furnace in operation and the microturbine being turned off for maintenance or unscheduled repair. The flow rate and back pressure for the blower are the lowest in that scenario. Higher flow rate and backpressure occur when the engine is on due to the added ballast from the engine and the increase in inlet air temperature to the blower. When the HRU is bypassed and no hot water is being generated, as indicated, the microturbine exhaust will be at the highest temperature, thus increasing the total actual cfm to the blower inlet even further. As the actual cfm increases, the velocity also increases and the back pressure increases. The back pressure accounts for the 2 inches of windbox pressure and the resistance in the two air ducts, shown in Figure 76, leaving the blower. On that basis, CMC-Engineering provided Momentive with the specifications for a new replacement blower that was purchased by Momentive and used as match funds for the installation. The new blower is based on a Twin City TBNS-19W10, which has a 19 inch diameter steel wheel (for elevated temperature) and is rated up to 500 F inlet temperature. Figure 77 shows the replacement blower.

Table 25: Blower Operation and Power Needs with CHP Installation

	Ambient Temperature, F	Blower flow rate, CFM	Back Pressure inches w.g.	Blower HP
Microturbine off	60	1,700	7.3	5
	100	1,830	7.4	
Microturbine on, HRU on	60	1,980	10.1	7
	100	2,130	10.4	
Microturbine on HRU off	60	2,770	13.1	12
	100	2,990	13.6	

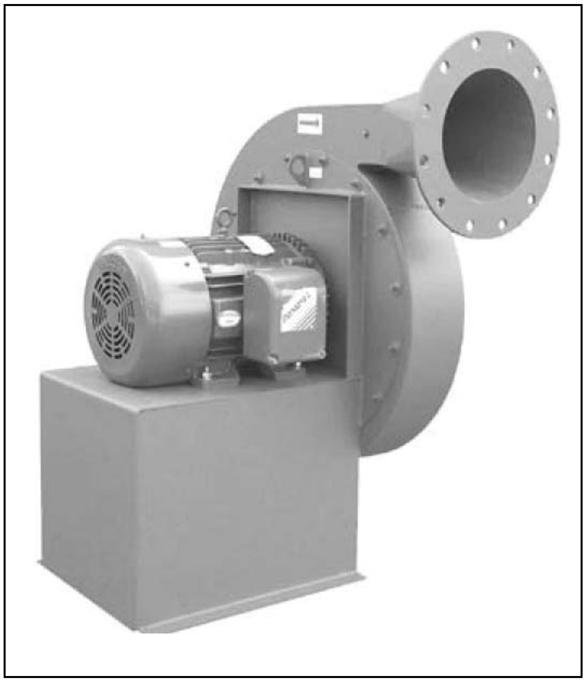
All data are at zero excess combustion air, verified with measurements of oxygen levels in the stack.

Source: CMC-Engineering

Figure 766:

Original combustion air blower discharge arrangement found at Momentive Specialty Chemicals located in Fremont, California. Photo Credit: CMC-Engineering

Figure 77: Twin City Blower TBNS-19W10 with Steel Wheel rated at 500 F Inlet



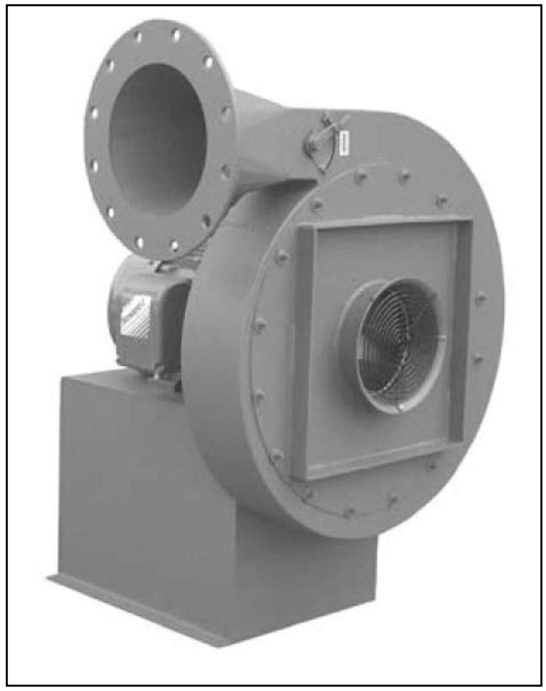


Figure shows type of combustion air blower used at Momentive host site

Source: Chicago Blower

5.4 FIELD REQUIRED PARTS AND COMPONENTS

In addition to the integrated TA-100 microturbine, the field installation will require additional parts to:

1. TA-100 Elliott microturbine with modified combustor – Supplied by CMC-Engineering, shown in Figure 34
2. Connect the natural gas line to the engine as illustrated in Figure 35- Supplied by Momentive. Parts needed:
    a. Step down gas regulator from 45 to 5 psig
    b. Manual NPT valves
    c. Assorted 2 in diameter gas piping for inlet to compressor
3. Connect the water to the Heat recovery Unit (HRU) for the option of hot water generation, as illustrated in Figure 36 – Supplied by Momentive. Parts needed:
    a. Water circulation pump
    b. Hot water storage tank

c. Shutoff valve

d. Assorted 2 inch diameter piping

4. Channel the microturbine exhaust with an insulated duct of the type connecting the engine exhaust to the TO/boiler combustion air blower intake- Supplied by Momentive. Parts needed:

   a. Microturbine exhaust flange (fabricated)

   b. 8 inch diameter duct and 600 F-rated insulation

   c. Bypass/isolation damper with actuator

5. Upgrade burner software to control and operate the actuators based on the operational status of the engine (validation of stack-oxygen trim control to match conditions specified with and without microturbine exhaust – Supported by CMC-Engineering.

6. Connecting the electrical power to the site electrical service panel with a minimum rating of 480 VAC and 200 amps (supplied by CMC-Engineering, including installation). Parts needed:

   a. 600 volts breaker

   b. Electrical conduit

   c. Electrical 2/0 wire for three phase 480 volts and 200 amps

   d. Ground 1/0 wire

7. Connecting Ethernet cable for remote monitoring. Parts needed:

   a. Ethernet cards (supplied by CMC-Engineering)

   b. Ethernet cable and conduit.

8. Power supply. Parts needed:

   a. Two closed 12 volt batteries (supplied by CMC-Engineering)

Table 26 summarizes the list of microturbine and boiler related parts and components required for the installation of the CHP system. A copy of the acceptance of the installation and field test agreement by Momentive can be found in Appendix 1.

Table 26: List of Parts and Components

TA-100 Microturbine related Parts	Boiler related Parts
1. Natural Gas Hookup a. Pressure regulator b. Shutoff valve c. Dual Fuel control valve d. Gas vent e. Gas meter f. Assorted piping	1. Exhaust duct from Microturbine a. Windbox connecting flange b. Isolation damper c. Exhaust gas thermocouple or equivalent
2. Hot Water Loop a. Water pump b. Manual shutoff valve	3. Boiler/Burner Control a. Oxygen trim loop b. Flue gas O_2 sensor
4. Exhaust Duct a. Insulated 8-inch diameter duct b. Isolation dampers with actuators	5. Burner damper control a. Combustion air blower damper control
6. Electrical Connection a. Connecting cable to isolation switch b. Connecting cable to 100 AMP 480 VAC panel	

Source: CMC-Engineering

Aside from the TA-100 and microturbine supporting component, many of the boiler related components were provided by the host site under match funds. The installation was subject to inspection by the field service engineer prior to commissioning the microturbine, test the performance, as described in Chapter 8, and turn operation to Momentive.

CHAPTER 6: System Assembly and Checkout

6.1 Goal and Objectives

The principal goal of this task was to prepare for final assembly at the host site after demonstrating operational readiness. This signified that the engine could be commissioned and the CHP was ready for use.

The objectives were to assemble all the parts for the microturbine; ship assembled components from the laboratory to the site; install temporary connections for natural gas; install the ductwork interconnecting the microturbine exhaust to the TO burner air intake; and confirm the operational readiness of the microturbine and burner assembly, including interface controls.

Some assembly work was performed at the site and some at the laboratory. The host facility requested early delivery of the microturbine to facilitate the installation tasks that were planned for the host site to undertake. Repairs and upgrades were performed on the microturbine in the laboratory, as discussed in Chapter 5.. The following sections describe the activities required to assemble the TA-100 Microturbine at the host site.

6.2 TA-100 Microturbine Assembly

As indicated, assembly work was initiated at the Altex laboratory to ready the engine for shipment to the site. The project team had intended to complete the assembly prior to shipment of the engine; however, the engine was taken to the host site to quickly assist Momentive in the installation. Therefore, part of the assembly was done at Momentive and additional work performed at the site with the assistance of the Elliott service engineer. An initial visit by the Elliott service engineering took place during these task activities. A second visit took place during the startup and checkout tests to commission the engine for CHP operation at the site.

The field assembly work took place in the warehouse at Momentive where the TA-100 microturbine was stored prior to moving it to the planned location. Figure 78 shows the microturbine in the Momentive warehouse. An initial activity was to prepare the gas compressor for use with a variable frequency drive (VFD) controller. The VFD was requested by the Elliott field service consultant. Figure 79 shows the assembly of the wiring necessary for compressor upgrade and for connection to the VFD. The Momentive staff agreed to fabricate any needed support bracket for the VFD and for the fabrication for the National Electric Manufacture Association (NEMA) box where the communication electronics will be housed. It was necessary to operate the gas compressor in soft start mode as recommended by the field service engineer who was hired as the consultant for the inspection, modifications, installation, and commissioning of the microturbine. Figure 80 shows the VFD getting ready for the assembly process.

Figure 78: TA-100 Microturbine in Momentive Warehouse

The picture shows the TA-100 microturbine in the Momentive Specialty Chemicals warehouse undergoing remaining assembly and upgrades
Photo Credit: CMC-Engineering

Figure 79: Gas Compressor

The photograph shows the assembly of the wiring necessary for the gas compressor upgrade and for connection to the VFD.

Photo Credit: CMC-Engineering

Figure 80: Assembly of the VFD in the Microturbine Cabinet

Assembly of the VFD in the microturbine cabinet at Momentive Specialty Chemicals located in Fremont, California.
Photo Credit: CMC-Engineering

6.3 Field CHP Assembly

Additional assembly work involved engineering support to Momentive on the replacement of the existing combustion blower used by the TO boiler furnace. CMC-Engineering made measurements of the pressure drop and flow requirement, including measurements of excess air and current emissions from the TO boiler furnace used for volatile organic compounds (VOC) incineration and tail gas treatment. Based on these measurements, CMC-Engineering evaluated the impact of microturbine operation with the current process demands on the combustion air blower. In addition, Momentive assembled key components required for the CHP configuration recommend by CMC-Engineering.

6.3.1 Combustion Blower Replacement

Table 27 shows how the microturbine exhaust affects the temperature of the air entering the blower. An increase in temperature will impose additional power requirement of the blower. Thus it was necessary to evaluate whether the blower motor and fan wheel are rated for the higher temperature and higher pressure drop. As shown, the maximum temperature that the fan wheel will see is 327 F when the 560 F microturbine exhaust is channeled directly to the inlet to the blower. Table 28 shows the fan motor power requirements with different ambient temperatures and under all operating conditions envisioned with either microturbine or off.

The engineering analysis indicated that the motor has to have a minimum rating of 12 hp. The existing motor was rated at 22 hp. Therefore, the unit was deemed oversized and adequate for dealing with the increased pressure drop that will result with the higher blower inlet temperature. However, the fan wheel and bearing were not rated for elevated temperature and therefore were considered vulnerable to the high temperature of 327 F. Therefore, the project team recommended that Momentive replace the fan wheel at a minimum. Momentive considered replacing the blower with a lower capacity unit and a smaller steel fan wheel. The replacement blower will continue to operate with the VFD drive shown in Figure 81. VFD driven motors are much more efficient especially at part load.

Table 27: Change in Blower Inlet Temperature with CHP Operation

	From Ambient Air	From Microturbine	Total
Combustion air needed by the VOC-furnace burner	688 SCFM	1,280 SCFM	1,948 SCFM
Total flow from combustion air blower to the VOC-Furnace	688 SCFM	1,550 SCFM	2,238 SFM
Temperature of Combustion Air to Blower Inlet and VOC-Furnace – HRU on	60 F (520 R)	180 F (640 R)	137 F (598 R)
Temperature of Combustion Air to Blower Inlet and VOC-Furnace HRU off	60 F (520 R)	560 F (1,020 R)	327 F (787 R)

Source: CMC-Engineering

The blower motor operatedg with a VFD, illustrated in Figure 81. Part of the inspection during the final stages of the assembly was to make any necessary changes to the blower VFD to secure operation with and without CHP configuration to provide the greatest operational flexibility.

Table 28: Horsepower Requirements for Combustion Air Blower

	Ambient Temperature, F	Blower flowrate, CFM	Back Pressure inches w.g.	Blower HP
Microturbine off	60	1,700	7.3	5
	100	1,830	7.4	
Microturbine on, HRU on	60	1,980	10.1	7
	100	2,130	10.4	
Microturbine on HRU off	60	2,770	13.1	12
	100	2,990	13.6	

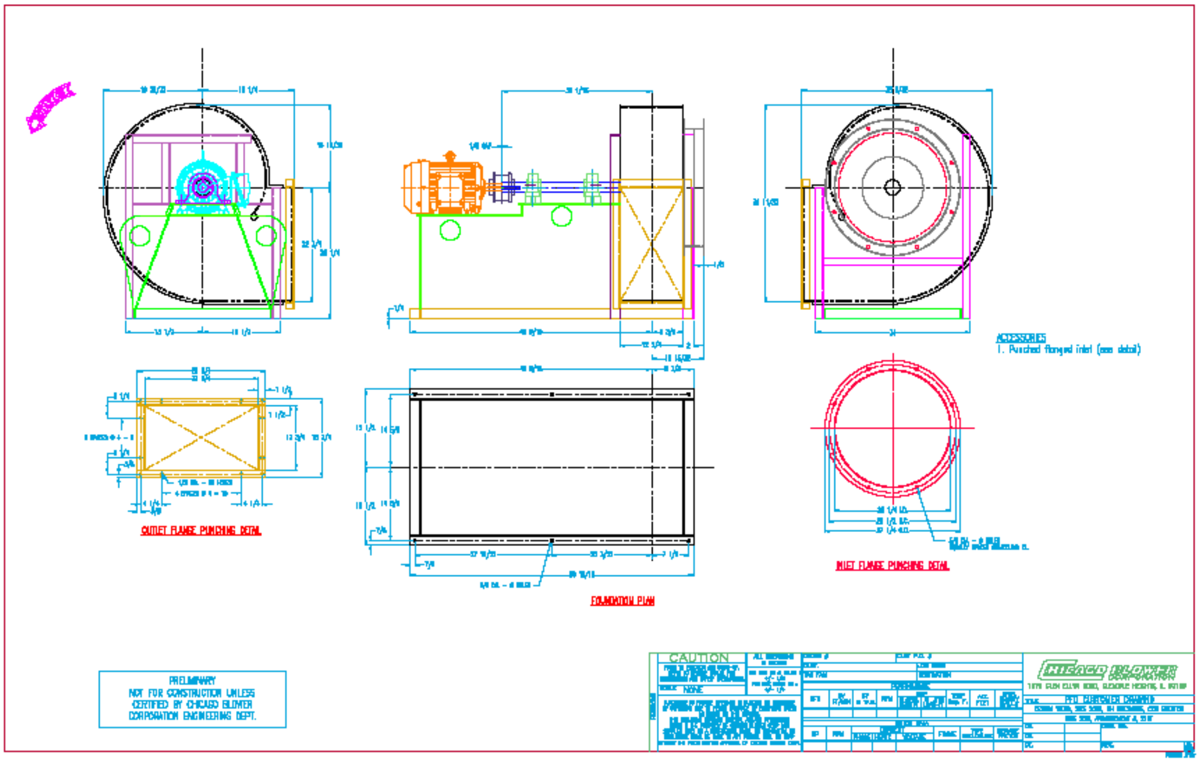
Source: CMC-Engineering

Figure 81: Combustion Air Blower VFD

Combustion air blower VFD found at Momentive Specialty Chemicals located in Fremont, California.
Photo Credit: CMC-Engineering

Because of lead time on the delivery of the blower, CMCEEngineering and AHM Associates provided Momentive with all the technical specifications and a least cost option for the blower. Chicago Blower was specified as the vendor. The design and performance data as seen in Figure 82 was delivered to Momentive for approval. Momentive was responsible for the purchase of this blower and it was part of the planned match funds for the project.

Figure 82: Chicago Blower Specifications



Specifications for Chicago Blower purchased for the new Momentive CHP assembly.
Source: Chicago Blower Corporation

6.3.2 Other Assembly Parts

CMC-Engineering provided support to Momentive in finalizing the assembly components needed for the full CHP installation. Aside from the TA-100, many of these components were provided by the host site under match funds, as indicated. Figure 83 shows the ducts used to connect the engine exhaust to the combustion air blower inlet. During the installation, all segments of the fully connected 68 feet duct was insulated as the microturbine exhaust temperature can range from 180F to 560 F leaving the HRU. Figure 84 and Figure 85 show the fully installed electrical connection with the conduit for the wires for the 480 VAC 250 AMP rating, and the isolation breaker designed to disconnect the microturbine from the electrical service panel. As shown in both figures, the engine was weather protected with a tarp. The tarp was replaced with an enclosed housing during the installation process. All connections, including electrical, gas fuel, and water were inspected by the field service consultant prior to the startup of the tests and full commissioning of the engine.

Figure 83: Fabricated Microturbine Exhaust Ducts

The photograph shows fabricated microturbine exhaust ducts readied for assembly at Momentive Specialty Chemicals located in Fremont, California.
Photo Credit: CMC-Engineering

Figure 84: Power Electronic Isolation Breaker

The photograph shows the power electronic isolation breaker designed to disconnect the microturbine from the electrical service panel.
Photo Credit: CMC-Engineering

Figure 85: View of Isolation Breaker and Power Conduit

View of the isolation breaker and power conduit found at Momentive Specialty Chemicals located in Fremont, California. Photo Credit: CMC-Engineering

6.4 System Checkout Test

Prior to the installation of all CHP assembled components, the project required that the microturbine be fully checked for operational readiness, especially with modifications made to the gas compressor operation on variable frequency drive (VFD) and combustor replacement. Therefore, CMC-Engineering arranged for the consultant field service engineer to assist CMCE in the commissioning of the microturbine. This system checkout was performed with two site visits. The first visit was limited to component checkout without firing the turbine because the air permit had not yet been issued. Commissioning of the microturbine requires the engine to be on with fuel and water connected to the microturbine. The microturbine cannot start and remain operating for very long without some water flow through the heat recovery unit (HRU) to prevent excessive temperature damage. In addition, the microturbine was subjected to a long shutdown period and underwent additional modifications that took place in the field. The second visit allowed the project team to test and commission the microturbine while under permit from the BAAQMD.

6.4.1 Component Checkout

The field service engineer also inspected the proper anchoring of the microturbine to the cement pad to ensure that there was, at minimum, four bolts and the pad does not allow any pooling of rain water. After completing these inspections, the engine was taken through the startup sequence while monitoring key process conditions to determine that all mechanical and electrical components are working properly. The initial startup tests brought the engine to full speed without generation first, relying on the facility-supplied power for the most part. The second startup tests, following an emergency shutdown confirmed this safety feature and the engine was taken to full generating power of about 100 kW net output.

During startup of the microturbine, the control logic on the microturbine was tested for proper operation according to the manufacturer specifications. Modifications by CMC-Engineering during this project did not alter these settings and therefore, the engine was checked according to the specifications shown in Table29. Remote monitoring data was accessed through the RS485 port of the power electronics, using the MODBUS protocol. By using this RS485 port the microturbine CHP system can also be controlled remotely.

Table 29: Series of Checkout Tests

Start Step	Description	Duration
Oil temperature adjustment	Cooling or heating of oil to a maximum of 75 C (167 F)	Until temperature is in the correct range
Engine acceleration during the purge phase	Set to accelerate to a speed of 16,000 RPM at completion of the purge. Adjustments can be made based on optimum operation of replaced combustor	Duration should not exceed 30 seconds. CMCE w adjusted ramp speed on power electronics as required
Purge time	Hold the purge at 16,000 rpm to remove any deposits or entrained gases	CMCE with assistance from field service engineer adjusted time as necessary
Engine ignition	Typically the Elliott microturbine will reduce speed to 10,000 rpm for ignition after purge	CMCE and field engineer adjusted speed based on back pressure on the microturbine with VOC furnace combustion air blower in operation
Acceleration to full rated speed following ignition	Engine will reach 68,000 rpm before power can be generated	Typically, it requires 2 minutes. During this time CMCE monitored critical engine functions and record for readiness

Source: CMC-Engineering

In the second series of startup tests, the unit was set on auto generate mode while grid connected. The microturbine warmed up for about 30 seconds and then ramped up to maximum load of 100 kW. At that point, the exhaust gas temperature (EGT) was checked to ensure that the limit of 600 C was not exceeded. Data was collected from the power electronics and included vital operating parameters, confirming that there are no alarms or engine trips.

6.4.2 Results of Checkout and Microturbine Commissioning Test

CMC-Engineering and its subcontractor completed the inspection of the microturbine and its components. This was possible only after grid power was supplied to the microturbine and gas pressure to the compressor was delivered in accordance with engine specifications. As indicated above, the microturbine was inspected from its foundations (anchored to the cement pad) to its ability to readily start after it was energized and the Start button pushed. The field service engineer identified a low level of oil in the holding tank. CMC-Engineering provided specified gas turbine oil to bring tank level to required supply. Figure 86 shows the engineer working with field service subcontractor inspecting all the faults on the power electronics panel and ensuring that each of the faults were corrected to ready the microturbine for normal operation.

Figure 86: Inspection of Power Electronics and Operational Faults

This photograph shows the CMCE engineer working with the field service subcontractor to inspect all the faults on the power electronics panel and ensuring that each of the faults were corrected to ready the microturbine for normal operation.
Photo Credit: CMC-Engineering

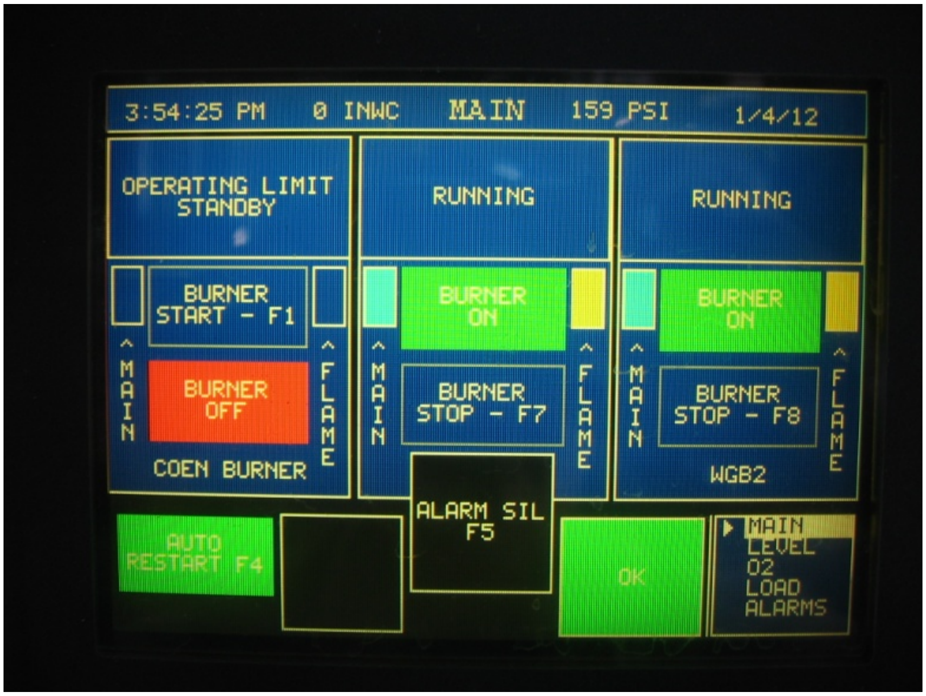
During this process, the field team identified installation problems with the wiring and programming of the gas compressor VFD, which was added by CMCE-Engineering to ensure proper operation of the gas compressor in line with the site power supply specifications. After several faulty starts, the wiring was inspected and redone, as shown in Figure 87. A review of the control settings on the VFD also identified that some of the programmed settings were incorrect. These had resulted in failures to start the gas compressor at the times specified by the settings on the power electronics. Consequently, the VFD was reprogrammed and on the final day of operation, the field team was able to correct the problem. At this time the microturbine was set to the light off speed and the gas compressor was monitored for an accurate startup. The microturbine had to be shutoff once it reached ignition speed (16,000 rpm for peak then dropping down to 10,000 rpm for light off) because the gas valve could not be opened ahead of a final permit by the Air district. Therefore, logoff took place following the completion of the installation work and after the final permit was received by the Momentive operations managers.

Figure 87: Rewiring and Reprogramming of the VFD

Repairs were made to the wiring and programming of the gas compressor VFD while preparing the microturbine for normal operation.
Photo Credit: CMC-Engineering

During these checkout tests, the facility was under operation. That is the VOC furnace was lit off on natural gas and once it reached the operating temperature, it was switched to burning 100 percent tail gas. Figure 86 shows the control panel indicating that the main gas burner, indicated by the red light, was turned off and the two tail gas burners, indicated by the green lights, were firing tail gas from the formaldehyde process.

Figure 88: Control Panel for VOC Furnace



Photograph of the control panel for the VOC furnace indicating tail gas burners in operation.
Photo Credit: CMC-Engineering

CMC-Engineering performed measurements of emissions from the VOC furnace to record levels of NOx and CO during pre-CHP operation. These data were also communicated to the Momentive management for transmittal to the Air District for their permit deliberations. Figure 89 and Figure 90 show the CMC-Engineering field engineer taking the readings with the Bacharach instrumentation and sampling probe.

CMC-Engineering informed Momentive that it was recommended to start the microturbine manually and operate only when the resin manufacturing process has reached steady state. Initial tests were performed with the engine on, followed by the blower to ensure that the blower can supply all the needed combustion air with a windbox pressure of 2 inches water gauge (w.g.). During regular operation, the microturbine will operate only in CHP mode when the VOC destruction is occurring. This generally takes place after 20 minutes from startup of the resin manufacturing process. At that time the VOC laden process gas will also reach steady flow rate and composition as the reactor catalyst will reach temperature equilibrium. Steady state operating of the VOC-furnace is necessary to minimize upgrades to the control system of the burner.

Figure 89: Sampling of Emissions from VOC Furnace

The sampling of emission from the VOC furnace at Momentive Specialty Chemicals located in Fremont, California
Photo Credit: CMC-Engineering

Figure 90: Sampling Probe in Stack

Location of sample probe
Photo Credit: CMC-Engineering

CHAPTER 7: Installation and Checkout

7.1 Goals and Objectives

The principal goal of this task was to complete the retrofit of the assembled and pre-tested CHP equipment at the selected demonstration site into a final CHP assembly, implying that the microturbine would be connected and interfaced with the existing TO/burner ductwork and would be in a state of readiness for performance testing.

Specific objectives included the following:

1. Secured the field service to assist in the installation and inspection of all components at the site
2. Secure the field service for the microturbine for electrical connection and inspection of all related components
3. Established that the replacement of the TO furnace burner was not necessary and not recommend by the host site
4. Implemented changes to the BMS to control combustion air blower with microturbine exhaust in CHP mode
5. Connected the microturbine power electronics (PE) cabinet to the service panel at the site
6. Interconnected the microturbine exhaust duct and its cooling vent
7. Connected the microturbine power to the local utility service panel
8. Connected the gas supply to the microturbine gas compressor
9. Connected the water supply to the microturbine heat recovery unit (HRU)

CMC-Engineering secured the support of the field service contractor specializing in Elliott microturbines. The contractor inspected the operation of the microturbine during the assembly and checkout activities and microturbine commissioning process. Replacement of the burner for the TO furnace was not required as the burners are specialized to incinerate tail gas and operate without any fuel gas supplement. All other installation activities were performed during this task. The following sections discuss the installation work. Permit to construct and operate was secured during the completion of the installation work.

7.2 Installation Drawings

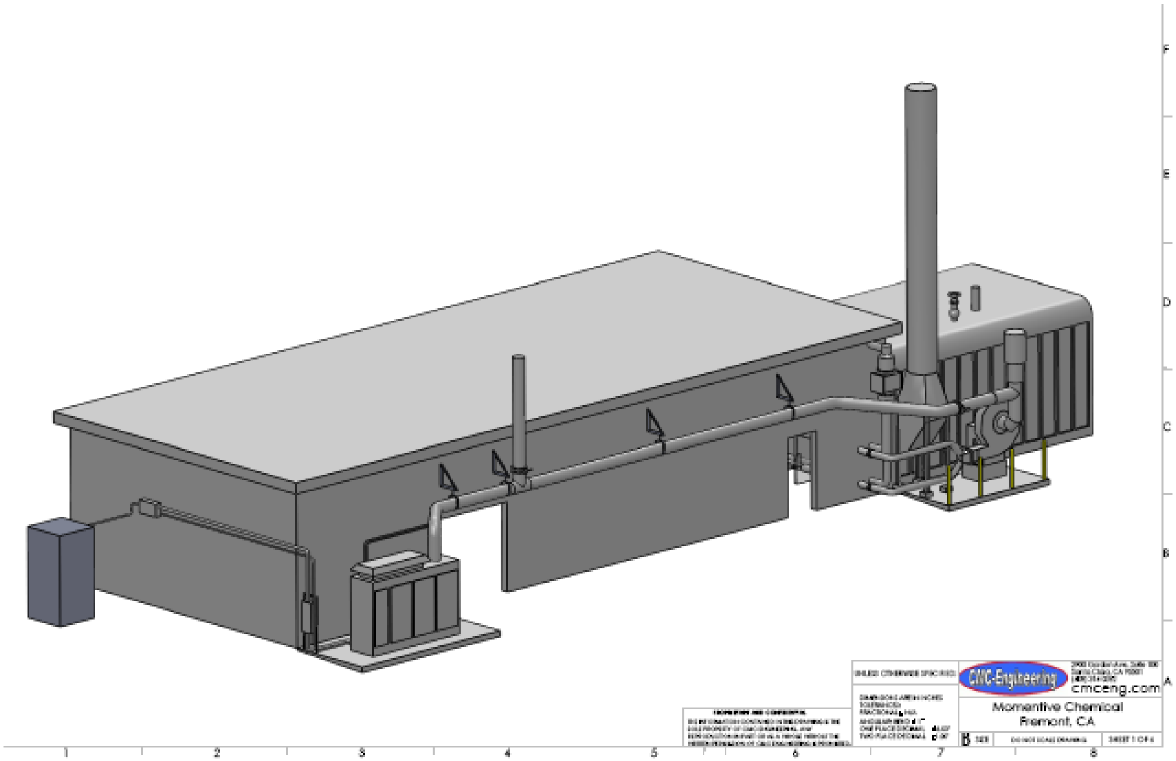
CMC-Engineering prepared the installation drawings after the general arrangement of equipment was agreed to with the host site management. Figure 91 shows the general arrangement of the host site and the location of the microturbine in relation to other key CHP equipment. The larger building on the left contains the thermal oxidizer boiler furnace, located at the far right of the building, and additional boiler equipment. On the far left of the large building is the transformer and electrical panels servicing the entire plant. The smaller building on the right houses the 400 kW steam turbine and generator. The steam turbine extracts energy from the high pressure steam from the Nebraska boiler furnace and produces low pressure steam needed for the process that generates formaldehyde-based resins. This bottoming cycle method for power generation, using a steam turbine, has a low efficiency. It is used at the plant simply because the amount of tail gas generated by resin manufacturing is sufficiently high to generate more steam than is required by the process. This excess steam is then utilized to generate 400kW of power.

Figure 91 also shows the location of the microturbine and the interface of the microturbine exhaust with the waste heat recovery in the TO boiler furnace. It was decided to locate the microturbine at the far left of the building for close proximity to the power transformer and the electrical service panel. Also this location was favored because the low pressure fuel gas supply was located just on the other side of the larger access door. The exhaust from the microturbine required a long exhaust duct to reach the combustion blower inlet, which is used to channel the waste heat from the engine to the TO boiler furnace. The installation drawings allowed for a bypass exhaust duct from the engine to permit the microturbine to startup, reach full speed and power generation, and slowly divert exhaust gas to the inlet of the already-running combustion air blower.

Figure 92 shows the distances from the microturbine location to the combustion air blower and details of the bypass damper. Provisions were made to operate the bypass with a remotely controlled actuator. However, the plant decided to activate the damper manually as necessary. Figure 93 shows the details of a second damper ahead of the combustion air blower inlet this allows the plant to completely isolate the microturbine in case of routing maintenance or unscheduled repairs to the modified TA-100 microturbine. Figure 94 shows the general layout of the electrical connections between the microturbine power electronics cabinet and the building supplied electrical service panel. The power cables are directed to an access box added to the side of the building. From there, the cables enter the building and the electrical service panel. Ground and neutral cables are run to the outside transformer.

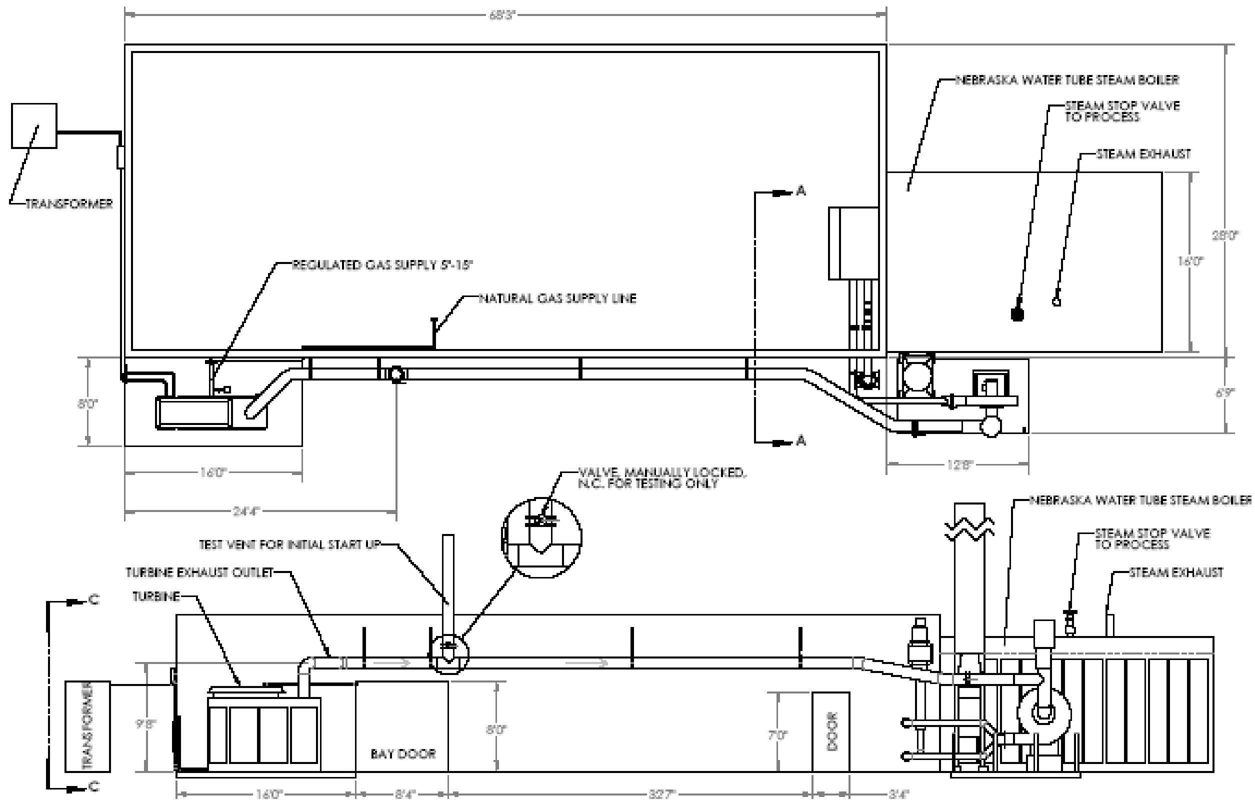
Figure 95 and Figure 96 provide some detail of the ductwork connecting the combustion air blower, on the right of the separating wall, to the tail gas burners and piping feeding the tail gas to the burners. The drawings show access piping dimensions and lengths. Existing ducting and blower were evaluated for ability to support added flows when operating in CHP mode. Other combustion air blower considerations included the need to upgrade or replace the combustion air blower to permit higher inlet air temperatures that also result with the operation of the microturbine in CHP mode.

Figure 91: Overall Installation Layout



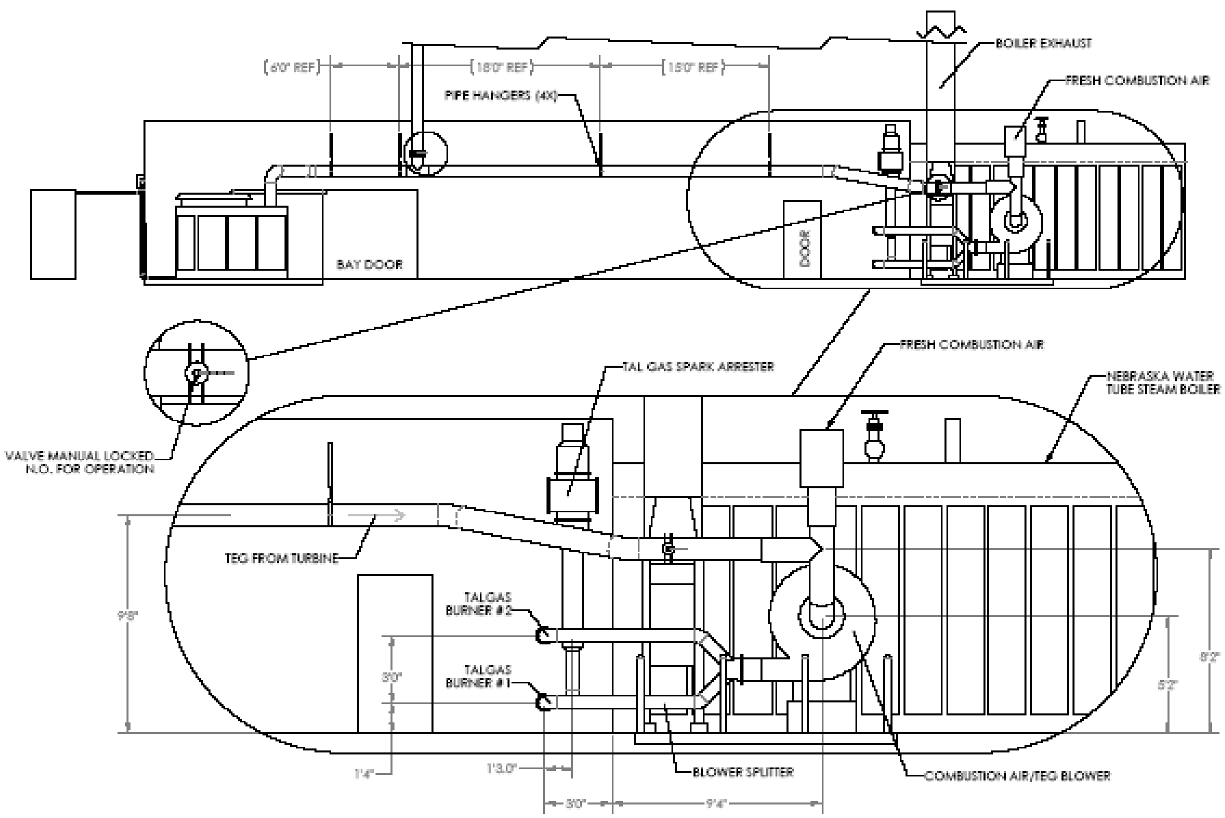
General arrangement at the Momentive Specialty Chemicals in Fremont, California and the location of the microturbine in relation to other key CHP equipment.
Source: CMC-Engineering

Figure 92: Plan and Front Views of Installation



This figure shows the distances from the microturbine location to the combustion air blower and details of the bypass damper.
Source: CMC-Engineering

Figure 93: Detail of Microturbine Exhaust Ductwork



This figure shows the details of a second damper ahead of the combustion air blower inlet.
Source: CMC-Engineering

Figure 94: Front and Side Views of Electrical Connection

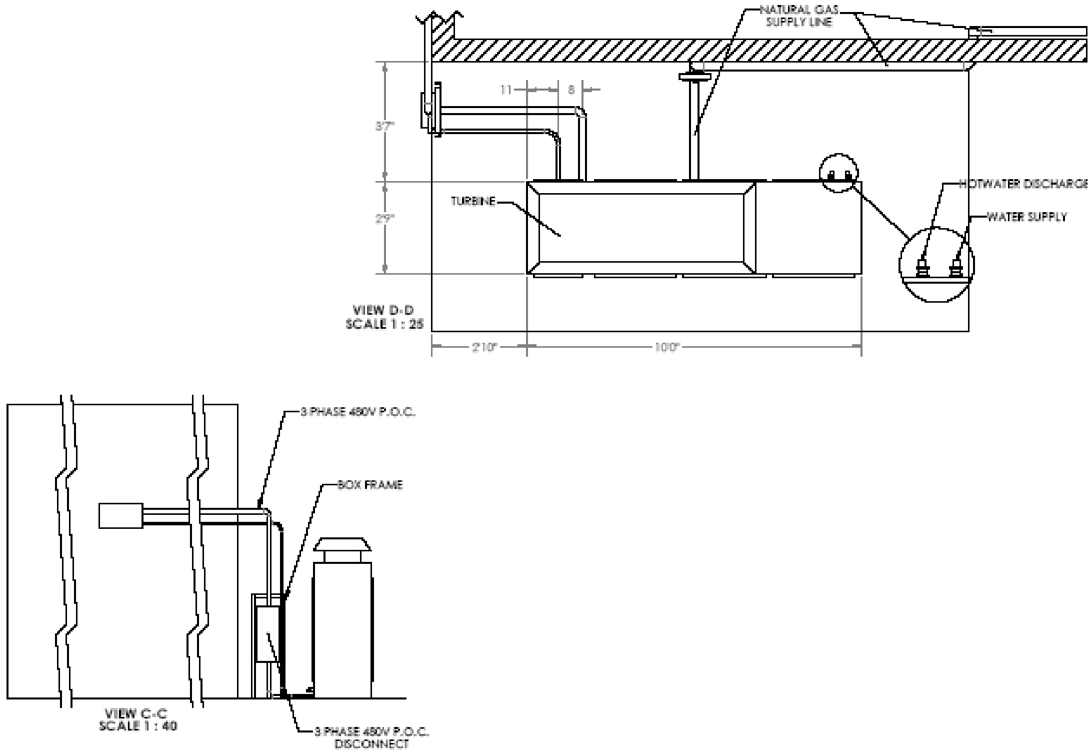
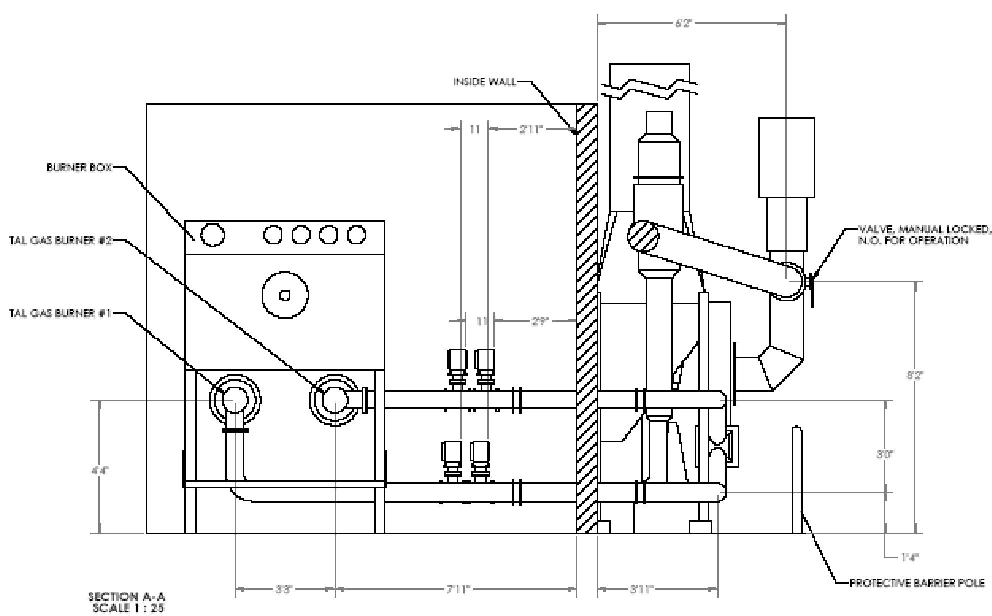


Figure 95: Detail of Combustion Air + Microturbine Exhaust and Tail Gas to Thermal Oxidizer Boiler Furnace



This figure shows the general layout of the electrical connections between the microturbine power electronics cabinet and the building supplied electrical service panel.
Source: CMC-Engineering

Figure 96: View of piping Carrying Tail Gas

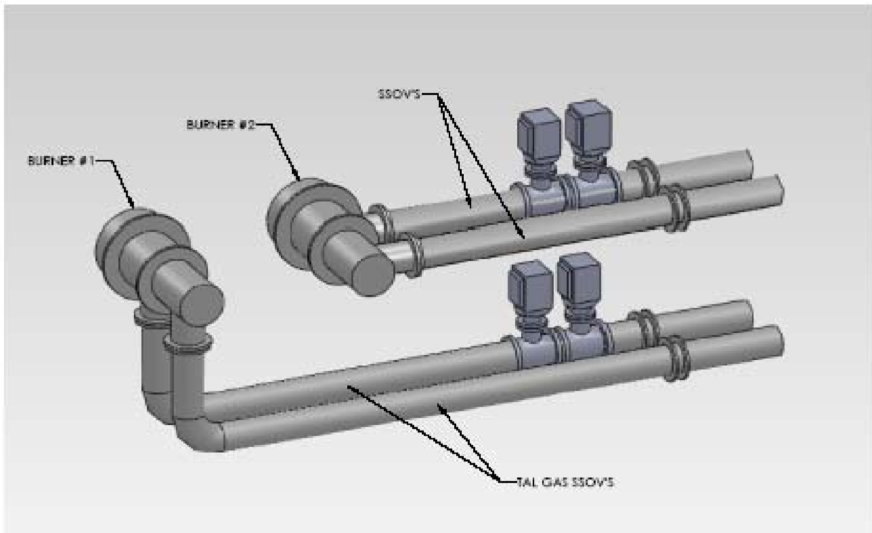


Figure shows piping carrying tail gas along with mixed microturbine, exhaust, and combustion air to TO furnace burners
Source: CMC-Engineering

7.3 Microturbine Delivery

Following completion of preliminary assembly and checkout test work at the laboratory, arrangements were made to ship the microturbine to the host site for further assembly and upgrades and to complete the installation of the CHP system. Figure 97 shows the assembled microturbine loaded on a flatbed for transport from Sunnyvale to the Fremont, CA demonstration site. Figure 98 shows the arrival at the site. The microturbine was temporarily stored in the warehouse where further upgrades took place prior to the installation at its final location.

7.4 Site Preparation

The location for the microturbine was selected from all available options and in consultation with personnel from the host site. The optimum site was determined to be near the electrical service panel, outside the boiler building where access to the gas supply provided for a short piping run to the microturbine. The final placement of the microturbine required the fabrication of a cement pad to support the microturbine in level position and to fasten it to the pad to prevent movement. Figure 99 shows the initial phases of the pad fabrication. Figure 100 shows the completion of the cement pad.

Figure 97: TA-100 Microturbine Loaded for Transport

This figure shows the assembled microturbine loaded on a flatbed for transport from Sunnyvale, California to the demonstration site located in Fremont, California.
Photo Credit: CMC-Engineering

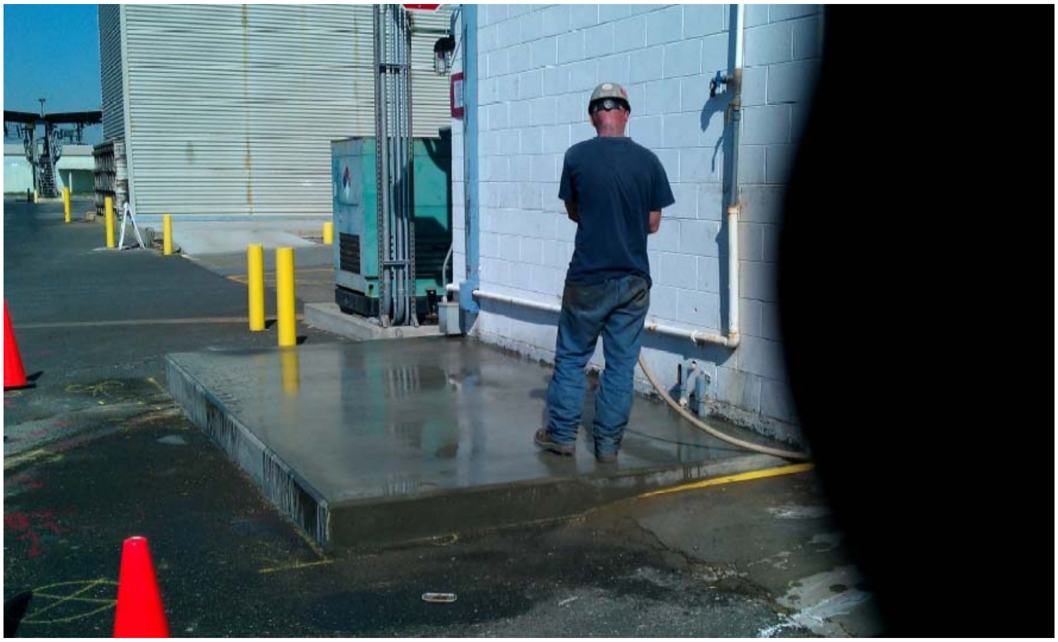
Figure 98: Microturbine at Demonstration Site

Microturbine arriving at the Momentive Specialty Chemical located in Fremont, California
Photo Credit: CMC-Engineering

Figure 99: Preparation of Cement Pad

Initial phase of preparing cement pad for the installation of the microturbine at Momentive Specialty Chemical site in Fremont, California
Photo Credit: CMC-Engineering

Figure 100: Completion of Cement Pad



The cement pad was completed for the installation of the microturbine at Momentive Specialty Chemical in Fremont, California.
Photo Credit: CMC-Engineering

After proper curing of the cement pad, the microturbine was placed on the cement pad and fastened with six anchor bolts, according with the instructions available in the installation manual and supplied by the microturbine supplier. In addition, the perimeter of the base of the microturbine was sealed to prevent accumulation of water under the microturbine which can cause rust formation over time. Figure 101 shows the completed installation of the microturbine on the cement pad.

Figure 101: Microturbine on Cement Pad

Installation of the microturbine on the cement pad at Momentive Chemical Specialty in Fremont, California
Photo Credit: CMC-Engineering

7.5 Installation

The installation process focused on three major activities: (1) installation of microturbine exhaust ductwork and associated equipment; (2) Connection of electrical cables to service panel for grid-tie microturbine operation; and (3) connection of natural gas fuel to the microturbine. The following sections highlight this installation work

7.5.1 Microturbine Exhaust Ducting

The ductwork connecting the microturbine to the combustion air blower inlet was undertaken with contracted union work by Momentive management. The sections of the ductwork were fabricated offsite and delivered to the plant. Figure 102 (left) shows one of the ductwork segments. The first few sections of the duct leaving the microturbine exhaust to the bypass damper can be seen on the right of Figure 102.

Figure 102: Fabricated Ductwork Section (left) and Installation (right)

Ductwork connecting the microturbine to the combustion air blower inlet at Momentive Specialty Chemical located in Fremont California.
Photo Credit: CMC-Engineering

The exhaust duct was extended for the length of the building as shown in the fabrication drawings. Figure 103 shows the section of the exhaust duct with the bypass damper and stack. This bypass will only be utilized when the microturbine is going through its starting cycle and until the combustion air blower inlet damper is opened to allow exhaust gas to be mixed with combustion air. Figure 104 shows the full extension of the duct to the combustion air blower, located about midway to the yellow colored safety barrier.

Figure 103: Microturbine Exhaust Ductwork

Exhaust duct with the bypass damper and stack, extending the length of the building at Momentive Chemical Specialty located in Fremont, California.
Photo Credit: CMC-Engineering

Figure 104: View of Full Ductwork Extension

Full extension of the duct to the combustion air blower at Momentive Specialty Chemical located in Fremont, California.
Photo Credit: CMC-Engineering

Figure 105 shows the welding work on the damper, a close-up view of the isolation damper that was installed at the inlet to the combustion air blower. Figure 106 shows the final connections of the exhaust duct with the blower inlet.

Figure 105: Contracted Welding Work (left) and Isolation Damper (right)

Welding work on the damper at the Momentive Specialty Chemical located in Fremont, California.
Photo Credit: CMC-Engineering

Figure 106: Connection of Ductwork to Combustion Air Blower Intake

Final connections of the exhaust duct with the blower inlet at Momentive Specialty Chemical located in Fremont, California.
Photo Credit: CMC-Engineering

7.5.2 Electrical Connections

CMC- Engineering coordinated the installation of the power cable from the microturbine power electronics cabinet to the electrical service panel. As indicated, the microturbine was located near the electrical panel to minimize the length of the power cable and facilitate installation. With this setup, the microturbine operates in grid-tie mode, where power will be supplied by the grid to maintain the batteries in the power electronics cabinet fully charged and be able to start the engine. After reaching full operating speed the microturbine will supply a maximum of 100 kW of power to the grid, thus reducing the power purchased from the grid.

Figure 107 shows the electrical conduit and installation of the breaker. This was to isolate the microturbine when not in operation. The microturbine was under weather protection during the installation process. Figure 108 shows the wiring work for the breaker. Figure 109 shows the electrical panel that will take the 100 kW of power from the microturbine for use within the plant.

The microturbine will be operated only when the plant is running and producing product. Therefore all the power generated onsite will be used onsite, reducing the load on the grid.

Figure 107: Electrical Conduit for Power Cable and Breaker

Electrical conduit and installation of the breaker to isolate the microturbine when not in operation at Momentive Specialty Chemical located in Fremont, California.
Photo Credit: CMC-Engineering

Figure 108: View of Breaker Wiring

Wiring work for the breaker at Momentive Specialty Chemical in Fremont, California.
Photo Credit: CMC-Engineering

Figure 109: Connection to Electrical Service Panel

Electrical panel that will take the100 kW of power from the microturbine for use within the plant
Photo Credit: CMC-Engineering

7.5.3 Natural Gas Supply Connection

Low pressure gas supply is needed to operate the microturbine gas compressor. As indicated, the microturbine was located in close proximity to the low pressure gas supply line (Figure 110 - left) used for the fire tube boiler located inside the building. Union workers were contracted to install piping with tie-in to the existing low pressure line (Figure 110 – right). The line was fitted with gas pressure regulator to ensure constant low pressure supply to the gas compressor. Figure 111 shows the final connection to the microturbine cabinet.

Figure 110: Gas Supply Line (left) and Piping Work on Tie-In

Low pressure gas supply line (left) used for the fire tube boiler located inside the building and the installation of piping with tie-in to the existing low pressure line (right) at Momentive Specialty Chemical
Photo Credit: CMC-Engineering

Figure 111: Gas Connection to Microturbine Cabinet

Final connection to the microturbine cabinet.
Photo Credit: CMC-Engineering

CHAPTER 8: Performance Testing

8.1 Goal and Objectives

The overall goal of this task is to perform field tests to measure the emissions and energy savings of the CHP technology installed at the Momentive Specialty Chemicals plant in Fremont California. The goal of the performance testing is to establish the attainment of performance objectives summarized in Table 1. Prior to the field testing work, a test plan was prepared. The field testing was initiated after the issuance of the Operating Permit by the BAAQMD and Energy Commission approval of the test plan. A copy of the Operating Permit can be found in Appendix 2.

8.2 Test Plan

Prior to undertaking the field test work, the project was required to prepare a test plan for approval by the Energy Commission. Therefore, this section focuses on the details of the test plan for the validation of the anticipated performance of the CHP with TOs and attainment of the emission limits in accordance with the operating air permits for the site.

1. A description of the process flows to be tested
2. The rationale for the tests, test objectives, and approach
3. A test matrix showing number of test conditions and replicate runs
4. A description of the facilities, equipment, and instrumentation that will be used to conduct the tests
5. A description of test procedures, including:
    a. parameters to be controlled and how they will be controlled (5)
    b. parameters to be measured and instrumentation to measure them (5 and 6)
    c. calibration procedures to be used (6 and 7)
    d. recommended calibration interval and maintenance of test log (7)
    e. description of data analysis procedures (7)
    f. description of quality assurance procedures (7)
    g. contingency measures if test objectives are not met (8)

The test plan has to address the objectives of the field tests. For the demonstration of a novel integrated CHP system, the field test objectives consist of:

- Document efficiency of the CHP system

- Document the continued compliance with VOC destruction efficiency requirements
- Document the overall emissions to meet compliance with air permit and CARB 2007 limits
- Document the operational flexibility and reliability of the system

The first objective requires that all energy input and output streams be measured to the boiler and the simple cycle microturbine. Energy input streams are defined by the fuel intake, the feed water, and power consumption of the boiler air blower and gas compressor. Energy output streams are defined by useful energy, (for example, steam from the boiler and microturbine gross power), and waste heat leaving with the boiler flue gas. For the microturbine, the useful energy is in the form of electrical power (kW) output in alternating current of 480 volts and 60 Amps. Energy efficiency for the CHP system is calculated based on ASME Power Test Code PTC 4.1 using either the heat output/heat input or by quantifying heat losses. For the CHP system, the heat input is defined as the total fuel intake of the boiler and microturbine. The output is then the steam generation of the boiler plus the electrical generation of the microturbine. In mathematical terms, the CHP efficiency (ε) will be defined as follows:

$$\varepsilon_{CHP} = \frac{Q_{out}}{Q_{in}} = \frac{\left(H_{steam} - H_{Feedwater} + H_{HW}\right) + H_{MTG}}{Q_{boilerfuel} + Q_{MTG}}$$

Where H_{steam} is the enthalpy of the steam; $H_{Feedwater}$ is the enthalpy of the feedwater to the boiler; H_{HW} is the enthalpy of the hot water generated in the HRU of the microturbine; H_{MTG} is the energy output of the microturbine (3,412*kWe); $Q_{boilerfuel}$ is the heat from fuel burned in the boiler, and Q_{MTG} is the heat from fuel burned by the microturbine.

Energy losses parasitic loads from the CHP system include:

- Latent and sensible heat losses from the boiler stack
- Radiative losses of the boiler (defined by ASME PTC 4.1)
- Gas compressor power requirements (approximately 4 kWe)
- Power electronics losses
- Radiative losses from microturbine enclosure

The power conversion efficiency of the microturbine generator is reported both as gross and net. Net power conversion efficiency accounts for parasitic losses due principally to the required compression of natural gas and energy losses in the power electronics. Therefore,

$$\varepsilon_{PC-gross} = \frac{H_{MTG}}{Q_{MTG}}$$

$$\varepsilon_{PC-net} = \frac{(kWe - kWc - kWpe) * 3412}{Q_{MTG}}$$

Where kWc is the compression power and kWpe is the energy losses in the power electronics to convert generator output to 480 volts 60Hz.

Emissions are generated from the microturbine silo combustor and from the TO furnace burner. The microturbine will operate with natural gas and the TO furnace will operate with process tail gas. All tests are planned after the TO furnace has reached operating temperature and the tail gas accounts is introduced to the furnace for incineration and heat recovery. The flow of tail gas to the furnace is anticipated to remain constant at about 2,760 scfm. The natural gas flow to the microturbine will also remain relatively constant at about 20 scfm and will be affected only by ambient temperature and kWe generated.

All emissions are exhausted through the boiler stack. When burning natural gas and process tail gas, only NOx and CO emissions are typically generated in measurable quantities. CO emissions will be an indication of the destruction efficiency of the VOCs in the tail gas. NOx emissions in the stack are likely the sum of NOx formed in the microturbine combustor and NOx formed in the TO furnace. This is because little or no reduction in NOx from the microturbine is anticipated when the microturbine exhaust enters the burner flame.

The destruction efficiency of the VOCs in the tail gas is the calculated using the following equation:

$$DE_{VOC} = \left(1 - \frac{M_{CO}}{M_{VOC}}\right) \times 100$$

Where M_{CO} is the total CO emissions measured at the stack and M_{VOC} is the total mass emissions of VOCs in the tail gas, which according the tail gas composition in Table 23 is approximately 859 scfh. Note that if the TO furnace continues to burn natural gas when tail gas are introduced, then the equation above must be modified to account for the additional carbon introduced by the natural gas as follows:

$$DE_{VOC} = \left(1 - \frac{M_{CO}}{M_{CH} + M_{VOC}}\right) \times 100$$

Where M_{CH} is the total mass of carbon entering the TO furnace as C_xH_y found in natural gas.

Table 30 illustrates the effect of microturbine NOx on NOx emissions from the TO Nebraska boiler furnace. The shaded cells indicate the emission limits for the boiler and microturbine necessary to meet CARB 2007 emission standards. The BAAQMD permit allows for the CHP to operate as long as the VOC destruction of >99 percent efficiency is achieved and NOx emission from the stack are not increased significantly. Currently, the NOx emissions from the stack are approximately 1ppm to2 ppm, corrected to 3 percent O_2. As indicated, even when the microturbine emissions exceed the CARB 2007 limit, NOx emissions at the stack are not measurably affected.

Table 30: Effect of Microturbine NOx emissions on NOx Emissions from TO Furnace

MTG NOx			Boiler NOx			CHP NOx		
lb/MWh	ppm (15%O2)	lb/hr	lb/MMBtu	ppm (3%O2)	lb/hr	lb/MMBtu	ppm (3%O2)	lb/hr
0.07	4.55	0.007	0.0018	1-2	0.033	0.002	1.8	0.040
0.11	7.00	0.011	0.0018	1-2	0.033	0.002	2.0	0.044
0.15	10.0	0.015	0.0018	1-2	0.033	0.003	2.2	0.048
0.19	12.2	0.019	0.0018	1-2	0.033	0.003	2.4	0.052

Source: CMC-Engineering

Documentation of operational flexibility and system reliability depends on monitoring operation and performance with variable demands on load. The CHP system has been designed to operate with a fixed, full load, generator output of 100kW. Therefore, the installation will operate either with the microturbine off or a full generating capacity. The boiler furnace will also operate at constant steam output once steady process conditions are achieved following startup. Reliability in emissions and operational readiness involves the monitoring of emissions and operational performance of the CHP equipment over a period of time as required by the air permit. Table 31 lists the planned test matrix identifying microturbine and boiler loads and the use of the microturbine HRU for cogeneration of hot water.

The field test program was designed based on a five series of tests with the boiler furnace operating at steady load as determined by process requirements. Based on CMC-Engineering knowledge of the operation at Momentive, this would occur with the boiler TO furnace operating at a heat input of about 18 MMBtu/hr. The five test conditions were identified as follows:

1. Baseline without microturbine on. This will establish pre-retrofit emissions and boiler efficiency
2. Microturbine on with HRU off operating at rated power output. This will establish CHP operation, emissions, and efficiency when no hot water is cogenerated and microturbine exhaust reaching the combustion blower inlet is a maximum of 560 F

3. Microturbine on with HRU on operating at rated power output and maximum hot water generation. This will establish operation, emissions, and efficiency when hot water is cogenerated and microturbine exhaust reaching the combustion air blower inlet is at a minimum of about 190 F
4. Microturbine on with HRU on operating at rated power output and reduced hot water generation. This will establish operation, emissions, and efficiency when hot water is cogenerated at lower rate and microturbine exhaust reaching the combustion air blower inlet is at range of about 350 F
5. Microturbine on with HRU on operating at rated power output and maximum hot water generation. This will establish repeatability of operation, emissions, and efficiency when hot water is cogenerated and microturbine exhaust reaching the combustion air blower inlet is at a minimum of about 190 F. This represents the most anticipated CHP operation and thus will be tested for as long as process allows or for one week, whichever is less.

Table 31: Test Matrix

Run	MTG Load (kW)	Hot Water GPM and Temp (F)	ULN Burner Load (MMBtu/hr)	Stack Oxygen (% dry basis)
1	Not Operating	0	18 (max)	1-2
2	Not Operating	0	18 (max)	1-2
3	Not Operating	0	18 (max)	1-2
4	100	0	18 (max)	1-2
5	100	0	18 (max)	1-2
6	100	0	18 (max)	1-2
7	100	60 (120-130)	18 (max)	1-2
8	100	60 (120- 130)	18 (max)	1-2
9	100	60 (120-130)	18 (max)	1-2
10	100	30 (130-140)	18 (max)	1-2
11	100	30 (130-140)	18 (max)	1-2
12	100	30 (130-140)	18 (max)	1-2
13	100	60 (120-130)	18 (max)	1-2
14	100	60 (120-130)	18 (max)	1-2
15	100	60 (120-130)	18 (max)	1-2

Source: CMC-Engineering

Following consultation with the host site, the flexibility of operating the HRU at different water flow rates and different water outlet temperatures could be impaired by the process needs. Therefore, the actual testing was limited to one set of HRU settings according to the requirements of the host site.

8.3 Description of Test Equipment and Measurement Locations

Table 32 lists the measurements for each of the performance tests. The plant's tail gas flow meter, along with the composition analysis of the tail gas, was used to measure the heat input to the TO furnace. Steam pressure and flow rates determined the energy output of the TO furnace boilers. The heating value of the natural gas and the heat rate for the TA-100 microturbine determined the energy used by the microturbine. Feed water and steam conditions, pressure and flow rate, measured in the boiler control room and steam gauges on the boiler itself, were used to establish the heat recovery in the boiler and thus its efficiency, calculated using ASTM P.T.C 4.1 protocol. Power generation readouts were recorded by the power electronics (PE) cabinet servicing the microturbine. Boiler stack measurements were used to determine the emissions and thermal losses from the boiler. Emissions measurements with and without the microturbine on were to quantify the incremental NOx emissions produced by the microturbine. Hot water flow and inlet/outlet temperatures were recorded with the PE and were used to determine heat recovery in the heat recovery unit (HRU).

Table 32: List of Measurements and Data Sheet

	Variable	Units	Location
Ambient Conditions	Barometric Pressure	in of Hg	Ambient press gauge
	W/B Air Inlet Temperature	F	Wet/Dry bulb gauge
Gas Compressor	Inlet Gas Pressure	psig	Pressure gauge
	Outlet Gas Pressure	psig	Pressure gauge
	Power Consumption	kW	PE control panel
	Gas HHV	BTU/ft**3	Utility data
	Gas LHV	BTU/ft**3	Utility data
Boiler and Burner	Steam flow	lb/hr	Boiler control room
	Steam pressure	psig	Boiler control room
	Feedwater pressure	psig	Boiler control room
	Tail gas flow rate	lb/hr	Plant control panel
	Tail gas pressure	psig	Manometer fuel pipe
	TO furnace stack temperature	F	Thermocouple
Microturbine	Power Output	kW	Power electronics
	Fuel Flow	scfm	Calculated from heat rate
	Exhaust Gas Temperature	C	Power electronics
	Water inlet and outlet temperature	C	Power electronics
	Water flow rate	C	Power electronics

	HRU inlet and outlet temp	C	Power electronics
To furnace blower	Combustion blower out temperature	F	Thermocouple blower outlet
	Pressure	in of water	Manometer
	Oxygen Level	%	Gas monitor
Emissions	Exhaust Temperature	F	Boiler stack
	Oxygen Level	%	Boiler stack
	NOx Level	ppm	Boiler stack
	CO Level	ppm	Boiler stack

Source: CMC-Engineering

Portable emission monitors of the type shown in Figure 112 were used to measure NOx and CO concentrations in the boiler stack as required by air permit conditions. The instrumentation also monitors the temperature and excess O_2 levels in the TO furnace stack, and the combustion air blower outlet. The temperature of the combustion air blower outlet increases when the microturbine exhaust gas is diverted to the blower inlet for full CHP operation. The figure shows the Bacharach Model ECA 450 portable suitcase.

Figure 112: View of the Continuous Emission Monitor at the Stack Location

Photo credit; CMC-Engineering

Figure 113 shows the installation of instrumentation to monitor combustion air blower outlet conditions (temperature, pressure, and oxygen content) and tail gas conditions (temperature and pressure). As part of the installation task and in preparation for the field testing, CMC-Engineering installed instrumentation at the burners, at the combustion air blower inlet and outlet, and at the microturbine HRU water inlet and outlet. The instrumentation consisted of water manometers to measure pressure in inches of water and portable monitor for temperature measurements and oxygen content and water flow rates. These measurements were necessary to monitor the energy and mass balance of the CHP system and to calculate CHP efficiencies.

In addition, the test crew relied on the process instrumentation at the plant to determine tail gas flows to the TO furnace and the steam generation to establish TO furnace efficiency with and without CHP operation. Figure 114 shows a screen photo of the process from the instrument screen at the plant. The photo shows the reactors that are used to manufacture products based on reaction of methanol with steam over a catalyst. The process diagram provided information on the tail gas flow from the reactors, shown on the left of the screen about half way down. On this snapshot of the process, the tail gas flow was measured at 12,975 lb/hr.

Table 33 shows the instrument precision levels. This information provides a measure of the degree of uncertainty and variability anticipated in the reported measurements. As indicated, the continuous emission monitors have an inherent error band on 0.5 ppm for NOx and CO. Because the permit conditions call for meeting 30 ppm NOx and 400 PPM CO (condition 3 of permit in Appendix A), these potential error bands represent a relatively insignificant potential errors of 1.7 and 0.1 percent respectively.

Figure 113: Instrumentation Placed at the on Blower and Tail Gas Ducts

Photo credit: CMC-Engineering

Figure 114: Screen View of the Plant Process

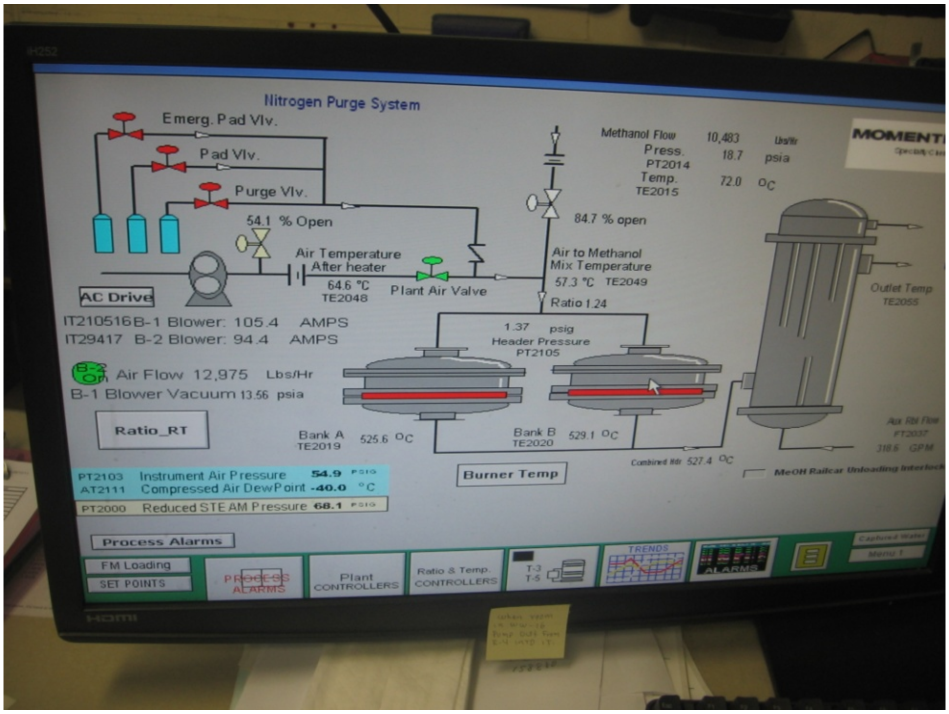


Photo credit: CMC-Engineering

Table 33: Acceptable Measurement Variability for Steady State Operation

Parameter	Units	Variability	Instrumentation
Microturbine (MTG) Power	kW	±0.45%	Power electronics panel
MTG Intake Air Temp	ºC [°F]	±1.1ºC [±2ºF]	Wet and dry gas bulb
Wind box Intake Air Temp	ºC [°F]	±1.1ºC [±2ºF]	
Barometric Pressure	of Hg	±2.0%	Local weather data
Wind box pressure	of H_2O	±3.0%	Pressure gauge on windbox
Feedwater pressure	psig	±2.0%	Line pressure gauge
Steam pressure	psig	±2.0%	Steam drum readout in control room
Steam flow rate	lb/hr	±2.0%	Steam chart in control room
Stack and MTG Exhaust Temperatures	ºC [°F]	±2.8ºC [±5ºF]	Exhaust stack
Gas Compressor Fuel Supply Pressure	psia	±1.5%	Gas line inlet pressure gauge and TA-100 heat rate
MTG Fuel Supply Flow Rate	scfm	±1.0%	
Boiler Burner Fuel Supply Flow Rate	lb/hr	±0.5%	Plant instrumentation

Windbox pressure	In H_2O	±0.2%	Available pressure meter or water manometer
Stack oxygen concentration	%	±0.2%	Bacharach ECA 450 cold gas sample drawn from stack and read with portable emissions monitors shown in Figure 7.
Stack CO emissions	ppm	±0.5 ppm	
Stack NOx emissions	ppm	±0.5 ppm	

8.4 Tail Gas Composition and Combustion Air Requirements

A sample of the tail gas was taken and analyzed by gas chromatography during the field demonstration testing. The results of the anlaytical work are shown in Appendix 3. Table 34 shows the composition of the tail gas. As indicated, the tail gas consists principally of nitrogen (66.16 percent). Hydrogen makes up the bulk of the combustible components (23.9 percent) followed by carbon monoxide (CO) at 4.23 percent. The tail gas has a high heating value (HHV) of about 1,800 Btu/lb or about 100 Btu/ft^3. Because the typical burning rate is 13,000 lb/hr, the heat input to the TO furnace is about 23.38 MMBtu/hr (HHV). The other observation is that the tail gas is nearly void of any oxygen. Thus the combustion air blower needs to supply all the combustion air to incinerate the tail gas and produce heat for steam production. The hazardous air pollutants (HAPs) in the tail gas are primarily methanol, methylformate, and dymethy mal

eate, each in concentrations of less that one percent by volume.

Table 34: Composition of VOC Stream

						MMBtu/hr	
Composition	VOC Stream Composition (%vol)		State	MW	lb/hr	HHV	LHV
Hydrogen	H2	23.907	gas	2	288	17.734	10.14
Oxygen	O2	0.01719	gas	32	3	0.000	0.000
Carbon Monoxide	CO	4.23271	gas	30	766	3.108	3.108
Carbon Dioxide	CO2	0.13727	gas	44	36	0.000	0.000
Water	H2O	4.90407	liq	18	532	0.000	0.000
Methanol	CH3OH	0.20461	liq	32	39	0.386	0.341
Methylformate	C2H4O2	0.42841	gas	60	155	2.112	1.925
Dymethyl Maleate	C6H8O4	0.00422	liq	144	4	0.040	0.037
Balance Nitrogen	N2	66.16452	gas	28	11175	0.000	0.000
	TOTAL				13000	23.38	15.55

Source: CMC-Engineering

Table 35 lists the results of the calculations of the the combustion byproducts of this tail gas stream in the TO furnace. The amount of oxygen needed to burn all the combustible elements in the VOC stream defines the amount of combustion ait supplied by the combustion air blower to the two furnace burners. The 2,809 standard cubic feet per minute (SCFM) of combustion air requirements is the minimum amount of combustion air that is required for complete combustion of tail gas. With 15 percent excess air, the blower would have to supply 3,231 SCFM of air.

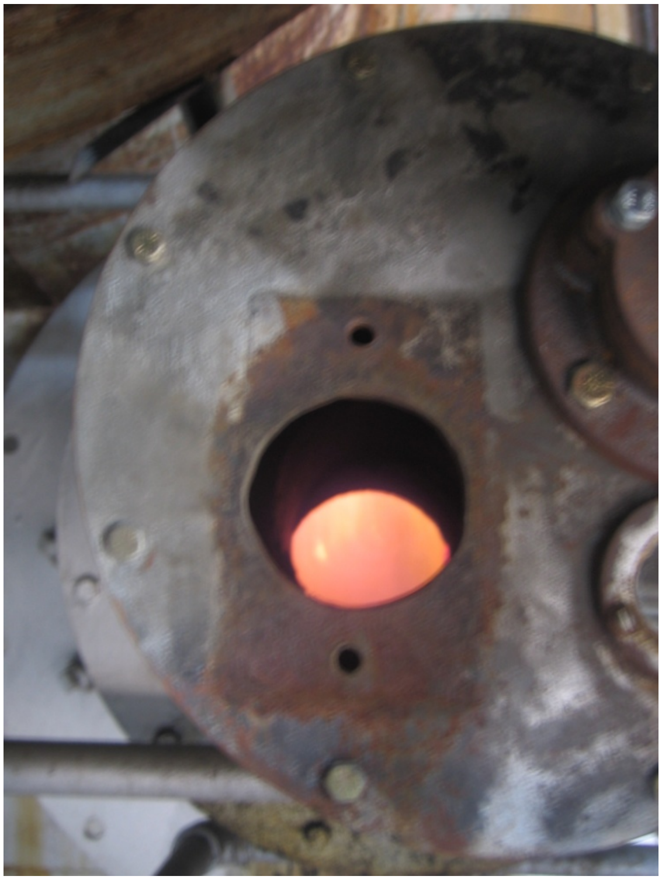
Table 35: Combustion calculations of the VOC Stream in Nebraska VOC Recovery Boiler

	SCFH	O2	N2	Total		CO2	H2O	N2	TOTAL
H2	55,521	27,760	104,432	132,193			55,521	104,432	159,953
O2	40	(40)	(150)	(190)				(150)	(150)
CO	9,830	4,915	18,490	23,405		9,830	9,830	23,405	43,064
CO2	319		-	-		319			319
H2O	11,389		-	-			11,389		11,389
CH3OH	475	713	2,681	3,394		475	950	2,681	4,107
C2H4O2	995	1,990	7,486	9,475		1,990	1,990	7,486	11,465
C6H8O4	10	59	221	280		59	39	221	319
Bal N2	153,659		153,659	153,659				153,659	153,659
TOTAL	232,237	35,397	286,818	322,215		12,673	79,719	291,733	384,125
BoilerAir Needed		168,557	SCFH	2,809	SCFM	THEORETICAL AIR			
Combustion Products		384,125	SCFH	6,402	SCFM				
BoilerAir Needed		193,840	SCFH	3,231	SCFM	WITH 15% EXCESS AIR			
Combustion Products		409,409	SCFH	6,823	SCFM				

Source: CMC-Engineering

Figure 117 shows the flame as seen from the available viewport on one of the two tail gas burners. The orange color of the inside of the furnace captures the hot refractory. Not clearly visible are the TO furnace boiler tubes for steam generation. The flame is intensively radiative contributing to significant heat transfer to the refractory wall and steam tubes while at the same time relatively transparent because of the high concentration of water from the combustion of the 24 percent hydrogen in the tail gas.

Figure 115: Tail Gas Flame Viewed Through Available Viewport



Temperature conditions inside the TO boiler furnace

Photo credit: CMC-Engineering

8.5 Test Results

A total of 12 separate tests were performed. The first 4 tests consist of baseline conditions, for example, TO furnace operating independently of microturbine and reflective of the pre-CHP operation. During tests 2, 3, and 4 the microturbine was at full power but the exhaust was not channeled to the TO furnace but instead bypassed. This was done to achieve steady-state operation of the microturbine prior to full CHP operation. The remaining eight tests were performed in CHP mode with the microturbine exhaust channeled to the combustion air blower inlet for heat recovery and with microturbine HRU operating to produce hot water for the plant. Field data sheets for these tests can be found in Appendix 4.

8.3.1 Baseline Tests

Table 36 summarizes the TO furnace operation during the baseline tests. For all tests, the TO furnace was operated entirely with tail gas and with no natural gas supplement. Tail gas flow averaged 13,988 lb/hr for a total steam output of 19.51 lb/hr. NOx and CO emissions averaged at 2.0 and 98 ppm corrected to 3 percent O_2, respectively. Emission measurements were taken after several hours to achieve steady conditions and following any upsets in operation.

Table 36: Baseline Test Results - TO Furnace Only

Test No.	1	2	3	4	Average
Tails gas flow, lb/hr	13,000	12,967	12,950	13,034	12,988
Steam flow, lb/hr	20,537	20,539	18,714	18,257	19,511
Stack temp. F	385	380	379	389	383
Stack O_2, % (wet/dry)	2.67 / 3.0	1.57 / 1.59	3.07 / 3.3	2.1 / 2.7	2.35 / 2.65
Heat input, MMBtu/hr(1)	23.40	23.32	23.31	23.46	23.37
NOx, ppm @3%O_2	2.0	2.0	2.0	2.0	2.0
CO, ppm @3% O_2	99	82	130	82	98

(1) – Heat input calculated with tail gas HHV of 1,800 Btu/lb
Source: CMC-Engineering

The baseline efficiency of the TO furnace is based on the total heat output divided by the heat input. The heat output is defined by the amount of steam produced times the enthalpy difference of the steam minus that of the feedwater. Since the steam pressure is at about 150 psig, the net enthalpy of the steam is 863 Btu/lb. Therefore the TO boiler efficiency can be calculated as follows:

$$\varepsilon_{TOfurnace} = \frac{Q_{out}}{Q_{in}} = \frac{(H_{steam} - H_{Feedwater}) * SteamFlow}{Q_{tail\,gas}} = \frac{19{,}511 * 863}{23.37 * 10^6} = 72\%$$

The efficiency of the TO furnace is lower than most industrial boiler steam furnaces because of the large quantity of nitrogen introduced with the tail gas. This ballast volume of nitrogen serves to increase the heat loss from the furnace, reducing its efficiency. However, the TO furnaces is being used for a dual purpose: the incineration of the tail gas and the heat recovery for steam production. Thus the TO furnace is used as an air pollution device and a steam boiler where the heating value of the tail gas is recovered.

The destruction efficiency of the HAPs is based on calculating the total carbon entering the furnace minus the carbon exiting the furnace, with the latter determined by the CO concentration in the stack. The total carbon input is based on the CO in the tail gas plus the sum of all the carbon-containinig HAPs in the tail gas. Since the total quantity of methanol, methyformate and dimethyl maleate is 198 lb/hr Table 34 and the total CO entering with the tail gas and emitted at the stack is 766 Table 34 and 40 lb/hr (from a sample test), the destruction efficiency of the VOCs can be calculated as follows:

$$DRE = \frac{CO_{inlet} + \sum HAPs - CO_{stack}}{CO_{inlet} + \sum HAPs} = \frac{766 + 198 - 40}{766 + 198} = 95.9\%$$

8.3.2 CHP Tests

With the microturbine at full generating capacity and with the stack bypass open, the damper to the combustion air blower was slowly opened while the bypass damper was slowly closed. This diverted all the microturbine exhaust to the combustion air blower and to the TO boiler furnace. Figure 116 shows the field engineer checking the operation of the blower inlet damper in preparation for the tests.

Figure 116: View of Microturbine Exhaust to Tail Gas Burners

Photo credit: CMC-Engineering

Table 37 and Table 38 summarize the test results for the CHP operation measured during eight separate tests.

The first objective of the CHP tests was to record the CHP efficiency. This requires that all energy input and output streams be measured to the TO furnace and the recuperated microturbine with operation of the HRU. Energy input streams are defined by the fuel intake, the feed water, and power consumption of the boiler air blower and gas compressor. Energy output streams are defined by useful energy, (for example, steam from the boiler and microturbine gross power), and waste heat leaving with the boiler flue gas. For the microturbine, the useful energy is in the form of electrical power (kW) output in alternating current of 480 volts and 60 Amps. Energy efficiency for the CHP system is calculated based on ASME Power Test Code PTC 4.1 using either the heat output/heat input or by quantifying heat losses.

The analysis relied on the heat input and output method for the boiler efficiency was selected as a more representative of the TO operation with the tail gas. For the CHP system, the heat input, is defined as the total fuel intake of the boiler and microturbine. The output is then the steam generation of the boiler plus the electrical generation of the microturbine. In mathematical terms, the CHP efficiency (ε) will be defined as follows:

$$\varepsilon_{CHP} = \frac{Q_{out}}{Q_{in}} = \frac{\left(H_{steam} - H_{Feedwater} + H_{HW}\right) + H_{MTG}}{Q_{boilerfuel} + Q_{MTG}}$$

Table 39 summarizes the results of the CHP efficiency calculations. Heat input and output values are taken from Table 37 and Table 38. In addition to the 100 kW of net power generated (0.3413 MMBtu/hr) by the microturbine, the total heat output from the microturbine is based on the waste heat recovered from the HRU and the increase in sensible heat acquired with the rise in combustion air blower outlet temperature to the TO. Overall CHP efficiency for the eight tests averaged 76.8 percent, an increase of 4.8 percentage points from the 72 percent baseline TO furnace efficiency. The fuel used by the microturbine was converted to useful energy (electrical plus thermal) at an average efficiency of 95.9 percent.

The microturbine efficiency is influenced by the amount of water flowing through the HRU, the temperature rise of the water, and by the sensible heat recovered using the exhaust gas from the HRU to heat the combustion air for the TO furnace. As shown in Table37 and Table 38, the amount of water that flowed through the HRU ranged from 38.8 to 41.2 liters/min (620 to 660 gpm) with a temperature rise of 100 to 103 F, corresponding to an enthalpy rise in the range of 0.51-0.55 MMBtu/hr. This heat recovery contributed significantly to the efficient use of the total fuel used by the microturbine (1.38 MMBtu/hr).

Table 37: CHP Test Results – Tests 5-8

Test No.	5	6	7	8	Average
Tails gas flow, lb/hr	12,982	13,030	13,006	12,990	13,002
TO furnace heat input, MMBtu/hr	23.37	23.44	23.41	23.38	23.40
Steam flow, lb/hr	18,257	20,500	20,539	20,500	19,949
TO furnace heat output, MMBtu/hr	15.78	17.69	17.73	17.69	17.22
Stack temp. F	389	388	389	389	389
Stack O_2, % (wet/dry)	2.35 / 3.2	2.01 / 2.8	1.91 / 2.8	1.7 / 1.9	12.0 / 2.68
NOx, ppm @3%O_2	6	6	6	6	6
CO, ppm @3% O_2	149	162	155	142	152
Microturbine kW (gross)	100	100	100	100	100
Microturbine kW (net)	92	92	92	92	92
Microturbine heat input, MMBtu/hr (HHV)	1.380	1.380	1.380	1.380	1.380
HRU flow, l/min	39.5	40.4	41.2	40.4	40.4
Water temp. increase, F	102	101	101	100	101
Water temp. outlet, F	162	161	161	161	161
Combustion blower outlet temp. , F	113	126	131	124	124
Microturbine waste heat recovery, MMBtu/hr	0.927	1.03	1.07	1.01	1.02
Total energy recovered by microturbine, MMBtu/hr	1.27	1.37	1.41	1.35	1.36
Microturbine CHP efficiency, % (gross kW basis)	91.9	99.3	102	97.8	98.6
Microturbine CHP efficiency, % (net kW basis)	90.1	97.3	1.00	95.8	96.6

Source: CMC-Engineering

Table 38: CHP Test Results - Tests 9-12

Test No.	9	10	11	12	Average
Tails gas flow, lb/hr	13,013	13,030	13,054	13,050	13,038
TO furnace heat input, MMBtu/hr	23.42	23.45	23.50	23.49	23.47
Steam flow, lb/hr	22,900	20,559	20500	20,500	21,115
TO furnace heat output, MMBtu/hr	19.76	17.74	17.69	17.69	18.22
Stack temp. F	390	391	392	390	3.91
Stack O_2, % (wet/dry)	1.8 / 1.9	1.86 / 2.1	1.76 / 2.5	1.76 / 2.5	1.80 / 2.25
NOx, ppm @3%O_2	6	6	7	7	6.5
CO, ppm @3% O_2	143	124	127	128	131
Microturbine kW (gross)	100	100	100	100	100
Microturbine kW (net)	92	92	92	92	92
Microturbine heat input, MMBtu/hr (HHV)	1.380	1.380	1.380	1.380	1.380
HRU flow, l/min	38.8	41.0	38	38.5	39.0
Water temp. increase, F	102	101	103	103	102
Water temp. outlet, F	163	161	163	164	163
Combustion blower outlet temp. , F	132	132	139	139	136
Microturbine waste heat recovery, MMBtu/hr	0.985	0.986	1.02	1.00	0.980
Total energy recovered by microturbine, MMBtu/hr	1.32	1.33	1.36	1.34	1.34
Microturbine CHP efficiency, % (gross kW basis)	95.7	96.4	98.6	97.1	95.7
Microturbine CHP efficiency, % (net kW basis)	93.7	94.4	96.6	95.1	95.1

Source: CMC-Engineering

Table 39: Overall CHP Efficiency

	Range	Average
TO Furnace Heat Input, MMBtu/hr (HHV)	23.37 – 23.50	23.44
Microturbine Heat Input, MMBtu/hr (HHV)	1.38	1.38
Total Heat Input, MMBtu/hr (HHV)	24.75 – 24.88	24.82
TO Furnace Heat Output, MMBtu/hr	15.79 – 19.76	17.72
Microturbine Energy Output. MMBtu/hr (HHV)	1.27 -1.41	1.35
Total CHP Output, MMBtu/hr (HHV)	17.06 – 21.17	19.07
Overall CHP Efficiency, %	68.9 – 85.1	76.8
Microturbine Energy Conversion Efficiency, % (net kW basis)	90.1 - 100	95.9

Source: CMC-Engineering

8.3.3 Emission Results

NO, NO_2, NOx ($NO+NO_2$), and CO emissions were measured at the TO stack for verifying compliance with the air permit and for measuring the impact of microturbine emissions on total emissions when the facility operates in CHP mode. The air permit from the Bay Area Air Quality Management District (BAAQMD) specifies that the TO furnace must be in operation when the microturbine is also in operation and that the microturbine exhaust must be fully diverted to the TO furnace combustion air blower so that no microturbine emissions are released to the atmosphere. Under this CHP mode, NOx and CO emission limits measured in the TO furnace stack were specified at 30 ppm and 400 ppm respectively, corrected to 3 percent O_2.

Table 40 shows the summary of emissions. Details of emissions under each test condition can be found in Appendix 4. The data shows that when the TO furnace operates without microturbine in operation (for example, baseline or pre-retrofit), NOx emissions were consistently measured at 2 ppm. All of the NOx was measured as NO_2. This is consistent with the fact that NO is prevalent when the furnace operates at low temperature as in the case of a TO furnace. CO emissions under baseline conditions ranged from 82 to 138 ppm with an average for the four tests at 98 ppm. As expected, the NOx increased under CHP operation. However, NOx was well below the permitted limit of 30 ppm. For the eight CHP tests, NOx averaged 6.3 ppm, again most was found to be NO2. CO emissions unexpectedly increased to a range of 124 to 152 with an average of 142 ppm.

Table 40: Summary of Emissions

Emissions,	**Baseline – TO furnace Only** **ppm corrected to 3% O_2**	**CHP** **ppm corrected to 3% O_2**
NO	0	0 – 1 (0.3)
NO_2	2	5 – 6 (6.0)
NOx ($NO+NO_2$)	2	6 – 7 (6.3)
CO	82 - 130 (98)	124 – 152 (142)

Figure 117 shows the levels of CO measured during baseline and CHP operation as a function of the excess oxygen in the TO furnace. CO emissions were expected to decrease with CHP because of the beneficial effect of air preheat. However, with CHP the combustion air to the TO was diluted with microturbine exhaust such that the concentration of oxygen in the combustion blower air discharge was reduced from 21 to 19 percent. This reduced O_2 partial pressure along with an increased combustion air velocity through the burners may have resulted in cooler flame with lower CO burnout. The observed trend of higher CO with increased excess O_2 supports the theory that lower TO furnace temperatures caused an increased in unburned carbon. Overall CO emissions remained well below the BAAQMD limit of 400 ppm.

Figure 117: CO Emissions during Baseline and CHP Operation

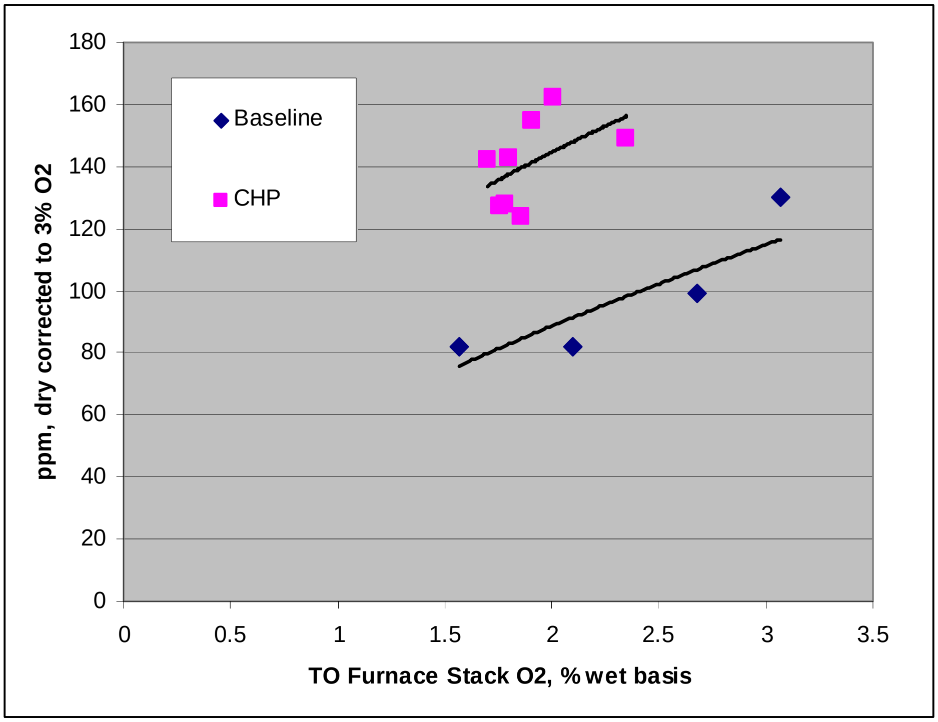


Figure shows that CO emissions increase with CHP and with increasing excess combustion air
Source: CMC-Engineering

CHAPTER 9: Conclusions and Recommendations

This project represents the first ever demonstration of a microturbine-based CHP with a TO furnace incinerating a tail gas containing HAPs and VOCs. The demonstration was a success in that it achieved all its planned performance goals and objectives. Overall CHP efficiency reached 85.1 percent with an average for eight tests of 76.8 percent. The overall efficiency of the CHP system accounted for the waste heat recovered in the hot water via the HRU within the microturbine cabinet and the waste heat recovered within the TO furnace. Because the TO furnace operates at relatively low boiler efficiency (72 percent) the overall CHP efficiency was limited to an average of 76.8 percent. This is compensated by the fact that the power conversion efficiency (the fuel used by the microturbine minus that recovered by the process) was converted to the 100 kW of power generated at an efficiency of 95 percent, making the onsite power the least cost possible. All emission targets were also met, including compliance with the CARB 2007 and BAAQMD NOx and CO limits.

The search for a dependable host site for the CHP demonstration proved difficult and resulted in significant delays in the project. The search process revealed some significant factors pertinent to the overall goals of field demonstrations of new technologies and new applications as well as the specific goal of CHP installations on TO furnaces. From a broader perspective, new technologies represent significant risk to the host facilities because CHP mandates the interactions of power generation components with existing onsite manufacturing processes. As such, management at the sites show significant resistance to demonstrations based on the potential of disruptions in their manufacturing activities. Furthermore, in the case of TO furnaces, these units are air pollution control devices which must have a high degree of reliability and on-time performance to maintain compliance with VOC destruction efficiencies during the manufacturing operations. In addition, many of these emission control devices do not have backups such that projects find it difficult to require host facilities to allow downtimes for the retrofit. The installation at Momentive Specialty Chemicals provided an opportunity for the retrofit not found at other facilities because the site was operating in a reduced capacity mode due to the economic downturn in the housing industry. This permitted the project to arrange for the retrofit during scheduled downtime without disruptions in the planned operations.

Overall, the variety in TO industrial equipment and waste gas composition and throughput capacity do not allow for a standard approach in the type of CHP equipment, retrofit configuration and operation. Therefore, a tailored site-by-site approach and engineering evaluation will be necessary to adapt the microturbine-based onsite power generation to each specific site. This will affect the degree of overall acceptance by the industrial community unless significant financial benefits and credits can be offered to the host facilities.

In order to diminish the perception of risk and improve host site participation in these PIER projects, it is recommended that PIER undertake a more segmented program focusing first on the commercial development of a new CHP technology and new applications. Once these technologies are fully developed on a commercial scale, they can be warranted and industry acceptance and field applications should become more readily attained. The commercial development of new technologies often requires key development stages that can clearly document the applicability, reliance, and benefits to the users prior to financial commitment by the host facilities.

GLOSSARY

AMP - Amperage

ASME – American Society of Mechanical Engineers

ASTM – American Society of Testing Materials

BAAQMD – Bay Area Air Quality Management District

Btu – British thermal unit

CARB – California Air Resources Board

CEC – California Energy Commission

CHP – Combined heat and power

CMCE – CMC-Engineering

DE – Destruction efficiency

DG – Distributed generation

DOE – U.S. Department of Energy

DRE – Destruction and reduction efficiency

EES – Elliott Energy Systems

EGT – Exhaust Gas Temperature

EPS – European Power Systems

FID – Flame ionization detection

FTA – Field Test Agreement

GC – Gas Chromatograph

GI&E - Gergho Industry & Engineering

gpm – gallons per minute

HAP – Hazardous air pollutant

HRU – Heat recovery unit

HHV – High heating value

IGBT – Integrated Gate Bi-Polar Transistor

JNJ – Johnson and Johnson Company

kW – kilowatt (3412 Btu for each kW)

LEL – Lower explosion limit

LHV – Low Heating Value

MEK – Methyl Ethyl Ketone

MMBtu/hr – Million British thermal units per hour

MSC – Momentive Specialty Chemical, or Momentive (host site)

MTG – Microturbine generator

NEMA – National Electric Manufacturer Association

OEM – Original equipment manufacturer

PE – Power Electronics

P&ID – Pipe and Instrumentation DrawingPIER – Public Interest Energy Research

PIER – Public Interest Energy Research

PLC - Programmable Logic Controller

PO – Purchase Order

PTC – Power test codes

QA/QC – Quality Assurance/Quality Control

RTO – Recuperative or regenerative thermal oxidizers

SCAQMD – South Coast Air Quality Management District

scfh – standard cubic foot per hour

scfm – standard cubic feet per minute

SCG – Southern California Gas Company

TET – Turbine exit temperature

TIT – Turbine inlet temperature

TO – Thermal oxidizer

VAC – Voltage alternating current

VOC – Volatile organic compounds

VFD – Variable frequency drive

wg – water gauge

APPENDIX A:
Agreement with Momentive Specialty Chemicals

MOMENTIVE™

Forest Products Division

41100 Boyce Road
Fremont, CA 94536
www.momentive.com

Date: 4/22/2011

Carlo Castaldini
CMCE, Inc. (d.b.a CMC-Engineering)
2900 Gordon Avenue, Ste 100
Santa Clara, CA 95051

Reference: Project for Demonstrating a 100 kW CHP Microturbine with Waste Heat Recovery in a Furnace Incinerating VOC – CEC Contract PIR-07-007

Subject: Momentive Specialty Chemicals Statement of Interest as Demonstration Site

Dear Mr. Castaldini:

Momentive Specialty Chemicals Inc. ("Momentive") located in Fremont, CA would like to express our interest in participating in the demonstration of the referenced Combined Heat and Power (CHP) project funded by the California Energy Commission. As stated in your meetings with Mr. Michael Chau, Momentive has an interest in the use of energy-efficient onsite power generation to cost-effectively reduce our demand for grid power. We believe that your project may fit well with our plans. Therefore, we would like to proceed to the next step in this process and evaluate an agreement based on your written proposal that we will receive from you. The management at Momentive reserves the right to make the final decision on the project following our review of your written proposal

We look forward to your further input as we move forward to a formal agreement on the proposed demonstration.

Regards

Michael Chau

The project team achieved an agreement with Momentive to move ahead with the project. This attachment shows the letter of intent received by CMCE.

APPENDIX B:
District Permit

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

Authority to Construct

(This is not a Permit to Operate)

Plant No. 151
Application No. 23914

Momentive Specialty Chemicals, Inc
41100 Boyce Road, Fremont, CA 94538

is hereby granted an *Authority to Construct* for the following equipment:
S-151 Microturbine, Elliott,TA-100 modified;1.24e6 BTU/HR

Equipment above is subject to attached condition no. 25170.

Approved by [signature]

for JACK P. BROADBENT
EXECUTIVE OFFICER / APCO

Issue date: February 7, 2012
Expiration date: February 6, 2014

Start-up Notification

Instructions: At least **seven days** before the scheduled initial operation contact your assigned Permit Engineer via email or complete and send this Start-up Notification to the District via fax or mail.

Engineer: Xuna Cai, Air Quality Engineer II
Tel: (415) 749-4788 **Fax:** (415) 749-5030
Email: xcai@baaqmd.gov

Plant No. 151
Source No. S-151
Application No. 23914

The initial operation of this equipment is scheduled for ______________ (month/day/year)

Print your first and last name ______________________________

Telephone No. ______________________________

Plant Name: Momentive Specialty Chemicals, Inc

S-151 Microtrubine, Elliott,TA-100 modified;1.24e6 BTU/HR

Condition No. 25170 Plant No. 151 Application No. 23914

1. The owner/operator shall not operate S-151 Microturbine unless S-3 Boiler is in operation except during the time period as specified in Part 2.
[Basis: Regulation 2-1-403; Toxics.]

2. During the initial startup period of S-151, the owner/operator shall not operate S-151 Microturbine without S-3 Boiler in operation for more than 8 hours.
[Basis: Regulation 2-1-403; Toxics.]

3. The owner/operator shall not operate S-151 Microturbine and S-3 Boiler unless the combined emissions from S-151 and S-3 do not exceed the following emission concentrations:
a) NOx = 30 ppmv @ 3% O2, Dry
b) CO = 400 ppmv @ 3% O2, Dry
[Basis: Regulation 9-7-112.2; Cumulative Increase.]

4. Within 90 days of startup of S-151, the owner/operator shall conduct a District-approved source test for the combined emissions from S-151 Microturbine and S-3 Boiler to determine compliance with the emission limits in Part 3. All source test methods used shall be subject to the prior approval of the Source Test Section of the District Technical Division. The owner/operator shall notify the Manager of the District's Source Test Section at least seven days prior to the tests, to provide the District staff the option of observing the testing. Within 30 days of test completion, a comprehensive report of the test results shall be submitted to the Manager of the District's Source Test Section for review and disposition.
[Basis: Regulation 2-1-403; Cumulative Increase.]

5. The owner/operator shall not operate S-3 Boiler for more than 306,600 therms in any consecutive 12-month period.
[Basis: Regulation 9-7-112.2]

6. The owner/operator shall fire only natural gas, not to exceed 108,330 therms, at S-151 Microturbine in any consecutive 12-month period.
[Basis: Cumulative Increase]

7. In order to demonstrate compliance, the owner/operator shall maintain the following monthly records in a District-approved log.

d25170

Plant Name: Momentive Specialty Chemicals, Inc

S-151 Microtrubine, Elliott,TA-100 modified;1.24e6 BTU/HR

Condition No. 25170 Plant No. 151 Application No. 23914

a. Readings of the natural gas utility service meter for the entire facility and the non-resettable totalizing meters for other boiler(s). The owner/operator shall determine the natural gas consumption at S-3 based on these readings.
b. Process gas consumption at S-3 calculated by using process data and mass balance;
c. The higher heating value of each fuel used at S-3;
d. Natural gas consumption at S-151;
e. Monthly usages shall be totaled for each consecutive 12-month period.

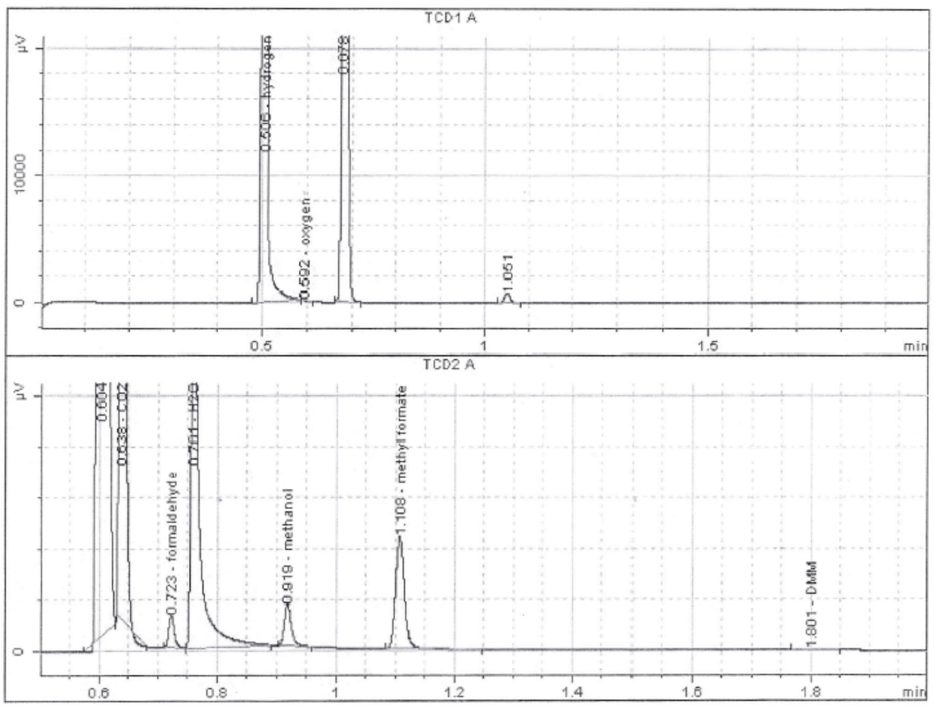
These logs shall be kept for at least a period of 24 months and shall be made available to the District upon request.
[Basis: Regulation 9-7-504; Cumulative Increase.]

End of Conditions

APPENDIX C:
Tail Gas Analysis During Tests

Agilent Cerity QA/QC Report

Sample name:	waste gas
Sample note:	
Submission time:	Tuesday, February 21, 2012 11:57:36 AM
Operator:	
Injection date:	Tuesday, February 21, 2012 11:57:53 AM
GC Description:	Borden - SN: US10422001
Signal description:	TCD1 A; TCD2 A
Method:	FREMONTsilver Feb 21 2012
Method last saved:	Tuesday, February 21, 2012 11:57:10 AM



ESTD Report

Calibration last saved:	Tuesday, February 21, 2012 11:57:10 AM
Multiplier:	1.0000
Dilution:	1.0000
Sample amount:	0.0000 mole%
Sample type:	Sample
Sampling source:	Inlet

Signal	Retention Time [min]	Type	Area [µV*s]	Amt/Area	Amount [mole%]	Name
1	0.506	PB	246878.92669	0.00010	23.90713	hydrogen
1	0.592	BBA	25.71753	0.00067	0.01719	oxygen
2	0.638	BBA	88450.83740	0.00005	4.23271	CO2
2	0.723	BB	2035.55048	0.00007	0.13727	formaldehyde
2	0.761	BBA	35913.10152	0.00014	4.90407	H2O
2	0.919	BBA	3328.59300	0.00006	0.20461	methanol
2	1.108	BBA	11342.56275	0.00004	0.42841	methyl formate
2	1.801	PBA	123.94527	0.00003	0.00422	DMM

Total amount = 33.83561

Report summary:
Warning(s): Calibrated compound(s) not found

Warning(s): Sample amount is zero. Absolute amounts calculated

Instrument run log:

APPENDIX D:
Summary of Field Test Data

This attachment shows copies of instrument printouts for six of the tests that were performed. The first test was taken during the startup of the VOC furnace when burning only natural gas. The remaining five tests were performed after the VOC reached thermal equilibrium and firing rate of 22 MMBtu/hr and burning only tail gas. Currently, the VOC furnace is categorized as an incinerator and is exempt from emission limits because it fires only tail gas, albeit after a period of about 2 hours for initial warm up. As indicated, NOx emissions with natural gas firing were recorded to be 66 ppm, corrected to 3 percent O_2. CO emissions were at 210 ppm, also corrected to 3 percent O_2. During normal operation, for example, with tail gas burning only, NOx emissions are significantly lower, ranging from 2 to 9 ppm. CO emissions are also lower. The very low NOx emissions are attributed to the tail gas composition which has a low heating value of only 76 Btu/cft. This low heat content produces a lower peak flame temperature and thus lower NOx emissions. The near absence of any carbon in the tail gas also results in lower CO emissions. The recorded CO_2 emissions are misleading because the Bacharach instrument does not measure CO_2 but instead calculates it based on the selected composition of the fuel. Since the instrumentation does not account for the composition of the tail gas, the CO_2 values should be disregarded. In fact, little or no CO_2 should be present in the stack gas because the tail gas has insignificant levels of carbon, only present in the VOCs at less than 1 percent by volume.

Date/Time	Feb 20, 2012 ; 8:30 AM			
Run #	1	Conditions: COOL OVERCAST		
Test Description TO furnace only. Microturbine off. TO furnace firing with 2 tail gas burners in operation and no natural gas backup – First baseline				
	Measurement	**Units**	**Location**	**Value**
Ambient Conditions	Barometric Pressure	in of Hg	Ambient press gauge	30.06
	Air Inlet Temperature	F	Bacharach ECA 450	60
Microturbine and Gas Compressor	Inlet Gas Pressure	inwg	Pressure gauge	
	Outlet Gas Pressure	psig	Pressure gauge	
	Power Generation	kW	Electronic Panel Display	
	Gas HHV	BTU/ft**3	Plant data	1,050
	Gas LHV	BTU/ft**3	Plant data	940
Microturbine	Calculates Fuel Flow	scfm	Engine Heat Rate of 12,355 Btu/kWh (LHV)	
	Turbine Exit Temp	C	Power Electronics Display	
	HRU Inlet Gas Temp	C	Power Electronics Display	
	HRU Outlet Temp	C	Power Electronics Display	
Heat Recovery Unit (HRU)	Water Inlet Temperature	C	Heat Storage tank	
	Water Outlet Temperature	C	Heat Storage Tank	
	Water Flow	lpm	Water Flow Meter	
Boiler and Tail Gas Burners	Steam flow	lb/hr	Boiler control room	20,537
	Steam pressure	psig	Boiler control room	150
	Feedwater pressure	psig	Boiler control room	185
	Tail gas flow rate	lb/hr / C	Plant fuel pipe	13,000 / 32
	Tail gas pressure at burner	inwg	Plant fuel pipe	0.6
Combustion air Blower	Outlet Temperature	F	Thermocouple	62
	Pressure / Temperature	In.wg / F	Blower Outlet	3.0 / 60
Emissions	Test Sample Location			
	Exhaust Temperature	F	Boiler stack	385

	Oxygen Level (wet/dry)	%	Boiler stack	2.68 /3.0
	NOx Level (NO/NO2/NOx)	ppm	Boiler stack	0 / 2 / 2
	CO Level	ppm	Boiler stack	99
Tail Gas Samples	Time Taken			

Date / Time	Feb 20, 2012 ; 10:35 AM			
Run #	2	Conditions: COOL OVERCAST		
Test Description Microturbine at full power with exhaust bypassed (not going to TO furnace). TO furnace on with 2 tail gas burners in operation and no gas backup – Second baseline				
	Measurement	**Units**	**Location**	**Value**
Ambient Conditions	Barometric Pressure	in of Hg	Ambient press gauge	30.06
	Air Inlet Temperature	F	Bacharach ECA 450	63
Microturbine and Gas Compressor	Inlet Gas Pressure	inwg	Pressure gauge	12.5
	Outlet Gas Pressure	psig	Pressure gauge	85
	Power Generation	kW	Electronic Panel Display	100
	Gas HHV	BTU/ft**3	Plant data	1,050
	Gas LHV	BTU/ft**3	Plant data	940
Microturbine	Calculates Fuel Flow	scfm	Engine Heat Rate of 12,355 Btu/kWh (LHV)	21.9
	Turbine Exit Temp	C	Power Electronics Display	577
	HRU Inlet Gas Temp	C	Power Electronics Display	295.7
	HRU Outlet Temp	C	Power Electronics Display	220
Heat Recovery Unit (HRU)	Water Inlet Temperature	C	Heat Storage tank	16.7
	Water Outlet Temperature	C	Heat Storage Tank	46.7
	Water Flow	lpm	Water Flow Meter	32
Boiler and Tail Gas Burners	Steam flow	lb/hr	Boiler control room	20,539
	Steam pressure	psig	Boiler control room	155
	Feedwater pressure	psig	Boiler control room	190
	Tail gas flow rate	lb/hr / C	Plant fuel pipe	12,967 / 32
	Tail gas pressure at burner	inwg	Plant fuel pipe	0.6
Combustion air Blower	Outlet Temperature	F	Thermocouple	60
	Pressure / Temperature	In.wg / F	Blower Outlet	1.5 / 60
Emissions	Test Sample Location			

	Exhaust Temperature	F	Boiler stack	380
	Oxygen Level (wet/dry)	%	Boiler stack	1.57 /1.59
	NOx Level (NO/NO2/NOx)	ppm	Boiler stack	0 / 2 / 2
	CO Level	ppm	Boiler stack	82
Tail Gas Samples	Time Taken			

Date/Time	Feb 20, 2012; 12:15 PM			
Run #	3	Conditions: Clear		
Test Description Microturbine at full power with exhaust bypassed (not going to TO furnace). TO furnace on with 1 tail gas burner in operation and gas backup – Third Baseline				
	Measurement	**Units**	**Location**	**Value**
Ambient Conditions	Barometric Pressure	in of Hg	Ambient press gauge	30.00
	Air Inlet Temperature	F	Bacharach ECA 450	63
Microturbine and Gas Compressor	Inlet Gas Pressure	inwg	Pressure gauge	12.5
	Outlet Gas Pressure	psig	Pressure gauge	85
	Power Generation	kW	Electronic Panel Display	100
	Gas HHV	BTU/ft**3	Plant data	1,050
	Gas LHV	BTU/ft**3	Plant data	940
Microturbine	Calculates Fuel Flow	scfm	Engine Heat Rate of 12,355 Btu/kWh (LHV)	21.9
	Turbine Exit Temp	C	Power Electronics Display	579
	HRU Inlet Gas Temp	C	Power Electronics Display	290
	HRU Outlet Temp	C	Power Electronics Display	184
Heat Recovery Unit (HRU)	Water Inlet Temperature	C	Heat Storage tank	15
	Water Outlet Temperature	C	Heat Storage Tank	52.0
	Water Flow	lpm	Water Flow Meter	33.4
Boiler and Tail Gas Burners	Steam flow	lb/hr	Boiler control room	18,714
	Steam pressure	psig	Boiler control room	145 /
	Feedwater pressure	psig	Boiler control room	160
	Tail gas flow rate	lb/hr / C	Plant fuel pipe	12,950 / 31
	Tail gas pressure at burner	inwg	Plant fuel pipe	0.6
Combustion air Blower	Outlet Temperature	F	Thermocouple	60
	Pressure / Temperature	In.wg / F	Blower Outlet	1.5 / 60
Emissions	Test Sample Location			

	Exhaust Temperature	F	Boiler stack	379
	Oxygen Level (wet/dry)	%	Boiler stack	3.07 / 3.3
	NOx Level (NO/NO2/NOx)	ppm	Boiler stack	1 / 1 / 2
	CO Level	ppm	Boiler stack	130
Tail Gas Samples	Time Taken			
Date/Time	Feb 20, 2012; 3:00 PM			
Run #	4	Conditions: COOL OVERCAST		
Test Description Microturbine at full power with exhaust bypassed (not going to TO furnace). TO furnace on with 2 tail gas burners in operation and no gas backup – Fourth baseline – Increased HTU flow				
	Measurement	**Units**	**Location**	**Value**
Ambient Conditions	Barometric Pressure	in of Hg	Ambient press gauge	30.06
	Air Inlet Temperature	F	Bacharach ECA 450	58.5
Microturbine and Gas Compressor	Inlet Gas Pressure	inwg	Pressure gauge	12.5
	Outlet Gas Pressure	psig	Pressure gauge	85
	Power Generation	kW	Electronic Panel Display	99.5
	Gas HHV	BTU/ft**3	Plant data	1,050
	Gas LHV	BTU/ft**3	Plant data	940
Microturbine	Calculates Fuel Flow	scfm	Engine Heat Rate of 12,355 Btu/kWh (LHV)	21.8
	Turbine Exit Temp	C	Power Electronics Display	575
	HRU Inlet Gas Temp	C	Power Electronics Display	286
	HRU Outlet Temp	C	Power Electronics Display	103
Heat Recovery Unit (HRU)	Water Inlet Temperature	C	Heat Storage tank	15.7
	Water Outlet Temperature	C	Heat Storage Tank	68.6
	Water Flow	lpm	Water Flow Meter	41.9
Boiler and Tail Gas Burners	Steam flow	lb/hr	Boiler control room	18,257
	Steam pressure	psig	Boiler control room	160
	Feedwater pressure	psig	Boiler control room	180

	Tail gas flow rate	lb/hr / C	Plant fuel pipe	13,034 / 32
	Tail gas pressure at burner	inwg	Plant fuel pipe	0.6
Combustion air Blower	Outlet Temperature	F	Thermocouple	68
	Pressure / Temperature	In.wg / F	Blower Outlet	3.3 / 66
Emissions	Test Sample Location			
	Exhaust Temperature	F	Boiler stack	389
	Oxygen Level (wet/dry)	%	Boiler stack	2.1 /2.7
	NOx Level (NO/NO2/NOx)	ppm	Boiler stack	0 / 2 / 2
	CO Level	ppm	Boiler stack	82
Tail Gas Samples	Time Taken			
Date/Time	Feb 20, 2012; 5:25 PM			
Run #	5	Conditions: COOL Clear		
Test Description First CHP test with microturbine exhausting to TO furnace. HRU water flow set at max per plant demand. TO furnace with 2 tail gas blowers no nat. gas backup				
	Measurement	**Units**	**Location**	**Value**
Ambient Conditions	Barometric Pressure	in of Hg	Ambient press gauge	30.06
	Air Inlet Temperature	F	Bacharach ECA 450	59.5
Microturbine and Gas Compressor	Inlet Gas Pressure	inwg	Pressure gauge	12.5
	Outlet Gas Pressure	psig	Pressure gauge	85
	Power Generation	kW	Electronic Panel Display	100
	Gas HHV	BTU/ft**3	Plant data	1,050
	Gas LHV	BTU/ft**3	Plant data	940
Microturbine	Calculated Fuel Flow	scfm	Engine Heat Rate of 12,355 Btu/kWh (LHV)	21.9
	Turbine Exit Temp	C	Power Electronics Display	589
	HRU Inlet Gas Temp	C	Power Electronics Display	301
	HRU Outlet Temp	C	Power Electronics Display	108
Heat Recovery Unit (HRU)	Water Inlet Temperature	C	Heat Storage tank	15.8
	Water Outlet Temperature	C	Heat Storage Tank	72.2

	Water Flow	lpm	Water Flow Meter	39.5
Boiler and Tail Gas Burners	Steam flow	lb/hr	Boiler control room	18,257
	Steam pressure	psig	Boiler control room	170
	Feedwater pressure	psig	Boiler control room	190
	Tail gas flow rate	lb/hr / C	Plant fuel pipe	12,982 / 32
	Tail gas pressure at burner	inwg	Plant fuel pipe	0.6
Combustion air Blower	Outlet Temperature	F	Thermocouple	113
	Pressure / Temperature	In.wg / F	Blower Outlet	3.4 / 60
	O2 concentration	% wet	Blower outlet	19.6
Emissions	Test Sample Location			
	Exhaust Temperature	F	Boiler stack	389
	Oxygen Level (wet/dry)	%	Boiler stack	2.35 / 3.2
	NOx Level (NO/NO2/NOx)	ppm	Boiler stack	0 / 5 / 6
	CO Level	ppm	Boiler stack	149
Tail Gas Samples	Time Taken			

Date/Time	Feb 21, 2012; 9:44 AM			
Run #	6	Conditions: COOL Clear; Engine on all night		
Test Description Second CHP test with microturbine exhausting to TO furnace. HRU water flow set at max per plant demand. TO furnace with 2 tail gas blowers no nat. gas backup				
	Measurement	**Units**	**Location**	**Value**
Ambient Conditions	Barometric Pressure	in of Hg	Ambient press gauge	30.06
	Air Inlet Temperature	F	Bacharach ECA 450	58.5
Microturbine and Gas Compressor	Inlet Gas Pressure	inwg	Pressure gauge	12.5
	Outlet Gas Pressure	psig	Pressure gauge	85
	Power Generation	kW	Electronic Panel Display	100
	Gas HHV	BTU/ft**3	Plant data	1,050
	Gas LHV	BTU/ft**3	Plant data	940
Microturbine	Calculated Fuel Flow	scfm	Engine Heat Rate of 12,355 Btu/kWh (LHV)	21.9
	Turbine Exit Temp	C	Power Electronics Display	588

	HRU Inlet Gas Temp	C	Power Electronics Display	300
	HRU Outlet Temp	C	Power Electronics Display	107
Heat Recovery Unit (HRU)	Water Inlet Temperature	C	Heat Storage tank	15.7
	Water Outlet Temperature	C	Heat Storage Tank	71.8
	Water Flow	lpm	Water Flow Meter	40.4
Boiler and Tail Gas Burners	Steam flow	lb/hr	Boiler control room	20,500
	Steam pressure	psig	Boiler control room	174
	Feedwater pressure	psig	Boiler control room	190
	Tail gas flow rate	lb/hr / C	Plant fuel pipe	13,030 / 32
	Tail gas pressure at burner	inwg	Plant fuel pipe	0.64
Combustion air Blower	Outlet Temperature	F	Thermocouple	126
	Pressure	In.wg	Blower Outlet	3.4
	O2 concentration	% wet	Blower outlet	19.4
Emissions	Test Sample Location			
	Exhaust Temperature	F	Boiler stack	388
	Oxygen Level (wet/dry)	%	Boiler stack	2.01 / 2.8
	NOx Level (NO/NO2/NOx)	ppm	Boiler stack	0 / 6 / 6
	CO Level	ppm	Boiler stack	162
Tail Gas Samples	Time Taken			
Date/Time	Feb 21, 2012; 12:44 PM			
Run #	7	Conditions: COOL Clear		
Test Description Third CHP test with microturbine exhausting to TO furnace. HRU water flow set at max flow. Dampers to TO fully open TO furnace with 2 tail gas blowers no nat. gas backup				
	Measurement	**Units**	**Location**	**Value**
Ambient Conditions	Barometric Pressure	in of Hg	Ambient press gauge	29.96
	Air Inlet Temperature	F	Bacharach ECA 450	61
Microturbine and Gas Compressor	Inlet Gas Pressure	inwg	Pressure gauge	12.5
	Outlet Gas Pressure	psig	Pressure gauge	86
	Power Generation	kW	Electronic Panel Display	100
	Gas HHV	BTU/ft**3	Plant data	1,050

	Gas LHV	BTU/ft**3	Plant data	940
Microturbine	Calculated Fuel Flow	scfm	Engine Heat Rate of 12,355 Btu/kWh (LHV)	21.9
	Turbine Exit Temp	C	Power Electronics Display	592
	HRU Inlet Gas Temp	C	Power Electronics Display	304
	HRU Outlet Temp	C	Power Electronics Display	108
Heat Recovery Unit (HRU)	Water Inlet Temperature	C	Heat Storage tank	15.9
	Water Outlet Temperature	C	Heat Storage Tank	71.9
	Water Flow	lpm	Water Flow Meter	41.2
Boiler and Tail Gas Burners	Steam flow	lb/hr	Boiler control room	20,539
	Steam pressure	psig	Boiler control room	174
	Feedwater pressure	psig	Boiler control room	190
	Tail gas flow rate	lb/hr / C	Plant fuel pipe	13,006 / 32
	Tail gas pressure at burner	inwg	Plant fuel pipe	0.60
Combustion air Blower	Outlet Temperature	F	Thermocouple	131
	Pressure	In.wg	Blower Outlet	3.3
	O2 concentration	% wet	Blower outlet	19.4
Emissions	Test Sample Location			
	Exhaust Temperature	F	Boiler stack	389
	Oxygen Level (wet/dry)	%	Boiler stack	1.91 / 2.8
	NOx Level (NO/NO2/NOx)	ppm	Boiler stack	0 / 6 / 6
	CO Level	ppm	Boiler stack	155
Tail Gas Samples	Time Taken			
Date	Feb 21, 2012; 3:45 PM			
Run #	8	Conditions: Clear – 18% O2 engine out NOx=11		
Test Description Fourth CHP test with microturbine exhausting to TO furnace. HRU water flow set at max. Dampers fully open TO furnace with 2 tail gas blowers no nat. gas backup				
	Measurement	**Units**	**Location**	**Value**
Ambient Conditions	Barometric Pressure	in of Hg	Ambient press gauge	29.98
	Air Inlet Temperature	F	Bacharach ECA 450	59

Microturbine and Gas Compressor	Inlet Gas Pressure	inwg	Pressure gauge	12.5
	Outlet Gas Pressure	psig	Pressure gauge	85
	Power Generation	kW	Electronic Panel Display	100
	Gas HHV	BTU/ft**3	Plant data	1,050
	Gas LHV	BTU/ft**3	Plant data	940
Microturbine	Calculated Fuel Flow	scfm	Engine Heat Rate of 12,355 Btu/kWh (LHV)	21.9
	Turbine Exit Temp	C	Power Electronics Display	578
	HRU Inlet Gas Temp	C	Power Electronics Display	293
	HRU Outlet Temp	C	Power Electronics Display	106
Heat Recovery Unit (HRU)	Water Inlet Temperature	C	Heat Storage tank	16.1
	Water Outlet Temperature	C	Heat Storage Tank	71.8
	Water Flow	lpm	Water Flow Meter	40.4
Boiler and Tail Gas Burners	Steam flow	lb/hr	Boiler control room	20,500
	Steam pressure	psig	Boiler control room	176
	Feedwater pressure	psig	Boiler control room	208
	Tail gas flow rate	lb/hr / C	Plant fuel pipe	12,990 / 32
	Tail gas pressure at burner	inwg	Plant fuel pipe	0.58
Combustion air Blower	Outlet Temperature	F	Thermocouple	124
	Pressure	In.wg	Blower Outlet	3.3
	O2 concentration	% wet	Blower outlet	19.4
Emissions	Test Sample Location			
	Exhaust Temperature	F	Boiler stack	389
	Oxygen Level (wet/dry)	%	Boiler stack	1.7 / 1.9
	NOx Level (NO/NO2/NOx)	ppm	Boiler stack	0 / 6 / 6
	CO Level	ppm	Boiler stack	142
Tail Gas Samples	Time Taken		11:57	
Date	Feb 22, 2012; 12:53 PM			
Run #	9	Conditions: Clear – 18% O2 engine out NOx=11		

Test Description Fifth CHP test with microturbine exhausting to TO furnace. HRU water flow set at max. Dampers fully open TO furnace with 2 tail gas blowers no nat. gas backup				
	Measurement	**Units**	**Location**	**Value**
Ambient Conditions	Barometric Pressure	in of Hg	Ambient press gauge	29.98
	Air Inlet Temperature	F	Bacharach ECA 450	55.5
Microturbine and Gas Compressor	Inlet Gas Pressure	inwg	Pressure gauge	12.5
	Outlet Gas Pressure	psig	Pressure gauge	85
	Power Generation	kW	Electronic Panel Display	100
	Gas HHV	BTU/ft**3	Plant data	1,050
	Gas LHV	BTU/ft**3	Plant data	940
Microturbine	Calculated Fuel Flow	scfm	Engine Heat Rate of 12,355 Btu/kWh (LHV)	21.9
	Turbine Exit Temp	C	Power Electronics Display	579
	HRU Inlet Gas Temp	C	Power Electronics Display	295
	HRU Outlet Temp	C	Power Electronics Display	106
Heat Recovery Unit (HRU)	Water Inlet Temperature	C	Heat Storage tank	15.9
	Water Outlet Temperature	C	Heat Storage Tank	72.5
	Water Flow	lpm	Water Flow Meter	38.8
Boiler and Tail Gas Burners	Steam flow	lb/hr	Boiler control room	22,900
	Steam pressure	psig	Boiler control room	176
	Feedwater pressure	psig	Boiler control room	210
	Tail gas flow rate	lb/hr / C	Plant fuel pipe	13,013 / 32
	Tail gas pressure at burner	inwg	Plant fuel pipe	0.60
Combustion air Blower	Outlet Temperature	F	Thermocouple	132
	Pressure	In.wg	Blower Outlet	3.3
	O2 concentration	% wet	Blower outlet	19.9
Emissions	Test Sample Location			
	Exhaust Temperature	F	Boiler stack	390
	Oxygen Level (wet/dry)	%	Boiler stack	1.8 / 1.9
	NOx Level (NO/NO2/NOx)	ppm	Boiler stack	0 / 6 / 6

	CO Level	ppm	Boiler stack	143
Tail Gas Samples	Time Taken		11:57	
Date/Time	Feb 22, 2012; 3:55 PM			
Run #	10	Conditions: 213 F HRU out temp to blower		
Test Description Sixth CHP test with microturbine exhausting to TO furnace. HRU water flow set at max. Dampers fully open TO furnace with 2 tail gas blowers no nat. gas backup				
	Measurement	**Units**	**Location**	**Value**
Ambient Conditions	Barometric Pressure	in of Hg	Ambient press gauge	29.98
	Air Inlet Temperature	F	Bacharach ECA 450	63
Microturbine and Gas Compressor	Inlet Gas Pressure	inwg	Pressure gauge	12.5
	Outlet Gas Pressure	psig	Pressure gauge	85
	Power Generation	kW	Electronic Panel Display	100
	Gas HHV	BTU/ft**3	Plant data	1,050
	Gas LHV	BTU/ft**3	Plant data	940
Microturbine	Calculated Fuel Flow	scfm	Engine Heat Rate of 12,355 Btu/kWh (LHV)	21.9
	Turbine Exit Temp	C	Power Electronics Display	584
	HRU Inlet Gas Temp	C	Power Electronics Display	298
	HRU Outlet Temp	C	Power Electronics Display	107.4
Heat Recovery Unit (HRU)	Water Inlet Temperature	C	Heat Storage tank	16.0
	Water Outlet Temperature	C	Heat Storage Tank	71.9
	Water Flow	lpm	Water Flow Meter	41.0
Boiler and Tail Gas Burners	Steam flow	lb/hr	Boiler control room	20,559
	Steam pressure	psig	Boiler control room	176
	Feedwater pressure	psig	Boiler control room	200
	Tail gas flow rate	lb/hr / C	Plant fuel pipe	13,030 / 32
	Tail gas pressure at burner	inwg	Plant fuel pipe	0.58
Combustion air Blower	Outlet Temperature	F	Thermocouple	132
	Pressure	In.wg	Blower Outlet	3.3

	O2 concentration	% wet	Blower outlet	19.4
Emissions	Test Sample Location			
	Exhaust Temperature	F	Boiler stack	391
	Oxygen Level (wet/dry)	%	Boiler stack	1.86 / 2.1
	NOx Level (NO/NO2/NOx)	ppm	Boiler stack	1 / 5 / 6
	CO Level	ppm	Boiler stack	124
Tail Gas Samples	Time Taken		11:57	

Date/Time	Feb 22, 2012; 5:550 PM	
Run #	11	Conditions: Clear

Test Description Seventh CHP test with microturbine exhausting to TO furnace. HRU water flow set at max. Dampers fully open TO furnace with 2 tail gas blowers no nat. gas backup

	Measurement	**Units**	**Location**	**Value**
Ambient Conditions	Barometric Pressure	in of Hg	Ambient press gauge	29.98
	Air Inlet Temperature	F	Bacharach ECA 450	75.5
Microturbine and Gas Compressor	Inlet Gas Pressure	inwg	Pressure gauge	12.5
	Outlet Gas Pressure	psig	Pressure gauge	85
	Power Generation	kW	Electronic Panel Display	100
	Gas HHV	BTU/ft**3	Plant data	1,050
	Gas LHV	BTU/ft**3	Plant data	940
Microturbine	Calculated Fuel Flow	scfm	Engine Heat Rate of 12,355 Btu/kWh (LHV)	21.9
	Turbine Exit Temp	C	Power Electronics Display	600
	HRU Inlet Gas Temp	C	Power Electronics Display	307
	HRU Outlet Temp	C	Power Electronics Display	108
Heat Recovery Unit (HRU)	Water Inlet Temperature	C	Heat Storage tank	16
	Water Outlet Temperature	C	Heat Storage Tank	73
	Water Flow	lpm	Water Flow Meter	38
Boiler and Tail Gas Burners	Steam flow	lb/hr	Boiler control room	20,500
	Steam pressure	psig	Boiler control room	176

	Feedwater pressure	psig	Boiler control room	205
	Tail gas flow rate	lb/hr / C	Plant fuel pipe	13,054 / 32
	Tail gas pressure at burner	inwg	Plant fuel pipe	0.58
Combustion air Blower	Outlet Temperature	F	Thermocouple	139
	Pressure	In.wg	Blower Outlet	3.3
	O2 concentration	% wet	Blower outlet	20
Emissions	Test Sample Location			
	Exhaust Temperature	F	Boiler stack	392
	Oxygen Level (wet/dry)	%	Boiler stack	1.76 / 2.5
	NOx Level (NO/NO2/NOx)	ppm	Boiler stack	1 / 6 / 7
	CO Level	ppm	Boiler stack	127
Tail Gas Samples	Time Taken		11:57	
Date/Time	Feb 23, 2012; 13:50 PM			

Run #	12	Conditions: Turbine exit at HRU out = 236 F		
Test Description Seventh CHP test with microturbine exhausting to TO furnace. HRU water flow set at max. Dampers fully open TO furnace with 2 tail gas blowers no nat. gas backup				
	Measurement	**Units**	**Location**	**Value**
Ambient Conditions	Barometric Pressure	in of Hg	Ambient press gauge	29.98
	Air Inlet Temperature	F	Bacharach ECA 450	76
Microturbine and Gas Compressor	Inlet Gas Pressure	inwg	Pressure gauge	12.5
	Outlet Gas Pressure	psig	Pressure gauge	86
	Power Generation	kW	Electronic Panel Display	100
	Gas HHV	BTU/ft**3	Plant data	1,050
	Gas LHV	BTU/ft**3	Plant data	940
Microturbine	Calculated Fuel Flow	scfm	Engine Heat Rate of 12,355 Btu/kWh (LHV)	21.9
	Turbine Exit Temp	C	Power Electronics Display	601
	HRU Inlet Gas Temp	C	Power Electronics Display	308
	HRU Outlet Temp	C	Power Electronics Display	109
Heat Recovery Unit (HRU)	Water Inlet Temperature	C	Heat Storage tank	16
	Water Outlet Temperature	C	Heat Storage Tank	73.2
	Water Flow	lpm	Water Flow Meter	38.5
Boiler and Tail Gas Burners	Steam flow	lb/hr	Boiler control room	20,500
	Steam pressure	psig	Boiler control room	176
	Feedwater pressure	psig	Boiler control room	205
	Tail gas flow rate	lb/hr / C	Plant fuel pipe	13,050 / 32
	Tail gas pressure at burner	inwg	Plant fuel pipe	0.58
Combustion air Blower	Outlet Temperature	F	Thermocouple	139
	Pressure	In.wg	Blower Outlet	3.3
	O2 concentration	% wet	Blower outlet	19.8
Emissions	Test Sample Location			
	Exhaust Temperature	F	Boiler stack	390

	Oxygen Level (wet/dry)	%	Boiler stack	1.76 / 2.5
	NOx Level (NO/NO2/NOx)	ppm	Boiler stack	1 / 6 / 7
	CO Level	ppm	Boiler stack	128
Tail Gas Samples	Time Taken		11:57	