Integrated CHP Using Ultra-Low-NOx Supplemental Firing

FINAL REPORT

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ACRONYMS

GTI-Gas Technology Institute
CARB-California Air Resource Board
FlexCHP-Flexible Combined Heat and Power
NOx-Oxides of Nitrogen
CO-Carbon Monoxide
VOC-Volatile Organic Compounds
ULN-Ultra-Low-NOx
HP-Horse Power, Boiler
SCR- Selective Catalytic Reduction
TEG-Turbine Exhaust Gas
CHP-Combined Heat and Power
STEG-Simulated Turbine Exhaust Gas
CO_2-Carbon Dioxide
THC-Total Hydrocarbons
O_2-Oxygen
Accu Chem-Accu Chem Conversion, Incorporated

ABSTRACT

Title	Integrated CHP Using Ultra-Low-NOx Supplemental Firing
Contractor	Gas Technology Institute (GTI), CARB Grant Number: CAT 05-1
Project Manager	David Cygan
Report Period	May 2006-May 2010
Objective	The objective of this project is to deploy Gas Technology Institute's (GTI's) Flexible Combined Heat and Power (FlexCHP) system to deliver power and steam while holding NOx, CO, and VOC emissions below the 2007 Fossil Fuel Emissions Standard for microturbines. The system appropriately designated a FlexCHP-65, will combine a Capstone C65 microturbine, a GTI-developed supplemental Ultra-Low-NOx (ULN) burner, and a 100 Horsepower (HP) heat recovery boiler by Johnston Boiler Company.
Technical Perspective	The supplemental ULN burner is an innovative combustion approach that promises industrial end-users a dramatic increase in energy efficiency and reduced air emissions. The efficiency of microturbine based distributed generation systems is a strong function of the ability of the system to recover and use the waste heat in the exhaust of the microturbine. The major advantages of a supplemental burner coupled with a microturbine are an increase in total system efficiency due to lowering exhaust oxygen levels from 17-18 vol.% to 3-5 vol.%, and an increase in quality of the heat produced from the microturbine exhaust. By employing auxiliary burners in the exhaust of the microturbine, the amount and temperature of the available heat will be decoupled from the amount of electricity produced. This advantage will enable more systems utilizing waste heat recovery from turbines to be designed, manufactured and sold. The developed supplemental burner has unmatched emission characteristics, which will provide a competitive edge over existing low-NOx systems in the fast developing area of CHP applications for installations where low emissions is a performance requirement.
Technical Approach	Combining the supplemental ULN burner technology with state-of-the-art gas turbines, meeting the 2007 Fossil Fuel Emissions Standard for CHP installations without the use of end-of-pipe cleanup technology such as selective catalytic reduction (SCR). The supplemental burner, designed by GTI to be installed between the gas turbine and heat recovery boiler or absorption chiller, combusts natural gas using the turbine exhaust gas (TEG) as oxidant, just as current duct burners do. Integrating the supplemental burner technology with a gas turbine creates the additional benefit of reduced NOx emissions from the combined system. NOx created in

the gas turbine is also present during the combustion process of the supplemental burner and results in an overall NOx concentration reduction compared to the two units operating separately. The additional fuel combustion adds very little NOx and effectively completes combustion, keeping CO at very low levels in spite of the suppression of thermal NOx, which generally is difficult to achieve without raising CO emissions.

Results The supplemental ULN burner has demonstrated increased energy efficiency while meeting the 2007 Fossil Fuel Emissions Standard without the use of catalytic exhaust gas treatment. The key to this breakthrough performance is a simple and reliable advanced burner design with engineered internal recirculation. The burner exposes NOx and NOx precursors to a low temperature zone, resulting in a lower NOx content per unit of heat input than that of the original TEG. Preliminary laboratory testing with a 2.2 million Btu/h supplemental burner firing the exhaust from a 60-kW Capstone microturbine proved the capability of the system to deliver final stack NOx below 0.07 lb/MWh. Additional testing showed that the burner can be successfully scaled up to 7.5 million Btu/h. This also indicates the possibility of integration with megawatt-scale engines such as the Solar Mercury 50. Evaluation of a 4 million Btu/h burner firing with exhaust gas from a 65-kW Capstone microturbine is following the path to reduce NOx formed in the turbine and deliver final NOx emissions in the stack at levels which have not been achieved without SCR. The resulting CHP packages promise to make CHP implementation more attractive, mitigate greenhouse gas emissions, improve the competitiveness of industry, and improve the reliability of electricity.

Project Implications The FlexCHP system will provide CHP users with a highly efficient source of on-site heat for use with boilers and absorption chillers. The technology is environmentally superior and cost-competitive compared to state-of-the-art duct burner technology available on the market. The developed technical approach can be expanded to other combustion applications using TEG or preheated air as combustion air in situations where low combustion emissions are required.

INTRODUCTION

Gas turbines have a number of beneficial features that have led to their widespread application for Combined Heat and Power (CHP), including their relatively simple design, low capital cost per kilowatt, low maintenance requirements, and lower emissions as compared to reciprocating engines. However, because of the need to operate at high excess air (225-550%), exhaust losses from gas turbine based CHP systems are relatively high and offer an opportunity for further cost savings. A common approach to recoup some of the energy loss is through the use of supplemental burners (i.e. duct or parallel burners) to combust additional fuel in the oxygen-rich Turbine Exhaust Gas (TEG) and to raise the temperature for better downstream heat recovery in a boiler. For example, with natural gas as fuel and a final flue gas temperature of 275°F, reducing the excess air from 355% to 15% decreases the stack loss from 46% to 17% (higher heating value basis).

However, even with low-NOx duct or parallel burner designs, CHP systems have difficulty meeting the 2007 Fossil Fuel Emissions Standard, without exhaust gas cleanup by Selective Catalytic Reduction (SCR) or by other post combustion processes. Consequently, there is a need to develop integrated CHP packages that properly match a power generator (turbine), a low emission supplemental burner, and a waste heat user (boiler) to improve energy efficiency and still meet future clean air requirements. This requires a burner that produces very low NOx emissions even with high-temperature TEG (600-1000°F) as the oxidant. This is the final report for ICAT Grant 05-1 to design, build, and test a supplemental Ultra-Low-NOx (ULN) burner to deliver NOx, CO, and VOC emissions consistent with the 2007 Fossil Fuel Emissions Standard for turbines in the range of 30-1000 kW.

Gas Technology Institute (GTI's) research and development on supplemental ULN burners for gas turbine based CHP has achieved promising results. The innovative burner can fire natural gas with TEG and meet the emissions standard. The key to the design is staged combustion with engineered internal recirculation that exposes NOx and NOx precursors to a low temperature zone. Figure 1 shows the conceptual design of the supplemental burner. Natural gas partially mixes with the TEG before entering the combustion zone. The velocity of the gas/TEG mixture through several nozzles is sufficient to create a reduced pressure zone at the base of the primary nozzle exit, which induces flow from the exit of the primary zone. Inside the

recirculation insert, the products of partial combustion flow back to the root of the flame, as indicated by the curved arrows. These combustion products contain hydrogen species, which improves combustion stability in the primary zone, allowing combustion at relatively low stoichiometric ratios. Additional TEG is injected through a pipe, which is located at the center of the burner downstream of the primary zone. Mixing of the TEG with the combustion products from the primary zone is critical to the design of a very-low NOx burner. If the gaseous mixture is well mixed, there are no high concentrations of oxygen, which could cause hot spots and generate NOx. The recirculation insert also radiates heat to the cold boiler walls and allows products of partial combustion to cool before flowing to the secondary combustion zone and back to the root of the flame, cooling, and stabilizing it.

In earlier developmental work a concept burner was fired up to 2.2 million Btu/h on TEG from a Capstone 60-kW microturbine. Figure 2 shows the general layout of the laboratory test set up at GTI. The microturbine was exhausted to the supplemental ULN burner and then fired into a 20-inch diameter boiler simulator.

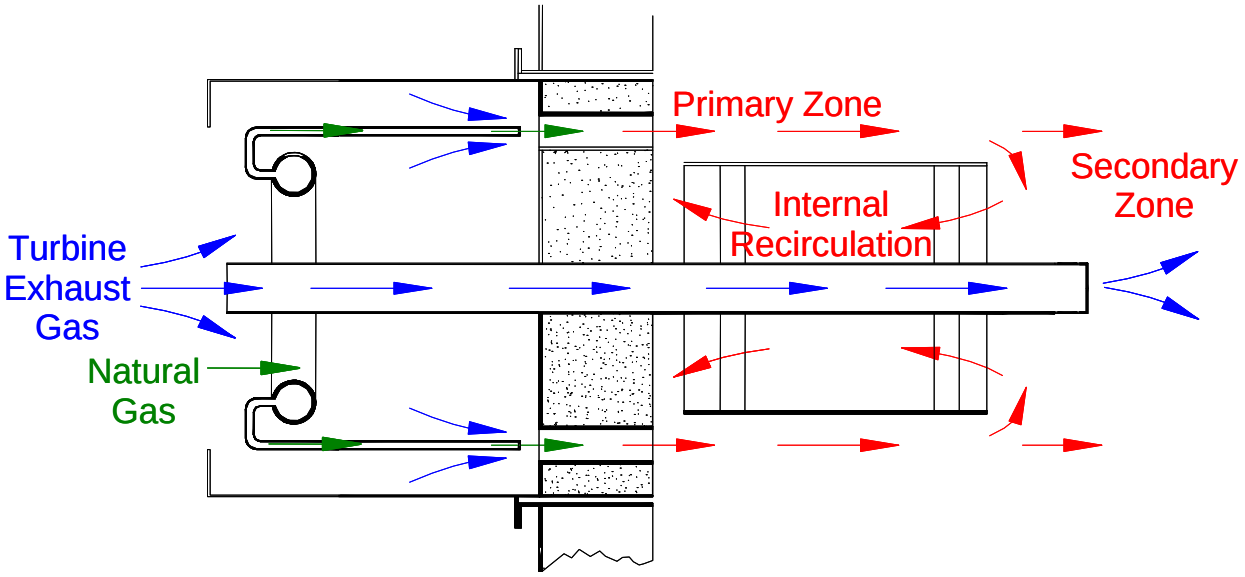


Figure 1. Supplemental ULN Burner Concept

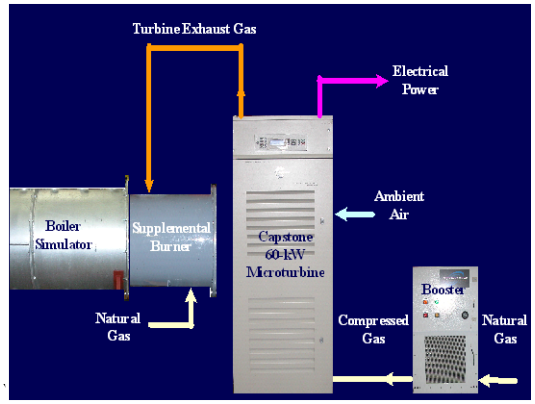


Figure 2. Layout of Microturbine Supplemental ULN Burner

Based on test results, the burner is capable of adding significant thermal energy to the TEG while contributing little additional NOx emissions at the stack. On a volume per volume basis, stack NOx emissions, after supplemental firing, are lower than NOx emissions from the gas turbine, even in the case of the ultra-low NOx emissions (3.4 ppmv on a 15% O_2 basis)[1] from the Capstone microturbine. In Table 1 the data shows a reduction in NOx emissions of 35% which are below those produced by the gas turbine alone. These data demonstrate that the combined turbine and supplemental burner can comfortably meet the 0.07 lb/MWh target for CHP systems. CO emissions are also within the 2007 Fossil Fuel Emissions target of 0.10 lb/MWh because in all of our tests CO was below 10 ppmv which corresponds to approximately 0.05 lb/MWh. System efficiency with the burner increases from about 38% to 70-80%, depending on the size of the burner and heat recovery unit (boiler or absorption chiller). Based on these data, gas-fired turbines or microturbines with up to 9 ppmv NOx (~0.43 lb/MWh) in the TEG can be combined with the supplemental burner at the current level of development and reduce stack NOx below 0.07 lb/MWh. This will include the Solar Mercury 50 and Taurus 60 model employing catalytic combustion.

[1] All emissions are corrected to 15 percent oxygen unless otherwise noted.

Table 1. Data from Laboratory Testing of Supplemental ULN Burner with Capstone Microturbine

	Microturbine	Microturbine + Supplemental ULN Burner
Turbine Output, kW	50	50
Burner Fuel Input, million Btu/h	--	2.11
O_2, vol%	17.8	8.1
NOx, ppmv	3.4	2.2
CO, ppmv	9	5
NOx Reduction, %	--	35.2

1 VALUE OF THE TECHNOLOGY

The value of the technology is to allow gas turbine based CHP applications to meet the most stringent California air quality rules without post combustion flue gas cleanup such as SCR. One of the more near-term attractive applications of the supplemental ULN burner is for CHP installations using Solar's Mercury 50 recuperated 4.3-MW turbine, which is designed for 5 ppmv NOx in simple cycle operation. In spite of its very low NOx rating, the Mercury 50 cannot currently meet the 2007 Fossil Fuel Emissions Standard without catalytic flue gas treatment. However, based on our laboratory results, we project that the Mercury 50 can meet these emissions goals with the supplemental ULN burner in an integrated CHP system while also increasing overall system efficiency. Figure 3 shows how the predicted NOx, measured as lb/MWh output, varies with the level of NOx reduction for a Mercury 50 combined with a 50 million Btu/h supplemental burner. In this case, any NOx reduction greater than about 10% is sufficient to satisfy the 0.07 lb/MWh standard.

The predicted performance of the same supplemental burner in a Mercury 50 installation is also shown in Table 2 along with laboratory performance data from the Capstone microturbine test unit, in this case based on a NOx reduction of 35 percent.

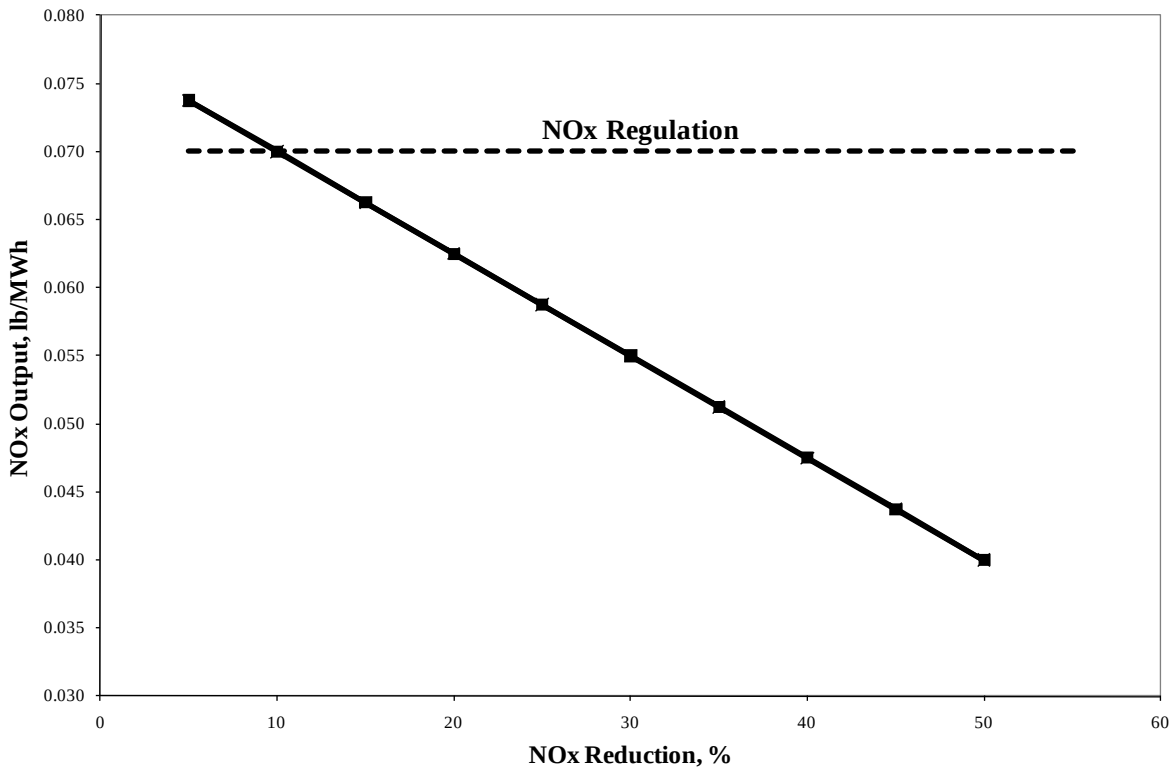


Figure 3. Variation of Output-Based NOx Emissions with Supplemental ULN Burner Effectiveness

Table 2. Comparison of Laboratory Data and Predicted Performance for the Mercury 50

	Capstone 60-kW (GTI Laboratory)	Mercury 50 (Predicted)
Turbine Output, kW	50	4,387
Turbine Fuel Input, million Btu/h	0.68	43.74
Turbine Efficiency, % (HHV)	28.0	38.0
TEG O_2, vol%	17.8	16.4
TEG NOx, ppmv	3.4	5.0
Burner Fuel Input, million Btu/h	1.95	50.0
Burner Exhaust O_2, vol%	8.1	11.0
Burner Exhaust NOx, ppmv	2.2	3.2
NOx Reduction, %	35.2	35.2
Heat Recovered in Boiler, million Btu/h	1.96	58.7
Overall CHP Efficiency, % (HHV)	80.0	74.9

Meeting emissions targets, however, is not the only challenge to proponents of CHP. The installed cost of CHP systems is a major barrier to implementing this energy-saving approach for small to medium-size industrial plants and commercial buildings. Achieving this output based emissions level with existing gas turbines or those that are expected to enter the market is challenging. A supplemental burner using advanced design to reduce NOx from gas-fired TEG will be a real breakthrough in bringing cost-effective CHP solutions to the market. This will present an alternative for future air emissions regulations and eliminate the need for costly SCR.

2 DEVELOPMENT

2.1 Turbine Exhaust Gas Generation

As a continuation of the earlier developmental work, the burner technology was scaled up to 7.5 million Btu/h. At this firing capacity, the microturbine was not capable of generating sufficient TEG at temperature to simulate the Mercury 50 gas turbine (see Table 3). At full load, the exhaust gas composition from the Solar Mercury 50 has 16.4 % O_2 and 5 ppmv NOx at 705°F.

Table 3. Summary of Mercury 50 Emissions Data

Solar Mercury 50				
Turbine Load, %	25	50	75	100
Exhaust Temperature, °F	637	666	681	705
O_2, vol%	17.8	17.2	16.7	16.4
NOx, ppmv	--	5	5	5
CO_2, vol%	1.8	2.2	2.4	2.6

2.2 Test Setup

The supplemental ULN burner was designed and evaluated up to 7.5 million Btu/h on a 40-inch water cooled simulator. The TEG was simulated with a mixture of flue gases from a low NOx auxiliary burner and dilution air post combustion to closely match the exhaust gas constituents and exhaust temperature of a Solar Mercury 50 gas turbine.

The Simulated Turbine Exhaust Gas (STEG) generator is shown in Figure 4. The low NOx auxiliary burner was fired on a 20-inch, water cooled, chamber that produced the flue gases. It then cooled them before entering a mixing section that introduced the dilution air. The

water cooled combustion chamber was sized appropriately to absorb enough heat from the flue gases so the mixture temperature matched closely to the Mercury 50. Mass flows and temperatures were monitored closely during all testing and recorded in the data acquisition system.

The 7.5 million Btu/h supplemental ULN burner is shown in Figure 5. The STEG enters the burner axially through a 16-inch duct. The STEG is directed to either the primary or secondary zone of the burner via a sliding damper. Prior to the primary zone combustion, STEG is introduced with natural gas at the nozzle entrance and then mixing occurs over a short linear distance and enters the combustion chamber for ignition. Downstream of the sliding damper is a butterfly damper assembly to enhance the control and distribution of STEG to the secondary zone of the burner. As this damper is further closed, additional STEG is directed to the primary zone of the burner. The natural gas supply manifold is located external to the burner to allow for on-the-fly adjustments during the test campaign. Various ports are available to collect gas constituency, pressure, and temperature within the burner.

Figure 4. Auxiliary Combustor to Generate STEG

Figure 5. 7.5 million Btu/h Supplemental ULN Burner

The supplemental ULN burner was installed on a 40-inch diameter simulator consisting of heat recovery and flue gas exit sections. The heat recovery section is constructed from four modules as shown in Figure 5. The four 24 inch-long modules are identical from the burner side and flanged on each side for flexibility. Each module has a water jacket type cooling system in which the city water enters from the bottom and exits from the top to drain. The entire simulator is mounted on one stand and can be easily moved. Gas composition and temperature sampling ports were installed downstream of the heat recovery sections in the stationary flue gas exit sections. Emissions measurements obtained at this location are representative of stack data. Further downstream is a water-cooled damper used to adjust the pressure in the combustion chamber. Additional ductwork leading to the stack consists of 30-inch diameter steel ducting lined with 6-inch thick composite refractory. The ducting is mounted on stands for support.

2.3 Natural Gas Supply

The natural gas supply line to the burner is standard 2-inch pipe with a double block-and-bleed valve arrangement. The components on the natural gas supply includes a Roots flow

meter, manual shutoff valve, gas pressure regulator, supply pressure gauge, Sierra mass flow meter, manual shutoff valve, supply pressure gauge, gas pressure regulator, low-pressure switch, safety solenoid valve, vent solenoid valve, second safety solenoid valve, and a high-pressure switch. The data from the Sierra mass flow meter is recorded directly to the data acquisition system. The gas supply line supplies gas to a North American flow control valve that meters natural gas to the supplemental burner. This natural gas train is connected to the burner inlet by a 1 inch diameter flexible hose. Although the natural gas supply manifold is located external to the burner, natural gas is combined with STEG internal to the burner.

The auxiliary burner, used to generate STEG, is independently supplied with natural gas and combustion air via modular combustion control skids. Each skid is a self-contained system that controls and meters flow to a selected combustion device.

2.4 Analytical Equipment and Measurements

A data acquisition system was used to collect data continuously and at specified points during evaluation of the supplemental ULN burner. The major flow rate measurements recorded were combustion air, natural gas, and diluent air for the auxiliary combustor; and natural gas for the supplemental burner. Appropriate furnace operation parameters and NO/NOx, CO, CO_2, THC, and O_2 emissions from the auxiliary burner and downstream of the supplemental burner in the exhaust gas were measured. A type "K" thermocouple was installed to measure STEG and supplemental burner exit gas temperatures.

The natural gas and combustion air flow rates were measured using Sierra thermal mass flow meters. The static pressure at the combustion chamber exit, burner windbox, and fuel manifold were measured with a manometer.

The exhaust gas sample was drawn through a 1/4-inch-OD by 3-foot-long, stainless steel probe. The gas sample was withdrawn using oil-less vacuum pumps and passed through sample conditioning trains, which consist of a water trap to remove any condensate and a membrane dryer for removing the moisture. The sample conditioning trains are located near the probe and are followed downstream by Teflon sample lines to deliver the gas sample to various gas analyzers through a sample flow control and distribution panel. The control panel (shown in Figure 6) facilitates easy switching between gas sampling and instrument calibration.

Figure 6. Panel Mounted Emissions Monitors

The flue gas composition was measured using continuous emission gas monitors. The following gas analyzers were utilized:

- A Thermo Environmental Model 42C chemiluminescence NOx analyzer
- A Rosemount Analytical Model 880A dispersed infrared carbon monoxide analyzer
- A Rosemount Analytical Model 880A dispersed infrared carbon dioxide analyzer
- A Rosemount Analytical Model 400A flame ionization total hydrocarbons analyzer
- A Rosemount Analytical Model 755R paramagnetic oxygen analyzer.

All of the instruments were calibrated prior to each test campaign using pure nitrogen to establish the "zero" and an appropriate span gas to set the "gain." An analysis of the certified span gas mixture used during the evaluation follows:

NOx: 7.4 ppmv

CO (low): 149 ppmv

CO (high): 24.93%

CO_2: 18.0%

THC: 341 ppmv

O_2: 3.92%

2.5 Results

The 7.5 million Btu/h supplemental ULN burner was tested on a 40-inch diameter boiler simulator. The main parameters varied were the firing rate, the number of primary nozzles, and the ratio of STEG between the primary/secondary zones. Figure 7 shows the supplemental burner flame looking from the exit of the simulator back towards the burner.

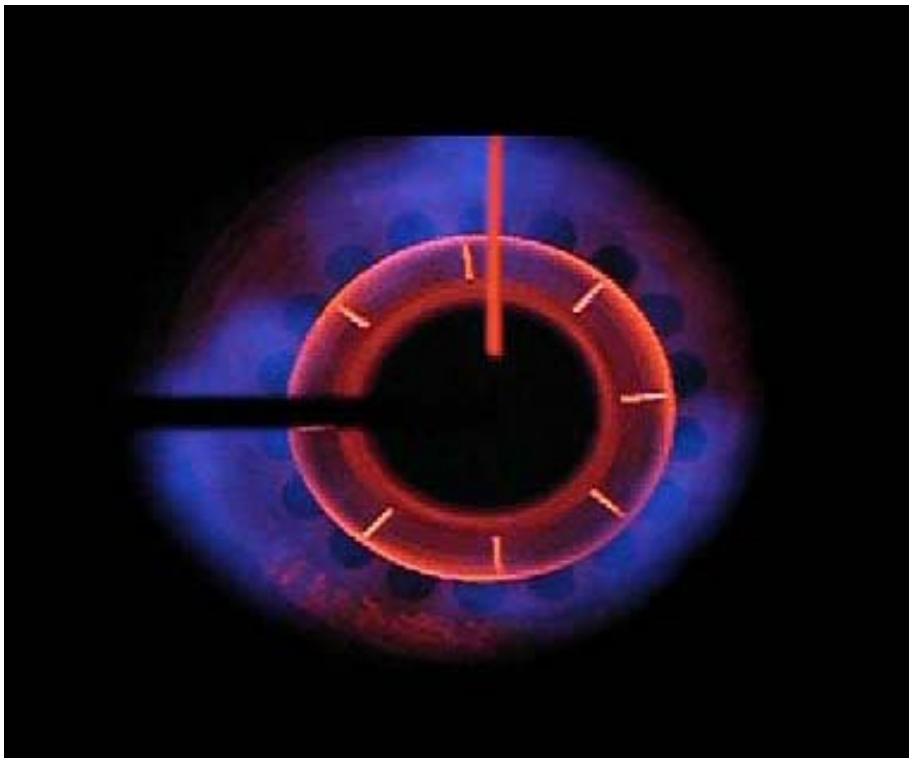


Figure 7. Supplemental ULN Burner Flame at 7 million Btu/h

An auxiliary burner, with a three to one turndown ratio, was used to generate flue gases that were mixed together with dilution air. The resulting mixture closely matched the gas composition and temperature of the Mercury 50 gas turbine across its firing range. NOx emissions from the STEG were consistent throughout the firing range (see Figure 8).

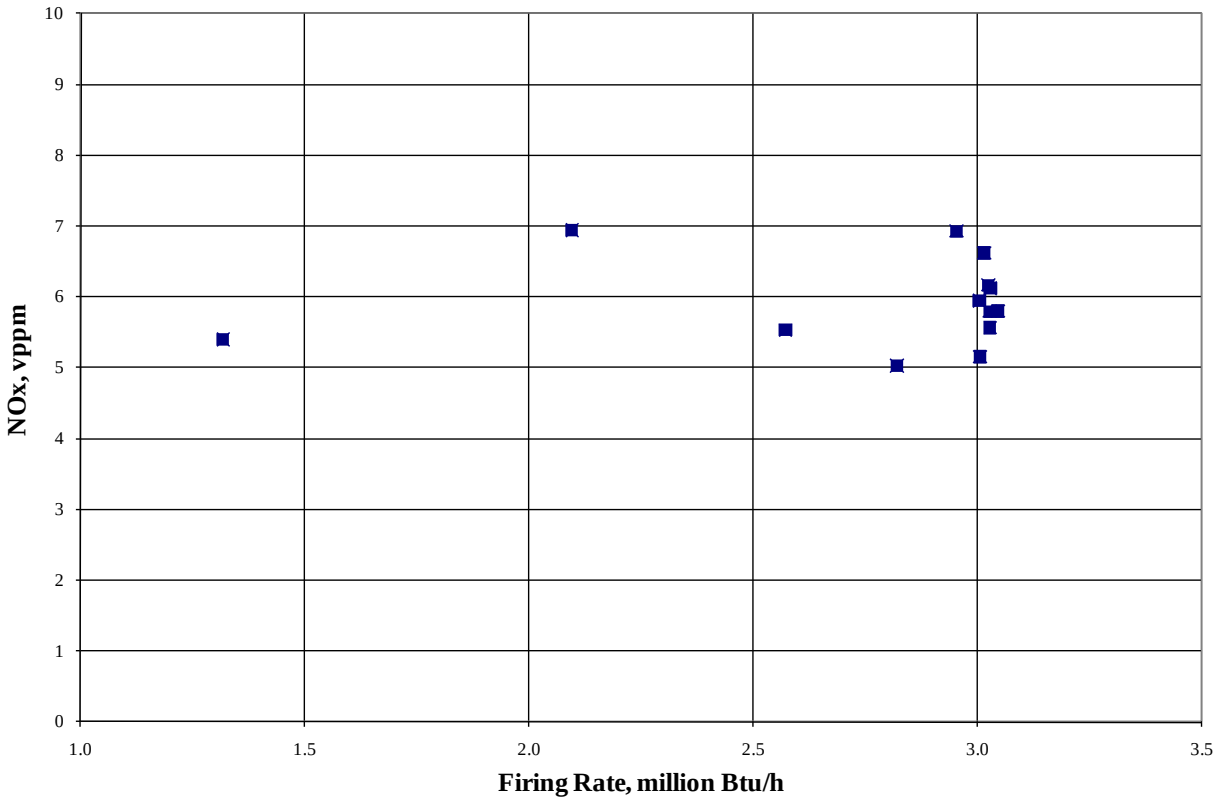


Figure 8. NOx Emissions Across the Firing Range

The supplemental ULN burner was evaluated with natural gas heat inputs ranging from 1.9 to 7.1 million Btu/h. Figure 9shows NOx emissions and oxygen concentrations as a function of burner firing rate. The data is representative of the Mercury 50 gas turbine operating at 100% load (oxygen concentration 16.4%). A dashed line represents the average NOx concentration measured in the STEG across the firing range. In all cases, the NOx concentration measured downstream of the supplemental burner; was the same or lower, than the NOx concentration measured in the STEG. Overall NOx concentrations decreased as the burner firing rate increased. Although not shown, at all test points CO and THC emissions remained below 50 ppmv. The oxygen concentration varied over the firing range while maintaining a fixed amount of STEG.

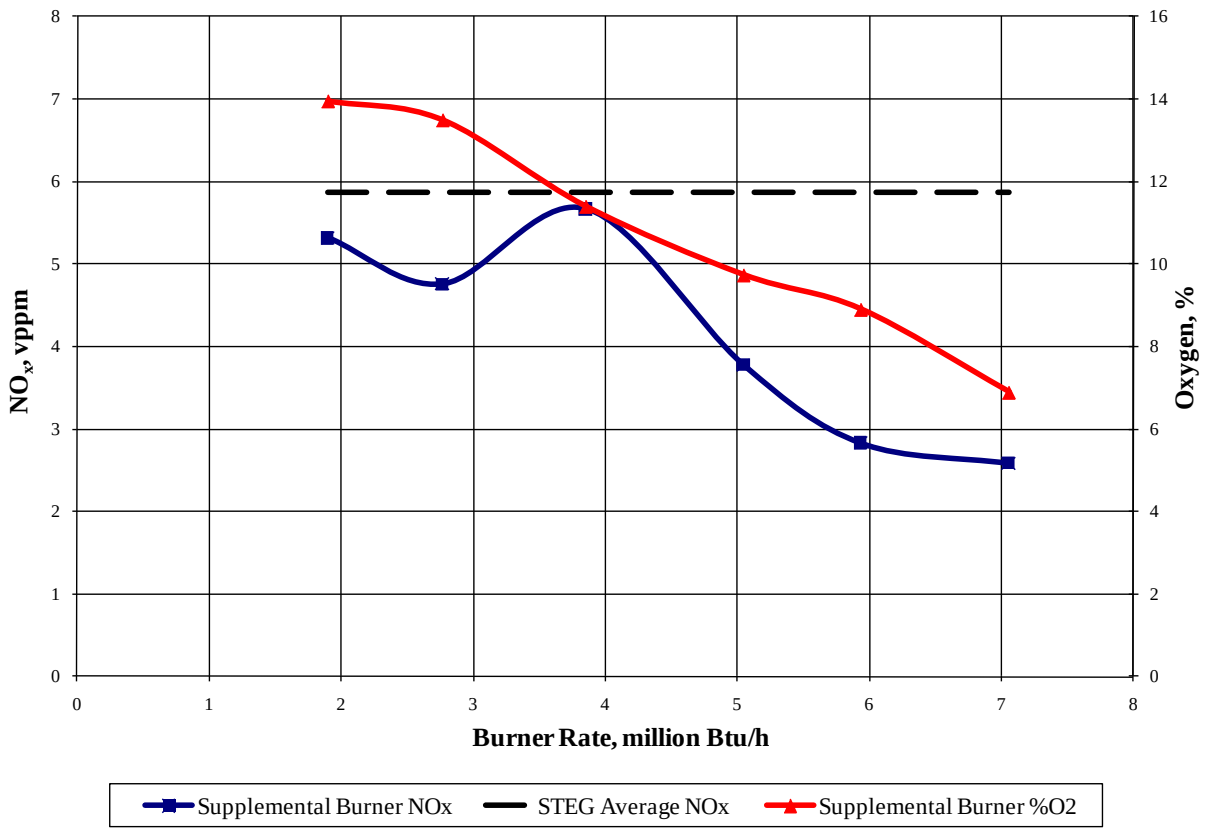


Figure 9. Supplemental ULN Burner Test Results Gas Turbine Load at 100%

Testing was also conducted at conditions representative of the Mercury 50 gas turbine operating at 75% load (oxygen concentration 16.7%). Figure 10 shows the results do follow the trend established at 100% load. The average NOx concentration measured in the STEG across the firing range for this test campaign is represented by a dashed line. In all cases, the NOx concentration measured downstream of the supplemental burner is the same or lower, than the NOx concentration measured in the STEG. Overall NOx concentrations decreased as the burner firing rate increased and; although not shown, CO and THC emissions at all points remained below 50 ppmv.

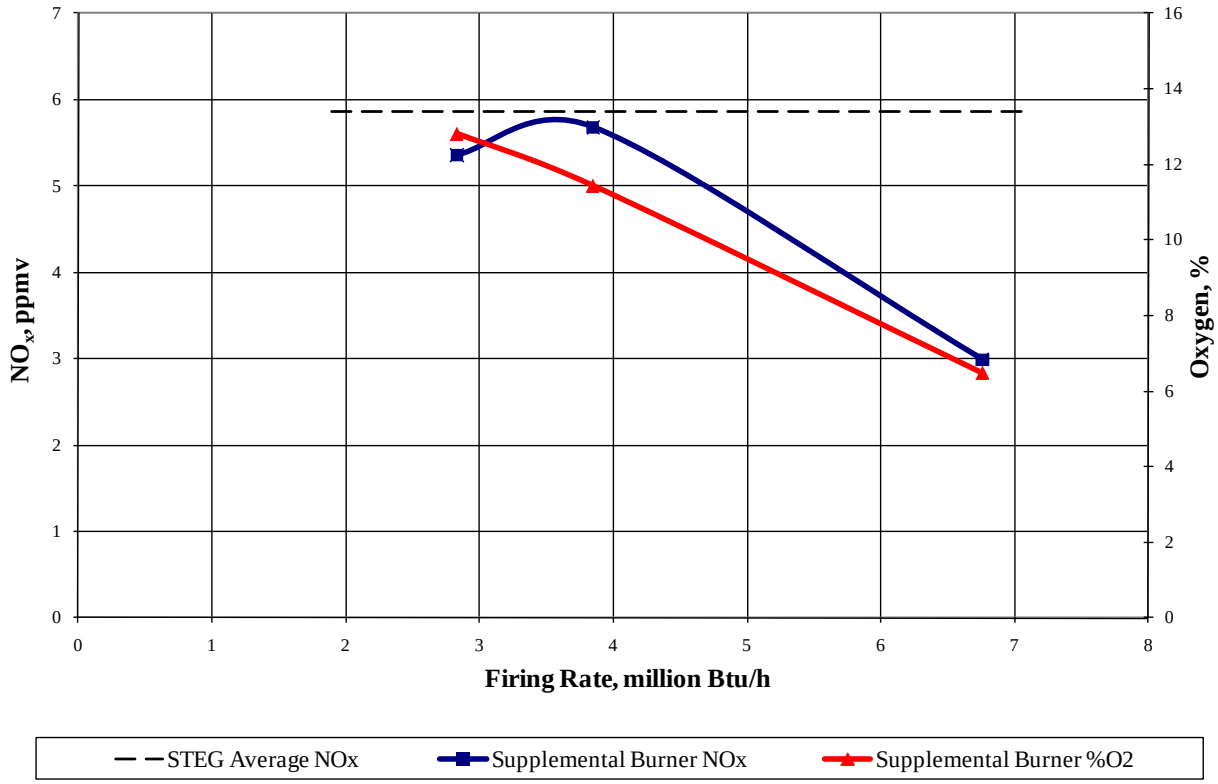


Figure 10. Supplemental ULN Burner Test Results Gas Turbine Load at 75%

Inherent to the burner design is a center tube that acts as a bypass and allows the burner to handle larger amounts of TEG than a typical burner. The center tube simply diverts the excess gases around the combustion zone. A test campaign was conducted at 100% gas turbine load to investigate the effect of oxygen concentration on supplemental burner NOx production. The quantity of STEG was varied to the supplemental burner; which in turn, varied the oxygen concentration at the exit of the supplemental burner. The results are plotted in Figure 11 and reveals there is a negligible effect on NOx production at different oxygen concentrations. This is an important point because, as the gas turbine changes load, the supplemental burner will be forced to handle varying oxygen concentrations.

The maximum pressure drop through the burner remained below 2.3 in wc. The pressure data is plotted in Figure 12. The natural gas supply pressure ranged from 3.0 psig at low fire rate to 28.6 psig at high fire rate.

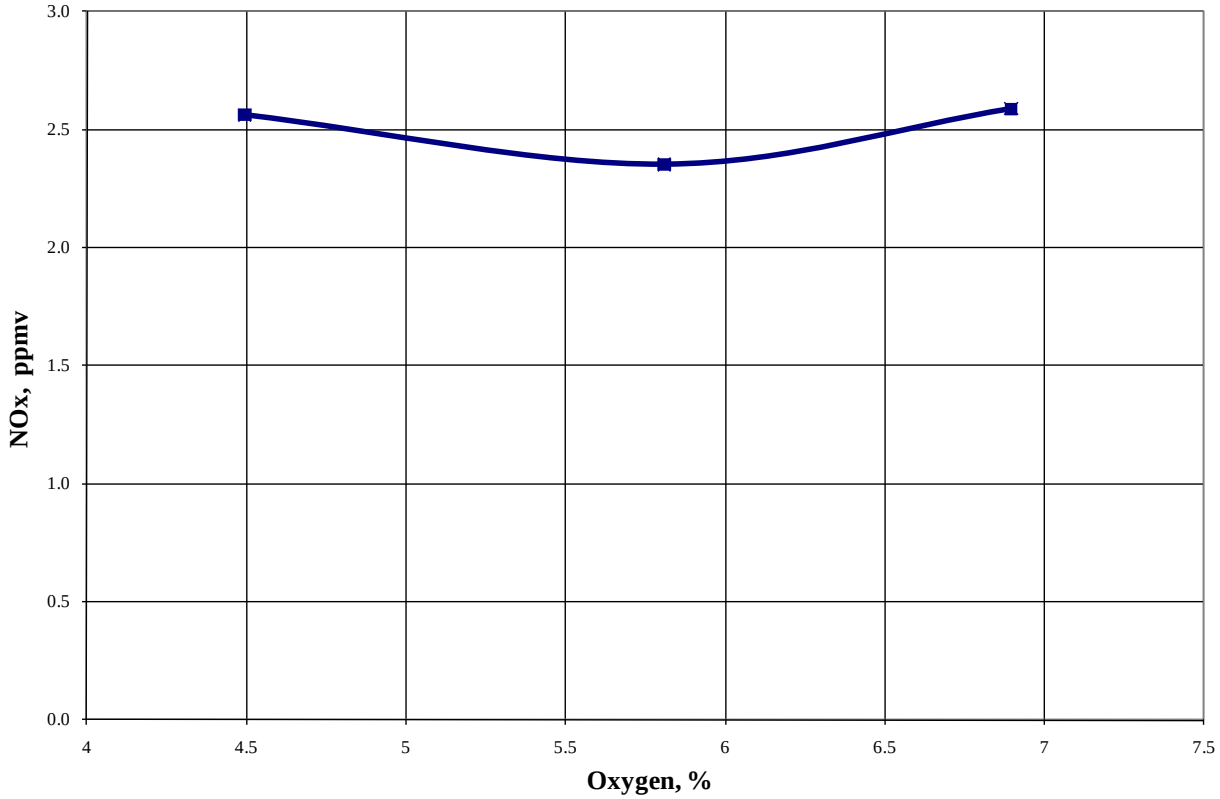


Figure 11. Supplemental ULN Burner Exhaust Oxygen Concentration

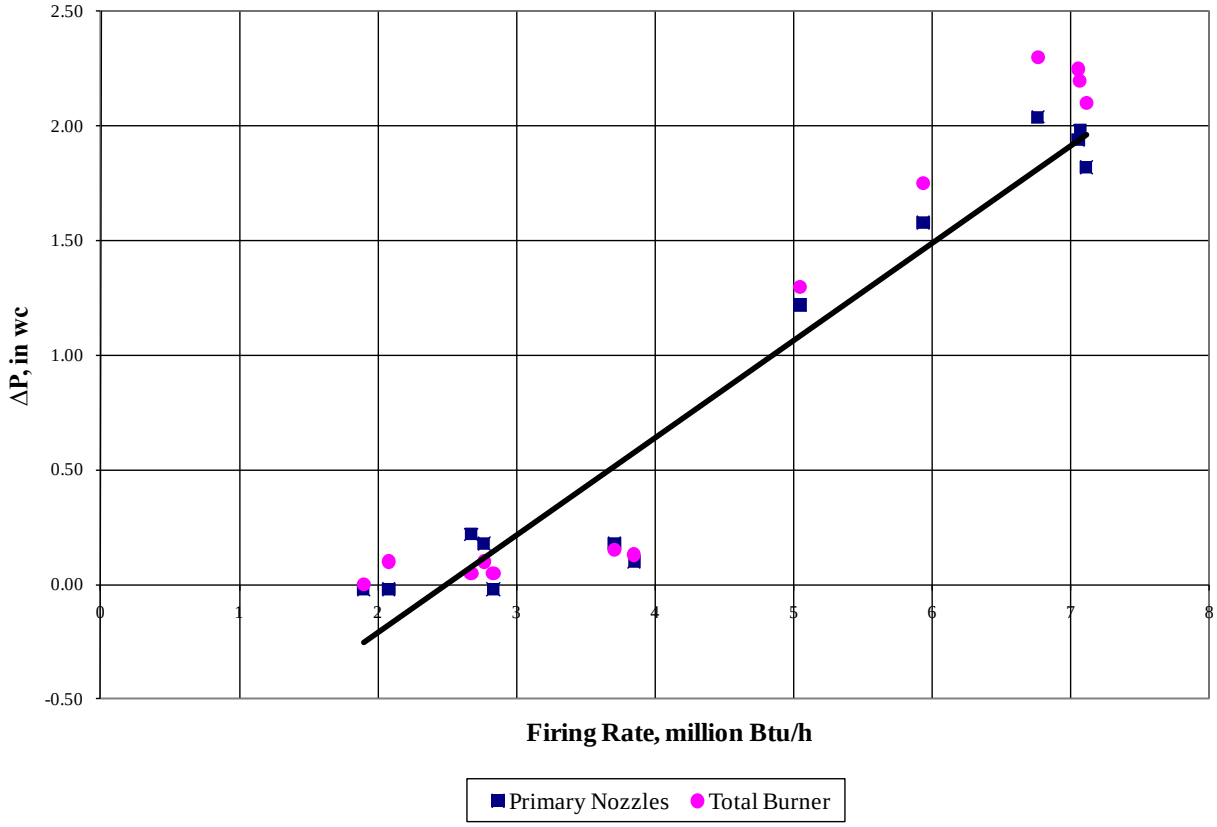


Figure 12. Supplemental ULN Burner Pressure Data

3 HOST SITE

The site for demonstration of the FlexCHP system is Accu Chem Conversion Incorporated (Accu Chem) located in El Centro, California. El Centro is approximately 100 miles east of San Diego and 10 miles north of the Mexican border. The site was visited by the project team to assess the suitability of the site for demonstration of the technology. The site visit was also used to identify the general items required to proceed with installation of the system including mechanical work, electric work, and permits.

The Accu Chem operation in El Centro is a trans-loading facility of hydrochloric acid from rail tank cars to cargo tank trucks. Additional materials handled in the facility include paraffin wax and other materials requiring steam heating to be kept in a liquid state. In 2007 a new refinery was added at the site converting tallow supplied by a nearby slaughter house into biodiesel. Biodiesel is scheduled to be produced on a 24/7 basis, with a maximum production rate of 3,000 gallons per hour. Electric power is provided by the Imperial Irrigation District

which is the local municipal power and water utility and natural gas is supplied by the Southern California Gas Company.

Figure 13. Accu Chem's Trans-Loading Facility (left) and Biodiesel Refinery (right)

4 CHP SYSTEM

The FlexCHP system will combine a Capstone C65 microturbine, a supplemental ULN burner, and a 100 HP heat recovery boiler by Johnston Boiler Company. The microturbine provides power to the facility and the exhaust is ducted to the supplemental ULN burner. The burner is connected to the boiler which provides steam and is interconnected to the existing steam header.

4.1 Site Loads

4.1.1 Electric Load

Based on process equipment provided by Accu Chem a table of equipment and operating schedule for each major piece of equipment was developed in order to project the electric demand profile of the process. The schedule is developed over the 12-hour batch process run time. Figure 14 provides as an estimate of electric demand during a process run. The graph provides the peak demand which includes equipment that has a duty cycle less than one hour, whereas the average demand only includes equipment that had a minimum of a one hour duty cycle. This is regarded as being somewhat conservative and does not include lighting or minor equipment associated with the process.

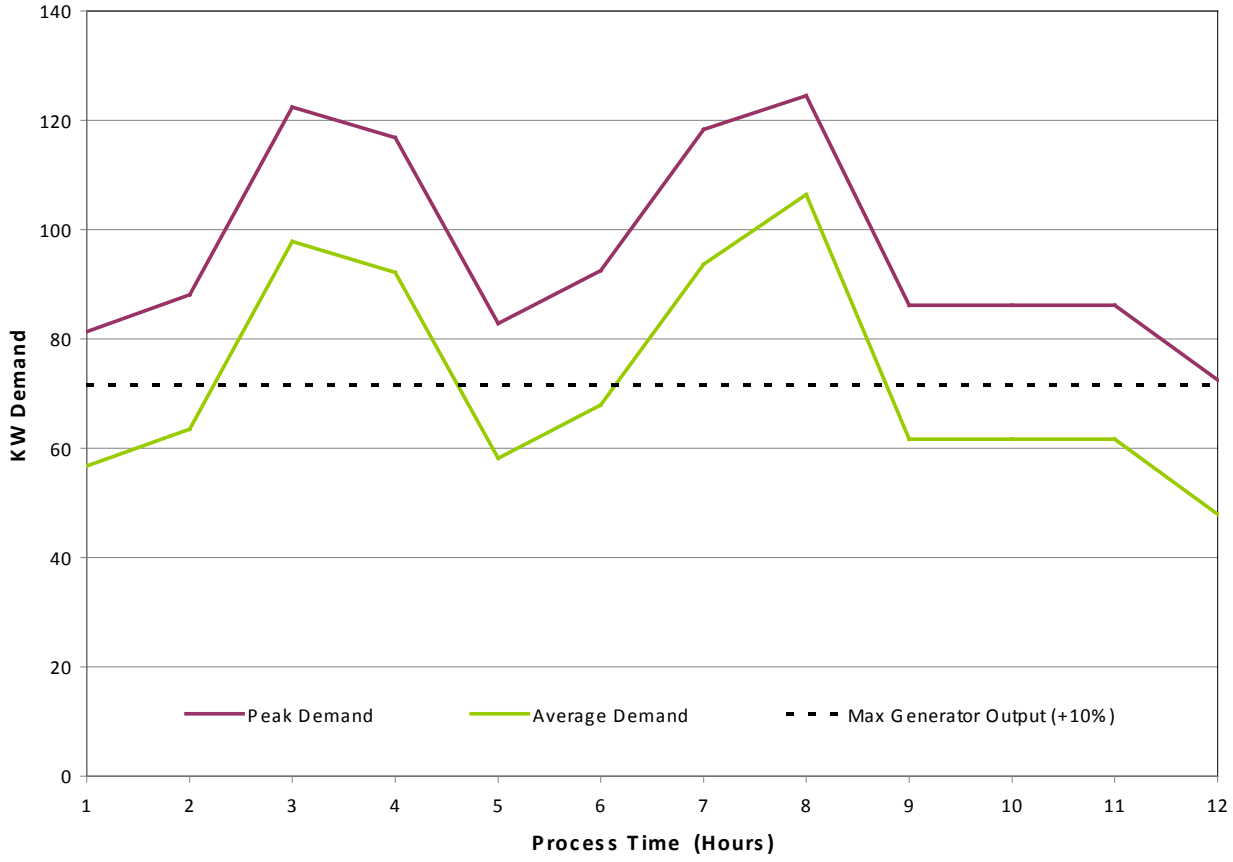


Figure 14. Representative Electrical Profile 12-Hour Batch

In Figure 14 the output at ISO conditions of a 65 kW generator with a 10% import requirement added for a total of 71.5 kW were overlaid on the load profile. This represents the maximum load required to maintain the generator at full capacity. Based on this analysis, the project team determined that a 65 kW turbine will have a sufficiently high load factor through the process run. It is envisioned the initial production at the biodiesel will consist of one batch per day with the potential to go to two batches per day in the future.

4.1.2 Steam Load

The existing plant provides steam to thirty-five rail cars stations and uses two boilers (main and back-up) that have a common steam header. The site currently has two McKenna 50 HP firetube steam boilers, as shown in Figure 15, either one of which can provide the steam required for the rail car operation. The new biodiesel refinery at the site will significantly increase steam usage for additional rail cars used to bring the raw materials and store the finished

product as well as for the refining process. The existing boilers have a water treatment system and feed a common steam header that supplies steam to the rail cars and the process. When the new refining process is running the site will need to add to its existing boiler capacity in order to provide back-up capability as the refinery and rail car operation will require both boilers to be operational.

Figure 15. Existing 50 HP Firetube Boilers

4.2 Microturbine

The microturbine shall be a Capstone C65 natural gas fired 65 kW unit. The FlexCHP-65 is used to describe the complete CHP package which includes the Capstone C65 microturbine, supplemental ULN burner and Johnston Boiler Company two-pass firetube boiler. Major turbine engine components include a compressor, a recuperator (exhaust gas heat exchanger), a combustor, a turbine, and a generator. The turbine engine is air-cooled and supported on air-lubricated compliant foil bearings. The compressor impeller, turbine rotor, and generator rotor are mounted on a single shaft, which comprises the only moving part in the engine. A gas

booster shall also be required to increase the available gas pressure to meet the microturbine requirements.

4.3 Burner and Boiler

The supplemental ULN burner is an innovative design that is intended to use the exhaust gas from the microturbine as feed air and combust natural gas to raise the exhaust temperature. The resulting emissions from the boiler stack are intended to meet or exceed the 2007 Fossil Fuel Emissions Standard requirements for NOx, CO, and VOC without catalytic exhaust gas treatment. The supplemental burner will connect to the new steam boiler and an exhaust duct from the microturbine will supply the supplemental burner with TEG. Figure 16 shows a cross-section of the supplemental burner for this demonstration.

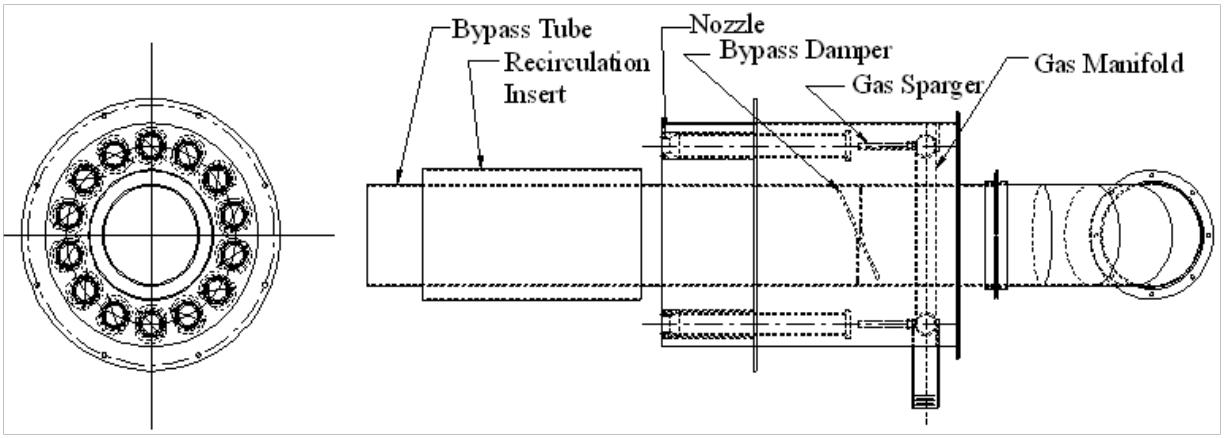


Figure 16. Supplemental ULN Burner Cross-Section

The boiler will be a standard firetube boiler with integrated heat exchanger economizer design adapted to meet the needs of the project. The boiler will be designed to provide 75 psig steam to the plant. Figure 17 shows the 100 HP boiler from the front and side. The existing boiler plant has a feedwater system that includes chemical treatment. A new line will be brought from this feedwater system to the new boiler.

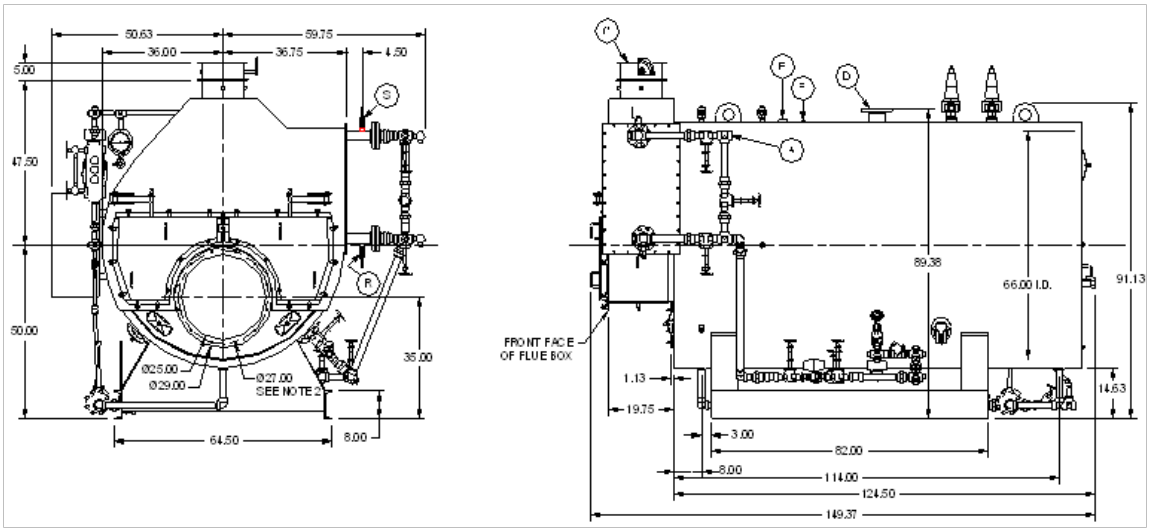


Figure 17. Firetube Boiler Perspective

4.4 Interconnection Plan

The FlexCHP-65 system is a steam and power system operating from natural gas. The electric power will be interconnected on the customer end of the utility meter and will be distributed to the process load through the new power distribution panel which was installed with the biodiesel refinery. The microturbine generator will be connected in parallel with the Imperial Irrigation District grid and will be provided with a pulse-output power meter to assure there is some level of constant import from the grid. This provides reverse power flow protection and enables the system to operate as a 'non export' system. Current sensors will be required at the meter which will be interconnected with the microturbine panel. When the import level drops to a preset margin, the microturbine will automatically be turned down. The system is not designed to provide emergency back-up power and so will not have black start capability.

The steam output from the FlexCHP-65 system will be interconnected with the existing steam header at 75 psig which is the same operating pressure as the existing boilers. Steam from the new boiler will be fed to a common header inside the biodiesel refinery. A steam pressure control valve and other required safety devices will be installed in the steam line.

The plant will require natural gas to both the supplement ULN burner and microturbine at different pressures. An existing Southern California Gas natural gas meter is available outside the control room with 45 psig of available pressure. A new line will branch off the supply line, complete with a new gas meter at the CHP location. One leg with a new pressure relief valve

will supply 10 psig pressure of gas to the microturbine gas booster and the other leg will have a new pressure relief valve supplying approximately 25 psig pressure gas to the supplemental ULN burner.

4.5 Equipment Layout Plan

Figure 18 indicates the layout of the CHP plant equipment relative to the existing plant and services.

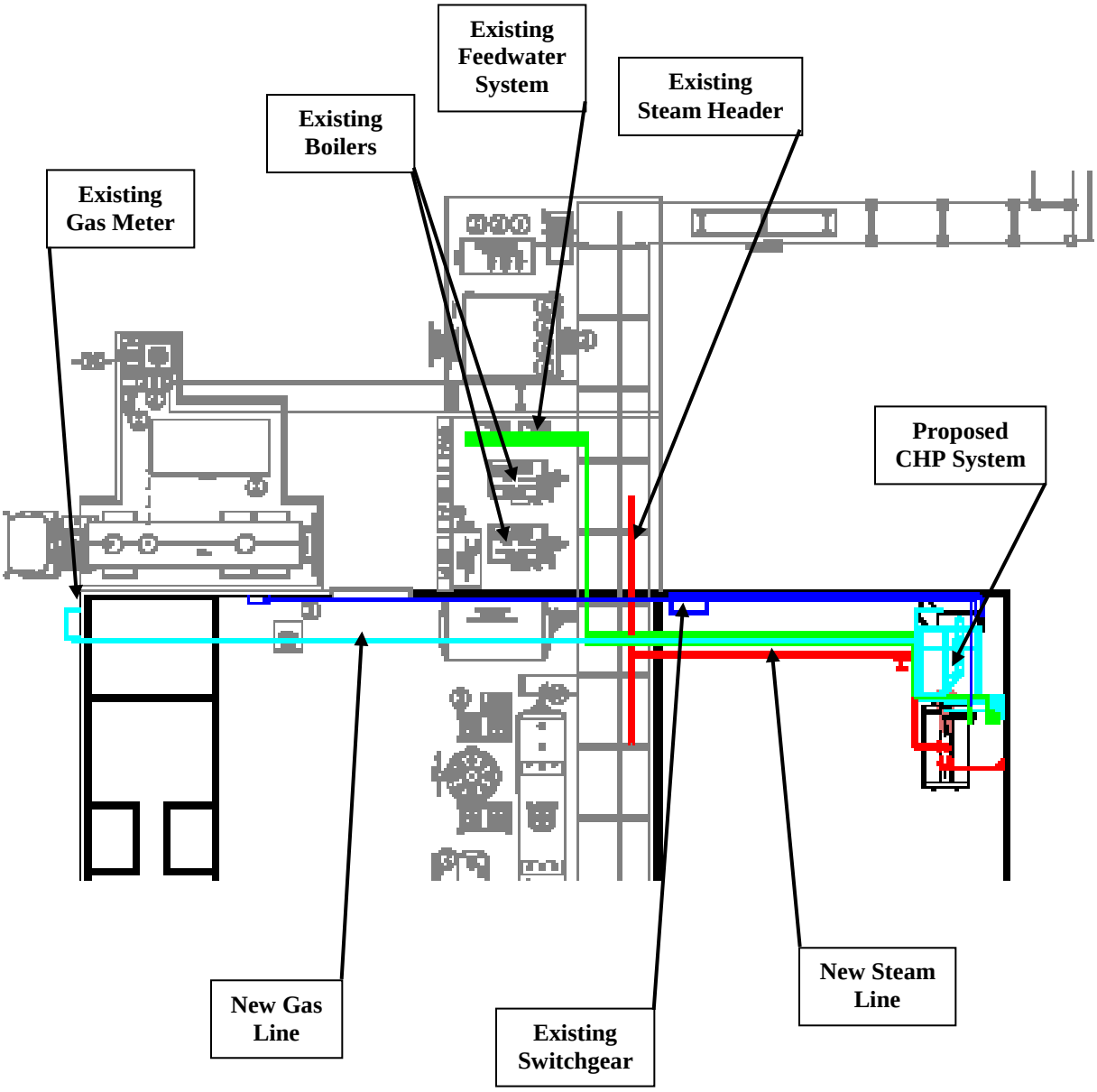


Figure 18. CHP Plant Layout

4.6 Project Requirements

4.6.1 Electric Interconnection

As the FlexCHP-65 system will only generate a portion of the electric power required during refinery operation, the electric output of the system will be connected in parallel to the grid. In order to meet the safety requirements of the local utility, a non-exporting control will be employed to prevent inadvertent export of power by turning down the microturbine, when the plant load is less than the turbine output plus the safety margin.

4.6.2 Steam Interconnection

The rail car stations and biodiesel plant steam loads are connected to a common header which is supplied by the two existing firetube boilers. The new system steam output will be brought to the same header and fed to the process load at a common pressure of 75 psig.

4.6.3 Structural

The location for the new CHP plant is inside the older building on the existing concrete slab. A review of any existing structural drawings or core drilling may be required to assess the need for additional concrete. New concrete curbing is required around the plant based on local code requirements. Two stacks will be required which will penetrate the existing roof structure.

4.6.4 Electrical

A new 100 A, 480 V switch will be located in the new switchgear to provide the power required for operation of the CHP plant. A new feeder will run to the microturbine. A second 30 A circuit and circuit breaker will feed power to the boiler control panel. This feeder will terminate on four terminals in the boiler control panel. The contractor will provide the conductors, conduits, supports, and seismic bracing as required by the local authorities and the National Electrical Code. The contractor will also provide testing of the conductors once they have been pulled but prior to connection. The following items will be required to be installed in addition to the utility approved grid parallel interconnection:

- Install new 100 A fused disconnect in the existing 480 V switchgear
- Install new 100 A feed between the new microturbine and the new switch
- Install a new 30 A 120 V circuit between the new boiler and the nearest panel

- Meggar the conductors prior to energizing and provide written report of the results
- Provide seismic bracing as normally required Southern California, (El Centro)
- Terminate the two circuits, (the boiler and the microturbine at both ends)
- Provide a new lighting circuit for four 250 W metal halide fixtures above the boiler and microturbine
- Obtain all requisite construction permits for the work in this scope.

4.6.5 Mechanical

The CHP plant will require makeup water to the new boiler as well as a natural gas supply to the microturbine and supplemental ULN burner. In addition, the contractor will be required to install a new steam header between the boiler and the existing steam header with two new isolation valves and pressure relief lines and a boiler blowdown line. The steam line will be required to be insulated with fiberglass insulation (where indoors), integral with self locking PVC jacket. The following items will be required:

- Install a new 2-inch carbon steel welded pipe between the existing natural gas meter location and the location of the new FlexCHP system. The new pipe will be supported as required by code and seismically braced to satisfy local authorities. Provide shut-off valve at both ends.
- Install a new 6-inch steam header between the header on the boiler that already includes the pressure relief and non-return valves, and the location of the main header in the building. Provide a shutoff valve at the location of the connection to the existing header to isolate the new an old boilers (two valves).
- Insulate the new steam header and repair existing insulation.
- Install two new steam relief lines up through the roof for the emergency relief valves. Support and brace as per local authority. Secure and patch roof at penetration.
- Install new boiler exhaust stack through the roof with provided roof collar, and patch the roof. Brace stack as per local authority.
- Install new 1-inch feedwater line between the location of the existing boiler makeup system and the new boiler. This line shall have a valve at both ends, be secured and braced as per local authority. The line shall be carbon steel.
- Install a new 1.5-inch steel gas line between the microturbine and the new boiler fuel train. Provide a valve at the location of the microturbine. Line will be run on supports provided by others between the microturbine and the boiler and will be less than 30 feet in overall length.

- Hydro and/or pressure test all lines to 1.5X working pressure as per final engineering specification.
- Provide a water blow down line to a safe location, assume within 50 feet.

4.6.6 Permitting

An emissions permit will be required for the FlexCHP-65 system from the Imperial County Air Pollution Control District and an interconnection permit will be required from the Imperial Irrigation District utility. In addition a building permit covering electric, mechanical, and structural issues will be required from the local building authorities.

5 DEMONSTRATION

The downturn in economy has halted operation of the Accu Chem biodiesel refinery. The site has explored the possibility of burning the biodiesel in a peaking power plant adjacent to their facility. A test burn was conducted with positive results. Together, Accu Chem and the peaking power plant are exploring various methods to transport the biodiesel between plants. Operation of the biodiesel refinery is tentatively scheduled to resume in the 3Q 2010.

As a result, the FlexCHP-65 setup is presently located at GTI's Combustion Laboratory in Des Plaines, Illinois. The location, orientation, and ducting connecting the microturbine to the burner as shown in Figure 19 are identical to that at the Accu Chem site. The ducting connecting the turbine to the supplemental burner was fitted with a pressure relief damper to protect the microturbine from overpressure. The steam produced by the boiler is vented to atmosphere and the power generated by the microturbine is dissipated by an Avtron 155 kW (240/480/3 ph/60 Hz) load bank.

A data acquisition system was used to collect data continuously and at specified points during evaluation of the FlexCHP system. The major flow rate measurements recorded were the microturbine and supplemental ULN burner natural gas flow. The natural gas flow rates were measured using Micro-Motion coriolis mass flow meters. The static pressure at the combustion chamber exit, burner windbox, and fuel manifold were measured with a manometer. The exhaust gas flow rates were determined with pitot tubes with inclined manometers with the pitot tube located in the boiler stack for the total flue gas and in the ducting between the microturbine and boiler to determine TEG flow.

Figure 19. FlexCHP-65 Setup at GTI

Appropriate emissions constituents measured were NO/NOx, CO, CO_2, THC, and O_2 emissions from the microturbine, supplemental burner primary zone, and boiler stack. The panel mounted analyzers were used for the boiler flue gas and a Horiba portable analyzer for the primary zone, and another Horiba portable analyzer for the microturbine TEG (Figure 20).

Type "K" thermocouples were used to measure temperatures for TEG, boiler flue gas, water inlet and outlet to the heat recovery exchanger, and natural gas temperatures. The sample conditioning trains were located near the probe and were followed downstream by Teflon sample lines to deliver the gas sample to various gas analyzers through a sample flow control and distribution panel. The control panel facilitates easy switching between gas sampling and instrument calibration.

Figure 20. Emissions Analyzers

The manufacturer, model number, and the technology used for the concentration of the flue gas constituents are list in Table 4 for the FlexCHP stack exhaust. The same information is in Table 5 for the supplemental ULN burner primary zone and microturbine TEG streams.

Table 4. Emissions Analyzers for FlexCHP Stack Exhaust

Constituent	Manufacturer	Model	Method
Oxide of Nitrogen	Thermo Environmental	42C	Chemiluminescence
Carbon Monoxide	Rosemount Analytical	880A	Non-dispersed infrared
Carbon Dioxide	Rosemount Analytical	880A	Non-dispersed infrared
Total Hydrocarbons	Rosemount Analytical	400A	Flame ionization total hydrocarbons
Oxygen	Rosemount Analytical	755R	Paramagnetic

Table 5. Emissions Analyzers for Supplemental ULN Burner Primary Zone and Microturbine TEG Streams

Constituent	Manufacturer	Model	Method
Oxide of Nitrogen	Horiba	PG250	Chemiluminescence
Carbon Monoxide	Horiba	PG250	Non-dispersed infrared
Carbon Dioxide	Horiba	PG250	Non-dispersed infrared
Oxygen	Horiba	PG250	Paramagnetic

All of the instruments were calibrated prior to each test campaign using pure nitrogen to establish the "zero" and an appropriate span gas to set the "gain." Lists of the certified span gas mixtures used are listed in **Error! Reference source not found.** for the FlexCHP stack exhaust and Table 7 for the supplemental ULN burner primary zone and microturbine TEG streams.

Table 6. Calibration Gases Span Values for FlexCHP Stack Exhaust

Function	Component	Units	Concentration	Analyzer Range
Zero gas	N_2, zero	vol%	100	all
O_2 span (high)	O_2 in N_2	vol%	8.0	0/10
CO_2 span	CO_2 in N_2	vol%	18	0/20
NOx span (high)	NO in N_2	ppmv	17.9	0/25
CO span (low)	CO in N_2	ppmv	147	0/200
CO span (high)	CO in N_2	vol%	4.9	0/30
THC span for 1st stage	CH_4 in N_2	ppmv	341	0/1000

Table 7. Calibration Gases Span Values for Supplemental ULN Burner Primary Zone and Microturbine TEG Streams

Function	Component	Units	Concentration	Analyzer Range
Zero gas	N_2, zero	vol%	100	all
O_2 span (high)	O_2 in N_2	vol%	7.9	0/10
CO_2 span	CO_2 in N_2	vol%	18	0/20
NOx span (high)	NO in N_2	ppmv	17.9	0/25
CO span	CO in N_2	ppmv	147	0/200

5.1 Results

The FlexCHP system is composed of a Capstone C65 microturbine coupled with a 100 HP heat recovery boiler, see Figure 21. The high oxygen content waste heat from the microturbine will provide the oxidant for the supplemental burner.

In addition to the electricity produced by the microturbine, a significant portion of thermal energy will be produced by the firetube boiler. The key component of the system is a supplemental ULN burner capable of meeting the 2007 Fossil Fuel Emissions Standard and the integration of the burner into a CHP system.

To meet the standard, NOx emissions produced by the supplemental ULN burner would need to be less than 10 ppmv, provided most of the waste gas is utilized for combustion.

Prototype testing with TEG from a 65-kW microturbine and 2.5 million Btu/h supplemental burner firing will demonstrate compliance.

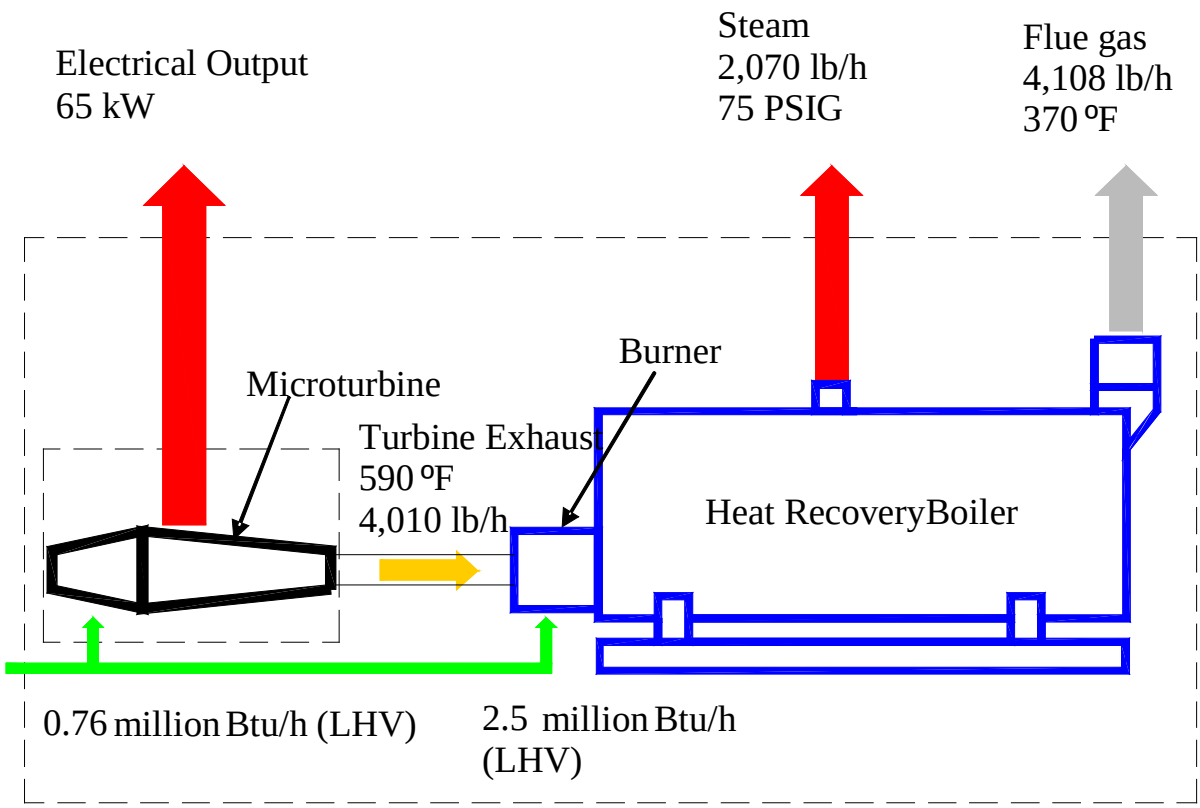


Figure 21. Process Flow Diagram for the FlexCHP System

Initial testing of the FlexCHP-65 began with installation and commissioning of the microturbine. The microturbine was connected to GTI's power grid and also with a load bank to dissipate the energy generated. Once installation was complete, a Capstone representative participated in its commissioning.

Laboratory testing was conducted to document the emissions performance. Emissions data and flow rates for the microturbine and supplemental burner were continuously collected during all the tests performed to determine if the burner firing rate and additional back pressure from combustion would influence the microturbine emissions and input. Figure 22 demonstrates the burner firing rate had no influence on the microturbine performance. The data represents

continuous test data collected during testing. The oxygen concentration, emissions, and gas input to the microturbine were constant despite the change in supplemental burner firing rate.

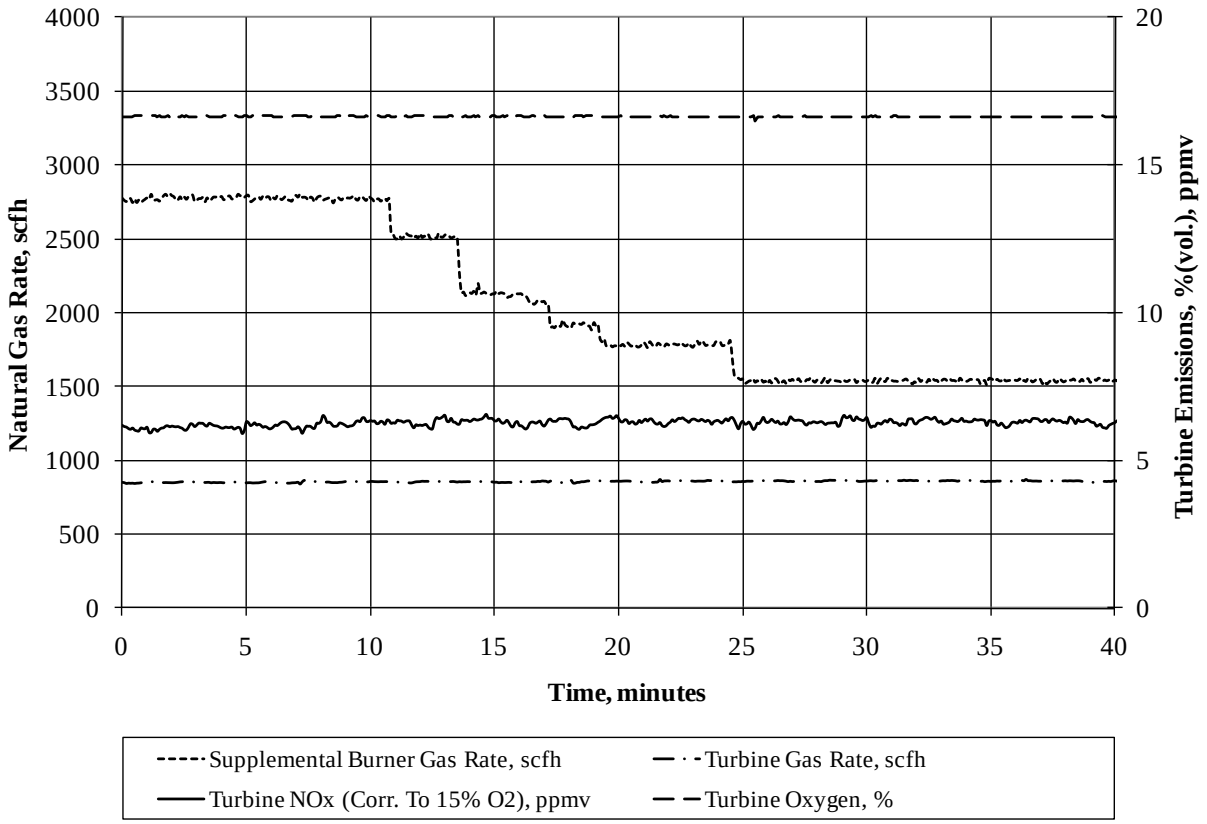


Figure 22. Microturbine Gas Rate and Emissions at Different Burner Firing Rates

The main component for evaluation of the FlexCHP-65 is the supplemental ULN burner. Different burner parameters were changed in order to optimize performance areas such as emissions, stability, reliability, and safety. The main parameters varied were firing rate, number of primary nozzles, and the ratio of TEG between the primary/secondary zones. A snapshot of a typical flame is shown in Figure 23.

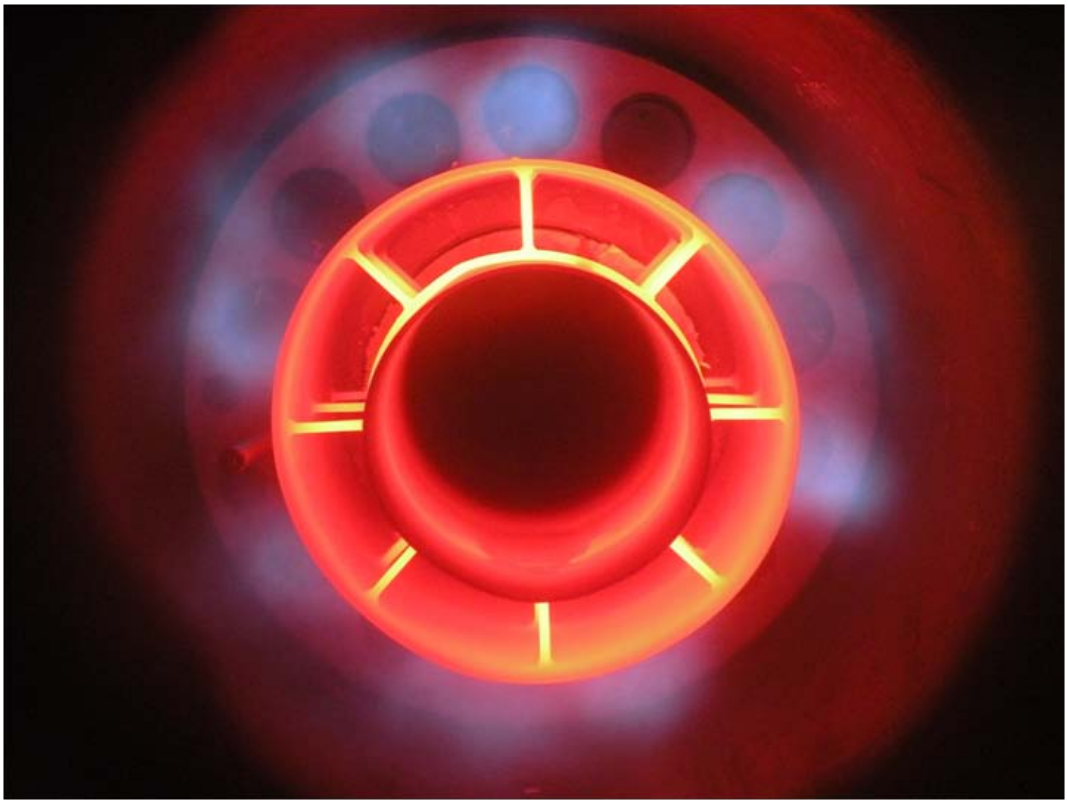


Figure 23. 3 million Btu/h Supplemental ULN Burner Flame

The performance testing of this burner proved more challenging than the previous burners for both emissions and stability. This is the first supplemental burner tested on a boiler vessel. Although, testing of the supplemental burner, with air as the oxidant, have been applied to similar vessels. The burner was able to be stable throughout the firing range from 1.5-3.7 million Btu/h. NOx emissions varied depending on the excess oxygen achieved in the primary zone which was similar to the previous supplemental burners. The challenge was at higher firing rates, as higher excess oxygen was difficult to achieve, directly impacting NOx emissions and performance.

Another parameter evaluated was the position of the natural gas injection spargers relative to the entrance of the nozzles. Early testing revealed the burner emissions and stability may have been effected by the quality of mixing natural gas and TEG prior to combustion. To evaluate this, the burner was modified to accommodate a variable injection point that could be adjusted during operation. By moving the injection point farther from the combustion zone, additional residence time for mixing was achieved. As shown in Figure 24 lower emissions

resulted from the points closest and farthest from the combustion zone. Overall, the farthest distance did show slightly reduced emissions.

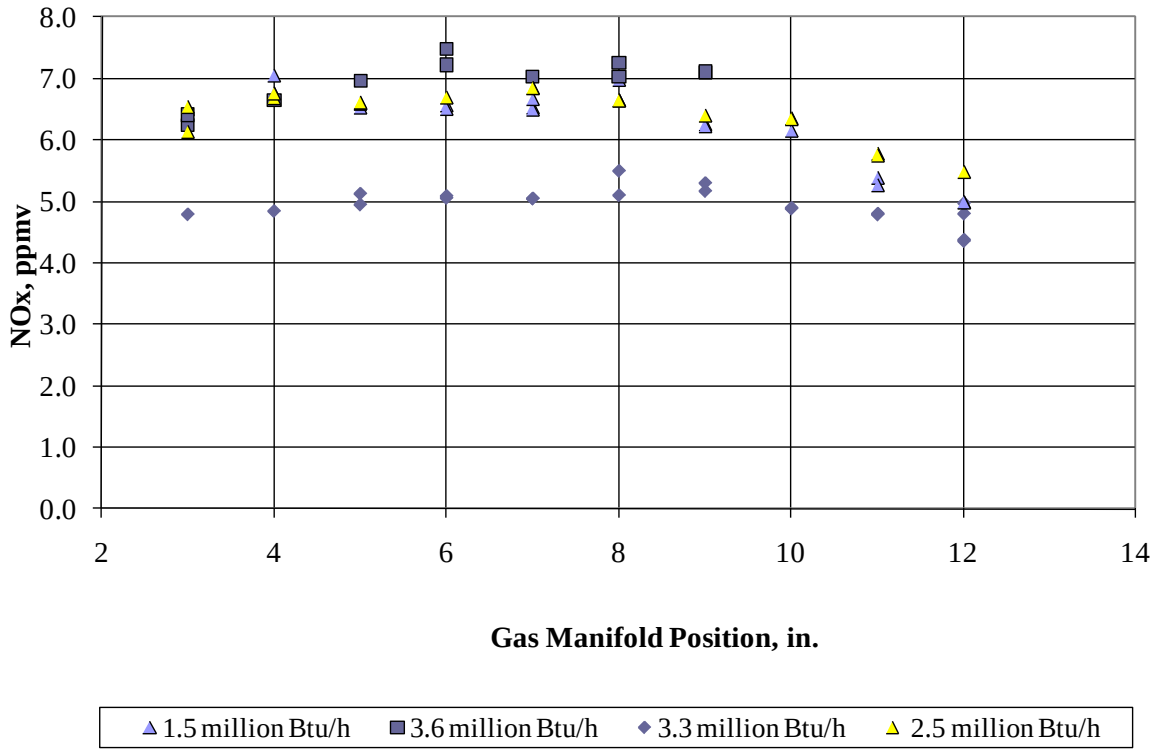


Figure 24. NOx Emissions at Varying Natural Gas Injection Points

Figure 25 represents NOx emissions and oxygen levels in the boiler stack as a function of firing rate. This plot shows the spread in NOx emissions at the different firing rates depending on the primary excess oxygen and natural gas injection position.

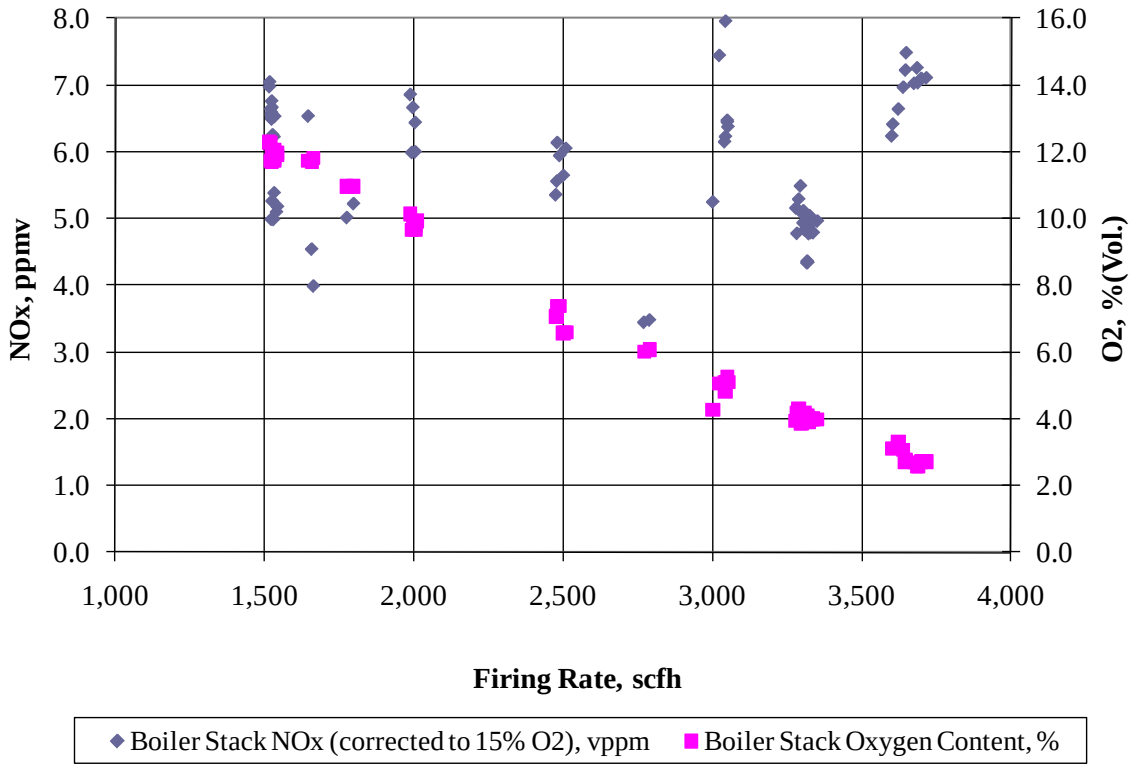


Figure 25. NOx Emissions and Oxygen Levels at Different Burner Firing Rates

The behavior of NOx emissions as a function of the stack oxygen content was similar to the 7.5 million Btu/h results, but the values were higher overall. NOx emissions at different oxygen levels tended to vary all over and were more dependent on primary zone excess oxygen and the position of the natural gas injection point. These values are presented in Figure 26.

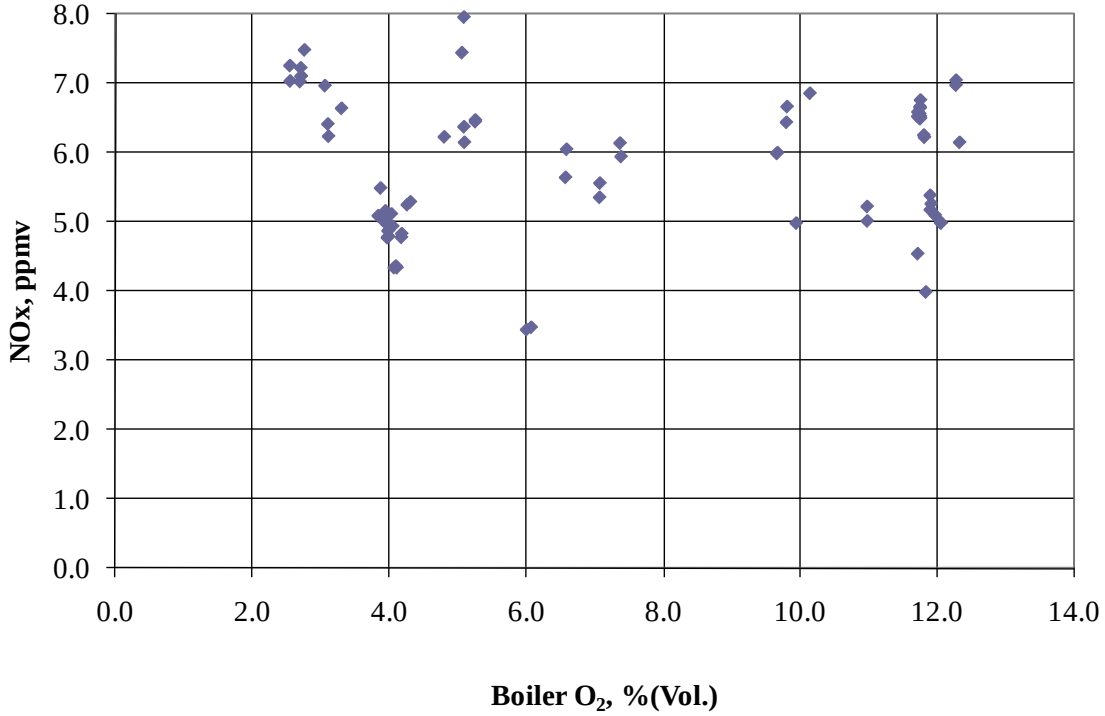


Figure 26. NOx Emissions Relative to Stack Oxygen Content

Another important performance parameter to evaluate was the supply pressure of the TEG to the supplemental burner. This is important because of the turbine manufacturer's design limitations for back pressure and because the higher the back-pressure the more turbine efficiency deteriorates. Alternatively, the burner requires pressure to provide velocity through the natural gas spargers that promotes internal burner recirculation for reduced emissions. This data is shown in Figure 27.

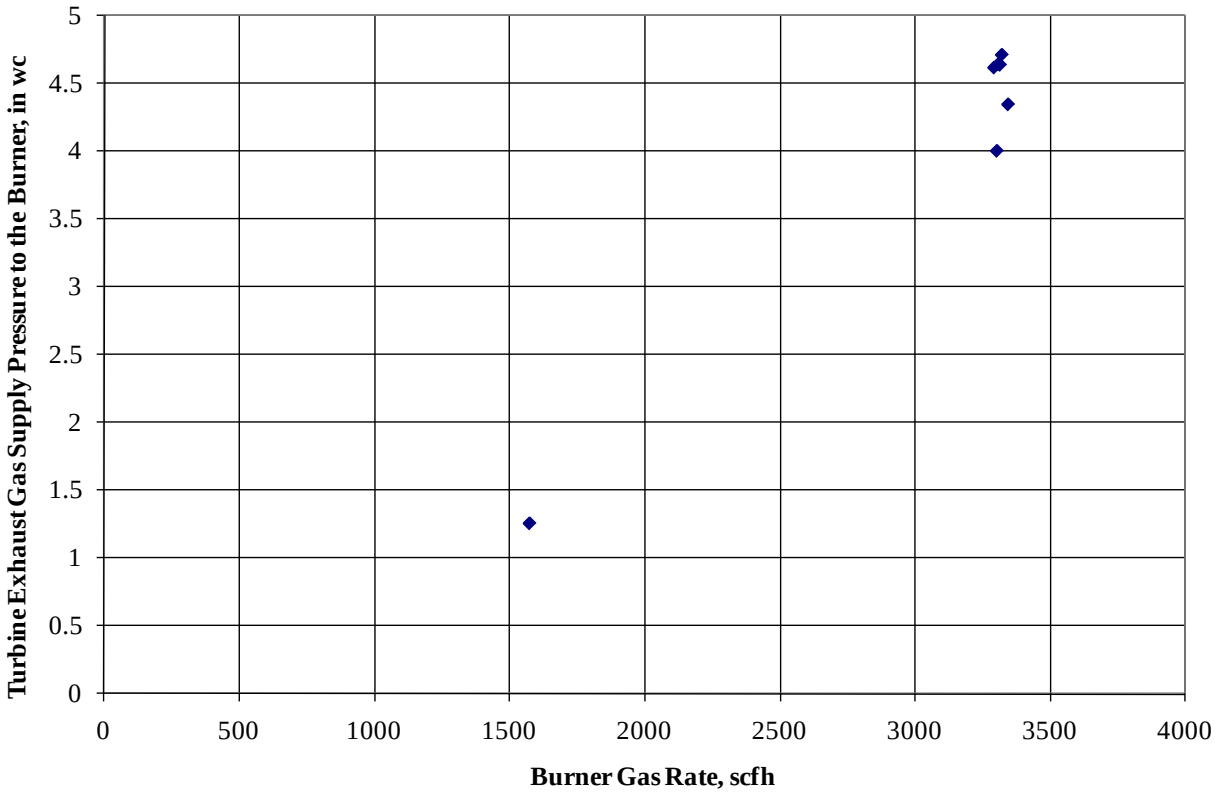


Figure 27. Turbine Exhaust Gas Supply Pressure to the Burner

6 MARKET ASSESSMENT

The objective of this study was to determine what opportunities exist for heating industrial thermal processes with a gas-fired supplemental or reheat burner, using the exhaust of microturbines as an oxygen source.

Microturbines are gaining acceptance for on-site generation of electrical power. They produce significant volumes of exhaust gases at temperatures of about 500-600°F. Those gases contain, on the average, 17-18% oxygen by volume, so they could be used as a source of combustion air for a burner system firing another process. The potential benefits from this turbine-process coupling include reduced gas and electrical consumption, lower installation costs and reduced air emissions, compared to the two systems operating separately.

The study identified seven generic classes of gas-fired applications with technical and operating characteristics that make them potential candidates for firing with turbine exhaust gas. Next, the potential energy efficiency and cost advantages of turbine exhaust systems were

investigated. These studies led to the conclusion for processes operating at or below 1400°F exhaust temperature, there will be up to a 12% improvement in fuel efficiency by converting processes fired with conventional ambient combustion air to reheated turbine exhaust, in addition to some savings in electrical energy. From 1400 to 2400°F exhaust temperature, efficiencies of the two competing methods are essentially the same.

Equipment costs were studied in great detail, leading to the conclusion the turbine exhaust system will cost about the same as a conventional combustion system. The study identified the cost of the exhaust ductwork and control valves as a major factor, suggesting applications with the best potential for financial acceptance were single-burner units located close to the turbine.

Emissions levels will have the greatest impact on the salability of the system. If the supplemental or reheat burner is able to produce NOx in the 20 ppmv range, there will be an overall reduction in emissions compared to a turbine and fired process operating separately. If the NOx emissions of the burner can be taken down to the 15 ppmv range or lower, it will be able to compete with low or ultra-low NOx systems and command a higher selling price.

Of the seven application groups studied, the boiler market encompasses about eight times the number of units as the other six combined. Boilers are most likely of all the types to be located where microturbines can be placed close to them, and the exhaust connection between the turbine and the reheat burner can be made at the least expense. These are compelling reasons to focus on developing supplemental burners for boiler applications only. The resulting burners will probably also be suitable for use on absorption chillers and some types of process heaters.

6.1 Microturbine/Process Heating Power Options

Five microturbine/process heating options (see Figure 28 and Figure 29) were initially studied. Three of those combinations were eliminated from consideration because they did not fit the objectives of this project. Options 2 and 4 were retained as the basis for further feasibility studies.

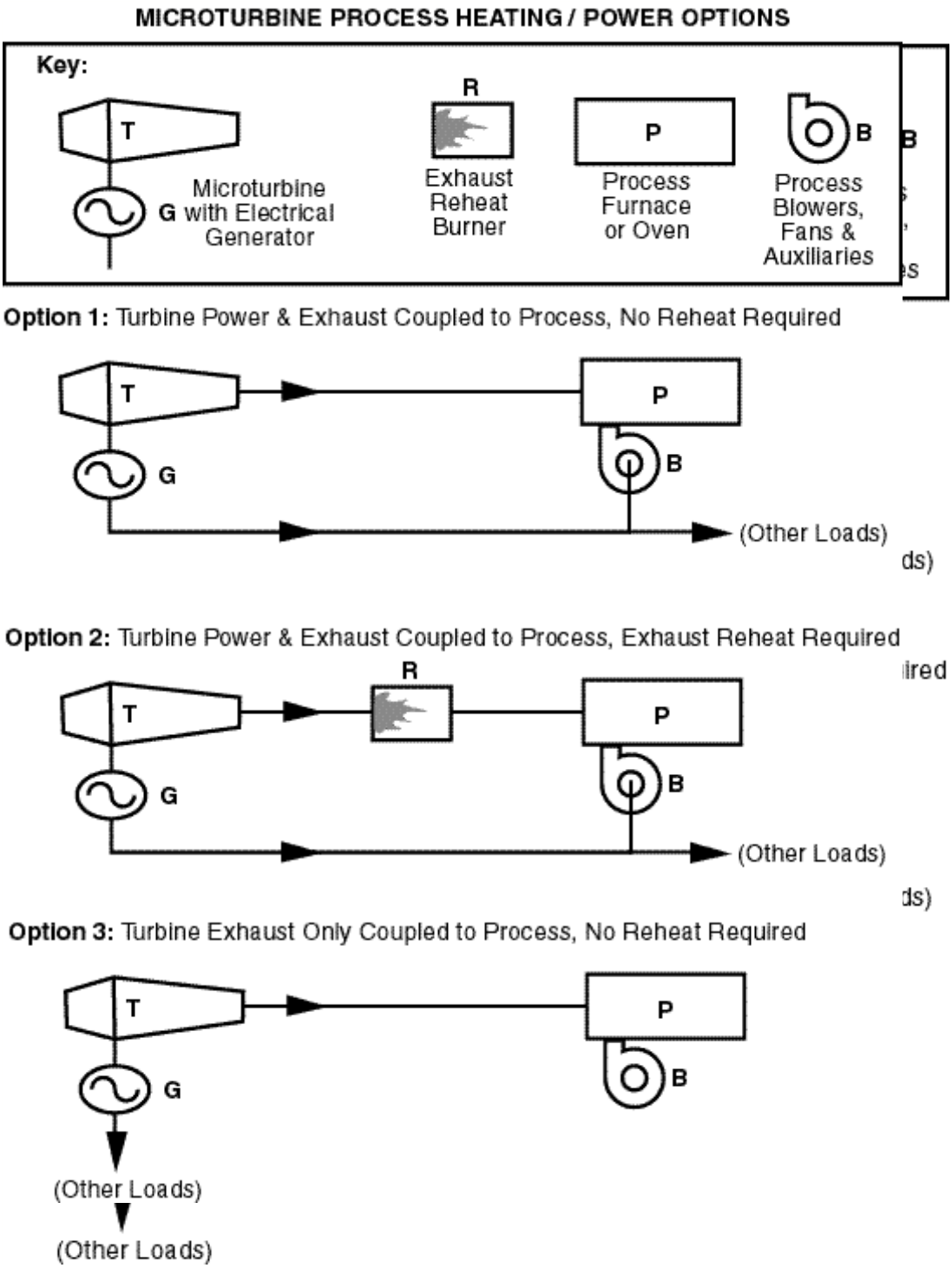


Figure 28. Microturbine Process Heating/Power Options 1-3

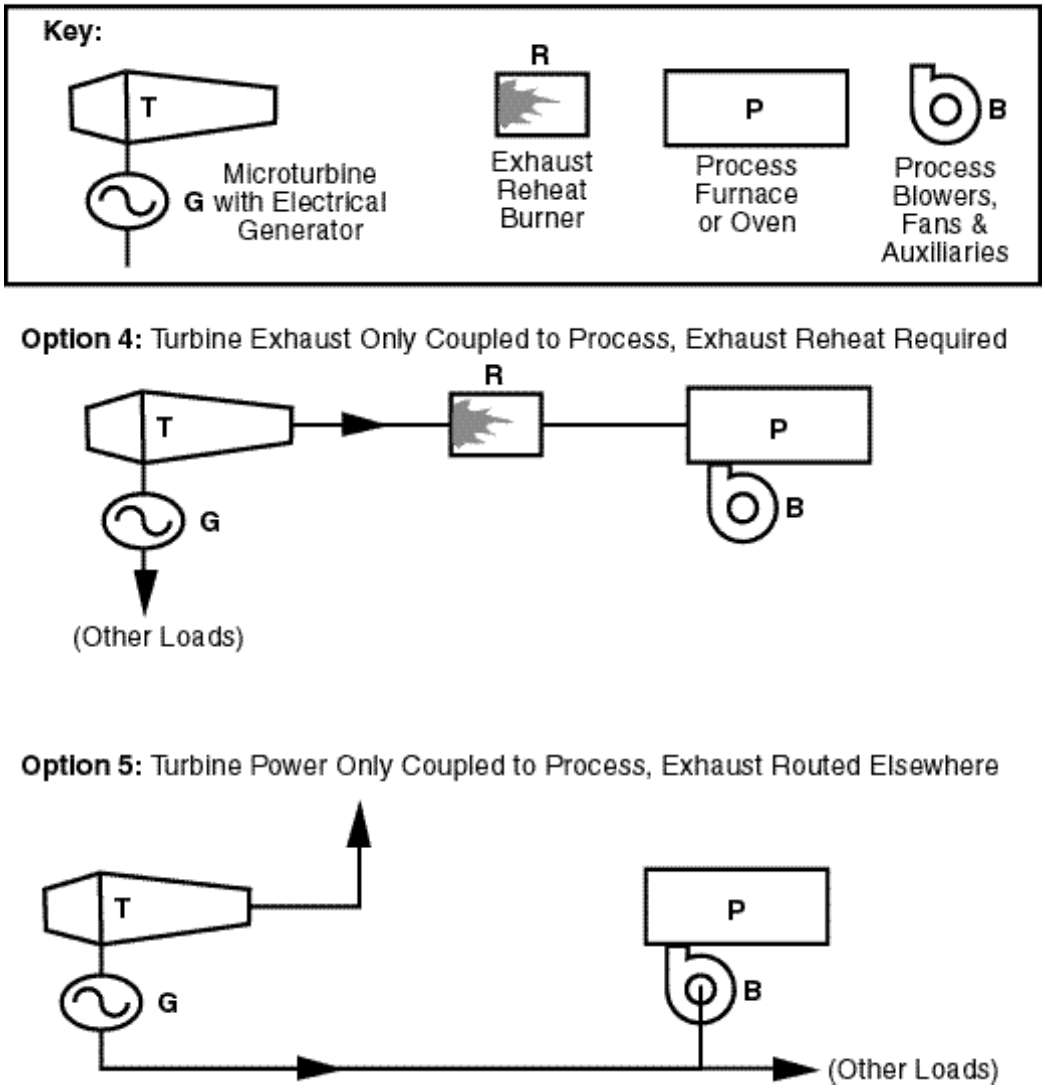


Figure 29. Microturbine Process Heating/Power Options 4-5

6.2 Microturbine Exhaust-to-Process Options

There are six possible ways to couple the microturbine exhaust to the fired process, as shown on Figure 30, 31, and 32. Advantages and disadvantages of each method are pointed out. From the standpoint of initial cost, adaptability to the greatest number of processes, and minimal interference with the operation of the turbine, Option 4 is the most desirable.

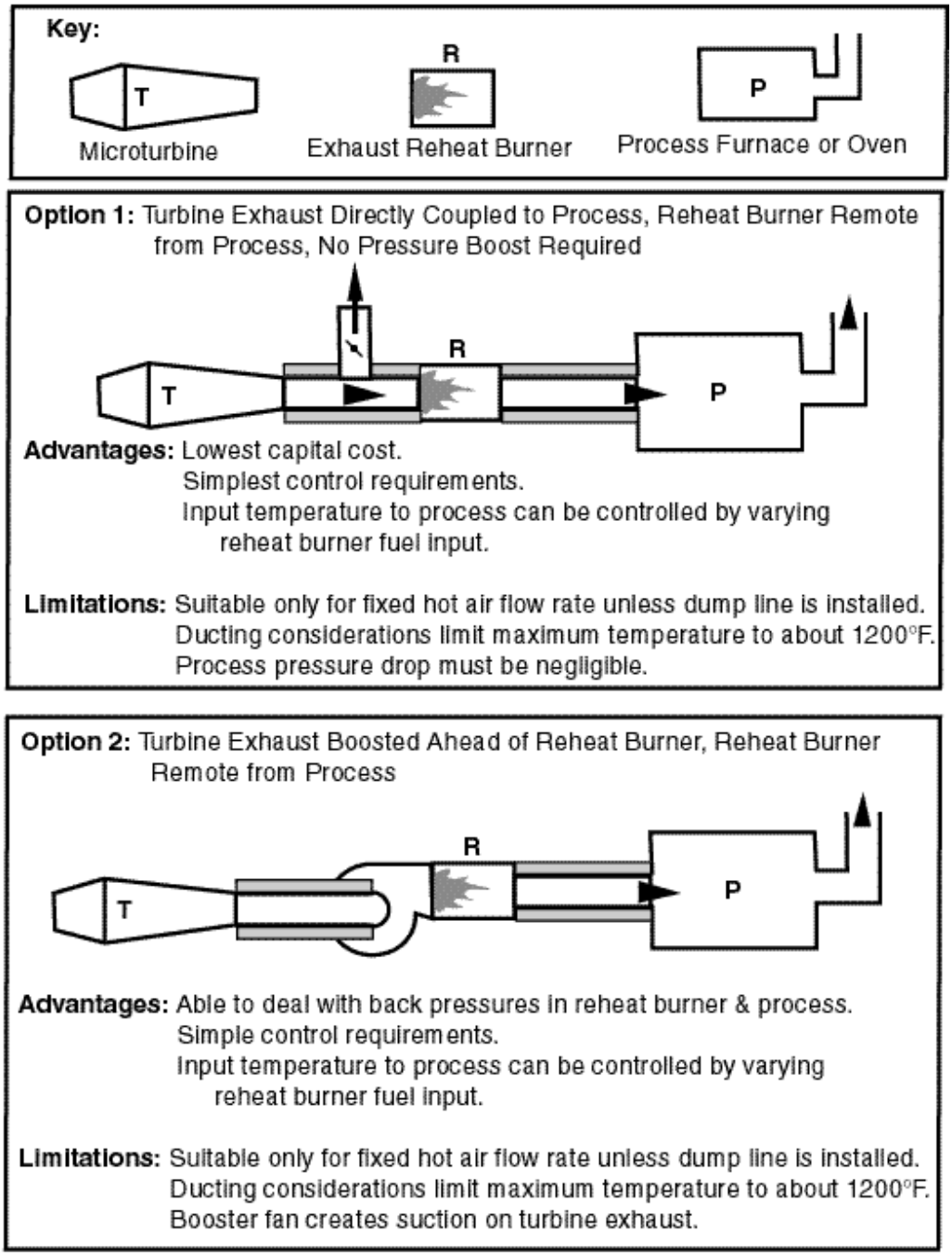
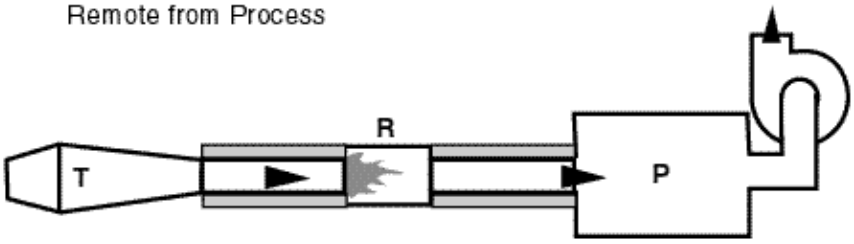


Figure 30. Microturbine Exhaust to Process Options 1-2

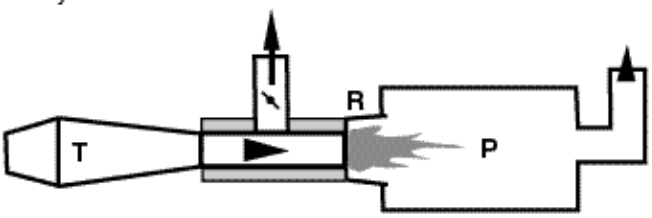
Option 3: Turbine Exhaust Drawn into Process by Exhaust Fan, Reheat Burner Remote from Process



Advantages: Able to deal with back pressures in reheat burner & process.
Simple control requirements.
Input temperature to process can be controlled by varying reheat burner fuel input.
Fan has less impact on turbine operation than Option 2.

Limitations: Suitable only for fixed hot air flow rate unless dump line is installed.
Ducting & exhaust fan considerations limit maximum temperature to about 1200°F.

Option 4: Turbine Exhaust Directly Coupled to Process, Reheat Burner Fires Directly into Process Chamber

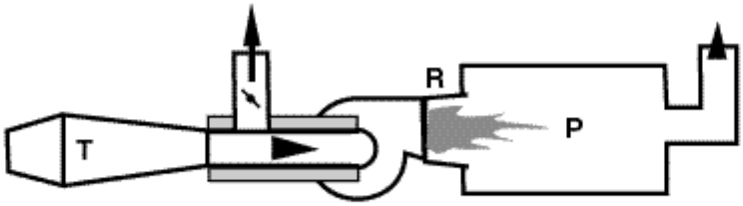


Advantages: Process heat transfer benefits from direct flame radiation -- most suitable for high temperature processes.
Simple control requirements.
Input temperature to process can be controlled by varying reheat burner fuel input.

Limitations: Suitable only for fixed hot air flow rate unless dump line is installed.
Process pressure drop must be negligible.
Burner must satisfy both reheat & process heating requirements.
Low momentum burner -- may not provide desired flame & heat transfer characteristics for some applications.

Figure 31. Microturbine Exhaust to Process Options 3-4

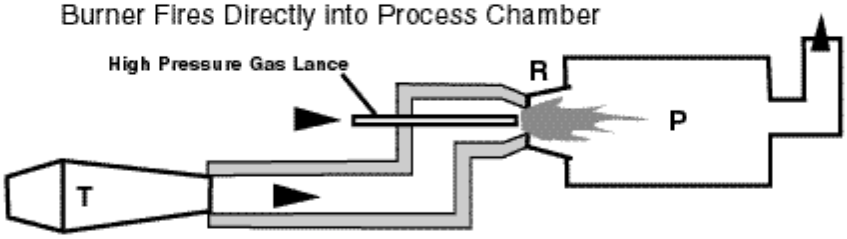
Option 5: Turbine Exhaust Boosted Ahead of Reheat Burner, Burner Fires Directly into Process Chamber



Advantages: Most practical layout for high temperature processes.
Process heat transfer benefits from direct flame radiation -- most suitable for high temperature processes.
Burner can be designed for greater process suitability -- flame shape, momentum, etc.

Limitations: Suitable only for fixed hot air flow rate unless dump line is installed.
Burner must satisfy both reheat & process heating requirements.

Option 6: Turbine Exhaust Induced by High Pressure Gas Injector, Reheat Burner Fires Directly into Process Chamber



Advantages: Process heat transfer benefits from direct flame radiation -- suitable for high temperature processes.
Input temperature to process can be controlled by varying reheat burner fuel input.

Limitations: Suitable only for fixed hot air flow rate unless dump line is installed.
Process pressure drop must be low.
Burner must satisfy both reheat & process heating requirements.
Injector inefficient & noisy -- requires supply of high pressure gas.
Gas-air ratios likely to be affected by draft fluctuations.
Injector creates suction on turbine exhaust.

Figure 32. Microturbine Exhaust to Process Options 5-6

7 CONCLUSIONS

The 2007 Fossil Fuel Emissions Standard for integrated CHP installations is 0.07 lb/MWh. GTI's application of the supplemental ULN burner to a heat recovery boiler or absorption chiller using the exhaust gas from a gas turbine will meet the new standard. Earlier

developmental work proved that the exhaust gas from a 60-kW microturbine produces enough oxidant at its full capacity to fire a natural gas burner to approximately 2.5 million Btu/h input. The exhaust temperature from the microturbine will be approximately 580°F and will add approximately 0.3 million Btu/h of heat to the boiler for a total input of 2.8 million Btu/h.

As a continuation of the earlier developmental work, the burner technology was scaled up to 7.5 million Btu/h. At this firing capacity, the microturbine was not capable of generating sufficient TEG at temperature to simulate the Mercury 50 gas turbine. An auxiliary burner was used to generate flue gases that were mixed together with dilution air. The resulting mixture closely matched the gas composition and temperature of the Mercury 50 gas turbine across its firing range.

The results from laboratory evaluation of the 7.5 million Btu/h supplemental burner show comparable performance to that of the smaller unit. The burner is capable of adding significant thermal energy to the STEG while contributing little additional NOx emissions at the stack. On a volume per volume basis, stack NOx emissions, after supplemental firing, are lower than NOx emissions from the gas turbine. The burner has also shown an ability to handle large differences in excess air from 20 to 280%. This is important when minimal heat is required and the gas turbine is producing the maximum amount of exhaust.

The development of the FlexCHP-65 system has not been completed at this point. The NOx emissions are on the borderline of the performance goals but need further development to reach a comfortable threshold. The goals for CO emissions have been achieved with the current design. The unit has also provided a safe reliable operation during testing. Currently, a thorough review is being performed of burner geometry and the scaling from the previous versions to determine the next steps. In the interim, additional testing with be performed with the current design.

The evaluation of the supplemental ULN burner of the FlexCHP-65 system was the first burner to be installed to a boiler. The two previous supplemental burners were tested on boiler simulators. The simulators have a circular furnace that represent the Morrison tube of a boiler, but the simulator has a water-cooled jacket that uses cold water to absorb heat. Because of this, the outer wall will be slightly cooler than that of a boiler. This could provide an advantage for reducing the thermal NOx over a boiler. The testing performed to date has shown this added

thermal component can be overcome with modifications to the burner design. Further testing will address these areas.

The downturn in economy has halted operation of the Accu Chem biodiesel refinery. The site has explored the possibility of burning the biodiesel in a peaking power plant adjacent to their facility. A test burn was conducted with positive results. Together, Accu Chem and the peaking power plant are exploring various methods to transport the biodiesel between plants. Operation of the biodiesel refinery is tentatively scheduled to resume in the 3Q 2010.

The deployment of Distributed Generation with CHP technologies capable of meeting 2007 Fossil Fuel Emissions Standard has the potential to save energy, to increase productivity across the nation, and to reduce the burden on centralized power plants. This supplemental burner technology meets CARB's mission of reducing ozone precursors through increased efficiency. In many cases, supplemental firing can boost heat output and thermal efficiency from gas turbine-based CHP in a cost-effective manner. However, the only method to currently meet the NOx targets are burner designs that use SCR, which increases capital cost by 10 to 25%.[1, 2, 3] This is a significant barrier to adoption of Distributed Generation/CHP systems, especially by small to medium-capacity facilities (10 MW or less).

The supplemental ULN burner can remove this barrier by eliminating the need for SCR. The burner adds no more capital cost than a conventional duct burner. This initial cost will be recouped in less than 1.5 years through increased energy efficiency. GTI's supplemental ULN burner can meet the standard with natural gas-fired TEG and is a breakthrough in bringing cost-effective CHP solutions to the market.

8 REFERENCES

1. CHP cost from *DG Application Guide, Chap. 4, CHP Technologies,* Energy Solutions Center.

2. SCR cost from "Cost-effective NOx Reduction", *Chemical Engineering*, Feb 2001, pp 78-82.

3. Kaarsberg, T., R.N. Elliott, and M. Spurr, "An Integrated Assessment of the Energy Savings and Emissions-Reduction Potential of Combined Heat and Power." Proc. ACEEE 1999 Industrial Summer Study, Washington DC, 1999.