Chapter 7

Controlling NOx Formation in Gas Turbines

Editor's Note:

Chapter 7 – Gas Turbines – Parts of Chapter 10 from the 2000 version of APTI 418 written by Sims Roy were edited and are included here and in Chapter 3. Substantial material on the current status of turbine technology and emerging technologies was supplied by Chuck Solt.

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Introduction to Combustion Turbine NOx Control

Combustion turbines are restricted to distillate oil or clean gas fuels because of their sensitivity to fuel contaminants. Hence SO_2 and particulate emissions are low or negligible. NOx emissions are the main concern. The nitrogen levels in the fuels appropriate for gas turbines are too low to contribute substantially to fuel NO_X formation. Therefore virtually all the NOx is of thermal origin and control technologies that focus on reducing flame temperature are quite effective.

Development of Control Strategies

The first major gas turbine regulations were included in the Clean Air Act Amendments (CAAA) of 1977. Non-attainment areas for CO and NO_X in 1977 were supposed to achieve attainment by 1987. Gas turbines were required to meet the New Source Performance Standard (NSPS) of 75 ppm for utility sources and 150 ppm for industrial sources (with adjustments for heat rates). The NSPS was based on steam injection and water injection controls, termed *wet controls*. Wet controls are combustion modifications that reduce the peak gas temperature in the combustor, thereby reducing NO_X formation.

EPA considered water or steam injection to be the best achievable control technology (BACT) during the late 1970s and early 1980s. However, by the end of 1987, EPA promulgated the top-down approach to determining BACT, and NO_X emissions from gas turbines began decreasing. The trend has been a steady decrease in NO_X emissions from gas turbines since the NSPS was originally promulgated in 1980.

Uncontrolled NO_X emissions from gas turbines range from 150 to 250 ppm (corrected to 15% O_2). The use of steam and water injection reduced these levels to the 75 ppm level required by the NSPS. By the mid-1980s, combustor development reduced demonstrated NO_X emissions for gas-fired units to approximately 25 ppm for gas-fired and 42 ppm for oil-fired units.

In the mid-1980s selective catalytic reduction (SCR) technology was first applied to gas turbines in the U.S. . SCR systems are add-on control systems capable reducing NO_X emissions by 75% to 90% or more. With the demonstration of this technology, the State of California began requiring gas turbines to meet a 10 ppm emissions limit.

In the late 1980s and early 1990s, lean pre-mix designs and staged lean pre-mix designs (termed *dry controls*) became available on new large gas turbines. These combustion modification techniques reduced NO_X emissions from 25 ppm to less than 10 ppm for gas-fired turbines without back end controls. The availability of systems with emissions much less than NSPS means that permitted emission levels are now case specific - driven by BACT, LAER and offsets. Although newer technologies are becoming available, as discussed later in this section, most new turbine installations today use a combination of dry low NOx combustors and SCR controls.

Control Technologies

The basic techniques for controlling NO_X emissions from gas turbines are: steam or water injection, dry low NO_X (also called lean pre-mix combustion) combined with SCR. Catalytic combustion and SCONOx have been available for a number of years and have been applied in a few installations. When back end controls are used, it is always in combination with combustors that minimize NOx formation. Table 7-1 provides typical emission levels accomplished with NO_X control techniques.

These control technologies can be categorized as either add-on control technologies or combustion modification technologies.

Table 7-1
Achievable Emission Levels with NO_x Control Techniques

Control Technique	NO_X Emissions, gas-fired turbines (ppm)	NO_X Emissions, oil-fired turbines (ppm)
Uncontrolled Emissions	155	240
Steam/Water Injection (Wet Controls)	25	42
Lean Pre-Mix Design (Dry Controls)	9	42*
Selective Catalytic Reduction (SCR)	2-5	4-10
Catalytic Combustion (without SCR)	3	Not applicable
$SCONO_X$	1-3	Not applicable

* Note: Combustor fires oil in a diffusion flame.

Fuel Types

The firing and flame temperatures are directly related to the type of fuel-fired in the combustor. Gas turbines are fundamentally able to fire either natural gas or distillate fuel such as kerosene (No. 1 oil) or diesel oil (No. 2. oil). Figure 7-1 shows the relationship between temperature and NO_X emissions for diffusion firing of gas and oil. Fuel oil has a higher flame temperature and produces more NO_X than natural gas. Other types of gas have NOx emission levels that can be higher or lower than for natural gas. Low-Btu gases, such as landfill gas, have lower flame temperatures and produce less NO_X than burning natural gas. Most gas turbine installations today are designed around natural gas fuel and some can fire oil as a back up or emergency.

Fuel oils are defined as grades No. 1 through No. 6. Lighter fuel oils, called distillate oils, are assigned low numbers and have undergone a more extensive refining process. No. 1 oil and No. 2 oils have low levels of impurities and suitable for gas turbines.

Aircraft engines, referred to as aero-derivative gas turbines, have been adapted to stationary power generation. In aircraft operation they required light distillate fuel with low viscosity at sub zero temperatures such as JP4 or kerosene (#1 oil). Depending on the location of the installation the fuel flexibility can be increased to any fuel that is free of sulfur, ash or other contaminants.

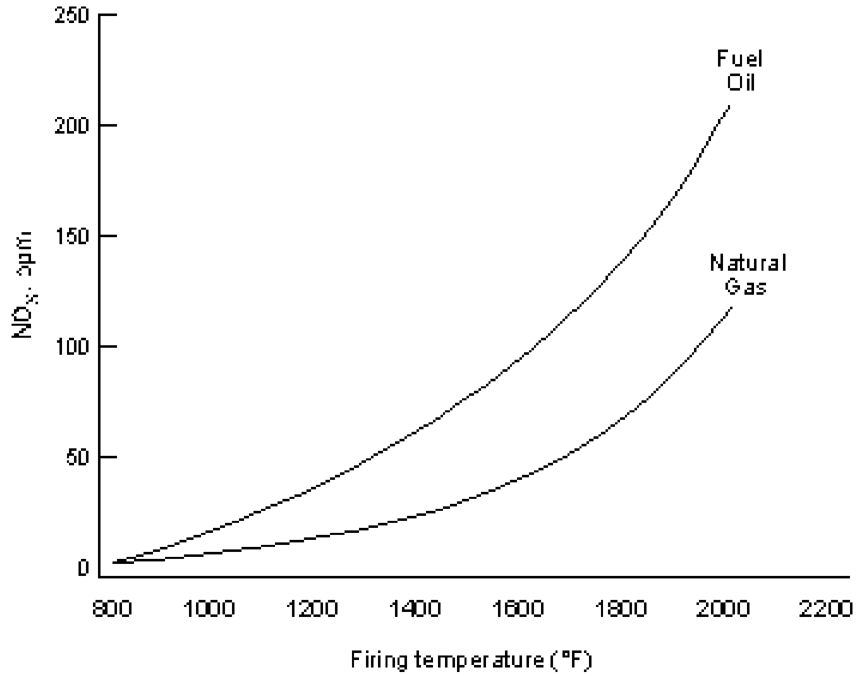

Fig.7-1. Temperature vs. NOx for diffusion firing gas or oil

NOx Reduction by Combustion Modification

Wet Control

The injection of water or steam into the combustor is commonly termed ***wet control*** for gas turbines. Steam or water injection reduces NO_X emissions by decreasing the peak flame temperature. Wet control has been successively applied to all types of turbines, except regenerative cycle combustors, for the reduction of thermal NO_X

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Evaporation of the water reduces the cycle efficiency by 2% to 3%, while power output is increased by 5% to 6%.[i] Steam formed or injected in the combustor raises the mass flow rate through the turbine, increasing the power.

NOx reduction efficiencies of 70% to more than 85% can be achieved with wet control.[ii] However, in practice, operating parameters and other emissions must be balanced and 60% to 70% reduction is more typical. Higher reduction efficiencies are experienced with fuel oil-fired combustors than with gas-fired combustors.

Either steam or water is injected with the fuel at typical water-to-fuel ratios of 0.2:1 to 1:1. Steam injection can be used where a boiler is already part of the system It is essential that the water or steam used for wet control be free of contaminants, so a water treatment system is a necessary component of a wet control system.

Mechanical Limits

The evolution of gas turbines with lower NOx emission rates has been slowed by various mechanical issues. The following parameters are some of the mechanical limits encountered during low NOx combustor development:

Combustion dynamic pressure oscillations (screech)
Combustion operating instabilities (rumble)
Increased CO
Heat rate penalty
Combustion flame blow-off and/or flame-out

Pressure Oscillations - Combustion Noise

Pulsing of the combustor can occur due to pressure oscillations and can damage the combustor and accelerate metal fatigue. Pulsing is a result of high water-to-fuel injection or poor mixing. To help correct for combustion dynamic pressure oscillations and operating instabilities, a multi-nozzle quiet nozzle design was applied to cannular combustors. The multi-nozzle cannular configuration produces better mixing within the combustor. The homogeneous mixture lessens pressure oscillations and results in smoother combustion. Installation of a six-nozzle quiet design can reduce NO_X emissions from 42 ppm to 25 ppm for gas-fired units without dynamic pressure disturbances.

Combustion noise is also reduced with the use of steam, as opposed to water injection. Steam injection produces a more thorough mixing of water with the combustion gases and fuel. This allows for fewer disturbances in the burners and is the generally preferable method of wet control.

Increased CO

As with most combustion based NO_X control techniques, use of wet control will increase CO and hydrocarbon emissions. CO emissions are increased considerably while the hydrocarbon emission increase is more moderate. Water-to-fuel ratios of 1:1 will result in a five-fold increase of CO emissions to approximately 300 ppm.[iii]

Heat Rate Penalty

The need to add more energy to heat the steam or water that is added to the system is called the *heat rate penalty*. Steam has twice the specific heat of the other combustion gases, so additional fuel is needed to create the same combustor exit temperature and generate the same amount of power. Heat loss with the injection of water is higher than steam injection due to the enthalpy of vaporization.

Flame Blow-Off and Flame-Out

Flame blow-off and flame-out are possible with wet injection. During engine deceleration cycles the combustor is especially susceptible to this problem. Wet injection is often reduced or suspended during these periods.

Dry Control

NO_X emission control requirements stimulated research of combustion modification techniques to reduce NO_X emissions below levels achievable by wet techniques. *Dry controls* are performed without the use of water or steam by reducing the peak flame temperature .

Lean Combustion

The average air-fuel ratio of a gas turbine combustor is extremely lean – typically three times as much air as is needed for complete combustion. However, the normal combustor primary zone, where NOx is formed, operates closer to stoichiometric (equivalence ratio = 1.0) in order to prevent flame out. Reduced flame temperatures can be achieved by premixing and carefully controlling the air/fuel ratio to prevent excursions that would cause a flame out. Properly executed, a combustor flame can be maintained at an air/fuel equivalence ratio up to about 2.

Development of lean premix combustors that are commercially acceptable took many years. Part of the challenge is starting the engine and bringing it up to its normal load range. This typically requires the combustor to operate in a diffusion flame mode for light off and low load operation followed by a programmed transition into the premix mode. As a result, the NOx emissions are much higher at idle and low load than they are at full load.

Staged Combustion

Gas turbine combustors normally stage the air injection. Enough air is supplied to the primary zone to operate near stoichiometric and maintain stable combustion. Additional air is injected in the dilution zone to bring the gas temperature down to the design turbine inlet temperature. Even the lean premix combustor, described above, uses some level of air staging. Another type of staging is to inject fuel at a second location, creating a secondary combustion zone. The primary zone can operate either rich or lean, but the secondary zone is always lean.

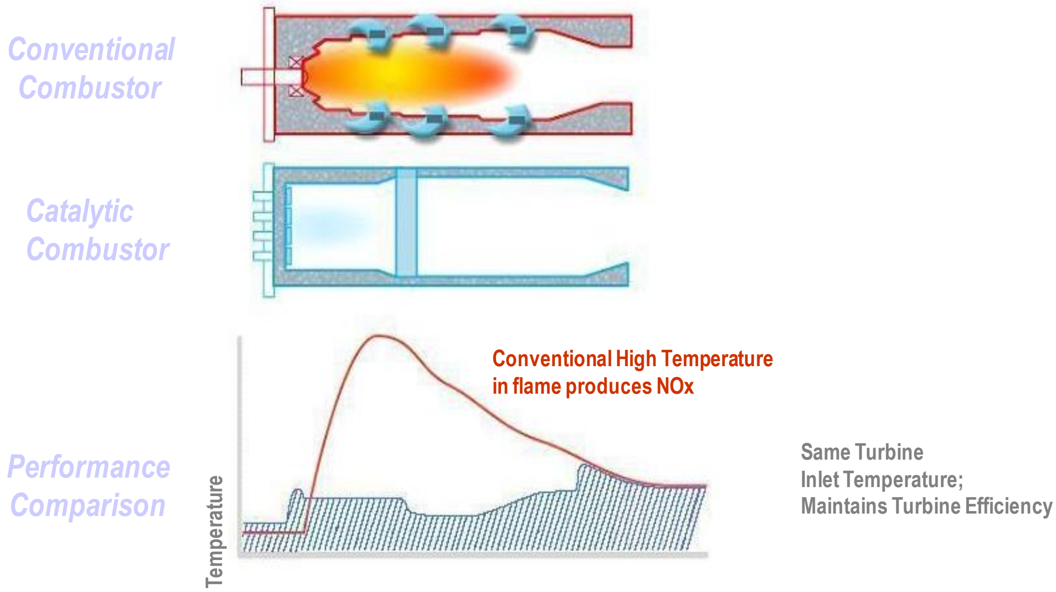
A portion of the fuel is used in the primary zone that can be either a fuel rich diffusion flame or a fuel lean premixed flame. In a fuel rich flame NOx is suppressed by a lack of oxygen, but combustion is incomplete leaving CO, carbon and hydrocarbons. These products of incomplete combustion are consumed in the secondary zone where lean combustion prevents substantial additional NOx formation. Premixed staged combustion is often referred to as Dry-Low NOx (DLN) or Dry-Low Emissions (DLE).

Staged combustion could, conceptually, be used in oil firing – the same is it is in boilers. However, there is very little demand for oil fired low NOx turbines except as a back up fuel.

Catalytic Combustion

Catalytic Combustion Systems, Incorporated (CESI) has developed a combustion system for gas turbines called XONON™ (NoNOx spelled backward). This system combusts the fuel catalytically so there is no visible flame. As a result, high flame temperatures are avoided and NOx formation is dramatically reduced. NOx emissions are typically guaranteed at 2.5 ppmvd at 15% O_2 and CO and VOCs are guaranteed at less than 10 ppm.

Fig. 7-4. Comparison of Conventional and Catalytic Combustors



Since the fuel and combustion air must be homogeneously mixed, XONON is only applicable to gaseous fuels such as natural gas or bio-gas.

Combustion is accomplished in two steps. Partial combustion takes place within the catalyst at a controlled temperature during which virtually no NO_X formation takes place. Completion of the combustion process is accomplished downstream with a flameless homogeneous reaction. A preburner which consumes only a small fraction of the fuel is used to raise the fuel/air mixture to the temperature required for catalyst activity. An insignificant amount of NO_X is produced in the first and second combustion step. All of the NOx is produced in the pre-burner.

Both GE and Solar Turbines have successfully operated on a 7.5 MW and a 10 MW engine using the XONON combustion system. Both engines demonstrated performance at less-than 2.5 ppmvd at 15% O_2, but neither has yet made them commercially available, and it is not likely that they will.

Figure 7-5 is a rendering of an actual combustor used on a 1.5 MW Kawasaki gas turbine. There are currently (2009) over 40 of these engines in commercial service. Some have been operating continuously for over 7 years. XONON is currently available only on the Kawasaki 1.5 MW gas turbine.

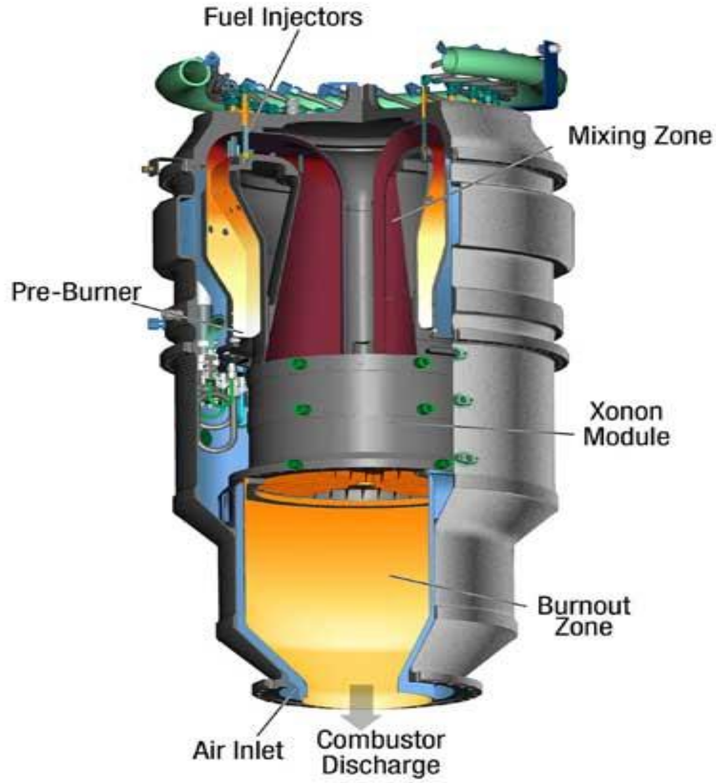


Figure 7-5. XONON Combustor for 1.5 MW Turbine

The US Department of Energy commissioned a cost comparison study to determine the economic feasibility of this technology. The results of the study are shown in the table below:

Net Present Value ($,000)

	5 MW	**25 MW**	**150 MW**
Application Technology	**Cogen**	**Peaking**	**Comb Cy**
Xonon	**1,326**	**2,587**	**29,397**
SCR + LPM	**2,454**	**4,576**	**30,543**
SCONOx + LPM	**3,921**	**7,857**	**63,319**

Based on data from DOE study: contract # DE-FC02-97CHIO87

Ultra-Lean Combustion

There are at lease 2 companies working on technologies that will allow gas turbines to operate at extremely lean pre-mix conditions and achieve very low NOx emissions.

Alzeta Corporation

This company has a number of combustion burners that provide stable combustion at extremely lean conditions and accordingly very low NOx emissions. One of these products called Nano-Star is designed for use in gas turbine engines.

The basis of most of their technologies is a diffusion burner. An air/fuel mixture enters the center of a porous cylinder. As the mixture diffuses through the cylinder wall, it burns on the outside. The hot outer surface stabilizes the combustion. In this manner, the burner can operate at very lean conditions and the NOx will be very low - in the range of 3 ppmvd at 15% O_2. Early burners made of porous ceramic were used in boilers and have operated satisfactorily for over 15 years.

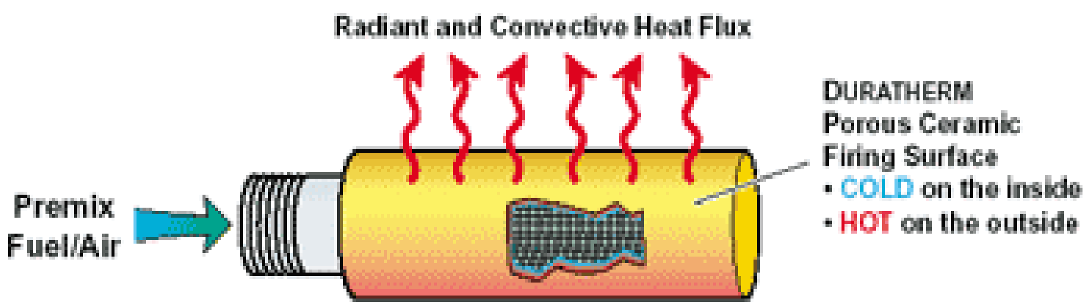


Figure 7-5. Alzeta Diffusion Burner

The heat flux in this configuration was low and burners of this design would be far to large to use in a gas turbine.

Alzeta worked on several development contracts to design a burner that could fit into existing turbines. The result was their NanoStar design shown in Figure 7-5. It uses a metal cylinger with a very large number of very small holes to serve the diffusion burner principle. In addition, there are longitudinal rows of larger holes. A small percentage of the air/fuel diffuses through the small holes and burns on the outer surfact which stablizes the combustion of the jets of air/fuel coming through the larger holes. The result is an increase of about 10 times the heat flux per unit of surface compared to the older designs. This configuration can be used in gas turbines without changing the casing design.

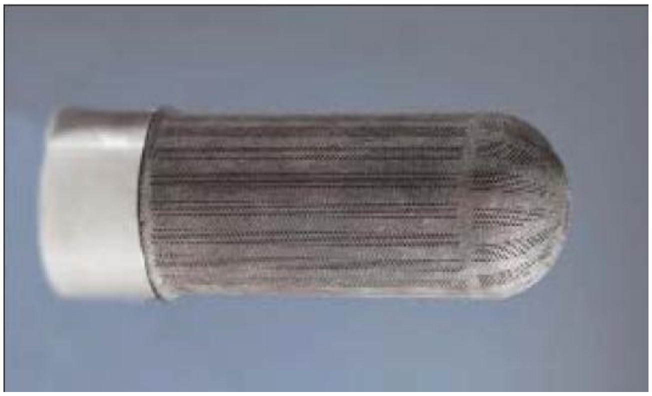


Figure 7-6. Alzeta NanoStar Burner

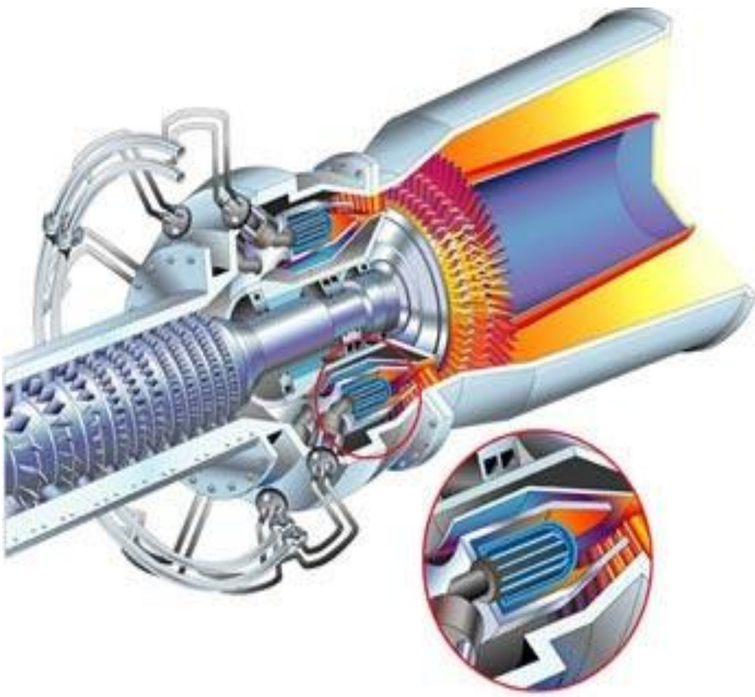
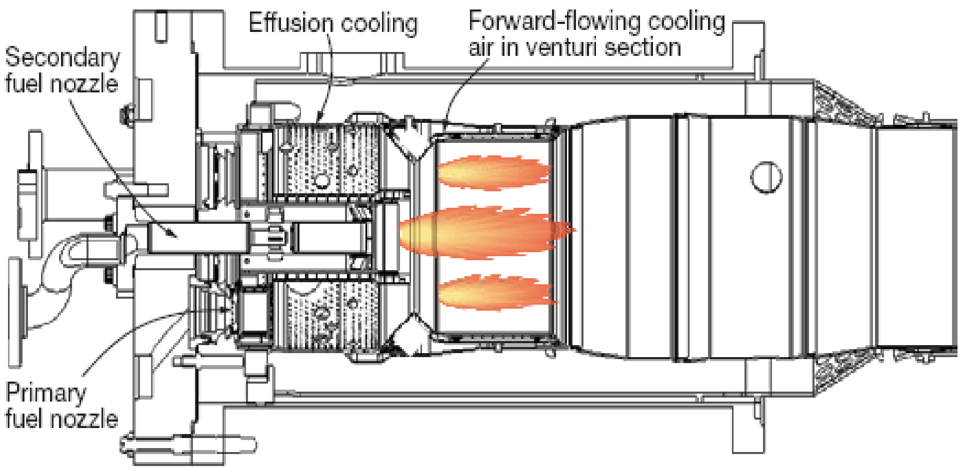


Figure 7-7. Gas Turbine with nanoStar catalytic combustor

Power Systems Manufacturing

One interesting product is offered by Power Systems Manufacturing or Jupiter, FL. Their primary business is offering replacement parts for large frame size gas turbines.

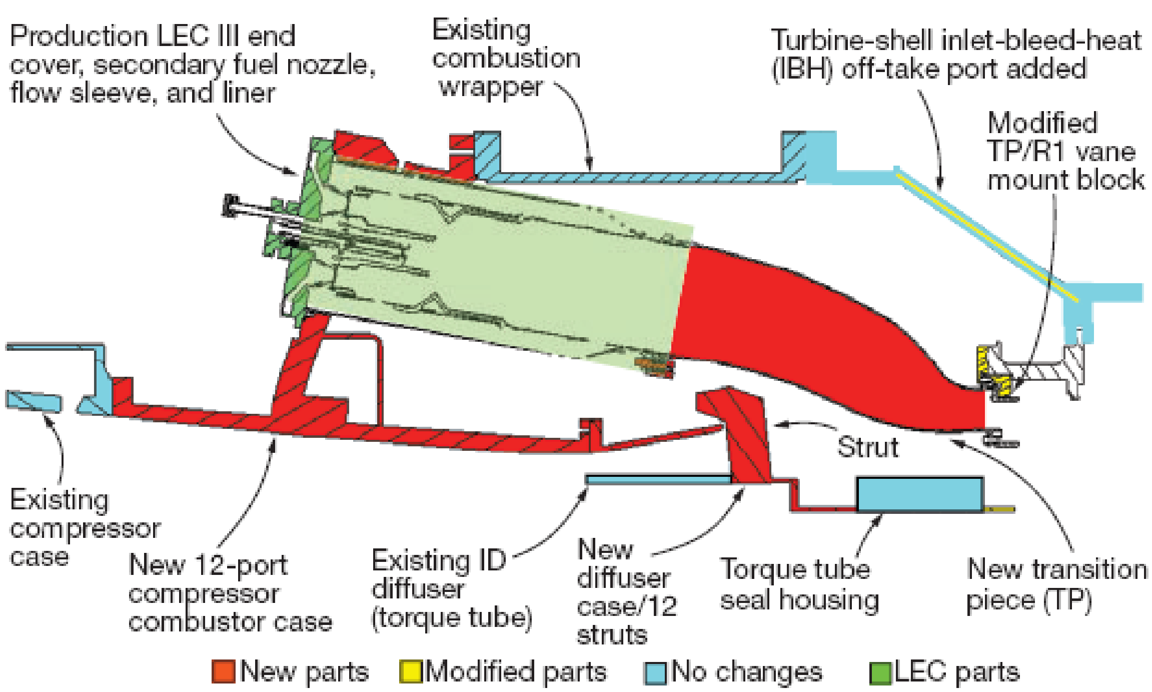
About 2000, PSM introduced a combustor to replace the DLN combustors on large GE frame machines which had lower emissions than the OEM combustors. They now have standard offerings for a number of over 50 MW engines and guarantee NOx emissions at less than 5 ppmvd at 15% O_2, compared to the 9to 25 ppm guaranteed by the OEM.



4-3. Maintaining a cool combustor with a minimum of air flow is critical to the success of the LEC-III design

Figure 7-8. LEC COmbustor by PSI Corp. 1

The combustor shown in Figure 7-8 is similar in size and function to the OEM unit it replaces, however, it may be longer and require replacement of other engine parts to accommodate the modification. Figure 7-9 is a section of a retrofit where the combustor case had to be replaced.



4-7. Conversion to LEC-III required replacement of some hot-gas-path parts, modification of others; some remained as is

Figure 7-9 LEC Combustor by PSI Corp 1

Advantages and Disadvantages of CC and UL

Advantages – CC and UL can meet the BACT/LAER emission limits established by SCR, but without the toxic reagents and without the cost. For peaking applications, the units can be permitted allowing continuous operation and allow the systems to be operated for economic dispatch. These systems have a lower profile, a smaller footprint and do not require the reagents. In most cases, community concern is mitigated.

Another possible advantage is the applicability of parametric emission monitoring systems (PEMS) monitoring systems. These systems are far less expensive than CEMS instrument systems, and the CC and UL have unique adaptability for the PEMS with very good accuracy and availability.

Disadvantages – Back-end-controls do not impact the combustion process, except for a slight increase in back-pressure. This means that they can be applied to almost any combustion process without the engine manufacturers involvement. CC & UL, on the other hand require modification to the combustion process, so the manufacturer will usually have to provide process information, investment of capital and assumption of warranty risk. In the face of these costs which can be in the range of $10 million to $100 million, many engine manufacturers are reluctant to commercialize these technologies without competitive pressure, particularly if there is no assurance that the air agencies will not simply require back-end-controls in addition to the CC or UL technology.

Post-Combustion Controls

The dominant post-combustion control system for gas turbines has been selective catalytic reduction (SCR) – see Chapter 8.

Review Exercises

1. Why is natural gas beneficial over distillate oils for gas turbine applications? (Select all that apply.)
   a. Natural gas is lower in sulfur content and other damaging impurities.
   b. Natural gas is a less expensive fuel.
   c. Natural gas is less explosive and easier to store.
   d. Natural gas burns at a lower temperature than fuel oils reducing thermal NO_X.
   e. None of the above

2. What are the benefits of the lean pre-mix combustion? (Select all that apply.)
   a. It is a cost-efficient NO_X control option.
   b. Can be applied in conjunction with post combustion control techniques.
   c. Produces stable combustion operation compared with diffusion combustion.
   d. Reduces CO and unburned hydrocarbons compared with diffusion combustion.
   e. None of the above

3. What are the benefits of water injection? (Select all that apply.)
   a. The cycle efficiency is increased.
   b. The power output is increased.
   c. Applicable to all gas turbine designs.
   d. Carbon monoxide emissions are decreased.
   e. None of the above.

4. Lean/lean staged combustion limits NO_X emission by the following? (Select all that apply.)
   a. Limiting the available oxygen during combustion.
   b. Limiting the fuel bound nitrogen content.
   c. Limiting the flame temperature.
   d. Limiting the residence time.
   e. None of the above

5. What are the benefits of SCR systems? (Select all that apply.)
   a. Low operating and maintenance costs.
   b. No increase in other emissions.
   c. Applicable to all gas turbine designs.
   d. Simple to install and operate.
   e. None of the above

6. What are the benefits of the multi-nozzle, quiet-nozzle design? (Select all that apply.)
   a. Provide better combustion stability.
   b. Reduces pressure oscillations.
   c. Increases the life span of turbine components.
   d. Reduces NO_X emissions.
   e. None of the above.

7. When were SCR systems first applied to gas turbines in the U.S.?
   a. Mid 1970s
   b. Mid 1980s
   c. Mid 1990s
   d. 1995
   e. None of the above

8. What is the approximate maximum pressure inside a turbine combustor?
   (ambient pressure = 1 ATM)
   a. 0.033 ATM
   b. 0.5 ATM
   c. 3 to 30 ATM
   d. 100 ATM
   e. None of the above

9. SCR works best in which temperature range?
   a. 600°F to 800°F
   b. 850°F to 1000°F
   c. 1000°F to 1100°F
   d. 2300°F to 2400°F

10. Which of the following control techniques utilizes a catalyst? (Select all that apply.)
   a. Lean Pre-Mix
   b. SCR
   c. XONON™
   d. SCONOx™
   e. None of the above

Review Excercises – Answer Key

1.. **a. Natural gas is lower in sulfur content and other damaging impurities.**
b. Natural gas is a less expensive fuel.
(a) Is the only answer that's unequivocally true. (b) Is currently true and is the overriding consideration. Answer (d) is true for a lean pre-mix combustor

2. **a. It is a cost-efficient NOx control option.**
b. Can be applied in conjunction with post combustion control techniques.
Answer (c) is false and (d) is generally false depending on the combustor.

3. **b. The power output is increased.**
c. Applicable to all gas turbine designs.
There is a small loss in engine efficiency (a), and CO (d) usually increases. Wet injection is applicable to most, but not all designs, answer (c).

4. **c. Limiting the flame temperature.**

5. **b. No increase in other emissions.**
c. Applicable to all gas turbine designs.

6. **a. Provide better combustion stability.**
b. Reduces pressure oscillations.
c. Increases the life span of turbine components.
d. Reduces NOx emissions.

7. **b. Mid 1980s**

8. c**. 3 to 30 Atm**
(Answer (d) is generic. The larger and newer the engine, the higher the pressure – 40 Atm in 2011.)

9. **a. 600 F to 800 F**
Answer (b) would be a simple cycle gas turbine installation using a zeolite catalyst – more expensive than base metal catalysts. The durability of catalysts at temperatures above 1050°F hasn't been demonstrated.

10. **b. SCR**
c. XONON™
d. SCONOx™
Answer (d) uses a catalyst, but the primary NOx collector is an absorption process.

References

[i] Barboxa, M. J., M. J. Cannon, N. J. Charno, and P.S. Oliver. 2000. *Air and Waste Engineering Manual*. John Wiley & Sons. New York, NY.

[ii] U.S. Environmental Protection Agency. February 1992. *Summary of NO_x Control Technologies and their Availability and Extent of Application*. EPA-450/3-92-004.

[iii] U.S. Environmental Protection Agency. July 1986. *Nitrogen Oxide Control for Stationary Combustion Sources*. EPA/625/5-86/020.