NTNU
Innovation and Creativity

Reduction of NOx Emissions from the Gas Turbines for Skarv Idun

Kristin Sundsbø Alne

Master of Science in Energy and Environment
Submission date: June 2007
Supervisor: Jan M Øverli, EPT

Norwegian University of Science and Technology
Department of Energy and Process Engineering

Problem Description

Background

The Skarv Idun development is located in the Norwegian Sea approximately 210 km west of Sandnessjøen. These are combined oil and gas developments with 75 % of the reserves as gas and 25 % as liquids. The field will be developed with a standalone turret-moored Floating Production Storage and Offloading vessel (FPSO) with offloading to shuttle tankers. Gas export will be through Åsgard Transport System to the onshore Kårstø facility.

Aim

1) Discuss the application of different technologies for reducing NOx emissions from the planned gas turbines.

2) Discuss the effects of the different technologies for NOx emissions on the selection and operation of the gas turbines.

3) Collect user experience of low NOx emission gas turbines.

The analysis should include the following elements:

1) Describe the current design and configuration of the gas turbines as a part of the power generation system.

2) Discuss the application and suitability of individual and combined technologies available for reducing NOx emissions from the planned gas turbines.

3) Discuss the effects of the different technologies in terms of engine stability, reliability/availability, emissions, thermal efficiency, load acceptance, rejection performance, maintenance requirements, etc.

4) Collect user experience of low NOx gas turbines applying different technologies (generator or mechanical drive).

Assignment given: 15. January 2007
Supervisor: Jan M Øverli, EPT

Preface

This report is the product of my Master thesis written during spring 2007 at the Department of Energy and Process Engineering at the Norwegian University of Science and Technology.

First of all I want to thank my mentor Øystein Johnsrud in BP for initiating the Master thesis and for guiding me through the semester. I would also like to thank Hallgeir Larsen and the rest of the BP Skarv Team for taking care of me in Stavanger and Oslo.

Gratitude is given to my supervisor Professor II Jan M. Øverli at the Norwegian University of Science and Technology for technical inputs and motivation.

I am grateful for the help from Heikki Oltedal, Marius Sønstebø, Conrad Carstensen and Arne Sørli in Statoil and Trygve Nyheim in Marathon Petroleum Company.

I also acknowledge the assistance from Tim Golden in British Sugar, Colin Bailey and Tore Næss in Dresser Rand, Stig Instanes in General Electrics, Randy Turley in IGT, Ken Daubert in Kauai Island Utility Cooperative and from everyone else who have had inputs to the report.

The thesis is written in English to get through to more people, not only in BP, but also to others in oil and gas related industries. I feel that I have learnt a lot from my thesis, both about technological challenges with NO_x reduction and by collecting user data from operators. These experiences are probably something I can bring with me into my working life. I hope that readers find the thesis interesting, and that more people can use some of the information presented.

Trondheim, 7 June 2007

Kristin Alne

Abstract

Nitrogen oxides (NO_x) are formed by oxidation of nitrogen during the combustion process, and production rate is highly affected by flame temperature. NO_x is regarded as a local pollutant causing smog, acid rain and health complaints, and strictest emission regulations are found in urban areas. Reduction of NO_x emissions from gas turbines can be achieved by modifying the combustion process or by exhaust gas clean up. Several technologies are already commercial available, but there are still a great many being developed. Increased focus on the environment also forces manufacturers to improve existing technology.

In this report, different NO_x abatement technologies are looked into, and an optimal solution for the coming gas turbines on Skarv Idun is presented. Different techniques are compared in terms of thermal efficiency, emissions, maintenance requirements, load acceptance and rejection, engine stability and reliability and availability. Application and suitability of available technologies for reducing NO_x from the selected gas turbines is discussed, and user experience for these is collected. It is showed that all technologies influence operation of the gas turbines to some extent, either by increasing/decreasing efficiency or by affecting engine stability. They also differ in their ability to reduce NO_x emissions over the entire load range.

Due to weight and space restrictions on offshore installations, limited technologies are suitable for platforms and boats. Gas turbines installed offshore are usually aero-derivative engines with high efficiency and relative low emissions of CO_2. This year, Norwegian government introduced a NO_x tax in order to reduce NO_x emissions from the petroleum industry. Operators are forced to use best available technology, and dry low emission control (DLE) is the only one considered qualified as far as NO_x is concerned.

DLE is also chosen as the optimal solution for the planned gas turbines on Skarv Idun, due to small operational impacts and positive experience from existing fields. It is however recommended to allocate space in case a new and better combustor with lower emission levels is developed. Looking at a longer perspective, Cheng technology including steam injection into the gas turbine combustor seems very promising for NO_x abatement.

Table of content

List of figures

List of tables

Nomenclature

Symbol	Name	Unit
ABAL	Acoustic and Blowout Avoidance Logic	-
AC	Alternating Current	[V]
BAT	Best Available Techniques	-
C_A	Annual cost of investment	[NOK]
C_F	Annual fuel costs	[NOK]
CEMS	Continuous Emission Monitoring System	-
DC	Direct Current	[V]
DLE	Dry Low Emissions	-
f	Fuel cost	[NOK/Sm^3]
FPSO	Floating Production, Storage and Offloading	-
GE	General Electrics	-
h	Enthalpy	[J/kg]
IPPC	Integrated Pollution Prevention and Control	-
LCP-BREF	Large Combustion Plants - BAT Reference Documents	-
LHV	Lower Heating Value	[J/kg]
m	Mass flow	[kg/s]
n	Lifetime	[year]
NMVOC	Non-Methane Volatile Organic Compounds	-
NO_x	Nitrogen Oxides	-
NPV	Net Present Value	[NOK]
OTSG	Once-Through Steam Generator	-
P	Power	[W]
PEMS	Preventive Emission Monitoring System	-
Q	Heat	[W]
r	Discount rate	-
RH	Relative Humidity	[%]
SAC	Single Annular Combustor	-
SCR	Selective Catalytic Reduction	-
SI	Steam Injection	-
SNCR	Selective Non Catalytic Reduction	-
SO_x	Sulphur oxides	-
SPRINT	Spray Inter-cooling	-
STIG	Steam Injected Gas Turbine	-
UHC	Unburned Hydrocarbons	-
W	Work	[W]
WHRU	Waste Heat Recovery Unit	-
WI	Water Injection	-
WLE	Wet Low Emissions	-
Wobbe number	Heating value	[J/Sm^3]
η_t	Thermal efficiency	-
ρ	Density	[kg/Sm^3]

1 Introduction

1.1 Background

The power demand on an offshore installation is substantial, and may vary from a few to some hundred megawatts. Usually it is covered by gas turbines producing electricity and heat, with process gas used as fuel. In periods when gas is not available, diesel may be used in turbines with dual fuel technology. Burning gas is the main source for CO_2 and NO_x emissions from the offshore industry. During emergency shutdowns, flaring do also contribute to emissions.

There is an increased focus on the environment around the world, and Norway has through the Kyoto protocol committed to stabilise CO_2 emissions within 2010. Government regulations are forcing oil and gas industry to improve energy efficiency offshore. Therefore, focusing on more efficient gas turbines and other rotating equipment plays an important role. As far as NO_x is concerned, the emission limitations are regulated through the IPPC directive with requirement of using best available techniques at all times.

While CO_2 is regarded as a greenhouse gas with global warming consequences, NO_x is a regional pollutant causing acid rain and health complaints. A CO_2 tax has existed for some years in Norway, while a NO_x tax was introduced this year. It applies to larger boilers and turbines, and forces the polluter to pay for its emissions. The philosophy behind these taxes is to stimulate operators to implement emissions reducing technologies.

When designing the Skarv Idun FPSO, BP has a high focus on choosing the right technology to ensure minimum risk and harm to personnel and the environment. In 1998, BP committed themselves to reduce their emissions of greenhouse gases with 10 % compared to 1990 level within 2010. This was achieved already in 2002, and the new target is to keep annual emissions at the same level.

1.2 Objective

The overall objective of this work has been to find an optimal solution for reducing NO_x emissions from the planned gas turbines for the Skarv Idun FPSO. This is obtained by:

- Discussing the application of different technologies for reducing NO_x emissions.
- Discussing the effects of the technologies on selection and operation of the gas turbines.
- Collecting user experiences of low NO_x gas turbines.

1.3 Organisation

In its first part, this report will give an introduction to the Skarv and Idun field development and to current status on the Norwegian Continental Shelf. Thereafter, gas turbine combustion and NO_x formation mechanisms are explained, and different NO_x reducing technologies for gas turbines are presented. These technologies are compared in terms of thermal efficiency, emissions of NO_x and CO, engine stability, maintenance requirements, load rejection and acceptance and availability and reliability. User data is collected for the most promising technologies, both onshore and offshore. Based on technology status and experience, different options are looked into, and a recommendation for the Skarv Idun FPSO is given.

2 The Skarv Idun field development

The Skarv Idun development is located in the Norwegian Sea, approximately 210 km west of Sandnessjøen. These are combined oil and gas fields with 75 % of the reserves as gas and 25 % as liquids, consisting of hydrocarbons from several different reservoirs and structures. The field will be developed with a standalone turret-moored Floating Production Storage and Offloading vessel (FPSO) with offloading to shuttle tankers. Gas will be exported through Åsgard Transport System to the Kårstø facility. The field is expected to enter into production in 2011.

2.1 Driver configuration

The facility load profile in Figure 2-1 is derived from the respective reservoir profiles, and it shows the highest estimated load per annum that Skarv can encounter. It includes a nominal thruster load of 7 MW, crude offloading and a 10 % contingency.

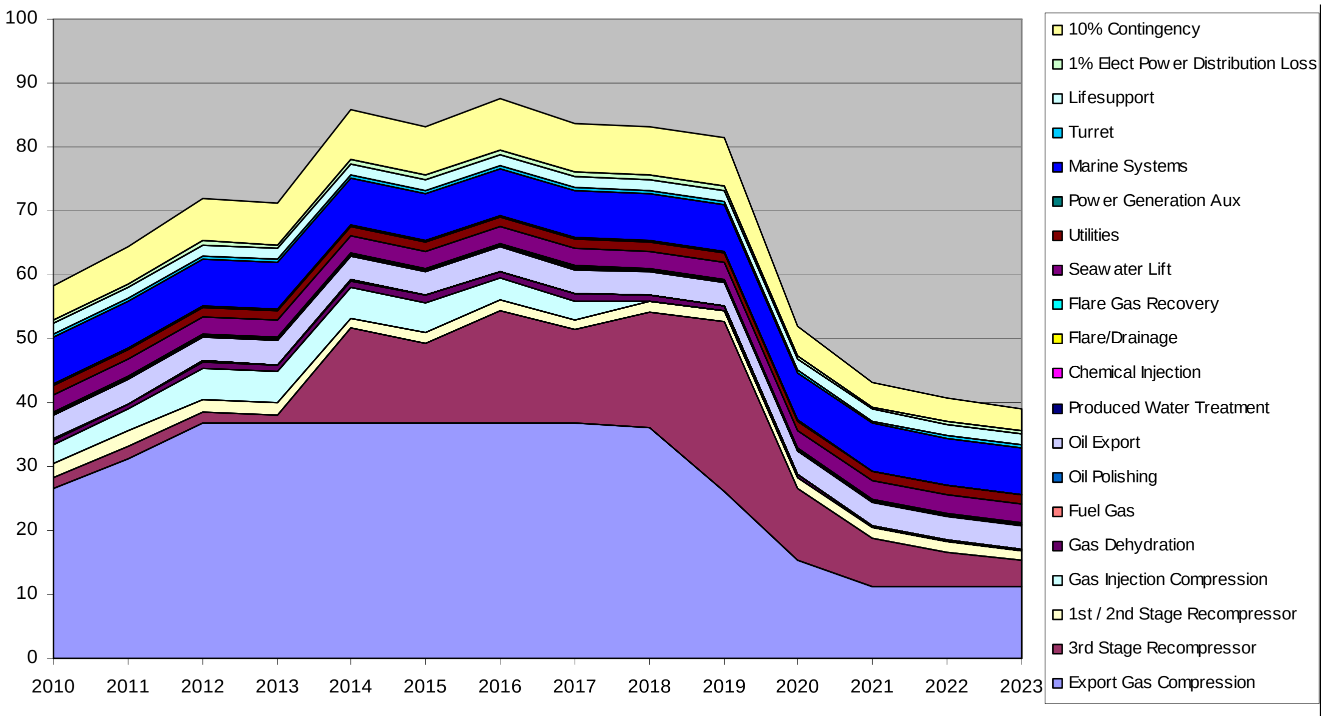

Figure 2-1: Skarv Idun load profile [1].

Maximum power demand is estimated to lie just below 90 MW during peak production years.

Two of the health, safety and environment targets for the Skarv Idun field development are to maximise energy efficiency and minimise emissions to air. A driver selection process has looked into various alternatives for power generation on the FPSO, namely mechanical drive, all-electric drive, and combined cycle gas turbines. Based on life cycle costs, health, safety and environment, production availability and technology risks, it was decided to choose an all-electric gas turbine scenario for the FPSO. This means that gas turbines will produce electrical power and motors with variable frequency drives will be utilised as mechanical drives for main rotating equipment loads. One reason for not choosing direct drive was the ignition risk associated with having gas turbines in the process area.

Skarv production efficiency target is set to 95 %, and the project team has therefore taken the decision to provide power generation design of N + 1 configuration. Four LM2500+G4 gas turbines rated at about 32 MW each will drive the generators. This gives a 4 x 33 % configuration, where three turbines will run continuously and one is spare. Figure 2-2 shows an LM2500+ gas turbine with a single annular combustor.

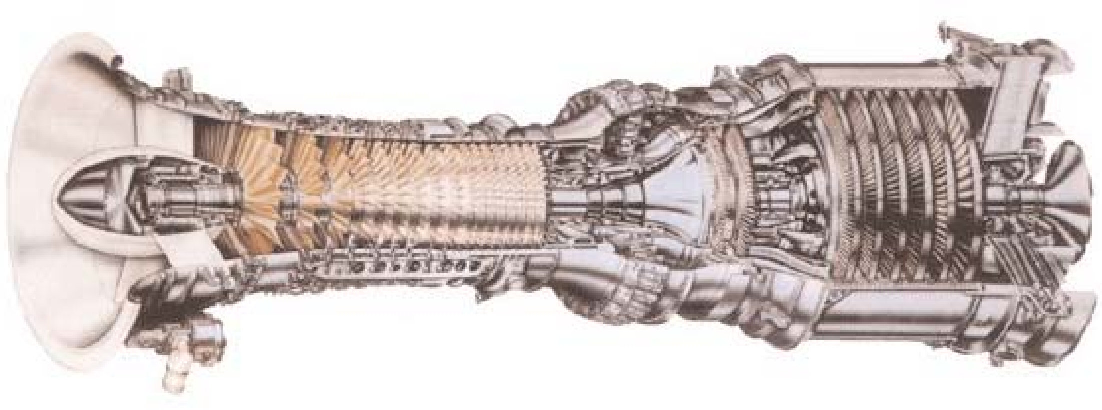

Figure 2-2: LM2500+ gas turbine [2].

Two of the turbines are single fuel machines, whereas two are dual fuelled and may run on diesel when gas is unavailable. If one of the generators shuts down unexpectedly during the peak production years, the load-shed system will shut down one of the export compressors and maintain production at reduced rates. Production impacts of planned outages of gas turbines can be eliminated because of the N + 1 configuration.

The all-electric gas turbine option incorporates waste heat recovery units (WHRU) on 3 out of 4 packages as such this option is considered a combined heat and power plant. Each WHRU is capable of providing 20 MW of heat energy for the process, which means a 3 x 100 % configuration [1].

2.2 Selection criteria for NO_x abatement technology

Norwegian Sea environment is characterised by marine surroundings, continuous operation, and high costs associated with weight, area and lost production. These factors influence both the driver selection and type of NO_x abatement technology, and require equipment to be compact and reliable. Selection criteria consist of:

- Capital costs
- Installed capital costs
- Operational and maintenance costs
- Costs of unavailability
- Emission costs

Figure 2-3 shows the relationship of these criteria, and illustrates why life cycle costs are decisive for selection of technology. It should be noted that development of new fields in Norway often requires some kind of NO_x abatement technology in order to get approval from the authorities.

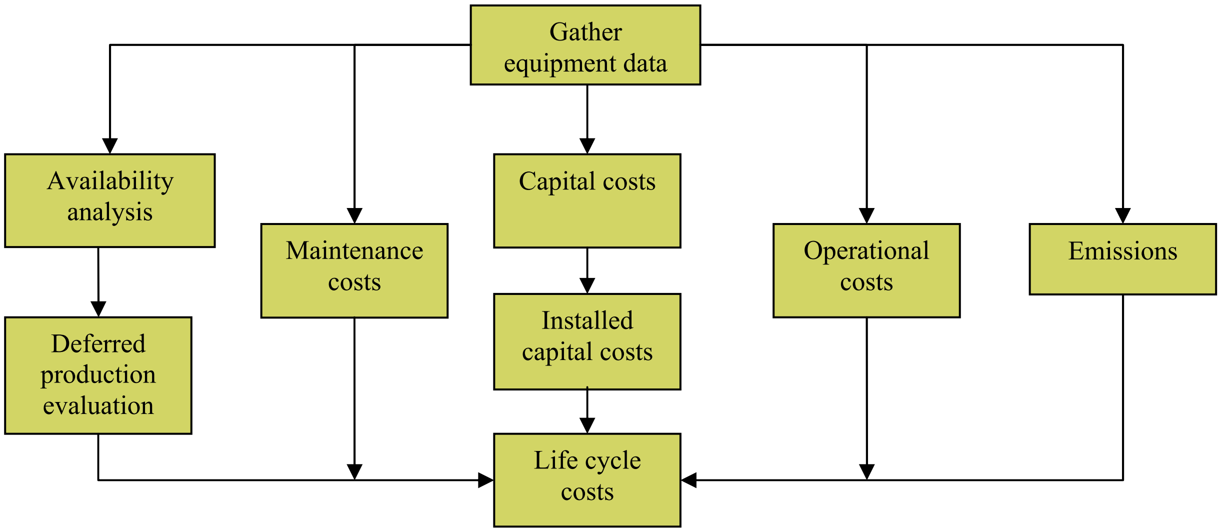

Figure 2-3: Determination of life cycle costs [3].

Some of the data required includes equipment cost, weight, and dimensions, maintenance requirements and reliability statistics. Operational costs are those related to operating the equipment over the lifetime of the field, with fuel costs as the most significant. This means technologies lowering efficiency have higher operational costs than those increasing efficiency. Emissions of CO_2 and NO_x from the Norwegian Continental Shelf have to be paid for, and taxes are therefore an important part of the operational costs. Installation costs are based on initial costs combined with costs to install and hook up equipment offshore. These costs are often calculated with project-specific installation factors.

Low availability might lead to deferred production and losses, and it is therefore important to perform an availability analysis for each NO_x abatement technology. It is often required that the technology has demonstrated operability for a certain period of time before installing it. This makes implementation of new technologies offshore difficult.

3 Status

In 2004, there were 182 gas turbines with a total capacity of 3200 MW installed on the Norwegian continental shelf. A great majority are aero-derivate engines because of their high power-weight ratio, simple change out and ease of maintenance. General Electrics is the major supplier of gas turbines, with LM2500 as the dominant model. 37 of the gas turbines had low NO_x technology, and these were all single fuel engines [4]. This year the first dual fuel machines with low NO_x technology will come into operation offshore. This happens on Alvheim, which is operated by Marathon Petroleum Company.

There is a general trend towards installing larger gas turbines with a higher efficiency and work output; this is made possible by a high pressure ratio and a high turbine inlet temperature. With more efficient machines, operators can save fuel and with that CO_2 tax. However, this is not necessarily optimal for NO_x emissions from the gas turbines, as higher temperature increases formation of NO_x.

3.1 *Emission requirements*

Oxides of nitrogen can react in the presence of sunlight to produce smog, which can be seen as a brownish cloud. NO_x, in combination with moisture in the atmosphere, also causes acid rain and ozone depletion at high altitudes. This was first put into agenda in the seventies in Los Angeles and the surrounding area. Today, strictest regulations are found in California in the US and in Tokyo in Japan. Emission control has now become one of the most important factors when designing industrial gas turbines, as the causes and effects of industrial pollution have become better understood.

In 2005, the Gothenburg Protocol entered into force, setting an upper limit for emissions of NO_x, SO_2, ammonia and NMVOC in 2010. Norway is far away from fulfilling the commitments for nitrogen oxides, and has not reduced emissions considerably since 1990. Through ratification, Norway has to keep annual NO_x emissions below 156 000 tonnes in 2010, which means a reduction of 60 000 tonnes in the period 2006 - 2010 [5]. Historical development and emission target can be seen from Figure 3-1.

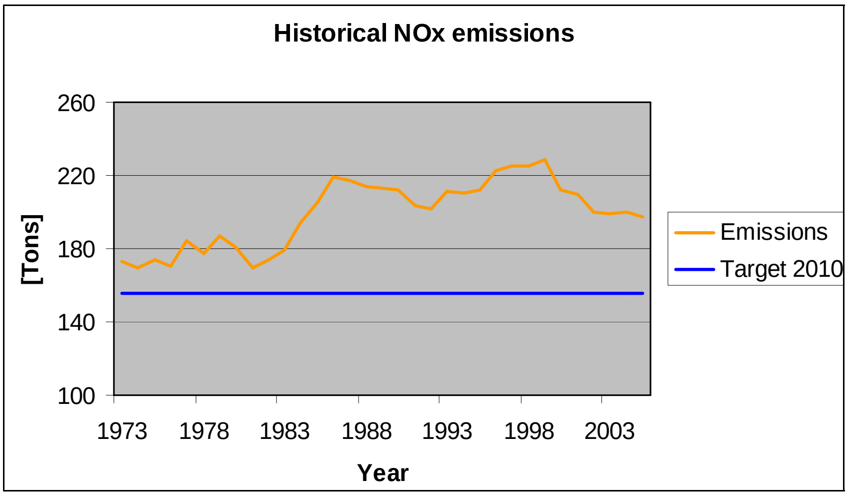

Figure 3-1: Historical NO_x emissions for Norway in the period 1973-2005 [5].

In 2006, the petroleum industry contributed to 22 % of the emissions. Norwegian Pollution Control Authority has therefore accomplished a study to look at the potential for reducing NO_x emissions from offshore installations. Costs were calculated for retrofitting DLE technology, since this is the only technology considered qualified. Older gas turbines are not arranged for retrofit. Not only does replacing the single annular combustor require large investments, but also it might lead to rebuilding of the entire gas turbine package. It is estimated that retrofit costs for old turbines will lie between 250 and 600 MNOK per unit. Since middle of the 1990s, it has been allocated space for DLE combustors on some of the gas turbines. Installation costs for these are calculated to lie between 50 and 200 MNOK per machine [6]. However, retrofit seems to be more complicated than expected in the first place.

Norwegian emission regulations are set according to the Integrated Pollution Prevention and Control (IPPC) directive. The purpose of this directive is to gather regulation of all emissions to air, water and ground from one activity in a single permission. It applies for large combustion plants with heat input higher than 50 MW, and it therefore covers most gas turbines in the North Sea. Operators are forced to use best available techniques (BAT), which are given in one of the reference documents for Large Combustion Plants (LCP-BREF).

According to Chapter 7.5.5 in LCP-BREF, BAT is limited to [7]:

- Installation of low-NO_x turbines on new installations
- Retrofitting low-NO_x turbines on existing installations
- Installation of heat recovery units
- Establishment of PEMS (Parametric Emission Monitoring System)
- Energy management, which includes objectives and plans for emissions reductions and energy efficiency improvements.

The Norwegian Government introduced a tax for NO_x emissions from January 2007. Its initial value was set to 15 NOK/kg NO_x, and it is estimated that it will reduce emissions with 25,000 tonnes. Therefore, it is indicated that the tax will increase to 50 - 60 NOK/kg within 2010 [8].

It seems like applications for new fields only will be accepted if a NO_x reducing technology is chosen. Onshore facilities, however, are committed not to exceed emissions of 5 ppm NO_x. This applies to the gas-fired power plants both at Kårstø and the Snøhvit facilities on Melkøya in Hammerfest.

3.2 Emission monitoring

Until now, emissions of CO_2 and NO_x from the petroleum industry have been reported and paid for on the basis of the amount of fuel gas burned and standard emission factors shown in Table 3-1. In some cases, operators have been allowed to use field specific factors, but none of these methods give actual emissions.

Table 3-1: Standard emission factors for gas turbines [9].

NO_x factors	Gas	Diesel
SAC combustor	16 g/Sm^3	16 kg/tonne
DLE combustor	1.9 g/Sm^3	

Emission measurements have until now only been taken at commissioning and mapping, and the government wants to look for more accurate methods. Continuous Emissions Monitoring System (CEMS) aims at having sensors in the exhaust stack and continuously monitor the accurate emissions of CO, NO_x and O_2. Calibration of CEMS will be done automatically. Because sensors would live in a quite rough environment, this is considered difficult to implement.

Preventive Emissions Monitoring System (PEMS) is today regarded as BAT for calculating emissions from gas turbines, both for existing and new installations operating offshore. The idea of PEMS is to utilise existing information registered by the control system and thereof predict emission levels. PEMS is the total system that receives signals from the control system, validates it, calculate emissions, and report.

Calibration of the system is of great importance, and a signal is needed for the system to know whether it is in gas or in diesel mode. In addition, there should be an alarm when PEMS is down. The system requires fuel measuring for each turbine, and it also needs measurements of CO_2 and O_2. An accuracy of +/- 10 % is required together with an availability of more than 95 % [10].

PEMS has two distinct advantages over hardware CEMS; much lower installation and maintenance costs, and ability to provide information on emissions under various conditions. However, PEMS for DLE machines is more challenging than PEMS for SAC machines, due to lower emission levels and with that lower accuracy. The models also need to be developed individually for each gas turbine to yield accurate results.

4 Gas turbine combustion

This chapter aims to explain the configuration of a gas turbine and to show what factors that impact the selection and operation of it. Thereafter, mechanisms for NO_x formation and the effect of various parameters on this formation will be explained.

4.1 The combustion process

A gas turbine consists of three main components: compressor (C), combustor (Comb) and turbine (T). Figure 4-1 shows flow diagram and a temperature-entropy diagram for an ideal, open gas turbine process.

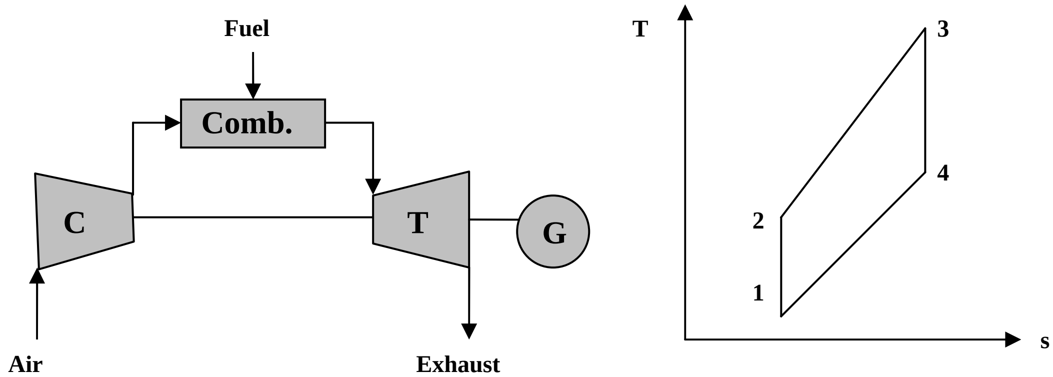

Figure 4-1: Flow diagram and temperature-entropy diagram for an open, ideal process.

1 – 2: Adiabatic compression.
2 – 3: Heating at constant pressure.
3 – 4: Adiabatic expansion.
4 – 1: Heat release at constant pressure.

As opposed to an engine, gas turbine combustion is a continuous process. The compressor takes air from the surroundings and compresses it to a pressure between 10 - 30 bars, depending on gas turbine type. Pressurised air is used as combustion air in the combustor, where a fuel is supplied. In that way, the gas mixture gets a high temperature rise before it expands through the turbine. To keep turbine inlet temperature at an appropriate value and protect the materials, fuel is burned with a large amount of excess air.

Approximately two thirds of the moment set up goes to driving the compressor, while the other third can be used for driving a generator or a mechanical load. From the turbine, exhaust gases are released into the atmosphere. Alternatively, a waste heat recovery unit can be used to supply process heat or produce steam.

A two-shaft gas turbine consists of a gas generator and a power turbine, where the high-pressure turbine drives the compressor. The power turbine has got its own shaft and can drive a generator or a mechanical load. A two-shaft turbine is shown in Figure 4-2 below.

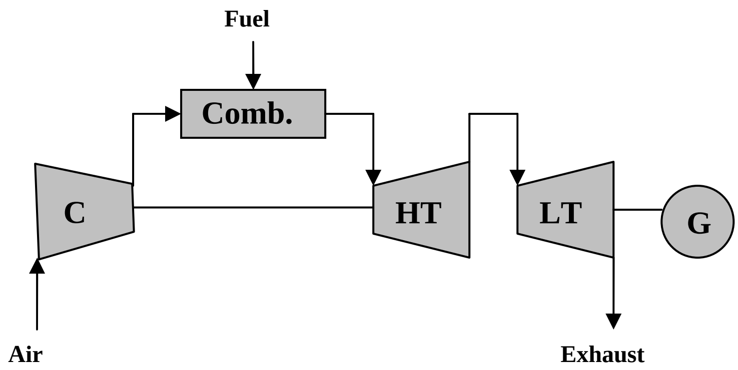

Figure 4-2: Two-shaft gas turbine.

The benefit of a two-shaft turbine is that the gas generator and the power turbine can be operated individually with optimum rotational speeds, which gives a good feed back control. The main drawback is that it makes operation and maintenance more complex.

4.2 Thermal efficiency

Net work output and thermal efficiency for a gas turbine can be defined as (ref. Figure 4-1):

$$W_{net} = W_{turb} - W_{compr} = m[(h_3 - h_4) - (h_2 - h_1)] \qquad (4.1)$$

$$\eta_t = \frac{W_{net}}{Q_{comb}} = \frac{(h_3 - h_4) - (h_2 - h_1)}{(h_3 - h_2)} \qquad (4.2)$$

Pressure ratio and turbine inlet temperature are the two factors that impact gas turbine efficiency the most. A more correct net effect is found by subtracting the power needed by the auxiliaries. Figure 4-3 illustrates how energy is utilised in a typical gas turbine offshore.

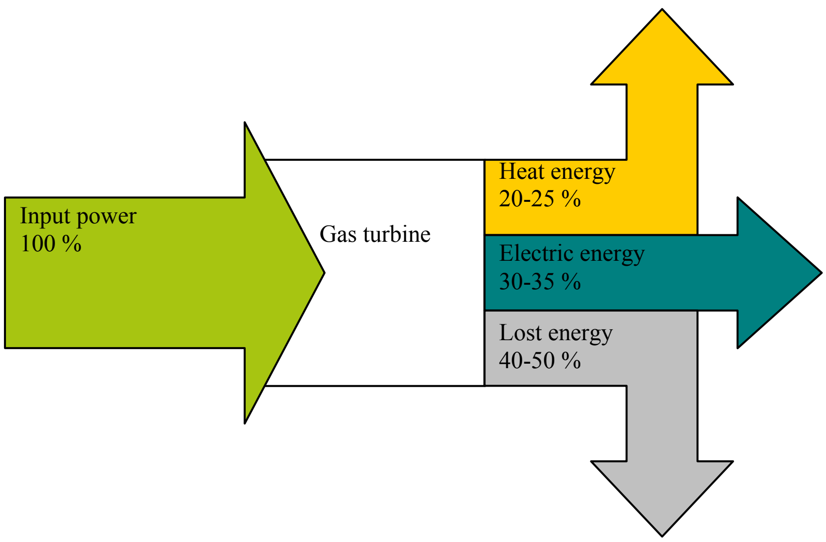

Figure 4-3: Energy utilisation in a gas turbine offshore [4].

The majority of gas turbines on offshore installations have thermal efficiencies in the range from 20 to 40 %. If the load is reduced below 75 %, efficiency might decrease 10 - 20 %. To minimise fuel consumption, it is advantageous to run as few turbines as possible at a high load [4].
Figure 4-4 illustrates the heat rate as a function of power for an LM2500+ G4, which increases as power and speed is reduced.

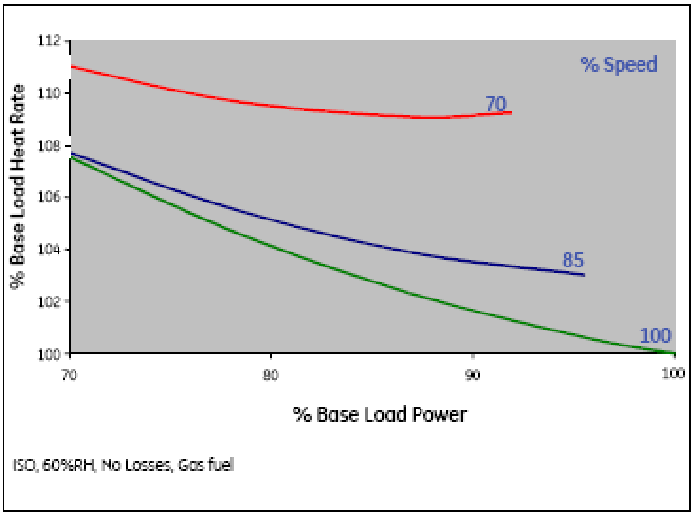

Figure 4-4: Part load performance [11].

4.3 Emissions

The equation for a stoichiometric combustion can be written as:

$$C_aH_b + (a + b/4)(O_2 + 79/21N_2) \rightarrow aCO_2 + (b/2)H_2O + (a + b/4)79/21N_2 \qquad (4.3)$$

This equation assumes complete combustion of carbon to CO_2, which is an ideal situation. Incomplete combustion results in small amounts of carbon monoxide (CO) and unburned hydrocarbons (UHC) being present in the exhaust. These are together with oxides of nitrogen (NO_x), considered as pollutants. Any sulphur in the fuel will result in oxides of sulphur (SO_x), but this is not common for natural gas. Due to a large quantity of excess air, a considerable amount of oxygen will also appear in the exhaust. Thus the exhaust of any gas turbine consists primarily of CO_2, H_2O, O_2 and N_2. Although the other components (NO_x, CO and UHC) represent a very small proportion of the exhaust, large flow of exhaust gases produces significant quantities of pollutants in a year [12].

Gas turbines without any NO_x abatement technology usually have emissions in the range between 180 and 400 ppm, depending on type and load. On the other hand, CO emissions are very low; often below 10 ppm. Relative NO_x emissions for diffusion combustors increase with an increasing load, due to a rise in combustion temperature. Statoil has calculated NO_x emissions for a LM2500 PE at various loads as follows:

Table 4-1: NO_x production as a function of load [31].

Load %	NO_x emissions [kg/h]	Reduction [%]
100	75	0
75	45	40
60	30	60

Data is based on manufacturer curves, but degradation is not taken into account. It is important to note that this rule of thumb only applies for gas turbines with SAC combustors.

4.4 NO_x formation mechanisms

NO_x refers to oxides of nitrogen, which generally include nitrogen monoxide (NO) and nitrogen dioxide (NO_2). They may also include nitrous oxide (N_2O), as well as other less common combinations of nitrogen and oxygen. The great majority (90 %) of NO_x exiting the exhaust stack is usually in the form of nitrogen monoxide, whereas 10 % is NO_2. At lower loads the ratio is reduced, which means more NO_2 is produced [13].

There are basically three chemical mechanisms forming nitrogen oxides during combustion: thermal, prompt, and the N_2O intermediate mechanism. Thermal NO_x is formed by the high-temperature reaction of nitrogen with oxygen and consists of two chain reactions:

$$N_2 + O_2 \rightarrow NO + N \tag{4.4}$$
$$N + O_2 \rightarrow NO + O \tag{4.5}$$

Thermal NO_x increases exponentially with temperature, and it is generally the predominant mechanism in combustion processes above 1100 °C. The mechanism becomes more important when air preheating or oxygen enrichment of the combustion air is used, as a result of an increasing flame temperature.

Prompt NO_x is formed by the relatively fast reaction between nitrogen, oxygen, and hydrocarbon radicals. It is given by the overall reaction:

$$CH + N_2 \rightarrow HCN + N \tag{4.6}$$
$$N_2 + O_2 \rightarrow 2\ NO \tag{4.7}$$

This process is in reality very complicated and consists of hundreds of reactions. Prompt NO_x is an important mechanism in lower-temperature combustion processes or under fuel-rich conditions [14].

The N_2O-intermediate mechanism is important in fuel-lean, low-temperature mixtures, and the three steps are the following [15]:

$$O + N_2 + M \rightarrow N_2O + M \tag{4.8}$$
$$H + N_2O \rightarrow NO + NH \tag{4.9}$$
$$O + N_2O \rightarrow NO + NO \tag{4.10}$$

There is also a fourth mechanism called fuel NO_x that is formed by the direct oxidation of organic-nitrogen compounds contained in the fuel.

Formation rate is strongly affected by the rate of mixing of fuel and air. Typically, flue gas NO_x concentration resulting from the oxidation of fuel nitrogen is a fraction of the level that would result from complete oxidation of all nitrogen in the fuel. Although fuel NO_x emissions tend to increase with a higher fuel nitrogen content, overall emissions increase are not proportional.

Natural gas has normally no organically bound nitrogen, but the mechanism may apply when heavier hydrocarbons like oil and diesel are being burnt [14].

4.5 Important factors affecting NO_x emissions

The single most important factor affecting formation of NO_x is flame temperature; this is theoretically a maximum at stoichiometric conditions and will fall off at both rich and lean mixtures. Unfortunately, while operating well away from stoichiometric could reduce NO_x, this results in increased formation of both CO and UHC.

Flame temperature may imply a measured value or a calculated one. If the latter, it is usually *adiabatic* flame temperature.

NO_x formation rate varies exponentially with flame temperature, so the key to reducing NO_x is reduction of flame temperature. This may be solved by introduce diluents into the combustion zone. CO is initially formed in large quantities in a flame and converts to CO_2. As blowout is approached, CO emissions climb rapidly because the flame temperature is not high enough to convert it to CO_2. At low loads, CO concentration is high due to airflow through adjacent unlit domes, which is caused by unburned air quenching the combustor. Low NO_x and CO emissions occur in a narrow band of flame temperature, which is seen from Figure 4-5. Optimum temperature range is usually between 1400 and 1600 ºC [16].

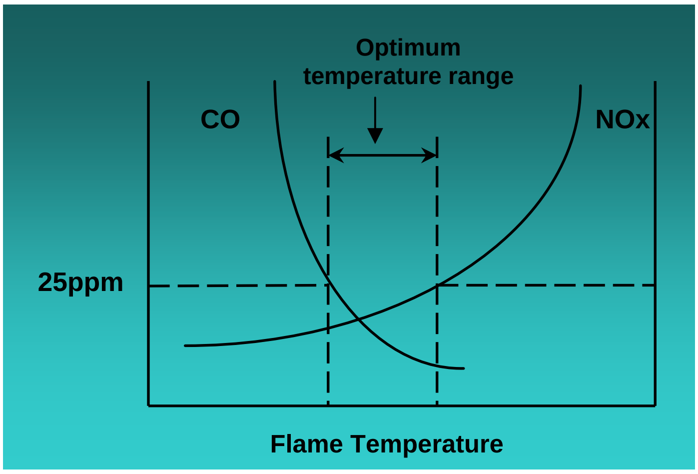

Figure 4-5: CO and NO_x production versus flame temperature.

Residence time affects NO_x formation slightly. NO_x decreases in a linear fashion as residence time is reduced; an increase in residence time, however, has a favourable effect on reducing both CO and UHC emissions. This implies a larger combustor cross-sectional area or volume [12].

There are also several other factors that have an impact on NO_x formation. These include the air and fuel compositions and temperatures, the fuel- air ratio, burner and heater designs, furnace and flue gas temperatures, and operational parameters of the combustion system.

For gaseous fuels, constituents in the gas can significantly affect NO_x emissions levels. Mixtures containing heavier hydrocarbons burn at higher flame temperatures, and can increase NO_x emissions greater than 50 % over NO_x levels for methane. Gaseous fuels containing large amounts of inert gases generally produce lower NO_x emissions. The inert gases absorb heat during combustion, and lower the flame temperature. Distillates have flame temperatures approximately 65 °C higher than that of natural gas, and consequently produce higher NO_x emissions [13].

4.6 Reliability and availability

Reliability and availability are two factors of great importance on offshore installations, and they are often key criteria in selection of gas turbines.

A power plant is considered available when it is ready for operation, and a high availability makes the need for spare capacity less. Depending on capacity, the plant may be more or less available. Unavailability for a plant includes planned shutdowns such as maintenance inspections, overhauls, test runs, in addition to “running” maintenance. If the plant can handle disturbances without tripping or capacity reduction, it is being regarded as reliable. Low reliability is often caused by limited experience with design and production of equipment, component failures, and “human errors” such as inadequate training or poor overhaul and maintenance strategy.

Reliability and availability may be defined as follows:

$$\text{Reliability} = \left(1 - \frac{\text{Forced Outage Hours}}{\text{Unit Period Hours}}\right) * 100$$

$$\text{Availability} = \left(1 - \frac{\text{Forced Outage Hours + Scheduled Outage Hours}}{\text{Unit Period Hours}}\right) * 100$$

Figure 4-6 shows maintenance costs and costs associated with unavailability as a function of availability. An economical optimum for maintenance is found as a trade off between the willingness to pay for maintenance and costs of shutdown. Curves are higher for gas turbines offshore compared to land-based units, especially for the curve showing unavailability costs. It can be concluded that maintenance is an important factor to ensure a safe power plant with high availability [17].

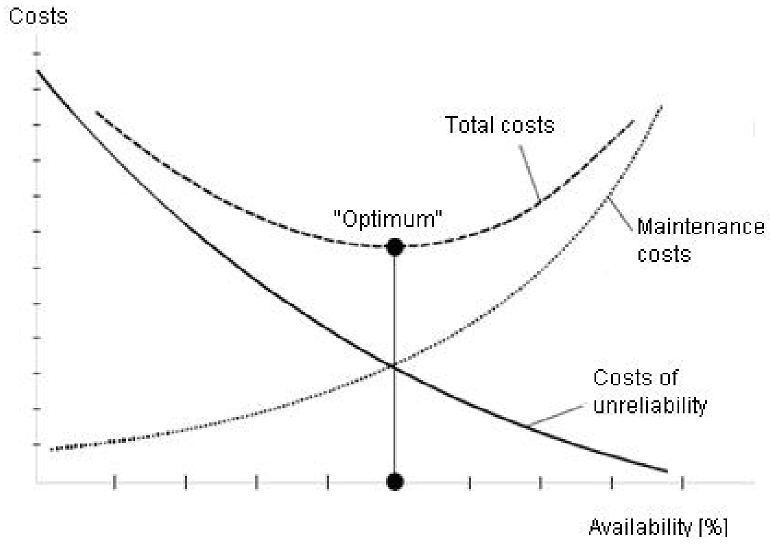

Figure 4-6: Economical optimum for availability of a power plant [17].

4.7 Load acceptance and rejection

Gas turbines operating in isolated areas are more vulnerable to system disturbances from faults or load fluctuations than gas turbines connected to strong electricity grids. Switching power could be in the megawatt range, which may cause interaction problems with connected generators. If a load suddenly drops, the power turbine will raise its speed and as a consequence the gas generator reduces its rotational speed. If the system does not stabilise, overspeed protection trips the unit if the speed exceeds 110 % of operating speed.

The opposite happens when a load is switched on; the power turbine will loose some of its speed and the gas generator has to accelerate it up again. Load acceptance is usually less complicated than rejection, as load is taken in appropriate steps. A fast responding control system is necessary to avoid any complications during loading and rejection. Figure 4-7 illustrates the principle of load rejection and acceptance for a conventional LM2500 gas turbine. The black line shows the load dropping from 5 MW to zero and then back to 5 MW. The green line shows the power turbine speed and the red line gas generator speed.

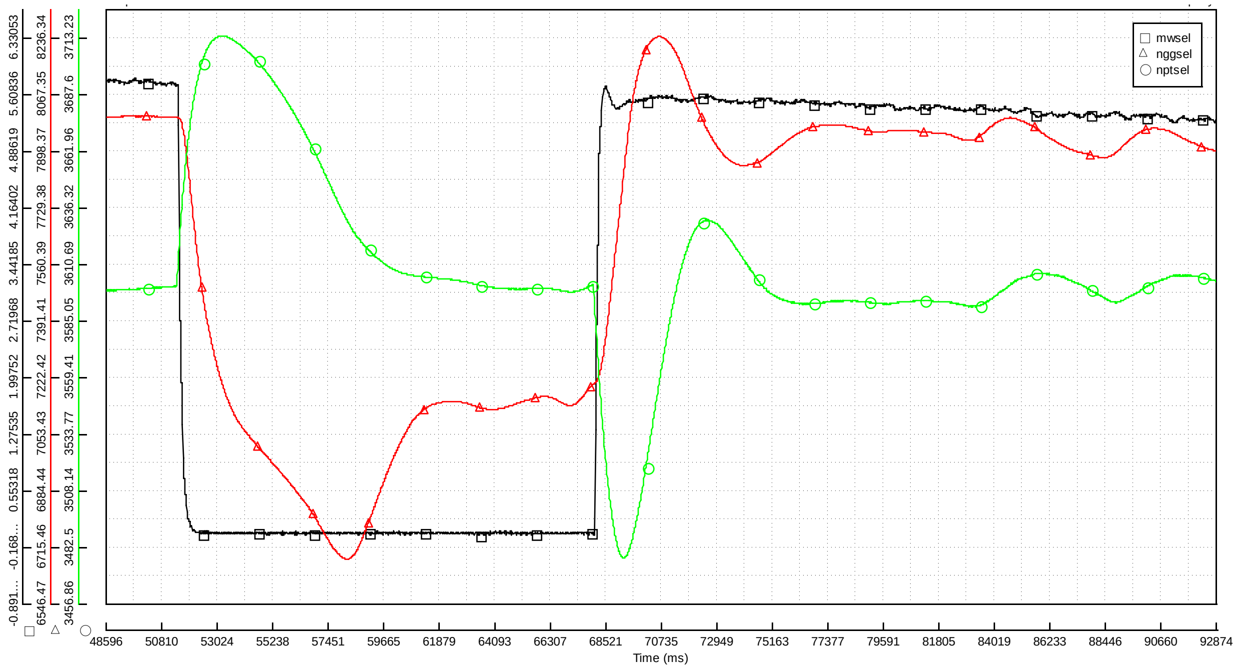

Figure 4-7: Typical load response [18].

A normal shutdown is made by reducing gas generator speed slowly and allowing it to operate at idle for some time. After a few minutes, fuel shutoff valves are de-energised. In an emergency, the gas generator can be shut down from any power setting by de-energising the fuel shut-off valves.

4.8 Maintenance requirements

Degradation of gas turbines causes a pressure drop and with that a decrease in power. Inlet filter, compressor and high-pressure turbine are the most vulnerable components. An important tool to lower degradation rate is to apply compressor cleaning, which is often done after 2000 hours of operation. It is worth noting that even with optimal wash intervals, efficiency will never reach its initial value after the turbine is put into operation.

Maintenance intervals are a function of several factors, and are usually set by the manufacturer. Borescope inspections are executed regularly to see if there is any damage to the turbine components. As an example, 8000 hours maintenance includes replacing filters, checking pumps and calibrating sensors. In addition, friction bearing and hydraulic actuator on the gas generator are changed [19]. The hot section of the turbine is usually overhauled or replaced after 25 000 hours. After 50 000 hours of operation, the entire gas generator is overhauled. Trips from full load, fast loading or emergency starts affect this interval negatively.

Online condition monitoring is now becoming more and more important to prevent failures and to optimise maintenance intervals. This may extend service intervals for gas turbines running at low loads and for installations operating in a favourable environment. As far as dual fuel machines are concerned, natural gas leads to less maintenance and a longer lifetime for combustion hardware than liquid fuel does.

4.9 Engine stability

Operability issues of interest are those related to operating the combustor in a safe, efficient, and reliable manner. This includes having the combustor reliably hold the flame, so that it neither flashes back nor blows out, and burn the fuel without too much noise. Combustion also has to be maintained over a wide range of operating conditions. Stability is often used to describe either the range of fuel-air ratios over which stable combustion can be achieved, or as a measure of the maximum air velocity the system can tolerate before flame extinction occurs. A typical combustion chamber stability loop is shown in Figure 4-8.

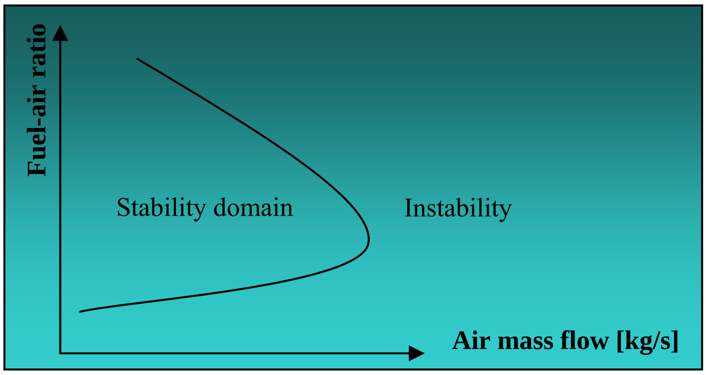

Figure 4-8: Example of combustion chamber stability loop [26].

Combustion instability refers to pressure oscillations that cause wear and damage to combustor components. It might lead to a flow reversal or flashback of the bulk flow into the premixing sections of the combustor. It is especially widespread in premixed combustion systems, but may also be a result of compressor surge [26]. Surge is a backflow in pressure giving a momentary change in the direction of airflow. It is typically accompanied by high fluctuating load on the compressor bearings. The phenomenon is most likely during rapid or emergency shutdowns.

Blowout occurs when time required for chemical reaction becomes longer than the combustion zone residence time. It is often referred to as the "static stability" limit of the combustor.

4.10 Summary

High pressure ratio and high turbine inlet temperature is important to achieve high efficiencies in gas turbines. This results in an increased production of NO_x due to the thermal NO_x formation mechanism. There are also two other formation mechanisms, named prompt NO_x and N_2O intermediate mechanism, which play a more important role in low-temperature combustions. Several factors influence NO_x emissions, with flame temperature as the single most important.

It is shown that reliability and availability are related to maintenance done on the equipment, and that degradation has to be taken into account when designing the power generation system.

For an operator, it is important to avoid instability in terms of pressure oscillations and noise, which may damage the equipment. Other considerations are blowout and flashback, but reliable control systems usually prevent these phenomena.

5 Methods for reducing NO_x emissions

Emissions from a gas turbine process may be tackled either during combustion, post combustion by exhaust clean up, or with a combination of the two. In this chapter, some of the available technologies for NO_x reduction will be presented, with the most promising described in-depth.

5.1 Selective catalytic reduction (SCR)

For applications requiring very low NO_x levels, systems such as selective catalytic reduction (SCR), can be used. This involves injecting a NO_x-reducing chemical into the exhaust stream in the presence of a catalyst within a specific temperature window. The catalyst itself is usually built up of a ceramic material, and the chemical is typically ammonia.

NO_x and NH_3 react on the catalyst surface to form N_2 and H_2O. The important reactions are:

$$6\ NO + 4\ NH_3 \rightarrow 5\ N_2 + 6\ H_2O \tag{5.1}$$
$$2\ NO + 4\ NH_3 + 2\ O_2 \rightarrow 3\ N_2 + 6\ H_2O \tag{5.2}$$

Some applications also have a CO catalyst installed that oxidises CO to CO_2. A representative temperature window is approximately in the range between 230 and 450 °C. Normally, the plant will be designed for reducing NO_x emissions with 85 - 90 % [12].

There are a number of potential problems and challenges with SCR techniques. Dirty exhaust streams may result in a plugged or fouled catalyst, which is especially challenging when firing liquid fuels. There are safety concerns regarding transport and storage of ammonia, both before and after use. Other major challenges include finding the proper location to inject the chemicals, injecting the right amount, and getting proper mixing of chemicals and the flue gas products. There will always be a trade-off between NO_x reduction rate and ammonia slip production. SCR systems are not very tolerant of constantly changing conditions, as a stable window of operation is required for optimum efficiency [14].

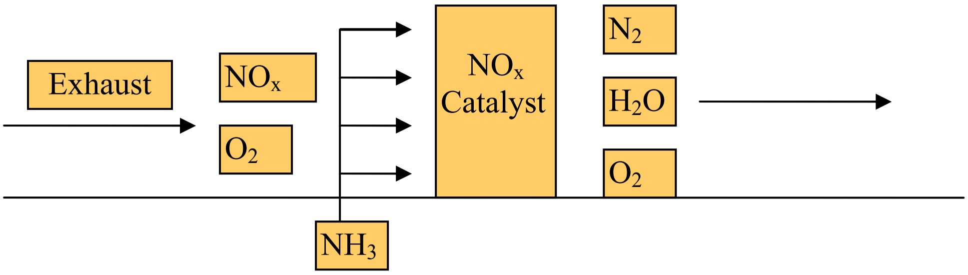

Figure 5-1: Schematic of an SCR system.

Ammonia slip may cause formation of ammonium sulphates, which can plug or corrode downstream components. In addition it may be absorbed by fly ash, which may affect disposal and reuse of it. It can be discussed whether it is worth reducing the NO_x emissions to a single digit or not, as ammonia slip may be a bigger problem.

Typically, the pressure drop in an SCR system lies between 70 and 100 mm H_2O in a NO_x catalyst, and between 25 and 50 mm H_2O in a CO catalyst.

SCR has little effect on turbine operation besides the pressure drop, which causes a slight decrease in power output. Load acceptance and rejection is not an issue, as long as they take place within the tolerance window for emissions excursions [20].

Operational costs are primarily a combination of ammonia consumption and catalyst replacement costs. Catalysts are typically guaranteed for five years in natural gas applications, but track record shows that catalyst life is typically far longer than guarantees. When firing liquid fuels, the guarantee is usually lower.

5.1.1 Experience

5.1.1.1 Eastridge Cogeneration Plant

Chevron's Eastridge Cogeneration Plant in California produces steam for thermally enhanced oil recovery and electricity to the utility grid. From the old requirement of maximum 42 ppm NO_x, Air Pollution Control District set new upper limit to 12 ppm, a reduction of 71 %. To meet this requirement, the two LM2500 gas turbines were retrofitted with selective catalytic reduction (SCR) technology. Installation of additional catalyst material and increased ammonia flow is necessary in order to achieve emissions below 3 ppm, if required.

Peerless was chosen as manufacturer, and shutdown was limited to 5 days only for major field modifications. Total installation costs for the environmental portion of the project, including all company costs, was $2.3 million. Annual operating and maintenance costs are estimated to 10 - 20 % and 5 %, respectively, of total installation costs. Annual NO_x reduction from Chevron's Eastridge units is around 350 tonnes [21].

Based on experience from several plants, SCR works best in base loaded combined cycle gas turbine applications where natural gas is fired. Reasons relate to temperature dependency of the catalytic NO_x-ammonia reaction and catalyst life, in addition to major problems associated with the use of liquid fuels containing sulphur. Above 450 ºC the catalyst may be damaged irreversibly. Exhaust gas from diesel engines is often cleaned by this technology. The exhaust gas temperature from an LM2500+ is 515 ºC, and in combination with weight and space requirement of this technology, it is considered unsuitable for Skarv Idun [22].

5.2 Selective non-catalytic reduction (SNCR)

SNCR is in principle similar to SCR, but no catalyst is involved in the process. Usually, the agent is ammonia, cyanuric acid or urea. SNCR is a mature technology for moderate reductions of NO_x (i.e. 40 - 60 %), but may achieve a higher reduction in combination with a combustor modification technology (70 - 75 %) [23].

Optimum temperature window, without adding other chemicals to increase the temperature window, is from 870 to 1200 ºC [14]. Reduction at higher temperatures is poor because the reducing agent itself oxidises to NO. Below the optimum temperature, selective reduction reactions are too slow and unreacted agent can be emitted. Although use of SNCR decreases NO_x, it may increase other undesirable emissions such as CO, N_2O and NH_3. This is a proven technology for onshore applications, but it will however not be discussed any further in this report.

5.3 SCONO$_x$

The SCONO$_x$ catalytic absorption system is a technology reducing NO_x and CO from exhaust streams without the need for ammonia. It uses a single catalyst of potassium carbonate for control, simultaneously oxidising CO and NO. NO_2 is absorbed on the catalyst surface while CO_2 exits up the stack. The chemical reactions that occur are as follows [24]:

$$2\,CO + O_2 \rightarrow 2\,CO_2 \qquad (5.3)$$
$$2\,NO + O_2 \rightarrow 2\,NO_2 \qquad (5.4)$$
$$2\,NO_2 + K_2CO_3 \rightarrow CO_2 + KNO_2 + KNO_3 \qquad (5.5)$$

Potassium nitrites and nitrates are present on the catalyst surface, so the catalyst must be regenerated to maintain maximum NO_x absorption. The SCONO$_x$ reactor is a series of horizontal shelves in a gas tight casing that wraps around the top, bottom, and sides of the unit. Each shelf holds multiple layers of catalyst, and exhaust gases flow through the catalyst from front to back. A typical system has got ten or fifteen sections of catalyst, where four in a group of five is absorbing while the last one is regenerated.

Optimum temperature for the system is in the range between 230 and 370 °C, which makes it suitable for cogeneration plants and not for simple cycle gas turbines. Catalyst blocks are often placed between the high pressure and the low-pressure heat recovery steam generators due to temperature requirement [24]. SCONO$_x$ gives the lowest emissions of NO_x and CO for the three post-combustion technologies presented. An LM2500 gas turbine with steam injection has demonstrated emissions as low as 2 ppm NO_x without any use of ammonia [25]. Its main drawback is costs, and like the other post combustion technologies, it will not be considered as a feasible option for Skarv Idun.

5.4 Catalytic combustion

Catalytic combustion is a flameless combustion process that utilises a catalyst to initiate chemical reactions in a premixed fuel-air mixture. The temperature in the combustion chamber is lower than in a conventional combustor, which makes it possible to avoid formation of NO_x emissions. A preburner is however required for start-up and part load operation, and in this way undesired NO_x emissions are generated. This principle of catalytic combustion is shown in Figure 5-2.

Fuel is injected upstream of the reactor to vaporise and mix with the inlet air. The mixture then flows into a catalyst bed, which may consist of several stages, each made of a different kind of catalyst. A portion of the fuel is combusted in the catalyst itself. Fuel and oxygen react on the catalyst surface and release the heat of combustion regardless of the fuel-air ratio in the gas mixture. Remaining fuel is combusted downstream in a homogeneous reaction, also at a temperature low enough to prevent formation of significant amounts of NO_x. In this zone, gas temperature is raised to the required turbine inlet temperature, and CO and UHC emissions are reduced to acceptable levels.

The harsh environment in a gas turbine combustor and its wide range of operating conditions pose challenges to implement catalytic combustion [26]. At the moment, the technology is at a conceptual stage with Xonon Cool Combustion as the only system that has demonstrated ultra-low NO_x emissions. Kawasaki has one commercial machine with power output of 1.5 MW operating with a catalytic combustor [27].

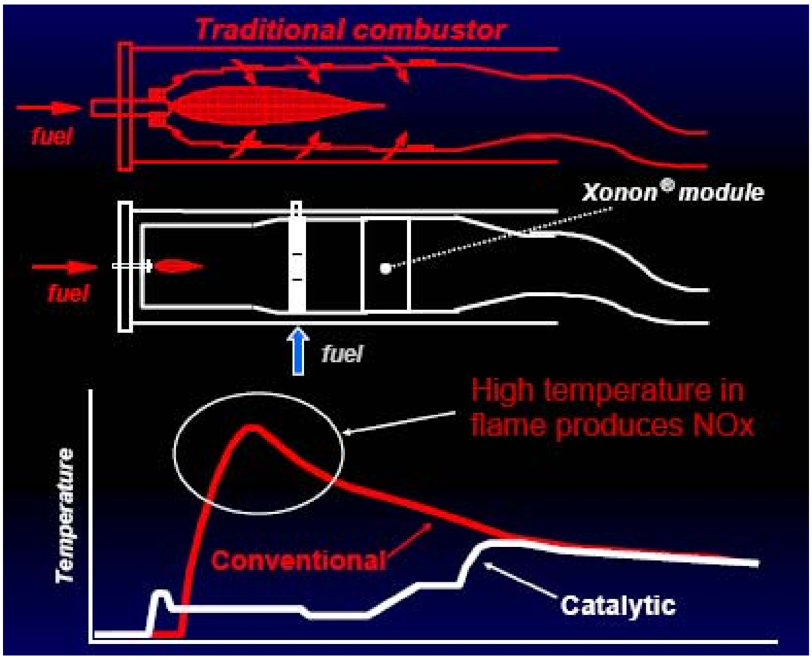

Figure 5-2: Temperature variation in a catalytic combustor [28].

5.4.1 Experience

General Electrics have implemented the technology on a GE10 industrial gas turbine, which has a power output of 11 MW. In 2005, a full-scale engine test was completed and the combustor managed to achieve NO_x emissions lower than 2 ppm above 90 % load range. At the same time, CO and UHC concentrations were kept below 10 ppm, which may be seen from Figure 5-3. Emission performances at part load were fairly poor, as expectable using a diffusive combustion preburner, and it raised the need for a complete redesign of the preburner. Tests also showed that inlet gas temperature has to be increased during the catalyst lifetime in order to maintain emission targets. There are still modifications that have to be done before commercialising, and efforts must focus on enhancing catalyst durability for low inlet temperature operation. It is desirable with a catalyst lifetime of at least 8000 operational hours [29].

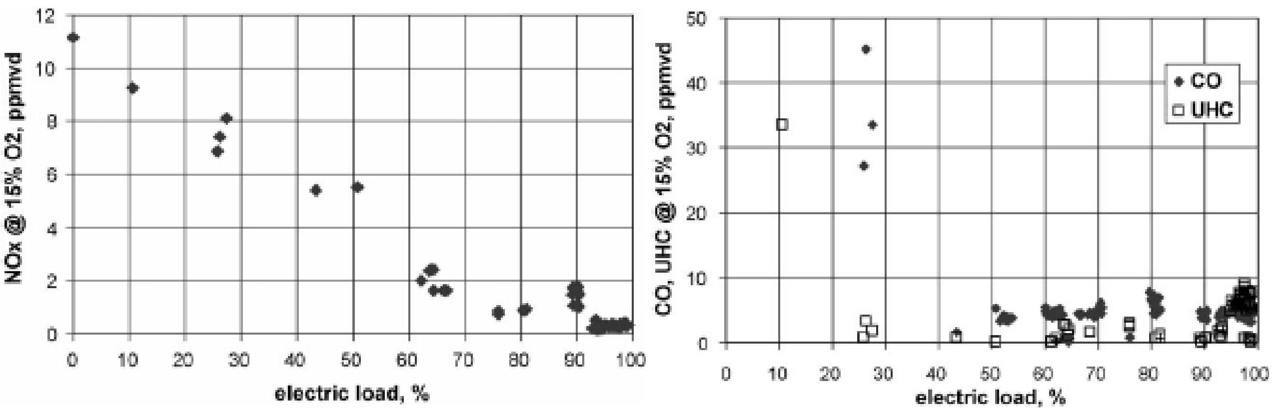

Figure 5-3: NO_x, CO and UCH emissions versus load [29].

Since catalytic combustion is not regarded as commercially available for the selected gas turbines, it will not be discussed any further in this report.

5.5 Wet Low Emissions (WLE)

Wet Low Emission Control is the generic term for water and steam injection. The purpose is to provide a substantial decrease in flame temperature, and this is achieved by quenching local hot spots in the area where NO_x usually is generated. Large amounts of water are required, and in order to prevent corrosive deposits in the turbine, water must be demineralised. It is found that increasing water-fuel ratio increases both CO and UHC emissions, while continuously decreasing NO_x. On an offshore installation, water is a scarce resource, and a treatment plant for seawater is necessary.

The Spray Inter-cooling (SPRINT) System is based on an atomised water spray injected trough spray nozzles into the compressor, and its main purpose is power enhancement. Water is atomised using high-pressure air taken off the eighth stage air bleed. The high-pressure compressor inlet temperature is lowered, which in turns lowers discharge temperature. Pressure ratio is increased and additional air can be directed through the compressor to increase the gas turbine output. The SPRINT system is well suited for power plants operating in areas with high ambient temperature, as power output is increased even more [30].

For reduction of NO_x emissions, water is usually injected into the combustor instead of the compressor inlet, but the technology may be combined with SPRINT. One LM6000 or two LM2500 water injected gas turbines would require approximately 3.9 tonnes of water per hour given a NO_x emission level of 42 ppm [31]. To achieve 25 ppm, even more water must be injected.

Another form of water injection is to inject it as vapour. A reason for doing so is that steam already includes latent heat of vaporisation needed to evaporate the water. It is often easier to blend steam into the combustion products, because liquid water must be injected through nozzles to disperse it uniformly with the combustion gases. Maximum amount of steam that can be injected is usually between 8 and 10 % of the airflow into the compressor [32].

In the steam-injected gas turbine (STIG) cycle in Figure 5-4, steam is typically produced in a heat recovery steam generator (HRSG) and injected via combustor fuel nozzles and the compressor discharge plenum. This system gives a flexible operating cycle, since the amount of steam injected is adjusted with varying load requirements and steam availability. If necessary, the HRSG can be additionally fired. The control system regulates the amount of steam sent to process and, typically, excess steam is available for injection.

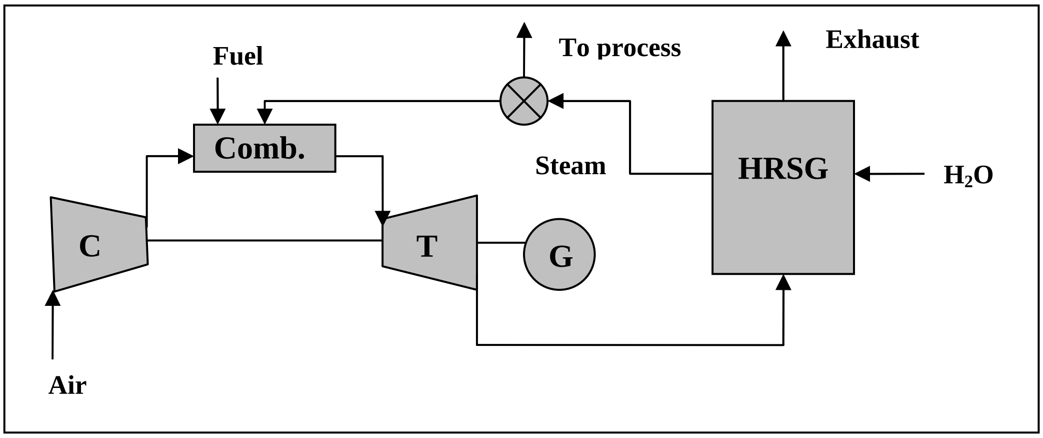

Figure 5-4: Typical STIG cycle.

For an LM2500+, steam flow capability and performance is as follows[1]:

Table 5-1: Data for an LM2500+ with steam injection [2].

Factor	Value
Rating [MWe]	32.5
Thermal efficiency [%]	40
Steam flow [kg/h]	10 750

Since steam is injected downstream from the compressor, it does not increase work required to drive the compressor. Impacts of steam injection include increased pressure ratio and lower exhaust temperature.

5.5.1 Thermal efficiency

Extra mass added to the turbine may be considered as free, due to low pump work for water compared with compression of air. As far as water injection is concerned, the increase in power is offset by a decrease in thermal efficiency. This is caused by a higher fuel consumption needed to evaporate water, and the difference with and without water injection is highest at base load.

Steam injection also gives a higher mass flow through the turbine and produces more work output. Since water already is in the form of vapour, higher efficiency is achieved. Some heat is added from the exhaust gas to the water while parts of it come from the fuel. The difference in efficiency at full load is around 3 %, but it diminishes as the load decreases. Because efficiency data for the selected gas turbines is considered proprietary, graphs will not be presented in this report.

5.5.2 Emissions

Unabated NO_x emissions from a gas-fired LM2500+ are 229 ppm, and 346 ppm when it is liquid-fired. Implementation of wet low emission control introduces guarantee limits of 25 ppm for natural gas and 42 ppm for distillate [2]. This represents emission reductions of almost 90 %. At low loads, the smaller amount of steam or water injected leads to higher emissions of NO_x.

CO emissions are substantially higher over the entire load range when applying wet low emission control. This is especially the case when injecting water, even though the trends from idle to full load are the same for both water and steam. Emissions data for the gas turbines on Skarv Idun have been obtained, but they are not published due to a confidentiality agreement.

[1] Standard base load, sea level, 60% RH, natural gas, 60 Hz, 102 mm inlet/254 mm exhaust loss, 25 ppm NOx.

5.5.3 Maintenance requirements

Wet low emission control can impact maintenance intervals and lifetime of turbine parts. This relates to the effect of added water on hot gas transport properties, because higher gas conductivity increases heat transfer and lead to high metal temperatures. The impact on part life from steam or water injection is related to the way the turbine is controlled. Turbine inlet temperature may be kept at a constant level since the steam injection rate can be decreased at part loads.

It is worth noting that with water injection the combustor maintenance interval is expected to decrease from 25 000 hours to 16 000 hours when running continuously at full load. However, hot section repair interval will remain the same as for conventional engines [33].

5.5.4 Load acceptance and rejection

The STIG system will start up as a simple cycle until a low idle condition is reached. Exhaust gas from the turbine gradually starts the evaporation process in the HRSG. It will take up to two hours before the boiler has reached high enough steam pressure. Once the steam pipe is warmed up, the amount of steam corresponding to the desired load can be injected into the gas turbine. Load acceptance is usually uncomplicated even though the mixture might become rich for shorter periods.

During a normal shut down of the system, steam can be reversed to the steam skid without any steam going into the gas turbine. Then the gas turbine will follow the procedure for a simple cycle shutdown. Both start up and shutdown are transient conditions that may take some minutes depending on gas turbine type. If the load suddenly drops, the amount of fuel is reduced, which in terms require a quick response from the steam system. Otherwise, the mixture might get too lean resulting in blowout.

5.5.5 Engine stability

As more and more diluent is injected, dynamic pressure oscillation activity in the combustor increases, resulting in increased wear of internal parts. Flame stability is affected, and if injection ratio were high enough, flameout might occur. Control of the combustion process is therefore very essential when injecting water or steam.

5.5.6 Reliability and availability

For most gas turbines, injection of water or steam results in increased wear of the thin plate parts. This is especially the case for water injection. As far as pollutants are concerned, there is a very small tolerance limit before corrosion can occur. According to [32], operating data has shown that reliability and availability is not affected by using water and steam injection. However, it has not been possible to obtain real data on this topic.

5.5.7 Weight and space considerations

A water injection plant will include combustor modifications, injection nozzles, water injection pumps, modification of control system and a water production plant. The next section gives an indication of dimensions and weight for such a skid. Steam injection will in addition require a heat recovery steam generator, and is therefore even more space and weight demanding. Chapter 5.8.10 shows Snorre B's boiler dimensions.

5.5.8 Experience

5.5.8.1 Schiehallion

BP-operated Schiehallion is an FPSO located outside Scotland. Its power generation system was supposed to consist of 2 LM6000 SPRINT gas turbines, but due to load profile changes the skid has not been installed yet. Water injection is therefore not applied on any offshore installation, and it is referred to section 5.6.9.4 for experience regarding SPRINT.

5.5.8.2 Norwegian Continental Shelf

Water injection may be implemented on gas turbines not qualified for dry low emission control. The main reason why it has not been used so far includes high costs of producing enough water, in addition to space and weight requirements. An advantage compared to DLE technology is that turbines may run even if the water skid shuts down. WLE control requires development of technology to purify and demineralise large amounts of seawater to make injection in gas turbines possible. It has been applied in several applications onshore, but none of the technologies are considered as BAT offshore today.

Statoil consider water injection in old gas turbines as more interesting than steam injection. A study has calculated retrofit costs of water injection for three gas turbines on an existing platform in the North Sea. These are estimated to about 200 MNOK. Qualification of new technology, experience from pilot testing and considering potential candidates will take time, and it is assumed that water injection will not be in operation before 2010. A 42 ppm NO_x level will imply additional operation and maintenance costs of 2 MNOK per year. The water injection skid will have a weight between 25 and 40 tonnes, and cover an area up to 150 m^2 [34].

5.5.9 Summary

Injecting water or steam into a gas turbine lowers flame temperature, which in terms contributes to a reduction of NO_x emissions. Both diluents increase work output from the turbine, but only steam injection results in a higher efficiency. If enough water or steam is injected, it may affect engine stability leading to blowout. A high water-fuel ratio might decrease the maintenance interval as a result of increased wear of the turbine hot part. As far as space and weight requirements are concerned, water injection has the smallest skid of the two. It may be discussed whether injection of diluents influences availability and reliability or not.

5.6 Dry Low Emissions (DLE)

Gas turbines with dry low emissions control was developed to achieve low emissions without using water or steam as diluents. A DLE combustor utilises the principle of lean premixed combustion, and is similar to the SAC combustor with some exceptions. Instead of one single concentric ring, there are two or three rings with premixers depending on gas turbine type. This configuration allows for “staging” as power demand changes, and low emissions can be obtained over the entire range. To operate properly, the DLE technology requires a more complicated control system.

Premixing of fuel and air lowers the heating value, and combustion takes place at a lower temperature. In order to obtain low CO and UHC emissions, the combustor must assure an adequate residence time. Maintaining the bulk flame temperature within a specified window for each mode controls NO_x and CO concentrations. To fulfil these requirements, the premixing system is arranged into concentric rings in the combustor dome. For the LM2500 series, three rings are used, and they are referred to as the A, B and the C ring, moving from outermost to innermost. The outer two circles each have 30 burners, while the inner has 15; this is due to space limitations.

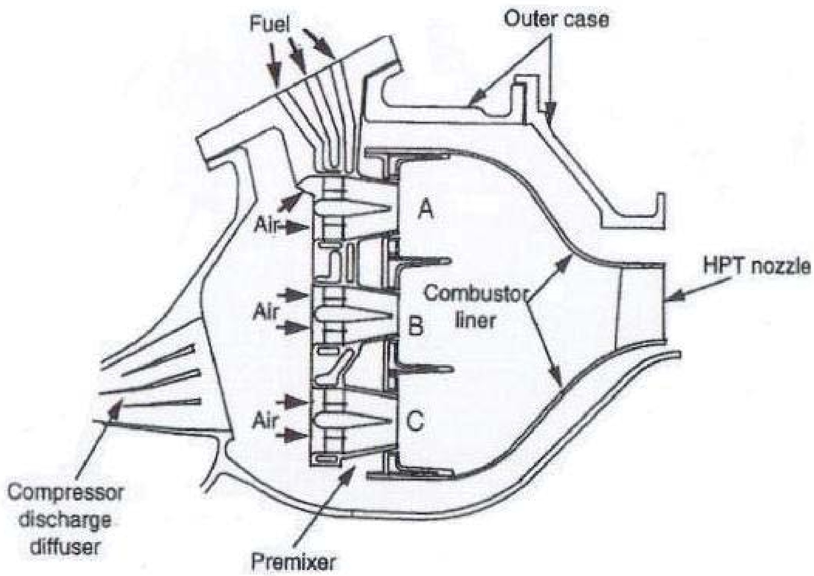

Figure 5-5: DLE combustor [37].

Each ring contains a set of fuel premixers that introduce fuel in the right proportion to the airflow upstream of the combustion zone. Bleed air is taken from the compressor discharge. For start-up, fuel is supplied only to the B ring acting as a pilot ring. As power is increased to the 5- 25 % range, fuel is supplied to both the B and C rings. Further power increase causes fuel to shift to the A and B rings. Above 50 % power, all three rings are fuelled and combustion takes place downstream of the zones. This is illustrated in Figure 5-6. It is important to note that DLE guarantees for NO_x and CO usually are given at loads from 50 or 75 % and above.

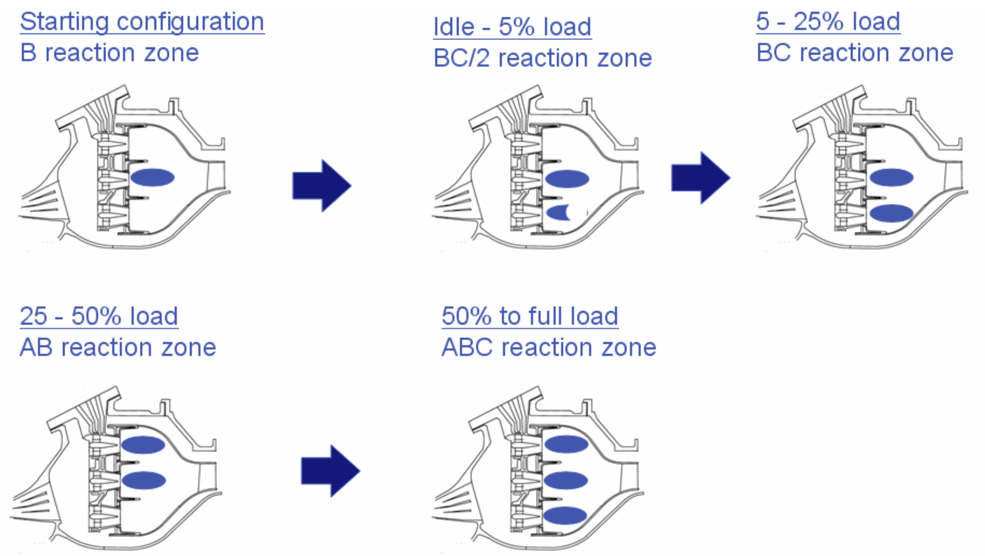

Figure 5-6: Different operation modes for DLE combustor.

The combustor configuration has to be changed once bleeds are either fully open or fully closed to maintain bulk flame temperature within limits. Stage up is required once bleed is fully closed and the flame temperature is at its maximum for the specific mode. Stage down takes place when bleed is fully open and the flame temperature is at its lowest. The principle is shown in Figure 5-7. Fuel staging operations guarantee primary zone condition just above blowout limit in every load conditions. As load decreases, the compressor discharge temperature and pressure decrease and the blowout limit moves towards a richer mixture, consequently increasing NO_x emissions.

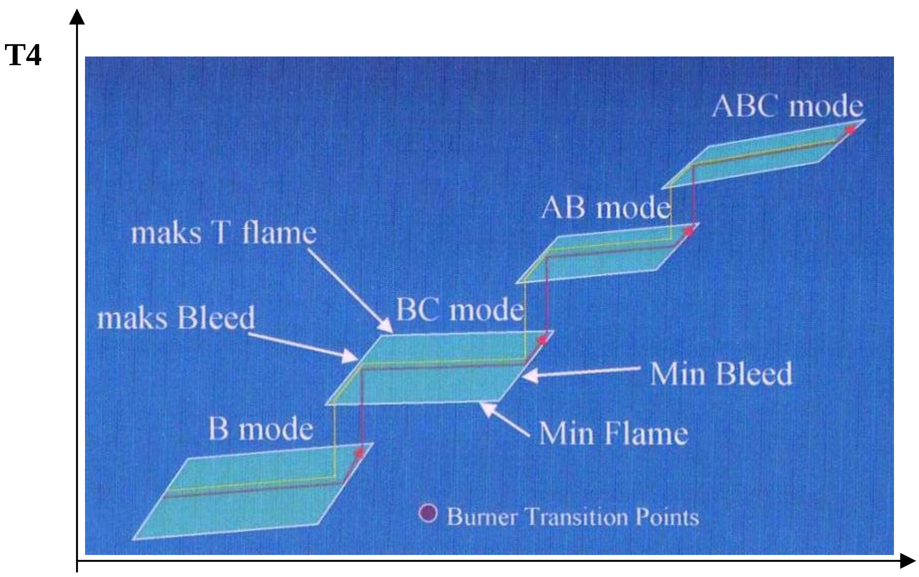

Figure 5-7: Fuel staging.

While SAC combustors can accommodate a wide band of Wobbe numbers, DLE machines have higher sensitivity to heating value and fuel quality. It is also more challenging to switch between gaseous and liquid fuels when applying DLE technology. Multiple DLE combustors offshore have gas properties varying due to changing gas wells. They use gas calorimeters or chromatographs to monitor the Wobbe index, and maintain low emissions with fuel property changes.

5.6.1 Thermal efficiency

For gas turbines with DLE technology implemented, thermal efficiency is somewhat lower than for conventional combustors. At base load, DLE turbines have only got about 0.5 % lower efficiency than corresponding SAC turbines [37]. Running at low loads, the difference is greater since a larger amount of air is compressed and bypassed. Figure 5-8 shows efficiency trend as a function of load for an LM2500+ machine. Efficiency variation for the selected gas turbines has been looked into, but is not presented due to confidentiality.

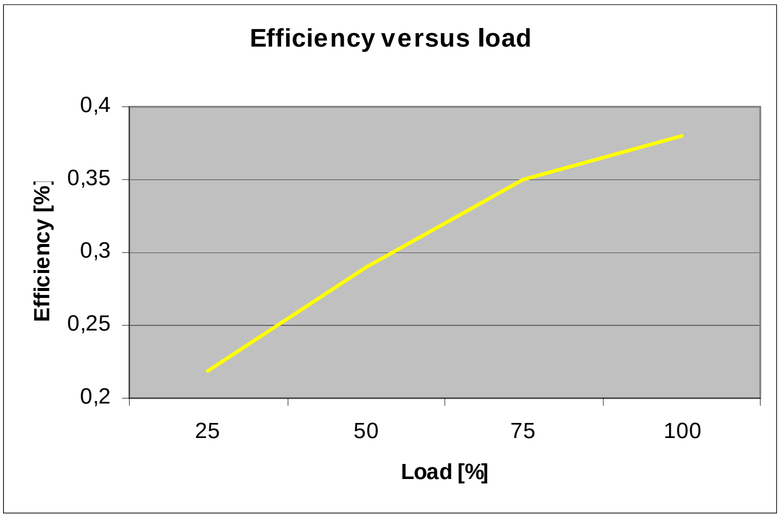

Figure 5-8: Efficiency versus load [37].

A pressure drop of about 5 %, which for an LM2500+ gas turbine corresponds to 1 bar is common for a DLE combustor. This may be regarded as a loss.

5.6.2 Emissions

NO_x and CO emission guarantees of 25 ppm are usually given above 50 or 75 % load for DLE machines. However, the emissions tend to stay relatively low across the entire load range. A SAC machine, on the other hand, increases NO_x production as the load is increased due to a higher combustion temperature. As far as CO emissions are concerned, the situation is directly opposite. While a SAC machine keeps CO levels at 5 ppm, emissions are 25 ppm for a DLE machine at high loads. It is therefore expectable that also levels of unburned hydrocarbons are higher for DLE machines.

Emissions are usually given in ppm; parts per million. Figure 5-9 shows actual NO_x and CO emission levels over the load range for an LM2500+ in [g/MWh], which tends to decrease as load increases. Note that emissions of CO_2 are given in [kg/MWh].

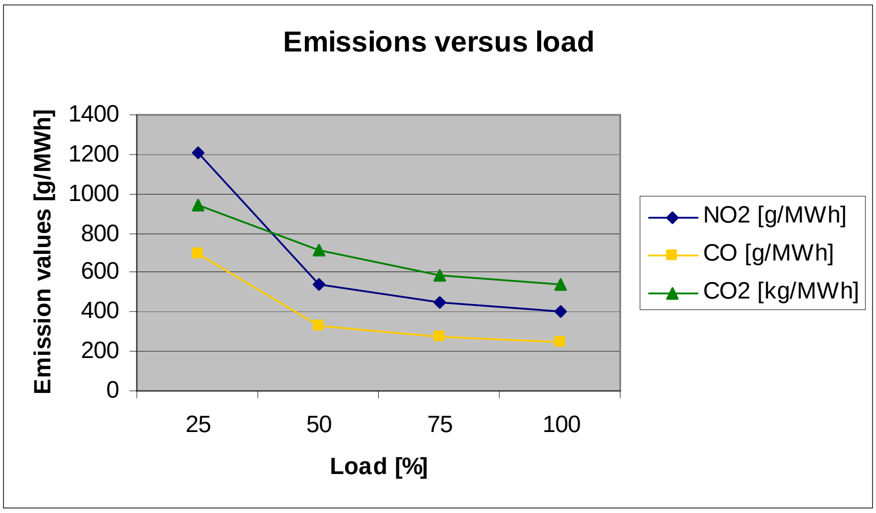

Figure 5-9: Emissions versus load [37].

For an LM2500+ running at base load, it yields the following emissions:

Table 5-2: Emission rates for an LM2500+ [37].

Pollutant	Emission rate [kg/h]
NO_2	12.0
CO	7.4
CO_2	16 100

It is interesting to note that emissions of CO_2 from DLE turbines are not lowered; on the contrary they increase as a result of lower efficiency. This technology therefore yields a conflict between the different emissions.

5.6.3 Mapping

Mapping is a process of systematically varying ring flame temperatures to find acoustic and lean blowout boundaries at fixed emissions level. It is usually done every time the turbine is replaced or overhauled, and may take from 3 to 5 days [35].

The fuel-air ratio is adjusted in each mode and sensors in the exhaust stack and the combustor register emission values continuously. If a high UHC level is detected in the exhaust stack it means the mixture is too rich, whereas high acoustics in the combustor indicates a mixture that is too lean. Figure 5-10 shows the optimum flame temperature as a function of load.

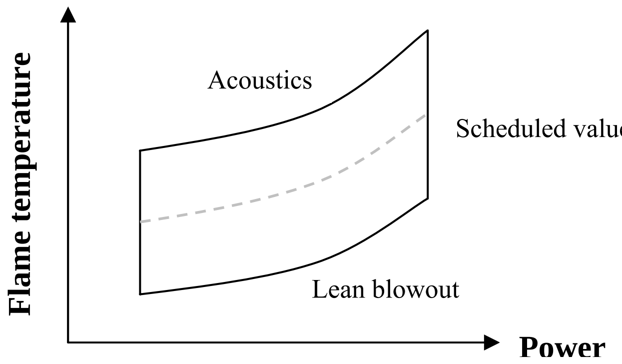

Figure 5-10: Mapping process.

5.6.4 Maintenance requirements

For a DLE machine supplied by GE, hot section overhaul intervals are usually 25 000 hours. This is the same interval as for SAC machines. Maintenance costs are however somewhat higher for LM2500 DLE machines; 300 NOK/hour compared to 250 NOK/hour [35]. For a gas turbine operating 8600 hours a year, this means extra costs of more than 400 000 NOK. Higher costs are mainly related to a more expensive combustor.

5.6.5 Load acceptance and rejection

The main feature of the DLE technology is to operate with a lean mixture in order to keep combustion temperature at an acceptable level. In cases where a load is suddenly changed or one of the turbines trips, the fuel supply to the other turbine is stopped and its fuel-air mixture may become too lean. This increases the risk of a blowout, and if fuel is still being supplied, spontaneous combustion might occur. A blowout is easily recognised since the engine is unable to continue operation. Caution must be taken when switching from diesel to gas and vice versa to avoid this phenomenon. Load acceptance is normally easier to handle than load rejection also for DLE turbines. For a short moment during loading, temperature in the combustor may be high due to a rich mixture.

5.6.6 Engine stability

A DLE combustor operates close to the lean stability limit. At very low fuel-air ratios, flames are highly unstable leading to flameout or fluctuations that may cause severe combustor vibrations. To avoid acoustics, a sensor (PX36) in the combustor registers the vibration level and sends a signal to the control system if divagation is too high.

Instability may occur before flame blowout is reached. Not only is poor combustion indicated, but also aerodynamic vibration is set up, which in turn reduces the life of the chamber and causes blade vibration problems.

5.6.7 Reliability and availability

There is an increased risk of trips for machines operating on installations where fuel gas is taken from different wells. It is therefore important that gas calorimeters or chromatographs are tuned to provide the control system with the right heating value.

For a gas turbine manufacturer it is important to satisfy customers by providing reliable machines. GE has worked continuously to improve reliability and availability of their gas turbine fleet. From July 2001 to July 2004, data was collected from 54 SAC machines and 7 DLE machines in the LM2500 and LM2500+ series. Results showed that the gas turbine packages had reliabilities above 99 %, and there were only small divagations between SAC and DLE packages. Availability lied between 97 and 98 %, with DLE turbines varying slightly from SAC machines [36].

5.6.8 Dual fuel versus single fuel DLE

A DLE turbine operating on both diesel and gas has a much more complicated configuration than a single fuel turbine. In addition to a gas fuel system, it needs a liquid fuel system with accompanied manifolds and valves. The premixer is modified with a liquid fuel circuit added to the gas premixer, and leads to a more complex control system. The gas generator can be started on either natural gas fuel or on liquid fuel, but not on a combination of the two. When operating on 100 % liquid fuel or a mixture of liquid and gas, it is necessary to purge the liquid portion of the fuel nozzles when switching to gas. Gas containing any liquid may damage the premixers and the combustor, and polluted gas may give component problems.

5.6.9 Experience

Statoil was the first operator to install gas turbines with DLE technology offshore. This resulted in a troublesome start-up period with shutdowns and combustor cracks due to acoustic vibration. A lot of the problems came as a result of a deviant fuel gas composition and poor gas quality lead to clogging of premixers.

In the beginning, availability and reliability for DLE turbines were lower than for conventional turbines. As a result, operational costs were 60 % higher compared to SAC combustors. The difference is related to higher fuel consumption and higher maintenance costs. DLE machines used to have problems with load acceptance and rejection, but modifications to the control software have eliminated these problems [16].

Today, the difference in operational costs is far lower than it was at start-up and reliability and availability deviations are small. Since 1997, Statoil has consequently installed DLE turbines on fields with a stable gas supply. Dual fuel technology is however not considered qualified, which means some platforms have SAC machines that may run on diesel. In the following section, experience regarding DLE on the Åsgard B platform will be presented.

5.6.9.1 Åsgard B

Åsgard B has got two LM2500+ gas turbines for generator drive, where one is a SAC machine and the other has got a DLE combustor. In addition, there are three LM2500+ gas turbines installed for compressor drive. All five turbines have installed waste heat recovery units. A relative constant compressor inlet temperature and fuel gas heating value over the year makes DLE technology favourable. Mapping is therefore only done at turbine overhauls.

Acoustics have been experienced during operation, but the Acoustic and Blowout Avoidance Logic (ABAL) adjusted temperature and tripping has so far been avoided. Blowout has only been a case when mapping, not during operation. Technical availability for the five gas turbines were in 2004 98.73 %, and this number does only include downtime related to corrective maintenance, not preventive [37].

In cases where of the recompression trains trips, DLE machines must deal with load rejections between 10 and 15 MW. The impression has been that DLE machines are just as robust as SAC machines, as far as load rejection is concerned [38]. Figure 5-11 shows the emission measurements from a mapping in 2006, and it illustrates how emissions of NO_x, CO and unburned hydrocarbons vary over the load range from idle to base load.

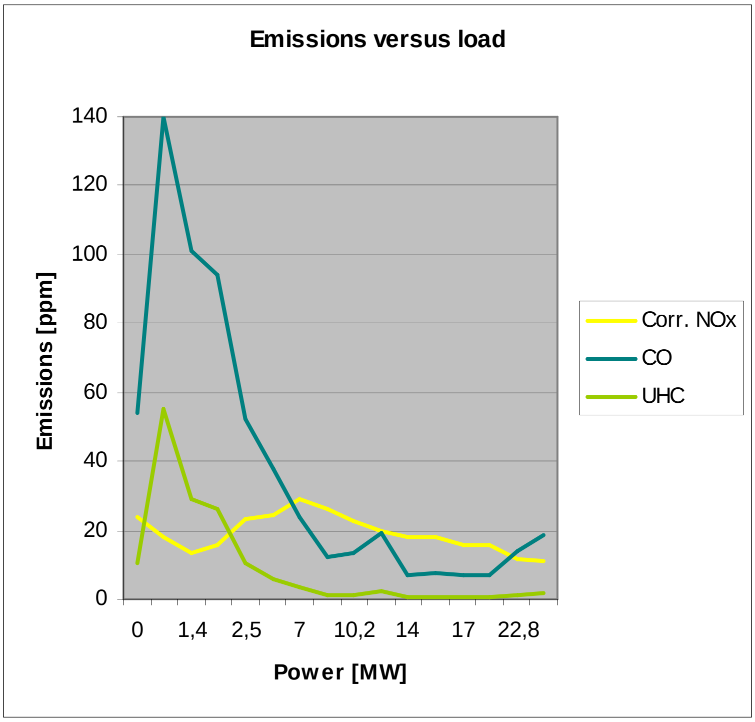

Figure 5-11: Mapping data for Åsgard B [37].

5.6.9.2 Valhall

The main generators on the injection platform on Valhall are driven by two LM2500 DLE gas turbines. For the time being, one is running on 50 % load and the other one is spare, but power demand on Valhall will increase when more water injection pumps are needed. Load variation for week 51, 2006, is shown in Figure 5-12 with 19 sample points taken.

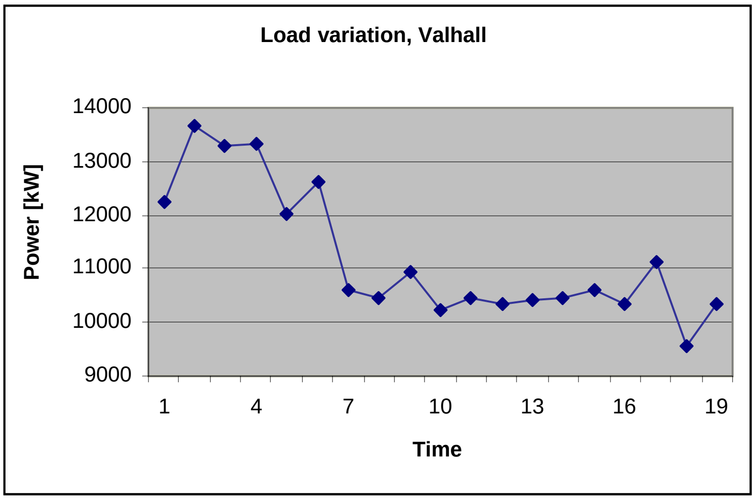

Figure 5-12: Load variation at Valhall week 51, 2006 [41].

Generator B has had twice as many start-ups as the A generator, due to trouble with the calorimeter. Located 40 - 50 meters away from the turbine, this might give wrong heating values. The calorimeter core is now changed, but it still has to be calibrated every month. Since the gas turbines have run on part loads, they have not been within the DLE guarantee window. After 12 000 hours of operation, the combustors do not have any damages, and this may be due to a low load profile so far. However, the B unit has a crack on one of its strut heat shields.

Unit A experienced load acceptance problems when load increased from 7 to 12 MW. The unit shed its load and went into normal shutdown sequence, and this was due to a faulty power management system.

There has also been some trouble with the compressor discharge pressure valve that regulates air-fuel ratio and the fuel gas valves. In the future, fuel gas valves will probably be changed every 10 000 hours, instead of waiting until they break down [39,40,41].

In 2010, all gas turbines on Valhall will be shut down, and its new field centre will be supplied with power from shore. Onshore, a rectifier will convert AC current to DC before it is transformed to 10 kV and sent as high voltage in a 292 km long cable. On Valhall, the current is converted back to AC and transformed to the required voltage levels. Total transmission capacity is 78 MW. The argument for choosing an all-electric solution included less maintenance, longer lifetime and higher availability than the alternative with a combined cycle. In addition, fuel gas, CO_2 and NO_x tax are saved when choosing power from shore [4].

5.6.9.3 Clair and Bruce

On the UK continental shelf, BP has got three Solar Titan generator sets on the Clair platform. These are all dual fuel machines with DLE technology, but they have not been set up for low NO_x yet due to loads below 50 %. Bruce has got two Solar Mars gas turbines for compressor drive, but these have neither high enough load to run with DLE [42].

5.6.9.4 Wissington

British Sugar was the first customer to order two dual fuelled LM6000 DLE gas turbines at two of their cogeneration plants in the Eastern part of England. Commercial operation started late 1998 with emission guarantees of 25 ppm NO_x from the gas turbines. Since that time, the combustors have been retrofitted with combustors achieving NO_x emissions as low as 15 ppm. This is made possible by a combination of DLE and SPRINT.

Mapping window for the new combustors is wider, and the gas has a fixed heating value and specific gravity. After a borescope inspection at 12 000 hours it was concluded that the combustors look brand new. The gas turbines have in addition showed excellent start reliability.

The plants run on base load only and the surplus power is fed into the local grid. The majority of the shut downs have been caused by a weak grid and the engines have shown capability of load rejections up to 42 MW without flameout or trips. Efficiency at full load lies between 40 and 41 %. If the gas compressor trips, it is necessary to switch to diesel as fuel. In one year, the turbines run approximately 400 hours on diesel, with NO_x emissions of 60 ppm.

British Sugar has not experienced any problems related directly to the DLE, but there have been some issues regarding switches and valves. A couple of times, hoses failed when switching from gas to liquid, which resulted in an explosion within the gas hoses. This has now been solved using a nitrogen purge system. Inspection intervals are increased from 3 to 6 months. A very good inlet filtration system makes water washing less important than for several other plants [43].

5.6.9.5 Alvheim

The Alvheim FPSO will start operating in 2007, and its main power generators will be 2 + 1 LM2500 dual fuel DLE machines. It is the first time that General Electrics supplies these gas turbines with dual fuel technology, and if successful, other fields will probably follow. Marathon has planned to map the machines 2 or 3 times due to changes in fuel gas [44]. The following table shows emission guarantees for the power generators for Alvheim, and they are given for loads above 75 % only.

Table 5-3: Emission guarantees for Alvheim.

Emission guarantees	Gas [ppm]	Liquid [ppm]
NO_x	25	100
CO	25	25

5.6.10 Summary

DLE combustors consist of concentric rings that can be operated separately in order to maintain low emissions of NO_x from idle to full load. At low loads, the compressor needs relatively more power due to compression of air that is not utilised for producing work. Maintenance costs are somewhat higher for DLE turbines, even though overhaul intervals are equal to those for SAC turbines. Blowout may be an issue because of a low fuel-air ratio for the mixture.

DLE machines are calibrated to operate within a narrow window, and are therefore more vulnerable to fuel gas deviations than conventional turbines. Low reliability and availability used to be a problem, but both have improved with maturation of technology and increased operational experience.

5.7 Cheng

Dr. Dah Yu Cheng started developing the Cheng Cycle already in 1974. Today there exist different cycles, both for emissions reduction (Cheng Low NO_x) and for power augmentation (Advanced Cheng system), or a combination of the two. The idea is to premix steam and fuel in the nozzles, and thereby suppress flame size and promote combustion efficiency to consume most of the excess oxygen. Unlike other conventional steam or water injection system for NO_x control, CO levels are very low, typically in the range of 1 to 5 ppm. In addition, increased mass flow rate results in a power increase.

The first Cheng cycle was made for an Allison 501-KH gas turbine. Initially, air bleed ports were used as steam injection ports, but the thrust bearing of the engine overheated. Therefore, six large ports located between the combustion cans just ahead of the premixed air inlet were used instead. Test results showed that the location of steam injection ports influenced the NO_x emission rate, but not power increase or efficiency [45].

Figure 5-13 shows thermal efficiency versus power output for increased steam injection rate. The peak is called the Cheng point, and any further increase of steam injection rate beyond this point will increase power output with diminished thermal efficiency.

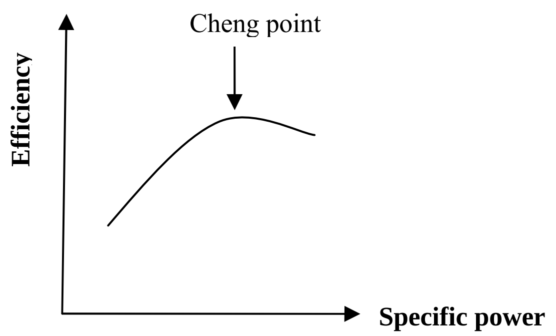

Figure 5-13: Thermal efficiency versus power [46].

There are basically two requirements for achieving ultra-low emissions with Cheng technology. One is a homogeneous premix of steam and fuel and the other is a fuel nozzle that will operate at high steam-fuel ratios. With two static mixers in series, the first requirement can be met without any problems. The challenge is therefore to design a fuel nozzle that can operate at steam ratios up to 4:1 without flame instability problems, and without increasing emissions of carbon monoxide or unburned hydrocarbons [47].

Even though Cheng technology is implemented, the gas turbine may operate without steam. A variable-pressure HRSG has an operating range extending from idle to full load. At start-up, the machine will work as a simple cycle gas turbine following the manufacturer's procedures. In the mean time, compressor discharge air is bled through the steam injection line going towards the HRSG.

For the required power level, there is a certain amount of steam that needs to be injected. Compressor air therefore flows backwards until steam is produced from the gas turbine exhaust. Once the steam drum pressure is raised beyond the compressor discharge pressure, air accumulated in the drum will be forced out and steam follows into the turbine. When the steam flow is at its required level, the steam valve starts to close and the HRSG drum pressure will go towards equilibrium.

At shutdown, the steam valve will close before the fuel control valve, and the machine will follow normal shutdown procedure. Therefore, no steam or condensate will be accumulated in the gas turbine [46].

5.7.1 Thermal efficiency

According to [48], a power output up to 100 % is achievable without need for excess fuel. As a result, thermal efficiency may be improved up to 40 %, depending on steam-fuel ratio. The pressure drop is substantially lower in a combustor with this technology compared to DLE combustors. Efficiency data for Kapaia power station is shown in Figure 5-14.

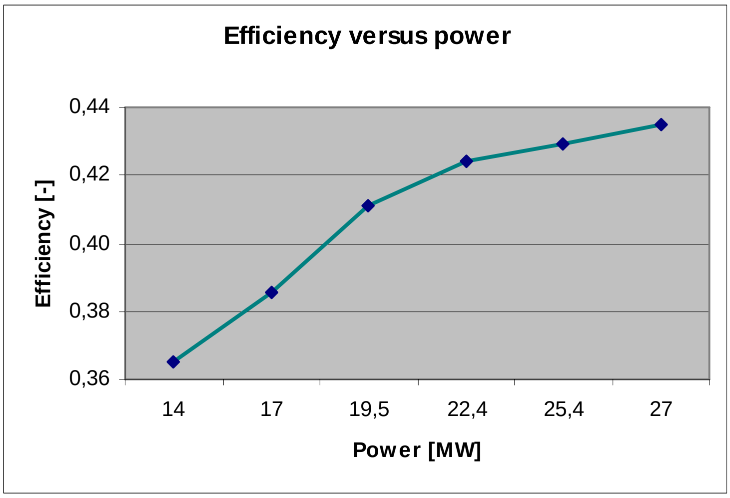

Figure 5-14: Efficiency versus power for Kapaia [46].

The figure clearly shows the advantage of Cheng technology when running on part load. Kapaia operates at more than 40 % efficiency when running on base load, and its load range goes from 60 to 100 %. With a 14 MW output, efficiency is more or less the same as for a conventional gas turbine. More information about the power plant is given in section 5.7.8.

5.7.2 Emissions

Since less fuel is burnt in the gas turbine, the emissions of CO_2 decrease. NO_x emissions are kept at a low value due to reduction of flame temperature. An advantage of the Cheng cycle is that also CO levels are kept low over a wide operating range. If the steam-fuel ratio is set to 2.5 or more, emissions of both NO_x and CO are less than 5 ppm. Some experiments have achieved levels as low as 2 ppm. More emissions data will be provided in the following sections.

Ecoxy has done some calculations regarding the offshore industry in Norway. If Cheng technology were retrofitted on 50 LM2500 gas turbines on the Norwegian Continental Shelf, annual NO_x emissions would decrease with 24 000 tonnes. In addition, CO_2 emissions in the range of 1 million tonnes per year could be avoided. This would be the direct result of an increase in power without adding any extra fuel [49].

5.7.3 Maintenance requirements

According to Cheng Power Systems, the cycle has got low maintenance costs and long hot parts life. It is important that the steam is very clean before it is injected. This is accomplished with steam separators in the steam drum and an external steam separator. In addition, the steam should not contain any sulphur, as it may cause high temperature corrosion in the turbine hot sections. If there are any air-cooled vanes or blades, they should be internally coated to prevent corrosive attack on the cooled metal surfaces [50]. Cheng surveyed temperatures of hot parts with thermocouples and optical instruments during testing, but no substantial change of metal temperature of the first and second stage nozzle and blades were observed [45].
Compared to water injection, premixing of steam and fuel will increase lifetime of the combustion liner and other hot section parts. However, maintenance for the overall cycle is expected more extensive than for conventional gas turbines.

5.7.4 Load acceptance and rejection

The advanced Cheng cycle has fast start-up and shutdown capabilities, and was developed to respond quickly on fluctuating market demands. If the load suddenly drops, the steam control valve will cut back the amount of steam immediately to follow steam-air ratio defined by the operating trajectory. On the other hand, if load demand suddenly increases, the valve will again set the steam-air ratio to its required peak efficiency point on the operating trajectory. Cheng can respond as rapidly to load changes as that of a simple cycle gas turbine, which is advantageous to a combined cycle [46].

5.7.5 Engine stability

Engine stability is not affected by steam injection assuming proper engineering of the fuel nozzles, combustion liners and steam injection ports [50]. A rapid response from the control system is also needed. Combustion noise can be reduced with a high steam-fuel ratio. Since load acceptance and rejection is handled primarily by temperature increase/decrease, chances of flameout are small. Some vibration may occur if steam supply is suddenly dropped.

5.7.6 Reliability and availability

Availability and reliability are not affected when injecting steam into the gas turbine, assuming good engineering in the steam injection piping and turbine controls. A reduced firing temperature and better flame pattern may increase hardware lifetime, according to the people who developed Cheng [50]. It is advantageous that the plant may run as a simple cycle if steam is not available for injection. Reliability and availability will be looked into in chapter 5.7.8.

5.7.7 Distinction between STIG and Cheng

The STIG cycle has an HRSG with a constant pressure level, whereas Cheng utilises a variable pressure steam generator. STIG also requires a special steam injection skid for start-up to avoid water droplets entering the gas turbine. Its steam pipe is heated before sending steam through it. In contrast, Cheng utilises compressed air flowing backwards through the steam injection pipe and bleeds it between the super heater and the evaporator for about 30 seconds at start-up. Once steam is generated, it will drive the accumulated air back out of the piping system.

GE's LM2500 PH is available both with STIG and Cheng technology, but differs in the amount of steam that could be injected. While Cheng Cycle injects 32 700 kg/h of steam, the STIG cycle can maximum inject 22 700 kg/h. For the latter steam rate is strictly limited by a maximum allowable compressor discharge pressure of 19.4 bars. This limit could in the future be removed by further opening the first stage turbine nozzle area.

Cheng has a more constant power output and a higher efficiency over varying ambient temperatures than the STIG cycle has [46].

5.7.8 Experience

The first commercial Cheng Cycle was built on San Jose State University campus to supply electricity and steam for power, heating, and cooling. Surplus power was fed into the local electricity grid. In 2002, this plant had been operating for 18 years with an average of 8200 hours a year and an availability level over 99 %. Today there exist more than 100 units in operation, the majority being industrial gas turbines [45].

Cheng technology has also been tested on an LM2500 turbine fired by natural gas at a rig in California. A set of six specially designed, reduced pressure drop fuel nozzles were set up in a segment of an annular combustor. NOx levels below 2 ppm were reached at a 4:1 steam-fuel ratio. CO emissions were constantly held at a 2 ppm level across the entire steam-fuel operating range, simultaneously maintaining a stable flame. At that level, equivalent heat rate reduction for constant power was about 28 % and the CO2 reduction 18 %. This is shown in Figure 5-15.

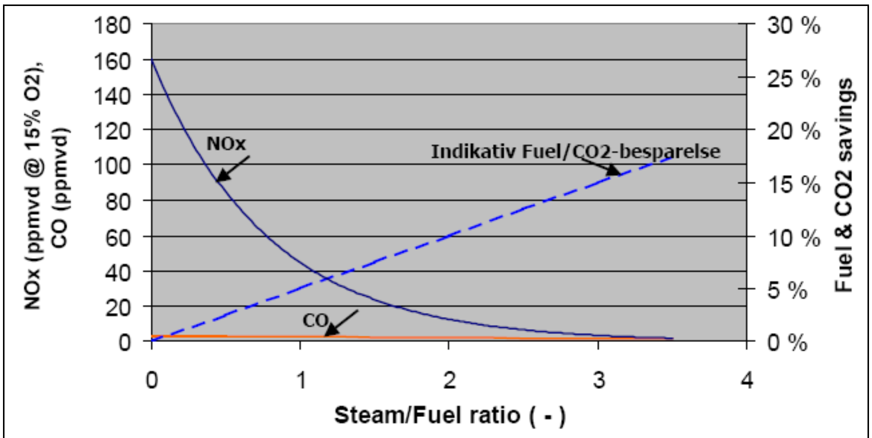

Figure 5-15: Results from combustor test for an LM2500 [51].

5.7.8.1 Kapaia Power Station

Kauai Island Utility Cooperative operates Kapaia Power Station, which is located on the island of Kauai, Hawaii. The plant supplies the island with about 50 % of its electrical power demand and usually runs 24 hours a day, 7 days a week. It features a Cheng cycle with a steam injected LM2500 PH gas turbine providing 27 MW to the grid. Naphtha fuel is burned primarily, although diesel is used for start and shutdown and for backup.

Steam is produced in a Once-Through Steam Generator (OTSG) and injected back into the gas turbine. The boiler has a fast start-up time, and full steam injection is available in less than one hour. Power augmentation is the main purpose, and steam is therefore injected at the compressor discharge. A smaller amount is added to the fuel nozzles for NO_x control. At full load, 26 500 kg/h of steam is added to the compressor discharge, while 4200 kg/h goes through the fuel nozzles. This gives a steam-fuel ratio of about 0.8. Low emissions are achieved by a combination of Cheng and SCR. By boosting nozzle steam injection up to 10 000 kg/h, NO_x levels can be kept below 12 ppm without the use of SCR. The trade off is that a lower flame temperature leads to incomplete combustion, with CO emissions up to 70 ppm, and lower overall efficiency. Kapaia has a Continuous Emission Monitoring System with a reliability of 98 % [52].

Although trips have occurred, they have usually been external to the power island. The plant has been very reliable, with inspections twice a year, and major overhauls every 25 000 hours. Flameout has been experienced occasionally at start up, but never during normal operation. This has been a fail to light rather than flameout [52].

5.7.8.2 Agnews

Calpine operates several power plants in the US, where one of them is the Agnes Power Plant in San Jose, California. The plant is a natural gas-fired combined cycle consisting of an LM2500 PE gas turbine and a steam turbine with a total power output of 28 MW. Water injection and selective catalytic reduction are today applied as NO_x abatement technologies. This involves an ammonia slip, and Calpine therefore wants test Cheng technology on the plant. Statoil were supposed to join the testing in May this year, but it has now been postponed.

5.7.9 Summary

Cheng has proven low single digit emissions of NO_x and CO, simultaneously increasing power output and efficiency. Since less fuel is burnt, it also means that emissions of CO_2 decrease. The technology requires clean water for producing steam without any pollutants. Extra capacity in manifold and nozzles is necessary to achieve a high enough steam-fuel ratio. The Cheng technology seems very promising, and will most likely be introduced onshore in Norway soon. It can easily be retrofitted to a gas turbine already capable of injecting steam. The potential for implementing Cheng on existing installations offshore seems huge, but is limited by space and weight requirements.

5.8 Combined cycles

In many applications, exhaust from gas turbines is released into the atmosphere with a temperature between 400 and 600 ºC. If exhaust gas is directed through a heat recovery unit, heat may be used in the process or for generating superheated steam, which in terms can drive a steam turbine. The turbine may be connected to either a generator or a mechanical load.

At the turn of the century, the worlds first combined cycles were installed on the Norwegian Continental Shelf. This happened primarily at Eldfisk and Oseberg, and thereafter at the Snorre B platform. A typical combined cycle configuration is shown in Figure 5-16.

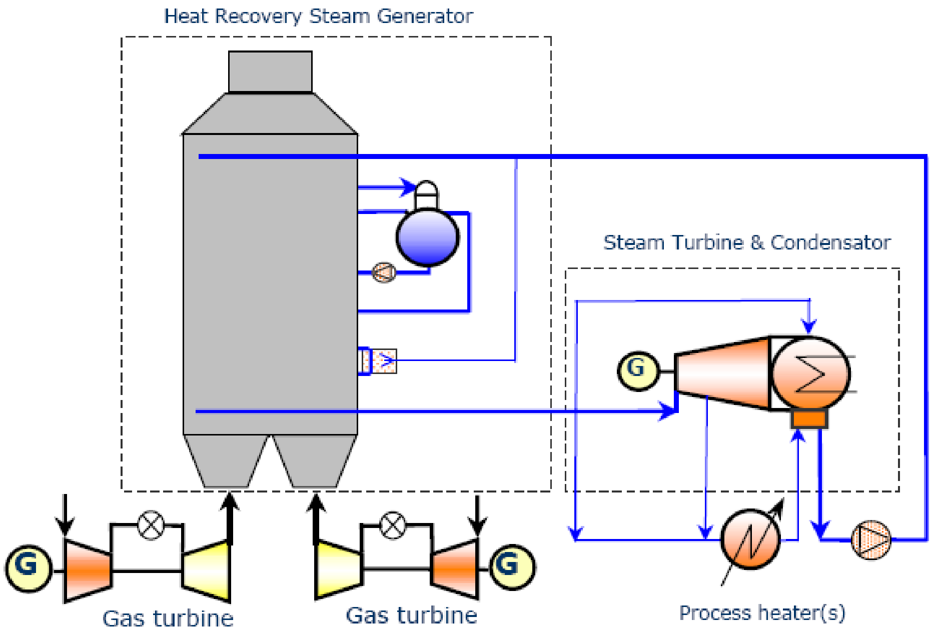

Figure 5-16: Schematic of an offshore combined heat and power cycle [53].

Exhaust gases are directed into a heat recovery steam generator consisting of three heat exchangers, namely economiser, evaporator, and super heater. Water is pumped in the opposite direction and leaves the heat exchangers as superheated steam. Then it flows into the steam turbine where the majority is utilised in the turbine itself, and some of it is extracted and used as process heat. To produce as much steam as possible, it is advantageous to have a high exhaust gas temperature. This technology is also best suited for installations with a moderate process heat demand.

5.8.1 Thermal efficiency

Thermal efficiency for a combined cycle is the ratio between the net work output and the fuel supplied. The equation below shows this connection.

$$\eta_t = \frac{W_{net}}{Q_{fuel}} = \frac{W_{gt} + W_{st} - W_p}{Q_{fuel}} \tag{5.6}$$

A simple cycle gas turbine has efficiency in the range from 20 to 40 %. If a steam turbine is connected to it, efficiency may increase up to 50 %. Figure 5-17 illustrates how this is possible. An onshore combined cycle might have three pressure levels in the boiler, which makes it possible to achieve an efficiency of almost 60 %. Offshore it is common to choose a lighter plant that requires a smaller footprint. The solution is then to connect several gas turbines to a single boiler, and to operate with one pressure level, resulting in a somewhat lower efficiency.

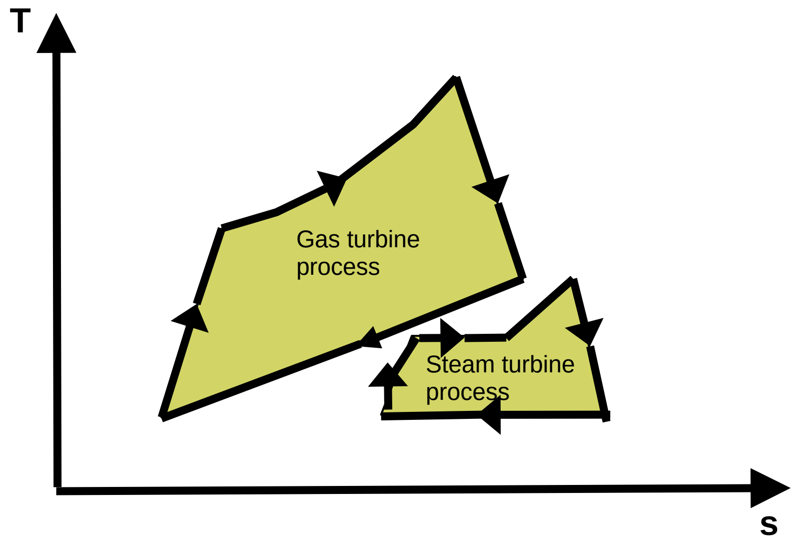

Figure 5-17: Temperature-entropy diagram for a combined cycle.

5.8.2 Emissions

The steam turbine itself does not generate any emissions to the air. As a consequence of not burning excess fuel to generate steam, the combined cycle gets lower specific fuel gas consumption and with that also lower emissions per produced unit. How much the emissions are reduced, depends on the number of gas turbines and their power output. A conventional LM2500 gas turbine generates about 100 000 tonnes CO_2 and 400 tonnes NO_x in one year [35]. If 3 gas turbines and one steam turbine are chosen instead of 4 gas turbines, total emissions are lowered 33 %.

5.8.3 Maintenance requirements

A steam turbine plant consists of robust units and requires in principle less maintenance than a gas turbine. Basically the turbine itself is maintained once a year, even though inspections and adjustments are done more frequently. Maintenance costs for a steam turbine are presumed to be around 5 - 10 % of the costs for a gas turbine. There is no need for extra personnel offshore to operate the steam turbine [54]. Daily cycling and weekly shutdowns can however reduce component life, as there is an increased risk of corrosion when the plant is standing still.

5.8.4 Load acceptance and rejection

Since steam turbines only have got one shaft, they are best suited for power generation applications running at constant speed. Steam turbines installed for generator drives onshore and in boats have shown they are very stable with load changes and process deviations. They work well at low loads, and the power output may be 10 % as well as 100 % [54].

5.8.5 Engine stability

Applying a heat recovery steam generator has a small effect on engine stability for the gas turbine. There will be some pressure loss resulting in a power decrease, but this does not have any influence on operation. As far as the steam turbine is concerned, it has a high stability.

5.8.6 Reliability and availability

A steam turbine itself is very robust and reliable, and requires little attention. For a combined cycle, however, the availability has to be somewhat lower than for a simple cycle, since it is dependant on having more gas turbines operating at the same time. If there does not exist spare capacity in the gas turbines, a steam turbine shutdown will have great impact on lost production and operational costs. It seems like the boiler is the limited factor for maintaining a high availability and this is described further in chapter 5.8.9.

5.8.7 Weight and space considerations

As far as space is concerned, a steam turbine itself is not much larger than a gas turbine with the same power output, but auxiliaries make the plant very complex. Condenser, feed water pumps and the heat exchangers need a lot of space, and the evaporator alone requires more than 6 kilometres of piping. The difference in weight between a steam turbine and a gas turbine configuration is also worth mentioning. For a steam plant, the increase in weight might be more than 300 tonnes compared to a LM2500 generator set. This makes installation of combined cycles on existing platforms difficult [54].

5.8.8 Other considerations

The corrosion risk is probably the biggest challenge for the operator of a combined cycle. Running with a pH value that is too low might lead to corrosion both in the steam turbine and the boiler. However, careful monitoring of the water and steam quality in combination with correct dosing of chemicals can eliminate the problem.

Table 5-4 shows annual savings in operational costs when replacing a 20 MW gas turbine with a corresponding steam turbine.

Calculations were done in the project thesis with the following assumptions [4]:

- Fuel cost: 1 NOK/Sm^3 gas
- CO_2 tax: 0.79 NOK/Sm^3 gas
- NO_x tax: 15 NOK/kg
- External maintenance: 335 NOK/h

Table 5-4: Annual operational savings for a 20 MW steam turbine [4].

Parameter	Value
Fuel gas costs	43 MNOK
CO_2 tax	34 MNOK
NO_x tax	6 MNOK
External maintenance	3 MNOK
Sum	86 MNOK

It is calculated that it is possible to save about 86 MNOK per year in fuel gas costs, taxes and external maintenance if one gas turbine is replaced by a steam turbine.

5.8.9 Experience

5.8.9.1 Snorre B

Two LM2500+ turbines provide a heat recovery steam generator with exhaust heat, and steam is produced in a counter current heat exchanger. The steam turbine was designed to run on 100 % load at all times, and the surplus power was supposed to be exported to Snorre A. If no steam is extracted at medium pressure, the electric output is 17.4 MW. With an 8 MW heat demand, the steam turbine can deliver 15 MW of electricity. However, steam is usually not extracted due to a low process heat demand.

During its initial phase, the steam cycle was very stable with 95.6 % availability and 98.7 % reliability for the three first quarters of 2003. Due to a low pH value in the system, problems with corrosion in the evaporator arose and lead to several shutdowns of the system. For longer periods, the combined cycle has worked only as a simple cycle with the two gas turbines producing electricity only. Fortunately, the power requirement has been lower than expected, and both of the gas turbines have had spare capacity to cover the demand [54]. Later this year, a new evaporator in low alloy steel will be supplied by Kanfa-Tec.

5.8.9.2 Eldfisk

The main power generator on Eldfisk A is driven by a steam turbine that utilises the exhaust heat from one LM2500 and two LM1600 gas turbines. Steam is produced at 16 bar pressure, and maximum output is 10.3 MW. Since the steam turbine is the only electricity producer, the amount of steam has to correspond with the power demand. To ensure control at load variations, the steam cycle is designed to produce 10 % more steam than necessary. Excess heat is sent directly to the condenser by means of a bypass valve. Injection water is used for cooling the condenser before it is injected, and in this way energy is saved.

The steam cycle has worked well, probably best of all steam cycles in the North Sea. The rotor of the steam turbine was damaged early due to leakage of seawater into the steam cycle. At that time, a borescope inspection indicated the turbine to be replaced. Afterwards, it has seemed like it would not have been necessary to change it. Pipe bends in the evaporator have also been replaced due to leakage, but there has not been any corrosion related problems. This is probably a result of holding the pH value above 9.5 at all times. Also, a mixed bed filter produces water with a very low conductivity. Average load during 2004 was 67 %, and the steam cycle had an availability of 90 % [54,55,56].

Compared to a simple gas turbine cycle, the combined cycle gives a reduction in fuel consumption of 23 MSm^3 per year. This corresponds to annual CO_2 reductions 50 000 tonnes, which today means savings of 16.5 MNOK. In addition comes revenue of 23 MNOK, assuming a gas price of 1 NOK/ Sm^3 [4].

5.8.10 Skarv Idun option

Figure 5-18 shows one of the driver options at Skarv Idun with three gas turbines connected to a heat recovery steam generator and a steam turbine.

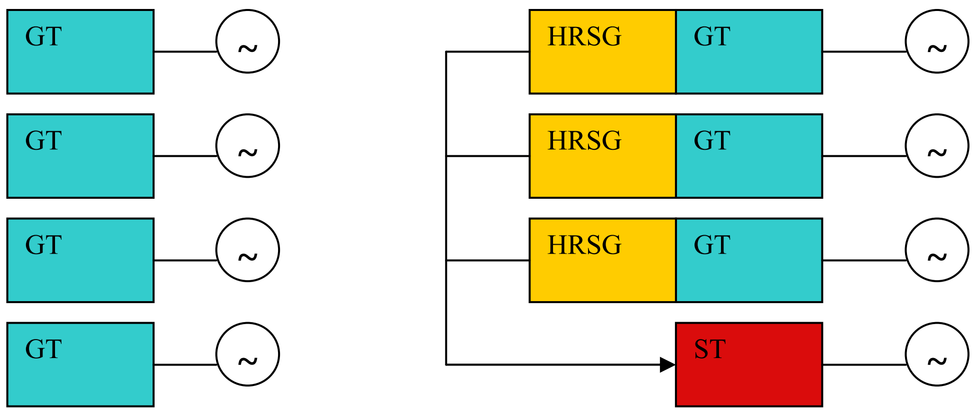

Figure 5-18: Skarv Idun driver option.

Dimensions from the combined cycle plant on Snorre B are used as a basis, but it is important to note that this plant only produces steam from two LM2500+ turbines. Therefore, a combined cycle plant on Skarv Idun will need a larger boiler and steam turbine.

Table 5-5: Dimension and weight for the steam cycle on Snorre B [54].

	Boiler	Steam turbine	Feed water pumps
Length [m]	18	20	3.5
Width [m]	12	5	3.5
Height [m]	17	5	2
Dry weight [tonnes]	240	230	7

With a 20 MW process heat demand, 40 MW heat will be available from the exhaust gases at base load. This means the steam turbine can be designed for producing about 20 MW of electricity. At part load, a relatively larger amount of the exhaust gas heat has to cover the process heat. As a consequence, less steam is available for the steam turbine.

This is an interesting option, but it does not provide the required N + 1 configuration. Therefore, any planned maintenance on one of the gas turbines would lead to production impacts for Skarv Idun. The situation would have been different if LM6000 machines with higher power output had been chosen.

5.8.11 Summary

A steam cycle alone is not considered as a NO_x abatement technology, but contributes to an emission reduction if it is chosen as an alternative to an extra gas turbine. Steam is produced in a heat recovery steam generator and directed to a turbine where power is generated. The combination of gas turbines and a steam turbine increases the plant output and efficiency. However, reliability and availability may be affected due to corrosion related problems and following shutdowns.

The three first combined cycles offshore have had performances as expected, and they were very stable the first years after they were put into operation. Introducing new systems justifies problems due to lack of experience with steam offshore. Next generation of these plants will probably be designed with other material and pressure parameters. Using alloy steel and a lower velocity flow at the evaporator exit may reduce corrosion problem in the heat exchangers. Operational pressure should be increased to 25 - 35 bars in order to avoid fluid inducteous corrosion, and part load pressure should not drop below 12 bars. More robust plants are estimated to become around 10 % heavier than existing offshore plants, and costs will therefore be somewhat higher. [54]

5.9 Combination of technologies

In urban areas, a common combination is to install DLE turbines and post combustion control like SCR. The gas-fired power plant at Kårstø in Norway will use these technologies, due to an emission permit of 5 ppm NO_x. The plant will be put into operation in October 2007. Water or steam injection may also be combined with catalytic reduction of the exhaust, since lowest guarantee limit is 25 ppm running on natural gas (15 ppm for LM2500). Several installations onshore have this combination applied, and they are both good options if ultra-low NO_x emissions are required. The gas turbines are often connected to a heat recovery steam generator for steam production, and the catalyst should be installed inside the HRSG to operate at its optimum temperature. For offshore installations, these combinations will need too much space, both for production of water and for storage of ammonia.

Cheng technology does not require any post combustion clean up if the cycle is gas fired, since a high steam-fuel ratio gives single digit emissions in the first place. Low NO_x levels can be achieved also when firing liquid fuels, but a very high steam-fuel ratio is then necessary. However, there will be a trade off between steam injection rate and overall efficiency. It is therefore possible to combine Cheng with SCR, as shown in section 5.7.8.

The tighter the air quality emission regulations, the more one have to spend on gas turbine and plant equipment. Basic emission control systems like water/steam injection or Cheng technology do not add extra costs on a large scale. Any combination of two or more technologies for NO_x abatement will however result in a more complicated operation of the gas turbines. In addition, equipment operational costs increase significantly.

5.10 Summary

There are advantages and disadvantages with every technology presented in this report. Control strategies incorporated within the combustion process often result in reduced combustion efficiency and stability and thus increased emissions of carbon monoxide and unburned hydrocarbons. The introduction of any diluent into the combustor lowers NO_x production rate, but may reduce efficiency and lowers flame stability.

With Cheng technology it is possible to increase power output without firing additional fuel. This also results in an increased efficiency similar to that of a combined cycle as long as enough steam is injected. The steam injection technology is designed to reduce NO_x and CO emissions to a single digit level.

Applying a DLE combustor decreases efficiency slightly at base load, but the difference increases when running on part load. Blowout is more likely to occur when operating with a very high air-fuel ratio, which is one of the reasons why more complex software is introduced. Aero-derivative engines have proven emission levels of 15 ppm, and a further decrease affects engine stability and reliability/availability.

Post combustion technologies results in a pressure drop and with that a reduction in the plant's power output. Injecting a NO_x reducing medium like ammonia will result in ammonia slip, which might be worse than the NO_x emissions themselves. In addition, catalysts are vulnerable to pollutants and have a limited lifetime. With the SCONO$_x$ technology, ammonia slip is avoided, but there is still a catalyst involved.

Catalytic combustion yields very low emissions, and there is no ammonia slip associated with it. Main drawbacks include high capital costs and limited catalyst lifetime. On the long view, catalytic combustion might become a very promising technology.

All technologies presented will have some emission excursion during off-load or on-load, depending on response time. When it comes to maintenance, combustion modifications can be done without significant impacts. Post combustion technologies are more expensive due to catalyst replacement and, for some, ammonia system filling. Availability and reliability have greatest impact on those technologies that are necessary to get the gas turbine operating.

Figure 5-19 and Figure 5-20 seek to summarise emission levels and efficiencies for all technologies presented. They give an indication of the potential for reducing emissions compared to SAC combustors and the price one have to pay in terms of efficiency. The figures should be regarded as rough estimates. As technologies are developed, the boxes can probably be pushed further down against the zero line. It is important to note that when firing liquid fuels, emissions are considerably higher for all technologies.

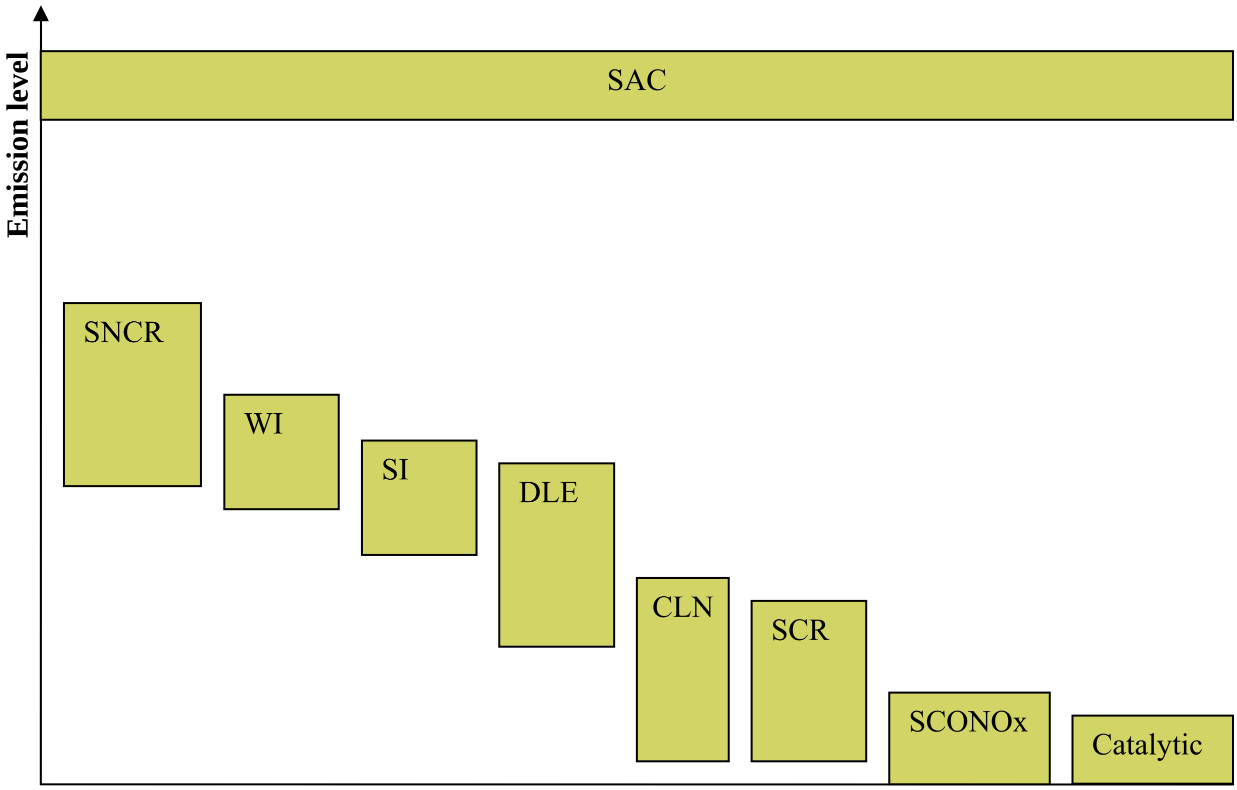

Figure 5-19: Emission levels for NO_x abatement technologies relative to SAC turbines.

SAC: Single Annular Combustor (Conventional gas turbine)
SNCR: Selective Non Catalytic Reduction
WI: Water Injection
SI: Steam Injection
DLE: Dry Low Emissions
CLN: Cheng Low NO_x
SCR: Selective Catalytic Reduction
$SCONO_x$: Catalytic absorption system

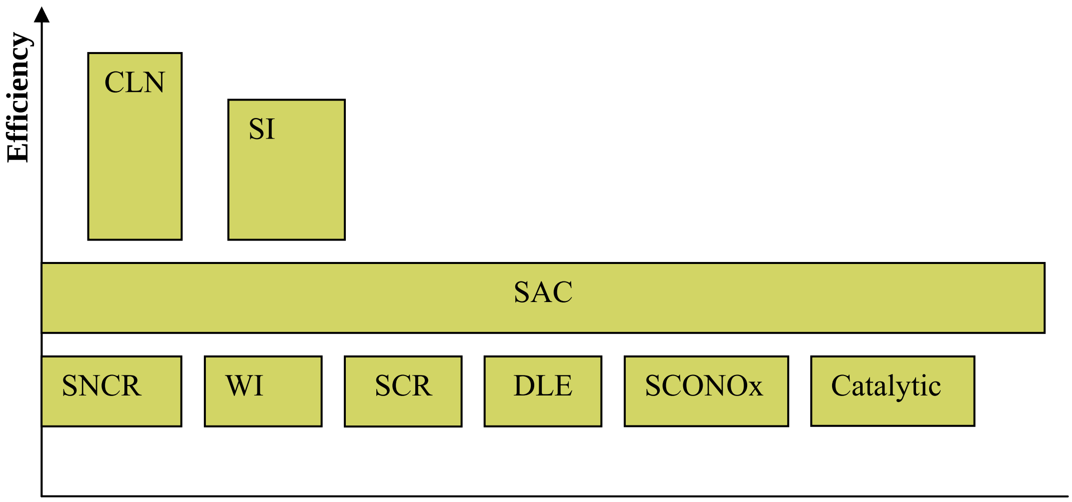

Figure 5-20: Efficiency for NO_x abatement technologies relative to SAC turbines.

6 Discussion

6.1 General

There is limited information regarding NO_x abatement technologies providing exact and reliable data for the public. Available publications on the Internet or in magazines are often angled only showing advantages. Since General Electrics is the major supplier of gas turbines on the Norwegian Continental Shelf, including Skarv Idun, emission levels and other data obtained are based on their technologies. There exist several other manufacturers providing low NO_x technologies, but time has been a limiting factor in covering all. Some techniques are only applicable for a narrow operating range, and in addition, there are very few techniques suitable for offshore installations.

Not all users who were contacted regarding experience of NO_x abatement technologies have responded. A great many of the installations do not have the desired information available, as efficiency, emissions, reliability and availability are not monitored. Also, several operators hesitate to give out too much information because they consider it confidential.

The recommendation in the following sections is based on papers and data found on the Internet in addition to communication with different operators and manufacturers. It is clearly that focusing on low NO_x technology is becoming more and more important for operators of gas turbines.

6.2 Economic Analysis

In this section, an economic analysis has been performed in order to compare CO_2 and NO_x tax with investment and fuel costs. Annual cost of investment and fuel are defined as follows:

$$C_A = NPV \cdot \frac{r \cdot (1+r)^n}{(1+r)^n - 1} \tag{6.1}$$

$$C_F = \frac{3600 \cdot P}{\eta_t \cdot LHV \cdot \rho} \cdot 8600 \cdot f \tag{6.2}$$

Table 6-1 shows symbols and assumptions for the calculations, based on experience from previous courses and the project thesis. Skarv Idun has an expected lifetime of 18 years, which may be extended if more reservoirs are connected to the FPSO [57]. It is therefore assumed a lifetime of 20 years in the calculations. For an LM2500 generator set, capital costs are in the range of 100 MNOK. Since the LM2500+ G4 is a larger and newer machine, costs for four gas turbines are presumed to 500 MNOK. Discount rate is incidentally set to 10 %.

When calculating fuel costs it is assumed that three gas turbines are running with a 32 MW load and 37 % efficiency 8600 hours per year. These costs may be regarded as indirect costs, as fuel gas could be exported and sold for about 1 NOK/Sm^3. Lower heating value and density for the natural gas are both taken from [58]. Results are found in Table 6-2 and Table 6-3.

Table 6-1: Assumptions for annual cost of investment and fuel.

Symbol	Name	Value
C_A	Annual cost of investment	
NPV	Net Present Value	125 MNOK per generator set (500 MNOK total)
r	Discount rate	10 %
n	Lifetime	20 years
C_F	Annual fuel cost	
P	Power	32 MW per turbine (96 MW total)
η_t	Thermal efficiency	0.37
LHV	Lower Heating value	45 MJ/kg
ρ	Density	0.87 kg/m^3
f	Fuel cost	1 NOK/Sm^3

Annual CO_2 emissions from three gas turbines on Skarv Idun are 465 000 tonnes, if they all run on base load [18]. CO_2 tax for 2007 is set to 0.80 NOK/Sm3, which corresponds to 330 NOK/tonne CO_2 [59]. Since the tax has only varied slightly after the introduction in 1991, this value will be used in the following calculations.

Today, NO_x tax is set to 15 NOK/kg, but the government has indicated that its value will increase before Skarv Idun comes into production in 2011. Therefore, calculations with NO_x tax of both 15 and 50 NOK/kg are done. Assuming a NO_x emission level of 180 ppm (SAC combustor) yields the following results:

Table 6-2: Annual investment, fuel and emission costs for SAC gas turbine.

Factor	Calculated value [MNOK]
C_A	58.7
C_F	205.2
CO_2 tax	153.5
NO_x tax (15 NOK/kg)	36.7
NO_x tax (50 NOK/kg)	122.4

The results are also illustrated in pie charts, and it is clearly that fuel costs have the highest impact on operational costs. Figure 6-1 and Figure 6-2 also show that CO_2 tax contributes to a large portion of total costs. If NO_x tax is set to 50 NOK/kg, it constitutes 23 % of the operational costs.

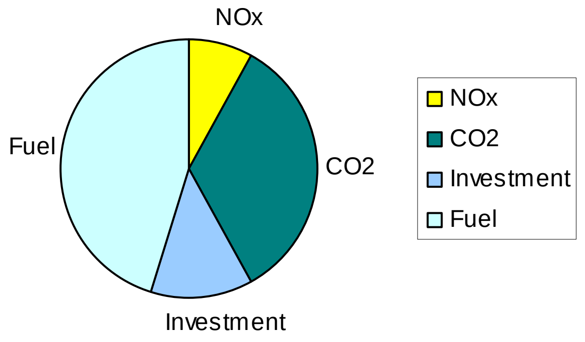

Figure 6-1: SAC and 15 NOK/kg NOx.

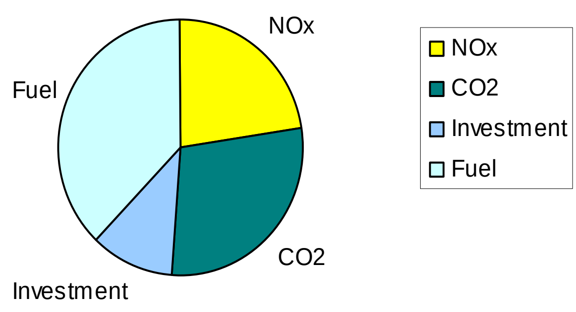

Figure 6-2: SAC and 50 NOK/kg NOx.

When applying DLE gas turbines with a 25 ppm NO_x level, emissions are estimated to a total of 340 tonnes NO_x/year during the peak period [18]. While CO_2 tax and investment costs remain more or less unchanged, fuel costs increase with 2.8 MNOK due to 0.5 % lower efficiency. Calculations of NO_x tax yield the following results:

Table 6-3: Annual investment, fuel and emission costs for DLE gas turbine.

Factor	Calculated value [MNOK]
C_A	58.7
C_F	208.0
CO_2 tax	153.5
NO_x tax (15 NOK/kg)	5.1
NO_x tax (50 NOK/kg)	17.0

As efficiency is slightly decreased, CO_2 tax is expected to be somewhat higher. This is however not taken into account in the estimates. The new relationship between investment, fuel and emission costs is shown in Figure 4-3 and Figure 6-4. NO_x taxation has only got a small impact on DLE turbines compared to CO_2 tax. Fuel costs constitute about half of the total operational costs in both cases. Maintenance and overhaul costs are not taken into account, but when looking back at section 5.8.8, these costs seem to be very low.

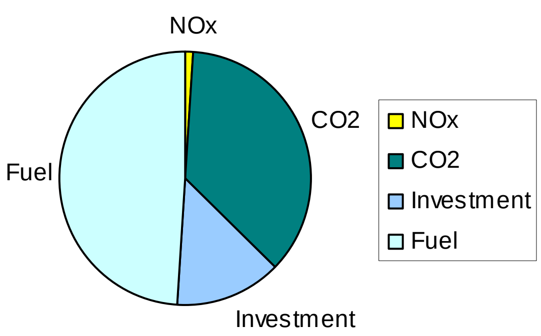

Figure 6-3: DLE and 15 NOK/kg NO_x.

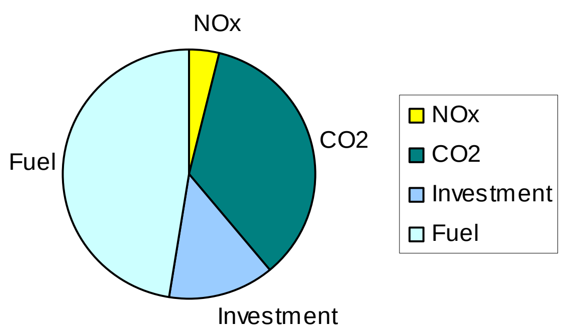

Figure 6-4: DLE and 50 NOK/kg NO_x.

With a NO_x tax of 50 NOK/kg, it seems like it is worth installing DLE turbines reducing annual NO_x tax with more than 100 MNOK.

Offshore operations require a reliable power generation system in order to maintain a high production rate and avoid shutdowns. Implementing a system with limited reliability may cause shutdowns and need for flaring, which in turns can yield huge amounts of undesired emissions from the installation. Gas is lost, and CO_2 and NO_x tax have to be paid for these emissions as well.

6.3 Recommendation for Skarv Idun

In order to get final approval from the authorities, it is necessary with some kind of emission control for the power generators. The selected gas turbines are available with wet and dry low emissions control, and there are several plants around the world where these techniques are applied. However, dry low emission control is the only option considered as qualified technology offshore. Experience from the three combined cycles offshore in Norway also illustrates the challenges related to water and steam production offshore.

With an emission permit of 25 ppm NO_x, it is not necessary to consider catalytic combustion or exhaust gas clean up. A reason for doing so would be if the NO_x tax were increased to such an amount that it would be profitable. Cheng technology for simultaneously reducing emissions of both NO_x and CO seems very promising, but there is probably not enough time to apply it already in 2011.

Even though FPSOs have less limitation regarding space and weight than conventional platforms, there are penalties in terms of installation costs when applying heavy and large equipment. Wet low emission control, Cheng technology and combined cycles all have the same challenges; production of clean enough water in the right amounts and the risk of introducing new technologies offshore. If fresh water can be produced from the sea, this will open for several of the technologies discussed. However, with operation starting in 2011, development of any non-commercial technologies is limited.

Today, General Electrics can supply the LM2500+ G4 DLE gas turbines with emission guarantees of 25 ppm NO_x when firing gas. This seems like the easiest technology to implement, and it is likely that it will be developed a new combustor that can achieve emissions of 15 ppm NO_x like it has been done for the LM6000 machine. Therefore, space should be allocated so that the combustor may be retrofitted when this technology is available.

It is decided to install two single fuel and two dual fuel machines on the FPSO. Even though DLE turbines are available with dual fuel technology, it may be worth waiting for operational experience from Alvheim. If not successful, there will still be time to change the configuration before start-up in 2011.

As far as NO_x emissions are concerned, optimum load will be in the range between 85 and 90 %. This means a power output between 27 and 29 MW for each gas turbine. From the load profile, it looks that this is feasible for the peak production years. CO_2 emissions, on the other hand, are relatively at their lowest when running on base load, and therefore causes a conflict between the two. Since CO_2 tax influences operational costs the most, all gas turbines should be run at as high load as possible.

6.4 Further work

With 40 MW exhaust heat available, it would have been interesting to design a Cheng cycle for the Skarv Idun FPSO. There are several factors that would have to be covered in order to come up with a realistic option. First of all, optimum steam injection rate for the selected gas turbines should fit the load profile. Cheng could be applied not only for power augmentation, but also for reducing emissions of NO_x and CO.

To meet the N+1 configuration requirement, steam-fuel ratio has to be high enough to eliminate one gas turbine package. Therefore, the Cheng cycle will consist of two LM2500+ G4 gas turbines with a net output of 64 MW and the remaining 26 MW has to be covered by injecting steam, which means a power increase of 40 %. If fuel nozzles are configured to handle a large steam ratio, very low emissions could be achieved, also when firing liquid fuel. Assuming a fuel consumption of 7000 kg/h for each gas turbine and a steam-fuel ratio of 1.5, 10 500 kg/h of steam has to be injected in each machine. A more detailed analysis should be performed in order to come up with a realistic solution.

According to Cheng Power Systems, capital costs are not increased compared simple cycle gas turbines. Implementation requires the hull to accommodate a steam injection skid, and installation costs are expected to increase due to weight and footprint penalty of extra equipment. Even though several Cheng cycles are installed onshore, there is an increased safety concern when applying them offshore. A high reliability and availability must be demonstrated in order to implement Cheng technology offshore.

Implementing steam injection results in lower fuel costs, since exhaust gases are used for producing steam and excess power. If there is capacity in the Åsgard Transport pipeline, surplus gas may be exported. Operational costs including CO_2 and NO_x tax are lowered as a result of saving fuel gas, eliminating one gas turbine. Optimum maintenance intervals are not necessarily equal to those plants operating onshore and must be looked into.

By implementing Cheng cycles offshore, BP could stand out as a green company and lead the way towards a more environmental friendly oil and gas industry. It seems like time is too short for Skarv Idun, but looking at a perspective of 10 - 15 years, maybe the next FPSO operated by BP could have Cheng technology implemented.

7 Conclusion

There exist several technologies for reducing NO_x emissions from gas turbines, and they all differ in maturity, emission reduction level and operational impacts. Wet low emission control has been used as NO_x abatement technology for several years and is suitable for onshore installations without space and weight restrictions. While reducing NO_x emissions, injection of water or steam increases CO emissions significantly.

Catalytic combustion has achieved ultra-low emissions of both NO_x and CO on high loads, but this technology is not commercially available for the selected gas turbines. It will probably take some years to develop a catalyst that can operate at the desired temperature range and has long enough lifetime.

Cheng technology has the advantage of very low CO emissions over the total load range and there is no catalyst involved. It increases power output and efficiency since no additional fuel is burned. Regulation is easier than for combined cycles, and less space is required since the steam turbine is eliminated. However, it seems like it may take some time before the technology can be implemented offshore. The main reason is water quality requirements and space demand.

Offshore, dry low emission control (DLE) is the only technology considered qualified. For single fuel gas turbines installed after 1996, this technique has been applied in order to reduce NO_x emissions. After a troublesome start-up period, these gas turbines now have reliability and availability levels equal to conventional gas turbines. At base load, thermal efficiency is somewhat lower, and the difference increases as load is reduced.

The easiest option for Skarv Idun is installation of gas turbines with DLE technology and emission guarantees of 25 ppm NO_x. Annual NO_x tax is reduced considerably compared with SAC combustors, and user experience has shown that these gas turbines have little operational impact. Space should be allocated for retrofitting a new combustor if GE develops a new one similar to the LM6000 combustor.

To fulfil Norwegian commitments in the Gothenburg protocol, there is still a long way to go. It is therefore likely to believe that the government will increase the NO_x tax further. A high enough level will force the offshore industry to install NO_x abatement technologies where only SAC combustors or diesel engines are supplying the power. Twenty years ahead, catalytic combustion and Cheng might be realistic options for the selected gas turbines. Statoil is now working with the Cheng technology, and it will probably be installed on gas turbines in Norway soon.

8 References

[1] Skarv Idun Development (2006): *Skarv Driver Selection Technical Report.* Document No: SKA-BP-R-000003, revision 0, November 27, 2006.

[2] G. H. Badeer (2000): *GE Aeroderivative Gas Turbines – Design and Operating Features*. Paper found at http://www.geenergy.com. Accessed 2007-02-06.

[3] D.A. Voltz, S.C. Beaver, C.L. McDonald (2004): *The right mix of drivers and power generation.* IEEE Industry applications magazine. http://www.ieee.org/ias.

[4] Kristin Alne (2006): *Kraftgenerering offshore / Power generation offshore.* Project thesis written at the Norwegian University of Science and Technology, autumn 2006.

[5] Statistics Norway (2006): *Considerable NOx reductions necessary*. Article found at http://ssb.no/english/subjects/01/04/10/agassn_en/. Accessed 2007-02-09.

[6] Norwegian Pollution Control Authority (2006*): Tiltaksanalyse for NOx / Needs assessment for NOx.* Available at http://www.npd.no/NR/rdonlyres/7FB96D98-97E7-4C2F-B5D4-380F00F16EAC/0/TiltaksanalyseforNOx.pdf Accessed 2007-05-01.

[7] European Commission (2006): *Integrated Pollution Prevention and Control. Reference Document on Best Available Techniques for Large Combustion Plants.* Chapter 7: Combustion Techniques for Gaseous Fuels.

[8] Finance Ministry (2006): *NOx avgift / NOx tax*. Article found at http://odin.dep.no/fin/norsk/aktuelt/nyheter/006071-210318/dok-bn.html. Accessed 2007-02-09.

[9] OLF (2000): *Revidering av utslippsfaktorer for CO_2 og NO_x. Sluttrapport / Revised emission factors for CO_2 and NO_x. Final report.*

[10] Sissel Wiken Sandgrid (2006): *SFT – PEMS og CEMS.* Presented at meeting 06.12.2006.

[11] Gilbert H. Badeer (2005): *GE's LM2500+G4 Aeroderivative Gas Turbine for Marine and Industrial Applications.* Available at: http://www.gepower.com/prod_serv/products/tech_docs/en/downloads/ger4250.pdf. Accessed 2007-02-26.

[12] Saravanamuttoo, Rogers, Cohen (2001): *Gas Turbine Theory*. 5th edition. Pearson Education Limited.

[13] OLF (2006): *Quantification of NOx emissions from gas turbines*.

[14] Charles E. Baukal jr. (2000): *The John Zink combustion handbook.* 1st edition. CRC Press.

[15] Stephen R. Turns (2000): *An introduction to combustion. Concepts and applications*. 2nd edition. Mc Graw Hill.

[16] Lecture in TEP10 'Gas turbines and compressors' held by Heikki Oltedal, Statoil. October 2006.

[17] Olav Bolland (1996): *Tilgjengelighet og pålitelighet for gassturbinbaserte kraftverk / Availability and reliability for gas turbine power plants.*

[18] Calculations made by Charles McDonald, Rotating Equipment Technical Authority, BP Skarv Idun Project.

[19] MTU (2006): *Repair on a rough sea.* Article available at http://www.mtu-aeroengines.com/en/take-off/report/inhalt/206_IGT/index.html. Accessed 2007-07-14.

[20] Personal communication with Mark X. Hughes, Solar Turbines.

[21] James G. Seebold (2006): *Gas Turbine NOx Reduction Retrofit.* Paper presented at 2006 AFRC International Symposium.

[22] Data sheet found at http://www.geenergy.com. Accessed April 23, 2007

[23] David L. Wojichowski (2006?): *SNCR System – Design, Installation, and Operating Experience.* Paper found at http://www.de-nox.com. Accessed April 30, 2007.

[24] Larry Czarnecki, Jim Fuhr, Rick Oegema, Robert Hilton (2000): *SCONOx – Ammonia Free NOx Removal Technology for gas turbines.* ASME paper IJPGC2000-15032.

[25] California Environmental Protection Agency (1998): *Evaluation of the Goal Line Environmental Technologies LLC SCONOx System.* Environmental Technology Certification Program.

[26] Arthur H. Lefebvre (1998): *Gas turbine combustion.* 2nd edition. Edward Brothers.

[27] Data sheet found on http://www.kawasakigasturbines.com. Accessed May 2, 2007.

[28] Rich Rapagnani (2003): *Technologies to reduce GT emissions.* Texas Technology Showcase. Houston, March 17-19, 2003.

[29] S. Cocchi, G. Nutini, M.J. Spencer, S.G. Nickolas (2006): Catalytic combustion system for a 10 MW class power generation gas turbine. Available at http://www.sciencedirect.com. Accessed 2007-04-15.

[30] Data sheet found at http://www.gepower.com/prod_serv/products/aero_turbines/en/downloads/lm6000_sprint.pdf. Accessed 2007-04-29.

[31] Statoil (2005): *Redegjørelse til SFT i forbindelse med fastsettelse av krav til utslipp til luft.* Available at http://www.sft.no/artikkel____31682.aspx. Accessed 2007-02-16.

[32] Olav Bolland (2004): *Thermal Power Generation.* Compendium in TEP9: Thermal Power Generation. Department of Energy and Process Engineering, NTNU.

[33] Information provided by Dresser Rand.

[34] NPD (2005): *Utredning av mulige NOx-reduserende tiltak på sokkelen / Review of NOx reducing actions on the Norwegian Continental Shelf.*

[35] E-mail correspondance with Marius Sønstebø, Statoil.

[36] Information provided by General Electrics.

[37] Data provided by Statoil.

[38] Personal communication with Arne Sørli, Advisor Rotating Equipment, Statoil.

[39] Personal communication with Lillian Sponaas, Rotating Engineer BP.

[40] Personal communication with Jostein Flatabø, Turbine Mechanic, BP.

[41] Information extracted from Process Net, BP.

[42] Personal communication with Nick A. Custard, Rotating Engineer BP.

[43] Personal communication with Tim Golden, CHP Manager British Sugar.

[44] Personal communication with Trygve Nyheim, Maintenance and Modification Superintendent Alvheim, Marathon Petroleum Company.

[45] Cheng, Dr. Dah Yu, Nelson, Albert L.C (2002): *The chronological development of the Cheng Cycle Steam Injected Gas Turbine during the past 25 years.* ASME paper GT-2002-30119.

[46] Dr. Dah Yu Cheng (2006): *The distinction between the Cheng and STIG cycles.* ASME paper GT-2006-90382.

[47] Victor de Biasi (2004): *Steam – fuel mix limits NOx and CO below 3 ppm without DLN or SCR.* Article printed in Gas Turbine World Octorber – November 2004.

[48] Information found at http://www.chengpower.com. Accessed 2007-04-04.

[49] Bjørn Haukebø (2006): *Steam Injection in Gas Turbines.* Presentation held at NOx seminar in Stavanger, June 28th, 2006.

[50] Personal communication with Randy Turley, President and CEO of International Power Technology, IPT.

[51] Ecoxy (2006): *Steam injection in gas turbines.* Available on http://www.ecoxy.no/nox-seminar/6_steam_injection_in_gas_turbines.pdf. Accessed 2007-04-04.

[52] Personal communication with Kenneth Daubert, Plant Superintendent Kapaia Power Station.

[53] Kanfa (2003): *Boiler design for offshore platforms.* http://www.ecoxy.no. Accessed 2007-04-15.

[54] Personal communication with Pål Kloster, Kanfa-Tec, autumn 2006.

[55] Personal communication with operators at Eldfisk's control room.

[56] ConocoPhillips (2005): *Vurdering av Ekofisk-områdets energianlegg og informasjon om utslipp av NOx.*

[57] BP (2006): *Konsekvensutredning Skarv Idun.* Available at http://www.bp.no. Accessed 2007-02-08.

[58] Jan M. Øverli (1992): *Strømningsmaskiner.* Bind 3 Termiske maskiner. 2nd edition. Tapir.

[59] NPD (2006): *Fakta Norsk Petroleumsverksemd 2007. Kapittel 9: Miljøomsyn i Norsk Petroleumsverksemd.* Available at
http://www.npd.no/Norsk/Produkter+og+tjenester/Publikasjoner/Faktaheftet/Faktaheftet+2007/Kapittel+9.htm.
Accessed 2007-06-03.