South Humber Bank Power Station

PPC Permit Application

Application Reference No MP3235LY

Centrica SHB Limited

Applicant and Operator

RSK ENSR Group

Applicant's Consultants

February 2006

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

NON-TECHNICAL SUMMARY

South Humber Bank Power Station (SHBPS) is a 1260 MW Combined Cycle Gas Turbine electricity generating station located near Stallingborough in North East Lincolnshire. It entered into commercial operation in 1997. Centrica acquired a 60% interest in 2001 and increased this to 100% in September 2005. The station is operated by Centrica SHB Ltd, an operating company of Centrica plc under its Centrica Energy division.

SHBPS offers the advantage of flexible operations, with the ability to operate in base load (continuously) or other non-continuous operating patterns to match the demands of Centrica's customers in a challenging electricity market.

The power station consists of two Combined Cycle Gas Turbine (CCGT) modules. The first ('Phase 1') comprises three gas turbines, three heat recovery steam generators and one steam turbine. The second ('Phase 2') comprises two gas turbines, two heat recovery steam generators and one steam turbine. Each gas turbine drives its own electrical generator and the hot turbine exhaust is used to generate steam in the heat recovery steam generators. The steam is used to power the steam turbine associated with each module, which drives another generator. The electrical output from the five gas turbine generators and the two steam turbine generators is combined to give the total net nominal output of approximately 1260 MW.

Each gas turbine has 72 burners. During loading of the gas turbines the burners are ignited in stages to ensure stable combustion. The burners use Dry Low NOx (DLN) technology in order to minimise the formation of oxides of nitrogen (NOx). The gas turbines exhaust through the heat recovery steam generators (HRSGs) during all stages of start-up, normal running and shutdown. No bypass stacks are present.

Due to the recovery of the heat in the gas turbine exhausts to generate electricity in the steam turbines, CCGT power stations have the advantage of generating much less waste energy than conventional thermal power stations.

Steam used in the steam turbines must be condensed. Cooling for the condensers at SHBPS is provided by a direct ('once-through') cooling water system for which water is drawn from the Humber Estuary via intake culverts. The abstraction of water is regulated separately (on a catchment-wide basis) by the Environment Agency under the Water Resources Act 1991. The cooling water is mechanically filtered to prevent solids, including aquatic life, from entering the system. Fish impingement issues are covered in the abstraction licence and are not considered under the PPC permitting regime.

In order to provide high quality boiler feed water that will not cause scaling or corrosion, industrial quality water is filtered and ion exchanged in a water treatment plant onsite. Some of the boiler water is purged to the Humber Estuary via the cooling water discharge, to prevent a build up of dissolved solids.

The power station has a nominal (full load) thermal efficiency of approximately 55%, which is considerably higher than conventional, coal fired power stations. Typically the station achieves a thermal efficiency of approximately 51% on an annual basis. Operating on a non-continuous basis inevitably results in slight efficiency losses relative to base load operation.

Emissions from the facility are continuously monitored to ensure ongoing compliance with the environmental consents granted by the Environment Agency. The primary air emission of concern from this technology is oxides of nitrogen (NOx). The station employs Dry Low NOx (DLN) burner technology in order to minimise the formation of oxides of nitrogen. The daily average NOx emission concentration for 2004 (excluding start-up and shutdown and outage periods) was approximately 62 mg/m^3 and is within the limits for the IPC Authorisation of 80 mg/m^3. The operational NOx concentration is below the benchmark emission value for the technology detailed in the IPPC combustion sector guidance of 75 mg/m^3.

The use of NOx reduction techniques has been evaluated within this application. SHBPS has the benefit of recent construction and employing recent innovations in emissions control. No suitable options are available that would economically improve the emissions performance of the station. Dispersion modelling of the station's air emissions predicts that he station releases only contribute a small proportion of monitored pollutant concentrations recorded around the site and that compliance with air quality standards designed for the protection of human health and the environment is achieved.

The station employs water-cooled condensers to dispose of waste heat. Cooling water is discharged to the Humber Estuary. The site reduces water usage by recycling water where possible. Discharges to the Humber Estuary are carefully controlled and monitored to ensure compliance with the station's current Integrated Pollution Control authorisation.

A gas oil fired auxiliary boiler, with low NOx burner technology, provides steam for start up of the first generator module after the very rare case of a complete shut down of the station.

A detailed site investigation has been undertaken to identify potential land contamination resulting from operations at the site. The risk of contamination is controlled onsite by both physical (i.e. bunding and containment) and management techniques (such as procedures and training).

A number of noise release points were identified during the station's design and have noise attenuation fitted. Noise surveys have been carried out to confirm that the power plant has minimal impact on the local community.

The power generation process results in relatively small quantities of wastes, which are generally non-hazardous. Ninety-eight percent of the waste was recycled in 2004.

Raw materials used, other than the fuels, are limited to relatively small quantities of chemicals, mostly used for controlling the properties of the water used in the HRSGs and steam turbines.

The station has an exemplary Health, Safety and Environment record maintained and supported by a fully integrated Business Management System (BMS) that covers:

- Quality,
- Training and development and
- Health, safety and the environment.

The BMS at SHBPS is certified to the international standards ISO 9001 (quality management), ISO 14001 (environmental management) and registered with the European Eco-Management and Audit Scheme (EMAS).

As a prescribed combustion process the power station is currently authorised by the Environment Agency (EA) under the Integrated Pollution Control (IPC) regulatory regime.

1 GENERAL INTRODUCTION AND OVERVIEW

1.1 Name of Installation

SOUTH HUMBER BANK POWER STATION

South Marsh Road
Stallingborough
North East Lincolnshire
DN41 8BZ

The Ordnance Survey national grid reference for the site centre is TA 2286 1327

The Applicant and Operator is:

Centrica SHB Limited

Whose registered office is at:

Millstream, Maidenhead Road, Windsor, Berkshire, SL4 5GD

1.2 Authorised Contacts

Contact for matters relating to the application:

Mr Dave Nicholls
Engineering Manager
Centrica SHB Ltd
South Humber Bank Power Station
South Marsh Road
Stallingborough
North East Lincolnshire
DN41 8BZ

Tel: 01469 554411

Fax: 01469 576466

Email: dave.nicholls@humberpower.co.uk

Contact for matters relating to ongoing operations:

Mr Dave Smales
Generation Manager

Centrica SHB Ltd
South Humber Bank Power Station
South Marsh Road
Stallingborough
North East Lincolnshire
DN41 8BZ

Tel: 01469 577236

Fax: 01469 576466

Email: dave.smales@centrica.com

1.3 Listed Activities

South Humber Bank Power Station (SHBPS) undertakes the following activity listed in Schedule 1 of **The Pollution Prevention and Control (England and Wales) Regulations 2000** (SI 2000 No. 1973) as amended.

Section 1.1. Combustion Activities, Part A(1), paragraph (a):

Burning any fuel in an appliance with a rated thermal input of 50 megawatts or more.

No activities are carried out onsite that are covered by the Waste Incineration Directive (WID).

In the preparation of this IPPC application the following documents have been referenced as primary sources of information.

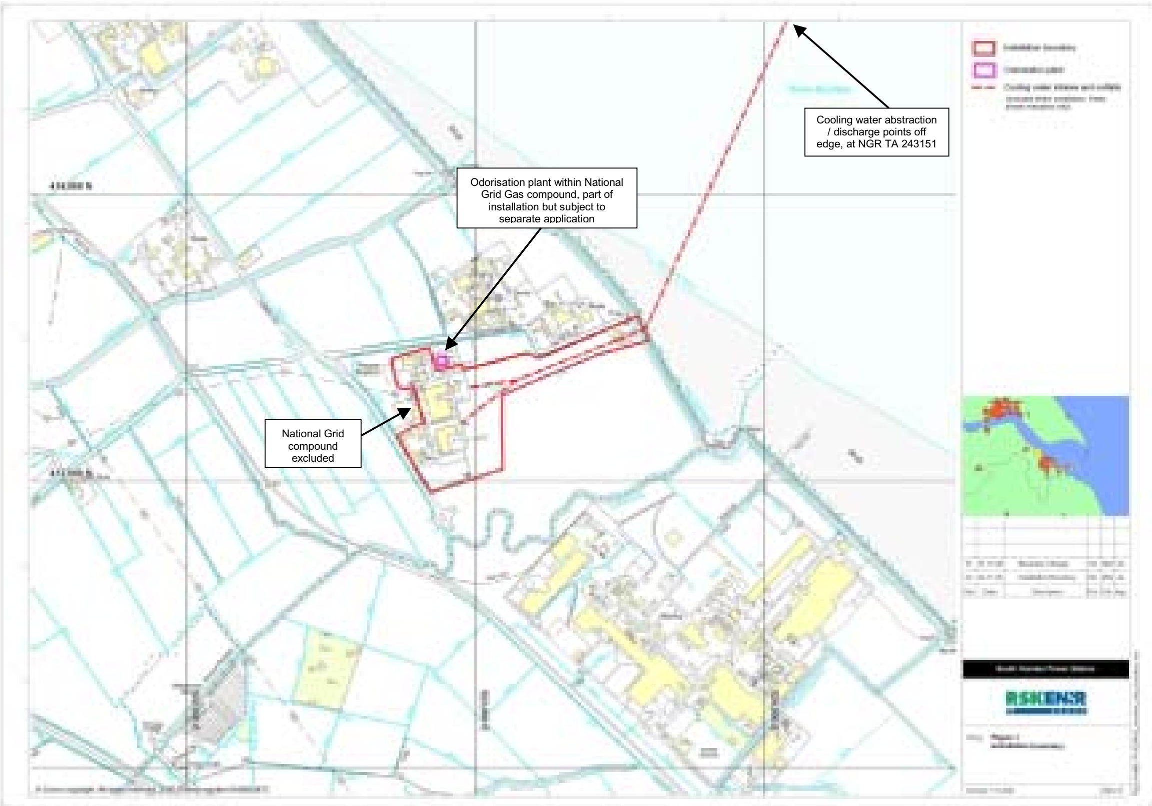
- IPPC Sector Guidance Note – Combustion Activities. Consultation version, November 2005.
- Reference Document on Best Available Techniques for Large Combustion Plants, May 2005.

1.4 Installation Boundary

The installation boundary is shown in Figure 1.1. In pre-application discussions with the local Environment Agency (EA) Inspector it was agreed that the boundary of the installation should exclude the following areas:

- National Grid electricity compound
- Fuel preheaters
- National Grid Gas compound (except the odorisation plant, which is part of the installation but subject to a separate PPC application prepared by National Grid Gas plc)

Figure 1.1: Installation Boundary and Immediate Surrounding Land



1.5 IPC Authorisation History

The station's Integrated Pollution Control (IPC) authorisation, reference number AF4195, was issued on 31 August 1993. The latest variation, reference number BY3568, was issued 19 November 2004. There have been a number of variations to the authorisation over the intervening years and these are documented in Table 1.1.

Table 1.1: IPC Authorisation Variation History

Description	Ref. number	Issued	Effective date	Change or changes made
Application				Application received 21 December 1992.
Authorisation	AH4195	31/08/1993		Authorisation issued prior to construction.
First Variation Section 11	AJ8877	01/01/1994		Major variation, direct cooling.
Second Variation Section 10	AY2559	26/03/1997	01/04/1997	Modification to several conditions in light of experience of operation
Third Variation Section 10	BD8983	25/11/1998	30/11/1999	Addition of ISR reporting conditions.
Fourth Variation Section 10	BF9760	13/05/1999	01/06/1999	Minor variation following 4-year review. NOx limits reduced, changes to discharges to controlled waters and consolidation of ISR reporting requirements.
Fifth Variation Section 10	BR4845	28/06/2002	01/07/2002	Minor variation following 4-year review and change in station operation.
Sixth Variation Section 10	BV0058	29/07/2003	01/08/2003	Minor variation to implement LCPD, changes to condition relating to discharges to water and additional improvement conditions.
Seventh Variation Section 10	BY3568	19/11/2004	27/11/2004	This variation includes monitoring and reporting requirements for compliance with the revised Large Combustive Plant Directive (Directive 2001/80/EC). The variation consolidates Corporate Scorecard Reporting.

The site is currently regulated by the Anglian Region of the EA. No compliance issues were raised during 2004 and 2005.

Table 1.2 summarises the IPC Operator Performance and Risk Appraisal System (OPRA) assessment scores for the site for the last three years and describes the performance of SHBPS. The OPRA is made up of two separate appraisals - one for the risk an installation poses to the environment (Pollution Hazard Appraisal) and another that rates how the operator manages that risk (Operator Performance Appraisal).

Under the **Operator Performance Appraisal (OPA)**, the facility is rated across seven attributes and given a score ranging from 1 (low performance) to 5 (high performance). The sum of the scores for all seven attributes gives the PHA score with higher scores indicating better performances. The seven attributes for OPA are:

1. Recording and use of information;
2. Incidents and complaints;
3. Environmental management system;
4. Knowledge and implementation;
5. Plant maintenance;
6. Management and training; and
7. Process operation.

Under the **Pollution Hazard Appraisal (PHA)**, the facility is again rated across seven attributes, each given a score ranging from 1 (low hazard) to 5 (high hazard). The sum of the scores for all seven attributes gives the PHA score with lower scores indicating reduced environmental risk. The seven attributes under PHA are:

1. Presence of hazardous substances – what is stored;
2. Scale of hazardous substances – what could be emitted;
3. Frequency and nature of hazardous operations – how complicated the process is;
4. Technologies for hazard prevention and minimisation- how the hazard is controlled at source;
5. Technologies for hazard abatement – how environmental emissions are reduced;
6. Location of process – how sensitive the local environment is to pollution;
7. Offensive characteristics – whether emissions are likely to cause local annoyance (such as smell).

The OPA and PHA scores included in Table 1.2 show that the site has been classified as having low to moderate pollution hazard potential and very good operator performance scores.

Table 1.2: Operator Performance and Pollution Hazard Appraisal Scores

Attributes	Operator Performance (OPA) score		
	2002	2003	2004
Recording and use of information	5	5	5
Incidents and complaints	4	4	5
Environmental management systems	5	5	5
Knowledge and implementation	4	4	5
Plant maintenance	5	5	5
Management and training	5	5	5
Process operation	5	5	5
OPA score (Max score 35 – high score is good performance)	33	33	35
Attributes	**Pollution Hazard (PHA) score**		
	2002	**2003**	**2004**
Presence of hazardous substances	3	3	3
Scale of hazardous substances	3	2	3
Frequency and nature of hazardous operations	1	2	1
Technologies for hazard prevention	2	3	2
Technologies for hazard abatement	1	1	1
Location of process	2	2	2
Offensive characteristics	2	1	2
PHA score (Max score 35 – high score indicates high pollution hazard)	14	14	14

1.6 Environmental Surrounding

The installation is located to the east of the intersection of Hobson Way and South Marsh Road, near to the village of Stallingborough in an area north west of Grimsby and east of Immingham, North East Lincolnshire. The site is approximately 500 m by 400 m in size. The centre of the site is at National Grid Reference 522860 413270 or TA 2286 1327.

The site is located in an industrial area and is bordered to the immediate south by Oldfleet Drain, beyond which is a works surrounded by open level farm land. Hobson Way and open level farm land lie to the west. To the north and east are industrial units, beyond which is the estuary of the River Humber. The site is in a low-lying fenland area in the estuarial floodplain of the River Humber.

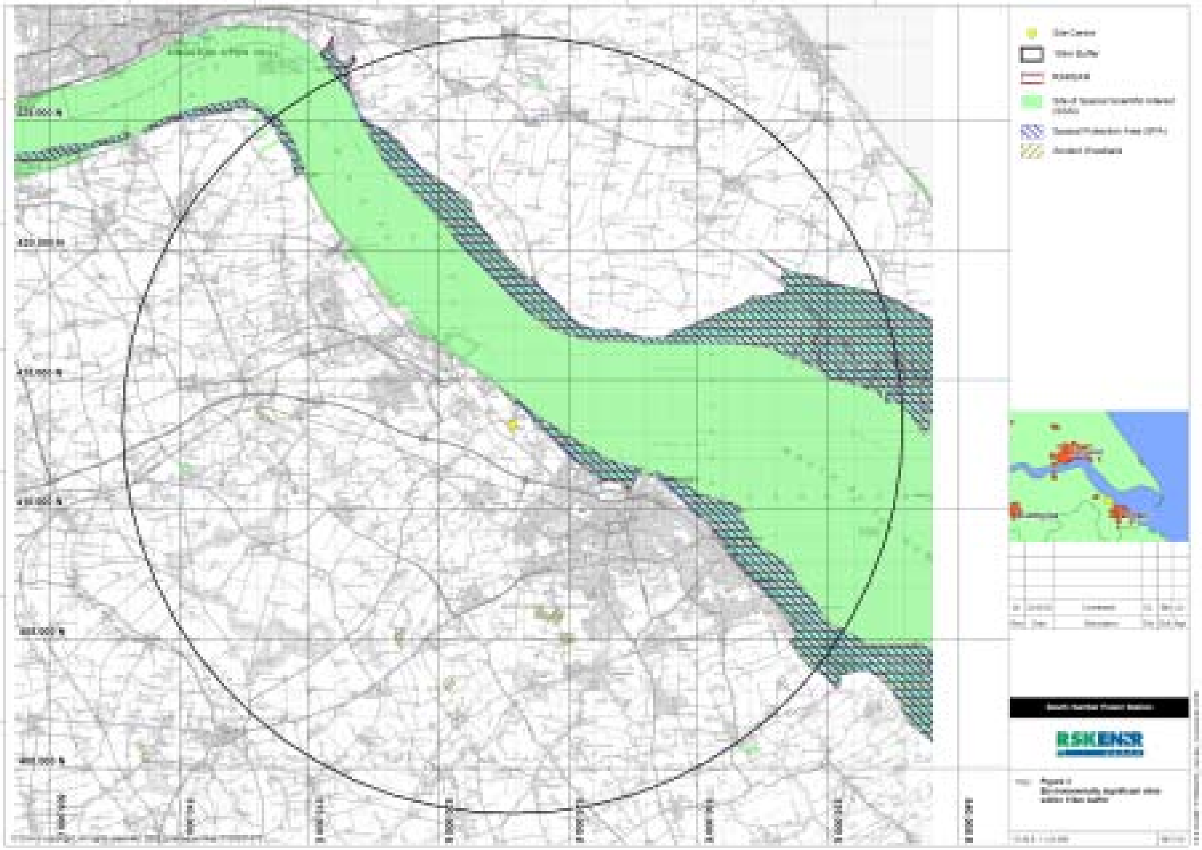
Figure 1.2 illustrates the site location and land use within 2 km of the site.

Within a 10 km radius of the site the Humber Flats, Marshes and Coast are classified as a Special Protection Area (SPA) under the European Council's Directive on the Conservation of Wild Birds (79/409/EEC), and under the Wildlife and Countryside Act 1981 the River Humber is a designated as a Site of Special Scientific Interest (SSSI). In July 1994 the wetland areas of the Humber Flats, Marshes and Coast were recognised as international importance and designated a Ramsar site under the Ramsar Convention.

The Humber Estuary SSSI has been put forward as a possible designated Special Area of Conservation under the EC 'Habitats Directive' (Council Directive 92/43/EEC on the Conservation of Natural Habitats and of Wild Fauna and Flora) although it has not yet been submitted to the European Commission. The area covers just under 40 000 hectares and crosses five local authority borders.

Figure 1.2: Site Location and Surroundings

Figure 1.3: Environmentally Significant Sites Within 15 km



1.7 The Site

The site was constructed in the mid 1990s. Commercial operation of Phase 1 started in 1997 with Phase 2 commencing operation in 1999. Prior to construction of the power station, the land was undeveloped and used for agriculture.

The site comprises:

- Gas and steam turbine halls (2 no.) incorporating control rooms
- Cooling water pump house at the riverside with underground intake and outfall pipes
- A gas compound for incoming supply (owned and operated by National Grid Gas plc)
- Administration block, gatehouse, car parks, workshops, oil storage building and gas cylinder storage compound.
- Electrical substation (owned and operated by National Grid plc)
- Water treatment plants (one for each phase) with raw and demineralised water storage tanks
- Waste collection area
- Auxiliary boiler house with gas oil storage tanks.

A site plan is presented as Figure 1.4 and a Process Flow Diagram is presented as Figure 1.5. This diagram shows major process flows for Phase 2 only. Phase 1 is essentially identical though it has 3 gas turbines where Phase 2 has only 2.

The electrical substation and gas compounds are outside the scope of the installation, except for the odorisation plant, which is located within the National Grid Gas compound and is part of the installation. A PPC permit application for the odorisation plant operated by National Grid Gas plc is being submitted simultaneously with this power station application.

1.7.1 Access and Security

The gatehouse building controls entrance to the site and is manned 24 hrs / day. Comprehensive CCTV coverage of the site is viewable at the gatehouse and control room. There are two emergency access gates that are normally locked with access via the fields.

The site is surrounded on all sides by a high chain-link fence and a surface water ditch. The site perimeter fence is fitted with an intruder alarm and routine inspection and maintenance of perimeter fencing is carried out to ensure the integrity of the fence system.

1.7.2 Historical Land Use

Historical maps identify the site and immediate surrounding area to have been open fields divided by drains mainly in a northwest southeast orientation, on plans from 1890. The only named feature is the Oldfleet Drain.

Between 1908 and 1932 Grimsby District Light Railway was constructed, it runs northwest and southeast and at its closest point is 500 m to the south of the site.

Between 1956 and 1966 there is of development of several industrial units, 700 m to the southeast.

By 1968 a small works development is mapped 300 m to the northeast of the site, and a pipeline is mapped, running from the large southerly works into the Humber.

The map of 1982 shows both of the works near the site have expanded.

Between 1989 and 2000 the Power Station has been developed, with continual development to the other facilities surrounding the site.

1.7.3 Operating Modes

SHBPS varies operation depending on demand employing either, or a combination of.

- Base load (continuous) operation; and
- ‘Two shift’ operation (one or more gas turbines shut down for two shifts i.e. 16 hours per day. One start up and one shut down per day).

Figure 1.4: Site Layout - Major Infrastructure

1.8 Requested Future Permit Conditions

The existing IPC authorisation was updated in November 2004 to take account of requirements identified under the Large Combustion Plant Directive. Accordingly it is anticipated that the authorisation conditions identified in the IPC authorisation will be transferred into any new PPC permit. The following modifications are however requested:

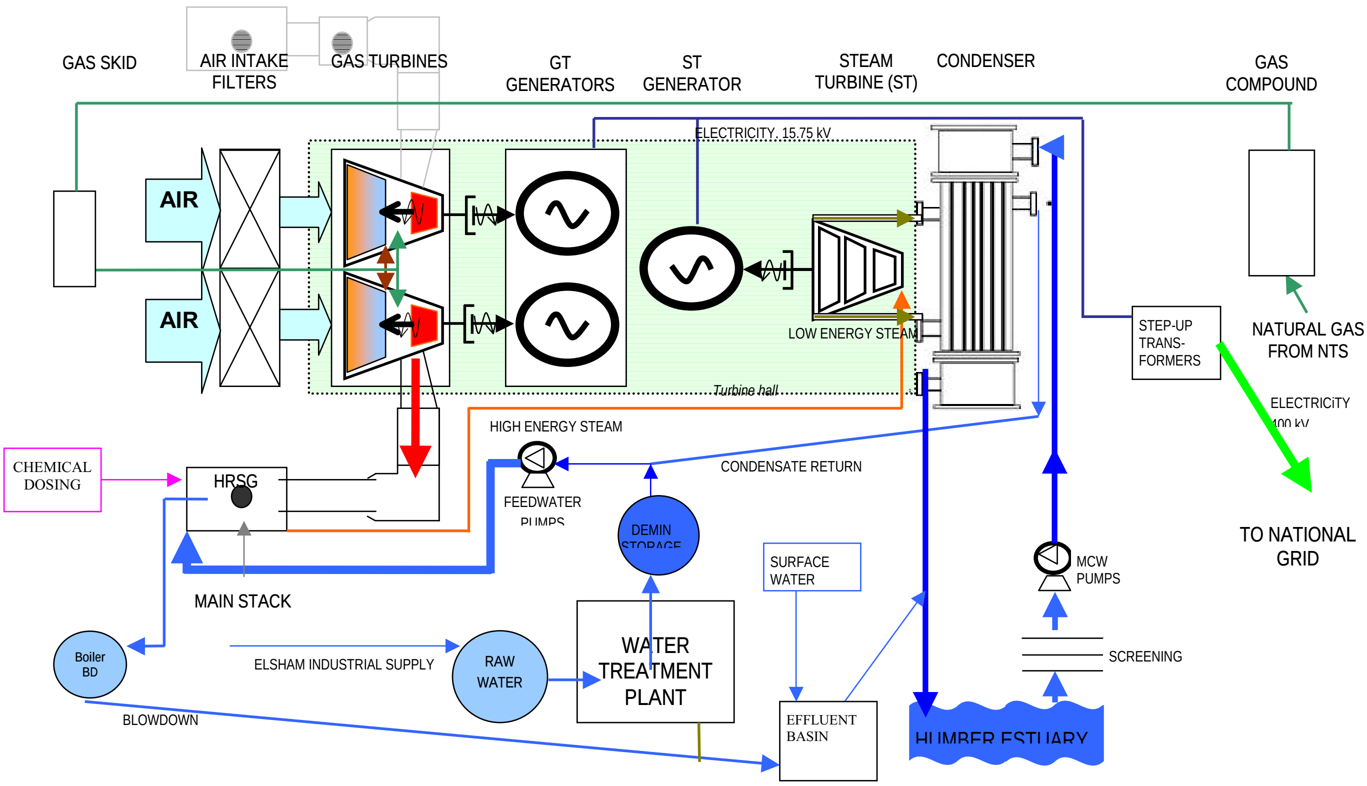
- Centrica requests that the current limit of 80 mg/Nm^3 for oxides of nitrogen excluding start-up and shut down periods is expressed as a daily average in line with PPC sector guidance. It is requested the same limits and definitions for start up and shut down conditions currently applied are also transposed into any future PPC permit; and,
- The current permitted differential temperature limit of 15°C for cooling water discharges is permitted for 96 hours of the year to allow essential maintenance of the cooling water system. Since the original IPC authorisation application was submitted prior to operation of the power station, operational experience has identified this is insufficient to control seaweed fouling in particular. It is requested that up to 200 hours be permitted to enable essential maintenance in future.

Neither of these modifications will have a significant detrimental environmental impact as illustrated in impact assessment reports included in this PPC permit application.

1.9 EP-OPRA Charging

The EP-OPRA calculation spreadsheet supports this application. The calculation sheet details the levels of fees paid to the regulator to reflect the regulatory effort required in determining the permit application. Where emissions from the installation are below the reporting thresholds for the EP-OPRA these have not been included in the spreadsheet. Only emission components that are currently regulated under the existing IPC authorisation are included in line with guidance provided by the Environment Agency at the launch of the combustion sector regulatory pack (October 2005).

Figure 1.5: Process Flow Diagram (Phase 2)



2 PROPOSED TECHNIQUES

2.1 Activities and In-Process Controls

SHBPS transforms the chemical energy stored within natural gas into electricity by the combustion of the gas. The station was built in two stages. Phase 1, with a nominal output of 750 MW, was completed in April 1997 and Phase 2, nominal output 510 MW, began commercial operation in January 1999. The station is a combined cycle gas turbine plant, with waste heat from five essentially identical gas turbines (3 in Phase 1, 2 in Phase 2) producing steam to drive two steam turbines (one in each phase).

Electricity is a highly valuable form of energy since it is readily transmittable over long distances and it can be transformed efficiently into other useful forms of energy such as heat, light and mechanical forms. It is essential for the operation of many modern technologies. Widespread use and availability of electricity is of critical importance to the local and national economy. The major drawback with electricity is that it cannot be readily stored in large quantities. Electricity must therefore be generated in direct response to demand and this is an important factor when defining the operational patterns of power stations.

Electricity in Great Britain is generated under a system known as the British Electricity Trading and Transmission Arrangements (BETTA), controlled by the Department of Trade and Industry (DTI) and the Office of Gas and Electricity Markets (OFGEM) and designed to facilitate a competitive generation market whilst protecting security of supply. The BETTA, in conjunction with Centrica Energy, determine:

- the number of start-ups and shutdowns,
- operating loads; and
- operating hours etc

The BETTA, and the electricity market conditions created under the arrangements, therefore directly influence the emissions from the power station and the overall operational energy efficiency that can be achieved. The operation of a power station must also allow for periodic shutdowns (outages) to allow for maintenance of the equipment in order to maintain its efficiency and to prolong its working life.

Operation on a non-continuous basis has a significant impact on the CCGT plant. Increased requirement for start-ups and shutdowns causes additional "wear and tear" on the components of the power generation system due to the thermal cycling (repeated heating and cooling cause strain on components). Each start-up and shutdown is equivalent to a number of continuous operating hours. With maintenance outages being specified by equipment suppliers on the basis of the number of operating hours accrued this can lead to more frequent maintenance requirements and plant outages. Regular maintenance is essential to maintain good operational order, efficiency and emissions performance.

In order to start-up or shut down the station it is necessary to operate systems in a defined sequence. For start-ups, in order to achieve steady state conditions, this may result in increased emissions for a period of time until all systems are brought on line and stabilised. The requirement for non-continuous operation puts increased importance on the impact of start-up in terms of environmental impacts.

CCGT operations require a periodic programme of scheduled shutdowns (planned outages) for routine maintenance purposes. A rolling programme of minor and major outages for both the gas turbines and steam turbine is in place, which ensures that an annual shutdown takes place with different activities taking place from year to year. During this time when the station is partially off-line the air and water emissions are significantly reduced (that is, no oxides of nitrogen (NO_x) emissions, no water regeneration, etc.) but it can be anticipated that the quantity of wastes for disposal may increase over the corresponding period as lubricating oils are replaced and equipment is cleaned.

During the scheduled outages personnel numbers on-site are increased significantly as specialist contractor teams are located on-site for the duration. Additional equipment will be brought onto site and stored in laydown areas and contractor cabins will also be present. During this period contractors are required to comply with all site rules, for example regarding the disposal of wastes and the storage of chemicals.

2.1.1 Electricity Generation – A Brief Overview

Electricity is generated readily from mechanical energy via a generator. This technology is very mature and the efficient conversion of mechanical energy to electricity is very high and is in the order of 98%.

The challenge associated with thermal electricity generation is transforming heat released into mechanical energy (work). Any machine capable of transforming heat into work is generally termed an engine; the development of the first engines defined the start of the industrial revolution. The physical processes undertaken within an engine is called a cycle – each cycle has limitations in its ability to transform heat to work posed by fundamental laws of thermodynamics (the study of heat and work). Engines use heat to transform the state of a working fluid, with the working fluid being used to generate mechanical energy (usually by expansion). Engines now form the industrial base of most economic activity in developed nations.

CCGT power stations represent the current pinnacle of this technology; they take advantage of two types of engine (cycles) that are connected (combined) to harness the maximum proportion of work available from the fuel. The first cycle (or engine) is a gas turbine. The most familiar example of gas turbine engines is jet-powered aircraft. Air is compressed and burned with a liquid or gaseous fuel. The resulting hot gases (exhaust) form the working fluid in a gas turbine and this is expanded to produce mechanical power. The mechanical power generated is used to turn an electrical generator.

The exhaust from the gas turbine still contains a lot of energy in the form of heat and this energy can be used to generate pressurised steam, which can be used as a working fluid in a separate cycle. The steam is then expanded in a steam turbine to very low pressures, generating useful work, which is used to turn an electric generator. The low energy steam is condensed back to water, which can be pumped to the necessary pressure to start the cycle over again (it is impossible to pump steam since it is compressible). Condensation releases the latent heat of the steam to the environment and this energy is lost from the cycle to atmosphere from the water-cooled condenser.

Only very clean fuel can be burnt in gas turbines since the resultant exhaust gases are used as the working fluid within the turbine. Gas turbines produce low levels of emissions in comparison with other forms of electrical generation utilising fossil fuels.

2.1.2 South Humber Bank Power Station Operation

Each morning the station obtains a detailed weather forecast. After reviewing the current state of the plant, the station determines the potential electricity output available from the plant for the next 48 hours.

This forecast technical availability is then conveyed to the energy trading section of Centrica Energy (based in Windsor). This section then specify the generation pattern for the following period (up to 48 hours) and may also offer the plant into the national electricity balancing mechanism, where the generation pattern may be varied in real time to exactly match grid demand. After confirmation from the trading personnel the station then determines the fuel requirement to meet the specified generation pattern and convey this information to the fuel supplier to secure the fuel.

The hours of operation of SHBPS are not strictly determined by the site but by demand for electricity from customers and that of National Grid. Centrica Energy plans the generation profile of the station to meet the demand.

The operation of the power station is controlled from the control room onsite. The control room is staffed 24 hours a day, 365 days of the year. Communication across the site is maintained via the use of two-way radio handsets. There are shifts with the following staff:

- The Team Leader is responsible for all site activity out of hours including the environmental monitoring and emission control;
- Operation Technicians are responsible for operating the plant in a safe and environmentally responsible manner reporting to the Team Leader.

Adequate staffing is maintained to ensure continued safe operation of the station and details of the management systems are provided in Section 2.3. The station's systems are constantly monitored and controlled. A Distributed Control System (DCS) allows information from the whole plant to be monitored and controlled by operations staff.

2.1.3 Gas Turbine-Generator Sets

2.1.3.1 Overview and Main Technical Data

The five gas turbines are ABB Alstom GT13E2 machines. There are three in Phase 1, two in Phase 2. They produce a nominal 165 MW each. They work by drawing in filtered air through an air intake and compressing it into an annular combustion chamber where gas burners heat it up to around 1100°C. The GT13E2 employs 72 of ABB's EV burners resulting in low emissions of oxides of nitrogen, or NOx. The compressed, heated air expands through a power turbine, which turns the shaft on which it and the compressor are mounted. The shaft rotates a generator, which is mounted on the intake end of the machine.

The exhaust gas leaves the turbine at around 540°C and is guided into a heat recovery steam generator.

The gas turbine-generator set (turbo set), delivers electric power to a grid and its exhaust gases to a heat recovery steam generator (HRSG) in combined cycle operation.

The following are key technical data related to the turbo sets

Turbine

- Type: ABB GT13E2
- Speed / frequency: 3000RPM / 50Hz
- Number of turbine stages: 5
- Number of cooled rotating blade rows: 3
- Number of cooled stationary blade rows: 2
- Number of compressor stages; 21
- Number of blow-off stages: 3
- Type of combustor: Single annular
- Number of burners: 72
- Type of burner: EV, cone, with premixing
- Number of ignition torches: 2
- Number of flame monitors: 3

Generator

- Generator type: WY 21 Z-092LLT
- Cooling: Air-water cooling in closed cooling circuit; coolers integrated into bottom of stator housing
- Gross electrical output (ISO): 164.3 MW
- Peak load gross electrical output: 172 MW
- Gross electrical efficiency (ISO): 35.7%
- Gross heat rate: 10,161 kJ/kWh

The major components of the gas turbo set are the air intake assembly, compressor, combustor, turbine, exhaust gas fixture, generator, excitation system, static frequency conversion system and lube oil, jacking oil, rotor barring and power oil systems. This section will briefly describe the function of these components.

2.1.3.2 *Air Intake and Filter Assembly*

The air intake assembly consists of:

- **Louvres**, which prevent large objects and rain water entering the intake duct.
- **Filters**, which filter out finer particulate matter in the intake. A 2-stage filter is used on the GT13E2 packages at South Humber Bank. Filter fouling is controlled by differential pressure monitoring.
- **Silencer**. The air – flowing at high speed and pressure, passes through a damper that lessens the sound levels produced.
- **Safety flap valves**, which open automatically if the filters become clogged and pressure within the housing becomes too low. This action prevents damage to the filter housing, air intake elbow and manifold.
- **Anti-icing device.** Prevents ice formation at the compressor inlet by heating the intake air with LP steam via heat exchangers.

2.1.3.3 *Compressor*

Air from the air intake system is forwarded through variable inlet guide vanes (VIGVs) to the compressor where it is compressed by the combined effect of rotating blades and stationary vanes. VIGVs control the air mass flow during start-up, shutdown and operation at partial load to reduce the power required. The thermal efficiency of the combined cycle plant at partial load is increased due to high exhaust gas temperatures being maintained. At the compressor outlet the compressed air is directed through a diffuser to the combustion chamber and into the hot gas path for cooling purposes. Another part of the compressed air is branched off for sealing purposes at those locations where the rotor passes through the casing. Blow off valves expel excess air to atmosphere during start-up and shutdown to prevent compressor stall, also reducing the power required during start-up. A blow-off hood and silencer reduce noise during blow-off.

The variable inlet guide vanes and blow off valves are controlled by the automated turbine control system EGATROL. Instrumentation and control systems also measure vibration and lubrication oil temperature in the bearings that hold and guide the compressor's rotor.

2.1.3.4 Combustor

The combustor is an annular device placed around the shaft between the compressor and the turbine. It is here that the combustion process takes place. Combustion is a chemical reaction between oxygen in the pressurised air and combustible components in the fuel. When the mixture is ignited in the combustor, the hot, pressurised combustion gas is forwarded via a transition piece (also known as the secondary zone) to the turbine where it is expanded through the blading. Owing to the heat developed during combustion, the combustor must be cooled with air from the compressor, this happens in a counter-flow manner.

The 72 double-zone **EV burners** are arranged in a 4-row ring pattern around the combustor. It is here that air and fuel are thoroughly mixed to ensure continuous combustion.

The burners consist of an axially divided hollow cone, the halves of which are offset from one another in a transverse direction; combustion air flows into the combustion zone through the resulting slots. The burners' geometric design produces a strong swirl flow with a back-flow area in which the fuel and air mixture are thoroughly mixed for combustion. Only in this zone are flow speeds low enough to permit ignition of the fuel and air mixture. This flow pattern and the lean mix of fuel and air ensure low flame temperatures, which in turn result in low levels of NOx emissions and low combustor vibrations. Flame stability is good and there are no flashback problems.

Ignition is by two electrically activated ignition torches, which are supplied with fuel from the ignition gas system, preheated to 150°C using steam from the HRSG's IP circuit. When the main burners are supplied with fuel, the flame spreads from burner to burner without further action. During ignition only 60 of the 72 burners operate. When combustion is established, the igniters are shut-off. The activation and deactivation of the fuel ignition system is controlled by the automated turbine controller.

Dry Low NOx burners are fitted to minimise the release of oxides of nitrogen to atmosphere.

2.1.3.5 Turbine

Major components of the gas turbine are described in this section.

The casing, which holds the turbine and its stationary blade carrier is thermally and acoustically insulated with easily mounted, numbered pads which reduce heat and noise radiation to the environment while ensuring an even temperature distribution within the casing.

The **rotor** is made of discs welded together to form a single shaft including both compressors and turbine sections.

The turbine section consists of stationary vanes and rotating blades. The conversion of heat energy into mechanical energy takes place within the turbine's blading. The hot compressed gas from the combustor is guided through the turbine blading where it expands and presses against the rotating blades. This action causes the rotor to turn, transmitting motion to the compressor rotor and on to the generator rotor.

The blading is arranged in rows, numbered from the turbine inlet to its outlet. The combination of stationary vanes and a rotating blades is called a stage. Because turbine blading is in contact with the hot combustion gas, at least the initial turbine stages must be cooled by air from the compressor.

Journal **bearings** support the turbine rotor. They are lubricated and cooled by oil from the lube oil system, as with the compressor bearings. Instrumentation for measuring vibrations and oil temperatures is present.

2.1.3.6 Exhaust Gas System

The exhaust gas system directs the exhaust gas flow to the atmosphere through the HRSG. The exhaust diffuser, which guides exhaust gas from the turbine exhaust casing to the HRSG, is a horizontal cylindrical structure that supports and holds all components. It connects the turbine exhaust casing with the base of the stack in a gas-tight manner and is insulated both from the outside and inside the inner lining to minimise the transfer of heat. To compensate for differences in thermal expansion, it is connected to the base of the stack through an expansion joint. The diffuser is insulated against noise and heat radiation by mineral wool insulation.

Emissions from the GTs are vented to air via one of three stacks (A1 to A3). No bypass stacks are present.

2.1.3.7 Generator

The generator converts mechanical energy from the turbine into electrical energy, which is fed to the grid. The generator is a 2-pole, synchronous, totally enclosed, water-to-air-cooled (TEWAC) machine. Instrumentation built directly into the generator is used to monitor the machine's operating parameters. *MICADUR* (an ABB proprietary system) insulation is used in the generator windings, so no permanently installed carbon dioxide fire extinguishing system is required.

The generator's main components are:

- The **casing**, which supports and holds the generator's components.
- The **stator**, a self-supporting core consisting of a large number of laminations, separated by ventilation slots.
- The **stator winding**, a 2-layer, 3-phase winding with indirect cooling.
- Six **stator terminals** on top of the casing, connected to the winding by flexible copper straps allowing for thermal expansion.
- The **rotor**, a rotating magnet that transfers the mechanical energy from the turbine rotor. The body is a single steel alloy forging with excellent mechanical and magnetic characteristics.
- The **rotor winding** is made up of rectangular hollow conductors of a copper alloy, which contains a small amount of silver.
- **Cylindrical end bells** firmly hold the end windings and prevent them from becoming deformed by centrifugal forces, which arise during operation. Since the rotor end bells are the most highly stressed parts of the generator, they are subjected to extensive material and load testing. To keep losses in the end winding as low as possible, the material used is high quality steel that is anti-magnetic and insensitive to stress-corrosion cracking.
- **Bearings** support the generator rotor in the radial direction. The bearings are supplied with lube and jacking oil by the same system used for the turbine. Vacuum in the bearing pedestal prevents oil vapour from escaping outward along the shaft.
- **Make-up air filters** prevent dirt from entering the generator with the cooling air.
- **Air coolers** cool the generators via a fully encapsulated cooling air system. Air is forced through the passage by fans mounted at each end of the shaft. The air is cooled in 4 heat exchangers supplied with closed cooling water, arranged cross-wise in the bottom of the generator housing.

2.1.3.8 Excitation System

The excitation system feeds the excitation coil of the generator rotor with direct current (DC) at the appropriate excitation current. This action is necessary to control the generator terminal voltage.

2.1.3.9 Static Frequency Converter

The generator acts as a motor during start up, allowing the turbine to be purged at 800 rpm removing all traces of unburnt gas, then runs down to approximately 450 rpm, where ignition take place. The static frequency converter is removed from service at a predetermined level when ignition of the combustor has stabilised.

2.1.3.10 Oil Systems

The **lubrication ('lube') oil system** supplies lubrication and cooling oil to the turbine, compressor and generator bearings, the jacking oil system and the power oil system.

Lube oil is stored in a tank, equipped with a built-in heater, which is located within the turbo set housing. The tank is ventilated through a filter, which cleans any oil vapours, returning oil particles to the tank and venting only clean air to atmosphere. The tank is equipped with level alarms, which issue in the control room.

Sensors measure lube oil and bearing metal temperatures and vibration levels. If measured values are outside the pre-set range, alarms are raised, load shedding is initiated and if the situation persists the turbo set is tripped.

The **jacking oil system** is supplied by the lube oil system and supplies the journal bearings of the gas turbo set with high-pressure oil during start-up and rotor barring operation. The high-pressure oil creates an oil film, which slightly lifts the rotors of the turbo set, reducing wear on the bearings and the turning torque required.

In addition, if lube oil system pressure drops below a pre-set minimum during a turbine trip, the jacking oil pumps and the emergency lube oil pump automatically start, to ensure a supply of oil to the bearings during the run-down.

The **power oil system** supplies pressurised oil to the hydraulic control, protection and safety systems for use by the electro hydraulic converters, stop valves, control valves, trip valves, testing relays and safety devices.

2.1.4 Heat Recovery Steam Generators

2.1.4.1 Overview and Main Technical Data

The Heat Recovery Steam Generator (HRSG) is directly coupled to the exhaust diffuser of the gas turbo set. Each GT has its own dedicated HRSG. The waste heat energy from the GTs flows through the HRSG and during this flow it dissipates its energy to the HRSG and thus converts water to steam.

The HRSGs were manufactured by CMI. They are triple pressure, forced circulation units.

Triple pressure refers to the 3 water / steam pressures that are generated by the HRSG for the operation of the steam turbine and other auxiliary systems:

- High Pressure (HP) @ 95 barg approx, superheated (514°C), 58 kg/s
- Intermediate Pressure (IP) @ 20 barg approx, superheated (513°C), 12 kg/s

- Low Pressure (LP) @ 3 barg approx, saturated (143°C), 8 kg/s

Forced circulation refers to the nature of the circulation of the water/steam systems to and from the evaporators where the change in state takes place. At South Humber Bank the HRSGs have been constructed with horizontal tube nests, which require forced circulation. This circulation is achieved via circulation pumps located on the ground floor, 2 x 100% pumps per pressure circuit, and 6 pumps in total per HRSG.

The HRSGs have been designed and constructed as a suspended boiler. Each HRSG is suspended from its top steel structures. It is constructed this way to accommodate the vertical gravitational effects between a full and empty boiler, and also due to the thermal expansion effects due to the change in boiler temperatures i.e. ambient at GT standstill up to approximately 540°C exhaust gas temperature. For this reason, along with the horizontal expansion of the GT, there is an expansion bellows situated at the rear of the gas turbo set exhaust diffuser and located outside of the GT hall.

The HRSGs consist of a series of heat exchangers (economisers, evaporators and superheaters), which vary the temperature of the feed water or steam. Other components include circulation pumps, dosing pumps, a blowdown vessel, a chemistry laboratory, a weather damper and the expansion bellows.

The HRSGs are controlled by a software system called BOILERMAT, which has equal status to EGATROL and TURBOMAT (the steam turbine sequencing controller).

2.1.4.2 The High Pressure Circuit

In the high pressure circuit, feed water enters at approximately 85°C flows through three economisers, which exchange heat with the hot exhaust gases, which are flowing in essentially the opposite direction round the circuit, gradually raising the water temperature to 300°C. It then goes to the lower half of the HP boiler drum, from where the circulation pumps control its progression to the evaporation circuit. Here the water begins to flash off to steam. This then enters the top of the drum along two return pipelines. The steam at this point is at saturation temperature. Within the top of the drum is a baffle arrangement, which is there primarily to reduce the water content of the steam before it exits for the final time towards the HP superheater. HP steam leaves the top of the HP drum via two pipelines, which takes the steam to the HP superheater - the lowest, and hottest, set of tube nests on the boiler. Here the steam is heated to 520°C (approximately 200°C of superheat). The HP steam exits the superheater and passes through an attemperator located on the right hand side of the boiler. Here HP feed water is injected into the steam path to control the steam temperature before it connects to the HP steam header. Prior to the steam leaving the HRSG system and entering the water-steam cycle there are two HP steam drains that take steam to the blowdown vessel. There is also a safety valve on the circuit, which vents via a silencer. Steam leaves the HP circuit at approximately 518°C and 95 bar. Throughout the circuit there are sampling points, which allow online continuous sampling, and dosing points for chemical injection.

The IP and LP circuits operate similarly, however the LP Circuit does not have a superheater

2.1.4.3 Boiler Chemistry

To control the boiler chemistry there are important systems, which continuously monitor various readings relating to the quality of feed water and steam. The readings that are monitored are crucial for the daily running of the station and also for the long-term performance and reliability of the boilers.

Both phases have a sampling laboratory equipped with instruments required for on-line monitoring and analysis of the water/steam quality of the water steam cycle and HRSGs.

The following parameters are continuously monitored: -

- Condensate acid conductivity
- Feedwater silica
- Feedwater raw conductivity
- Feedwater acid conductivity
- Feedwater carbohydrazide
- Feedwater / condensate dissolved oxygen conductivity
- LP drum pH
- LP drum raw conductivity
- IP drum pH
- IP drum raw conductivity
- HP drum pH
- HP drum raw conductivity
- LP steam acid conductivity
- LP steam sodium
- HP steam acid conductivity

Each HRSG has a trisodium / disodium phosphate (hereafter referred to as 'phosphate') dosing system, which uses 4 pumps to inject chemicals into the drums. The 4 pumps (one per each drum level plus one spare) have a manually adjustable stroke, which allows accurate dosing to the boiler drums. Each pumping circuit has its own dedicated accumulator, which maintains the pressure within the circuit along with pressure regulating valves and non-return inline check valves. The phosphate is delivered to site by road tanker to purpose built storage tanks.

Due to the nature of phosphate and its tendency to ‘fur’ up within the pipework and systems, there is a water circuit on each skid, which allows demineralised water to be injected through the dosing lines as a flushing agent when required.

This dosing system coupled with the water-steam cycle ammonia and carbohydrazide dosing is used to maintain the required boiler chemistry. The phosphate dosing skids are located in the compressor / diesel generator house (Phase 1) and on the ground floor of the steam turbine hall (Phase 2).

To further control boiler chemistry each boiler drum has a manually operated continuous blowdown valve. These valves are located on the boiler blowdown vessels. Each valve is graduated, controlling percentage of water blowdown to vary the amount of leak-off required to clear impurities from the drums.

2.1.5 Steam Turbine-Generator Sets

2.1.5.1 Overview and Main Technical Data

Steam from the HRSGs is used in steam turbine-generator sets to generate electricity. The following are key technical data related to the sets.

Table 2.1: Steam Turbine Sets – Key Technical Data

	Phase 1	**Phase 2**
Turbine type	ABB DKZZ3-4N41	ABB DK223-4N37
Frequency / speed (Hz/rpm)	50/3000	50/3000
Gross output (MWe)	272.3	184.5
Generator type	ABB 50WT 20H-100	ABB WY21Z – 092LLT
Generator cooling medium	Hydrogen	Air
Condenser type	Single pass, spring supported condenser shell with divided cooling water boxes to allow online maintenance. Mild steel housing with titanium tubes.	Double pass, spring supported condenser shell with divided cooling water boxes to allow online maintenance. Mild steel housing with titanium tubes.
Main cooling water flow (m^3/s)	15.5	10.3
Main cooling water inlet / outlet design temperatures (°C)	10/18	10/18

The components of the steam turbine-generator sets are described in the following sections.

2.1.5.2 Steam Turbine

Steam from the HRSG is admitted to the steam turbine (ST) causing rotation of the blades, a mechanical conversion process. The amount of steam entering the turbine is regulated by control valves. After all the available energy in the steam is used, the steam is condensed back to water and used again in the water-steam cycle.

2.1.5.3 Generator

The generator is attached to the steam turbine shaft giving the final conversion from mechanical to electrical energy. The rotating shaft (rotor) is excited so the induced voltage in the stationary windings (stator) can be varied.

A generator breaker provides the connection that enables power to be supplied to the National Grid.

Generator protection equipment protects the generator and its associated equipment from faults. When the equipment is activated, the generator breaker opens and main steam stop valves and control valves are closed.

2.1.5.4 Generator Cooling

Current flowing in the generators stator produces a great deal of heat in its laminated iron core. The rotor also produces heat in its low voltage windings, when creating the magnetic field used in operation. This results in losses, which affects the efficiency of the machine. High temperatures could also break down the electrical insulation in the stator, causing mechanical damage. Thus it is essential to cool the generator effectively.

Generator cooling is by hydrogen on Phase 1 and air on Phase 2. The difference is due to the sizes (outputs) of the generators. More powerful generators are more effectively cooled by hydrogen.

Phase 1 – Hydrogen Cooling

Hydrogen gas is supplied to the generator from a bank of bottles (pressurised cylinders). The hydrogen gas pressure to the generator is maintained by a pressure control valve to approximately 5.5 bar. Hydrogen supply pressure and daily usage are also monitored. When supply pressure starts falling, the hydrogen bottle bank pressure is monitored manually and at 16 bar a new bank is put in service to maintain supply.

During normal operation the hydrogen gas is circulated through the generator housing and components to the coolers by two shaft mounted axial fans.

Four closed cooling water heat exchangers maintain a constant cold gas temperature between 31^{o} C and 33^{o} C.

To ensure that the hydrogen gas is dry a silica gel moisture absorber is fitted in line. Checked on a daily basis, when the colour of the gel turns from a dark blue, the silica gel can be regenerated using heaters and a gel drier fan after first being purged with carbon dioxide.

For internal generator maintenance, before entry the generator will first be purged with carbon dioxide to remove all traces of hydrogen. The carbon dioxide is then purged with air.

Phase 2 – Air Cooling

Air-cooling is used in Phase 2. The air-cooling loop does not have any emissions and is not described further.

2.1.5.5 Oil Systems

Oil systems on the steam turbine sets work in a similar manner to those on the gas turbine sets. The **lube oil system** lubricates and cools bearings, feeds the **jacking oil system** (for raising the shaft during start-up and shutdown, thus reducing friction and the torque needed to turn the shaft) and the **hydraulic oil system**, which powers hydraulic actuators and control and safety valves.

In addition, there is a **seal oil** system on the Phase 1 steam turbine. The seal oil system seals the hydrogen used for generator cooling within the generator.

2.1.5.6 Instrumentation and Control

The following interlinked systems control the steam turbine sets:

- *TURBOTROL* provides automatic run up, loading and shutdown of the ST, adjustments to power output and frequency, automatic limiting actions and thermal stress evaluation via *TURBOMAX* inputs.
- *TURBOMAT* is the sequencing controller; it is used to order various plant into operation during start-up, loading and shutdown of the steam turbine and its ancillaries. This is achieved via programmed steps from standstill through to load. Various sequence “Stop” criteria are continually monitored.
- *TURBOVISORY* is a supervision system that monitors various parameters to allow safe operation of the steam turbine, such as shaft vibration, shaft position, expansion and speed.
- *TURBOMAX* provides constant monitoring of thermal stresses on the steam turbine and inputs this information for use by Turbotrol.
- *SYNCHROTACT* synchronises the voltage, frequency and phase of the generator output such that it matches that of the grid. It interacts with *TURBOTROL* for frequency and phase and *AVR (Automatic Voltage Regulation) UNITROL* for voltage. Synchronisation occurs as part of the start-up step sequence, controlled overall by *TURBOMAT*.

2.1.5.7 *Gland Steam System*

The gland steam system provides the sealing medium used in the steam turbine. It maintains vacuum in the LP section of the turbine and preventing steam leakage on the HP / IP section of the turbine.

Under normal operating condition the turbine is self sealing with steam tapped off from the HP turbine.

A vacuum breaking system reduces the speed of the steam turbine after a trip or when shutting down, enabling the turbine to pass quickly through critical speed ranges, reducing high vibration and stress on the machine.

2.1.6 Transformers

Electrical energy from the generators at 15.75 kV is stepped up to 400 kV for transmission on the national network by generator transformers. Each transformer consists of two coils of copper wire wound around an iron core and immersed in special transformer oil for insulation and cooling.

The oil that is used in the transformers is a highly refined mineral oil. The transformer oil is not classified as hazardous and is free of polychlorinated biphenyls (PCBs) (as confirmed by the plant manufacturer, ABB). The oil is a non-volatile, mobile liquid that is insoluble in water. It is inherently biodegradable and is not expected to have significant bioaccumulation potential due to its low solubility. It is not expected to be toxic to aquatic organisms or inhibitory to sewage bacteria. No adverse environmental effects are foreseen when the oil is used and recovered as intended using approved contractors in accordance with Duty of Care requirements.

2.1.7 Combined Cycle Plant Loading

The output of the combined cycle power plant is adjusted to the electricity demand by modulating the gas turbine load alone.

The steam cycle will recover available energy from the gas turbine exhaust. The steam turbine load always follows the gas turbine load.

Load variations of the gas turbine are followed by a corresponding load variation of the steam turbine some minutes later.

This happens naturally without any external action on the steam cycle. Indeed, steam pressure at the steam turbine inlet slides according to the gas turbine operating condition.

This continuous adaptation of the steam pressure is the so-called “sliding pressure running mode”. It guarantees the best energy recovery from the exhaust gas and, consequently, the best overall plant efficiency.

It is always required that the gas turbine loads are similar to one another. Therefore, the overall combined cycle load will be reduced by unloading gas turbines similarly. The reason for this is to keep the HRSGs in identical operating conditions. The steam pressure and temperature of the running HRSGs must be within given margins in order to mix their steam productions.

While unloading gas turbines, the plant efficiency will decrease because a gas turbine has its optimum efficiency at its nominal load. In order to maintain the maximum plant efficiency, one gas turbine will be shut down and the remaining ones reloaded up to full load as soon as the plant output in this last case is higher that the previous one.

2.1.8 Water-Steam Cycle

2.1.8.1 Overview

The water-steam cycle is a term that applies to the steam and process water system, as well as its component parts and operation. The system consists of:

- Main condensate system
- Feed water tank
- Drain system
- Feed water system
- Live steam system
- Evacuation system
- Condensation system
- Bypass systems
- Chemical dosing systems
- Phase 1 – Phase 2 interconnection

The water-steam cycle does not include the cooling water systems, which are described in Sections 2.1.9 and 2.1.10

After the steam has done its work in the steam turbine it is condensed in the condenser and collects in the condenser hotwell. From there it is pumped to the feed water tank by condensate extraction pumps. At the feed water tank the water is preheated using steam from either the steam turbine or the HRSGs. This process also removes air from the feed water via an air extraction line. From the feed water tank the water is pumped to the HRSGs by feed water pumps.

Air and other gases are evacuated from the condenser by air ejectors.

The components of the water-steam cycle are described further in the following sections.

2.1.8.2 *Main Condensate System*

This system begins at the condenser hotwell and ends at the deaerators, on top of the feed water tank. The system performs the following tasks:

- Pumps condensate from the condenser to the deaerator
- Delivers condensate to other systems.

Condensate is delivered from the hotwell by two of the three 50% extraction pumps. With the station at full load there are normally two extraction pumps running but the third pump will start automatically when the condensate line pressure drops below a preset level if, for instance, the steam bypass sprays are activated. If a pump should fail for any reason the standby pump will start automatically

Downstream from the pumps condensate is supplied to:

- Sealing water system (to seal valves, etc.).
- Steam turbine gland steam cooling (de-superheating spray).
- Steam turbine LP hood sprays (to cool the hoods during run-up/down).
- Flash box steam conditioning (to cool steam as it enters the flashbox).
- Bypass conditioning (to cool steam as it enters the bypasses).
- Vacuum breaker sealing water.

Valves control the level in the condenser hotwell, ensuring a minimum flow to prevent damage to the condensate extraction pumps.

2.1.8.3 *Feed Water Tank / Deaerator*

The feed water tank and deaerator system is at the point in the water-steam cycle where the process water changes from condensate to feed water. The system fulfils the following duties:

- Storage of feed water for the water-steam cycle.
- Preheating and deaerating the feed water.
- Removal of air and incondensable gases from the feed water.

The system starts at the main condensate nozzles at the top of the tank and ends at the feed water outlet nozzles at the bottom.

The feed water tank and direct-contact heaters are combination units. Two cylindrical, vertical, direct-contact deaerator domes are arranged on top of the horizontally mounted, cylindrical feed water tank.

The location of the tank is determined by the inlet head required by the feed pumps. The tank is mounted on several supports, fixed at one end and sliding at the other to allow for free expansion of the tank during operation.

The feed water tank is monitored for pressure, temperature and water level and there are relief valves to protect the tank against over-pressure.

The feed water is dosed with ammonia to achieve a pH in the tank of around 9 - 9.5. The temperature in the tank is controlled by the pressure. Pressure is controlled at 0.2 bar by LP economiser water and by steam that is extracted from the LP turbines. At this pressure the tank temperature is maintained at 60^{o}C. Pegging steam from the HRSGs is required when these conditions cannot be met.

2.1.8.4 Feed Water System

The feed water system feeds the HP, IP and LP boiler drums from the feed water tank. The system, which starts at the feed water tank outlet nozzles and ends at the boiler inlets, comprises the following major components.

- Three 50% combined IP and LP feed pumps (LAC10/20/30AP001)
- Four 33% HP feed pumps (LAC50/60/70/80AP001)
- LP, IP and HP feed water lines.

Feed water is fed from the feed water tank by the pumps through the feed water lines and the boiler feed stop valves into the boiler economisers. After the economisers the water is fed into the drums by the drum control valves.

The LP and IP feed water is a common system up to and including the economisers, the system splits after this into separate LP and IP systems.

Each feed pump is fitted with minimum flow valves and lines to protect the pumps when the demand from the boilers drops. Water from these is re-circulated back to the feed water tank.

2.1.8.5 Drain System

Drains perform the following tasks:

- Remove condensate to protect the steam turbine and heat exchange equipment from water damage and to prevent water hammer in the pipelines
- Warm-up (allowing small amounts of steam through the pipelines to warm them up prior to operation).
- Maintain temperature so that condensation does not occur during operation and excessive thermal stresses do not occur during start-up.

Drains are classified as internal or external, depending on where they flow.

Internal drains are in operation only when the turbine or condenser is also in operation. Generally, internal drain lines are lines installed downstream from the turbine control valves. Internal lines flow into the condenser flashbox. Internal drains can be further subdivided as follows:

- Start-up drains remove condensate that collects during start-up
- Continuous drains remove water that collects where continuous condensation occurs.
- Disturbance drains remove water that collects in lines that are temporarily out of operation.

External drains are installed upstream from the steam turbine’s control valves so can be in service when the turbine is not running and the condenser is not evacuated. These drains collect condensate from steam lines, handle the flashing of various condensates, separate steam and condensate and drain condensate to the waste water system.

External drains from the HP, IP and LP steam lines are connected to their relevant drain header and the condensate/steam mixture drains to the atmospheric drain vessel. Flashing steam is discharged to atmosphere and condensate is discharged to the waste water system.

2.1.8.6 Live Steam System

The HP, IP and LP live steam system performs the following tasks:

- Transfers live HP and IP steam from the HRSGs to the steam turbine via the HP and IP steam headers.
- Transfers HP live steam from the HP steam header to the gland steam system.
- Transfers HP live steam to the start-up ejector.
- Transfers IP live steam from the IP steam header to the service ejector.
- Transfers LP steam from the HRSGs to the steam turbine via the LP common steam line.
- Transfers LP steam from the common LP line to the pegging steam system at the deaerator/feed water tank.
- Transfers LP steam from the common LP line to the anti-icing system.

Each HRSG may be disconnected from the water-steam cycle by motorised steam isolating valves.

During normal operation the full HP, IP and LP live steam production of the boilers is delivered to the steam turbine.

2.1.8.7 *Evacuation System*

The evacuation system performs the following tasks:

- Evacuates the steam turbine, condenser, steam dumping devices (bypasses) and condenser flash box during start-up.
- Vents the condenser and condensate extraction pumps during normal operation.

The system consists of a start-up ejector, including a silencer, and two service ejectors. The system begins at the equipment's venting nozzles and includes all vent lines to the ejectors, the ejectors themselves, motive steam lines and discharge lines to atmosphere.

Air entering the steam turbine, condenser and the condensate extraction pumps as well as non-condensable gases are drawn out by the evacuation system. A single stage ejector is used for start-up evacuation. Evacuation during normal running is performed by one of two service ejectors.

Motive steam for the start-up ejector is taken from HP live steam or the auxiliary boiler, while the service ejectors are supplied from the IP live steam or the auxiliary boiler.

2.1.8.8 *Condensation System*

The large amounts of heat remaining in the exhaust steam of a condensing steam turbine must be extracted if the steam is to condense. This heat is removed by cooling water.

The condensation system performs two tasks:

- Condenses steam turbine exhaust and bypass steam
- Serves as the water-steam cycle's extraction point for incondensable gases

The system extends from the turbine exhaust to the hotwell condensate outlet and includes:

- Condenser neck.
- Main condenser, with various inlets.
- Hotwell.
- Flash box, installed next to the condenser with various drain lines into the condenser.

Absolute pressure in the condenser is very low (around 0.03 bar), corresponding to saturated steam pressure, which is determined by cooling water flow and temperature. In the interests of obtaining a high useful heat drop in the turbine, the pressure is kept as low as possible.

The condenser serves the water-steam cycle as a heat sink and as a collection point for the recovery of turbine exhaust steam. Steam condensate is collected in the hotwell and is returned to the plant as boiler feed water.

During steam turbine start-up, shutdown and load rejection, HP, IP and LP live steam is guided into the condenser via the relevant bypass station. Before live steam enters through the bypasses it is sprayed with condensate in the bypass stations to expand and de-superheat it.

The condenser is a surface heat exchanger of multi-bundle design with straight cooling tubes through which cooling (river) water flows. Steam flow from the turbine condenses on its outer surface. The tube bundle is enclosed in a shell, which has a rectangular cross-section.

The condenser is made of welded sheet steel. Tube sheets on the cooling water side are stainless steel clad to protect against corrosion. The insides of the water boxes are coated with epoxy resin or rubber. Protective anodes mounted on the tube sheet or stay bolts protect against electrochemical destruction. Appropriate connections are provided for monitoring pressure, temperature and level.

The condenser is mounted on spring elements, which compensate for vertical thermal expansion.

The flash box, which is under vacuum, serves as a steam or condensate flash vessel for the steam line drains and for re-circulating condensate.

2.1.8.9 Bypass System

The steam bypass system performs the following tasks:

- Processes HRSG and steam turbine start-ups, shutdowns, load rejections and trips (by routing steam to the condenser, bypassing the steam turbine, under these conditions), thus ensuring that only live, superheated steam is admitted to the steam turbine (in the case of HP & IP).
- Prevents the release of the steam safety valves, thus preventing water losses.

The steam is conditioned in the bypass stations by condensate injection to expand and de-superheat it.

2.1.8.10 Chemical Dosing

It is important that the chemical properties of the process water are kept within acceptable limits in order to ensure that corrosion does not damage the system.

This is achieved by dosing the feed water with ammonia (to control pH), and carbohydrazide (which consumes dissolved oxygen). The boiler drums are also dosed with sodium triphosphate and diphosphate mixture, as detailed in Section 2.1.4.3.

The dosing skids for both systems are located together on the ground floor of the steam turbine hall and consist of positive displacement pumps, distribution pipework and intermediate bulk chemical containers.

Ammonia dosing is automatic, controlling the pH between 9.0 and 9.6. The variable that is actually used to control this is feed water raw conductivity, which is easier to measure accurately. It is found that maintaining this variable between 4 and 8 μS/cm keeps the pH within limits. The ammonia is introduced into the system at the feed water tank.

Carbohydrazide dosing is turned on and off manually. It is introduced into the condensate line and into the closed cooling water in order to reduce the amount of dissolved oxygen in both systems. The carbohydrazide can be directed into the desired system by manually opening and closing valves at the dosing skid.

The process water dosing is conducted in response to continuous monitoring to maintain a dissolved oxygen concentration of around 10 ppb.

The closed cooling water is dosed in order to maintain a molybdate concentration of 100-300 ppb.

2.1.8.11 Phase 1 – Phase 2 Interconnection

In order to facilitate start-ups on both phases of the plant, interconnecting steam lines have been established. These comprise:

- LP steam line.
- Auxiliary steam line.
- Auxiliary boiler water supply line (Phase 2 – Phase 1)

The LP and auxiliary steam lines are to supply steam to the following systems during start-up of either plant.

- Anti-icing system.
- Gland steam sealing system.
- Start-up ejector (for vacuum-raising)

The use of these interconnecting lines must be planned well in advance since they are purged with nitrogen to preserve them and their manual isolation valves are kept locked to prevent inadvertent use. The HP interconnecting line has been blanked off since its use is not anticipated.

2.1.9 Main Cooling Water System

The main cooling water (MCW) system at South Humber Bank is a direct (once-through) system using water from the Humber Estuary. The water is used to process waste heat from the condenser and the closed cooling water intercooler.

Cooling water is taken directly from the Humber Estuary through the intake culverts into the cooling water pump house forebay.

Each intake culvert can be closed at the pump house end of each culvert by means of a motorised sluice gate.

The cooling water is then mechanically filtered to prevent solids from entering the remaining parts of the cooling water system. Issues connected to fish impingement are not covered under PPC and are covered under a separate licensing regime (the abstraction licence, also issued by the Environment Agency).

This filtration is provided by the mechanical cleaning system, which consists of the following:

- 2 raked course bar screens with 80 mm mesh size.
- 2 raked fine bar screens with 20 mm mesh size.
- 2 travelling band screens with 5 mm mesh size.
- 1 wash water pump for each band screen.

The filtered water is then transferred into the pump intake chamber which consists of 2 x 50% MCW pumps, 1 auxiliary pump, level indicators to stop the pumps running dry, injection points for biocide dosing and stop gates (used for pump maintenance).

The cooling water is then pumped to the power plant via underground pipes where it removes the waste heat from the main condenser and the closed cooling water intercooler.

As the cooling water first enters the steam turbine building basement it is mechanically filtered by two debris filters, one for each side of the main condenser. These remove any plant and marine organisms that have passed through the primary mechanical cleaning system located at the MCW pump house. It is important at this stage to remove all debris from the cooling water in order to prevent fouling of the main condenser tubes. This would eventually lead to reduced cooling surface area and flow, thereby lowering the plant's efficiency.

The debris filters are contained in a spool piece about half the pipe diameter in length. The water flows through a rotating basket wheel towards the condenser where the remaining debris is arrested and gathered in the cells of the wheel.

When filtering is required the basket is rotated at low speed and each cell of the rotating basket passes in front of a back wash scoop. The flow is reversed and the panels are back washed, transferring the debris to the outlet lines of the condenser.

The debris filter can be actuated by a timer, a differential pressure monitor or manually. The main cooling water, having now been filtered, is simultaneously supplied to the closed cooling water system intercoolers (see Section 2.1.10) and the main condenser.

Before the cooling water enters the condenser tubes it is 'injected' with tube cleaning balls. These balls pass through, and clean, the condenser tubes. A strainer section located in the condenser outlet pipes then separates the balls from the cooling water flow. The captured balls are led to the recirculation unit where they are caught and replaced if necessary or re-injected.

After cooling the condenser the cooling water returns to the pump house where it is fed to the estuary through the outfall chamber.

The outlet water is continuously monitored for residual chlorine, temperature (to calculate differential between intake and outfall) and pH. Section 2.10 details monitoring techniques in detail.

When the main cooling water inlet temperature is warm (>10°C approx) there is a risk of microscopic biological marine life being present which, because of its size, can pass through the filtration systems previously mentioned and grow in the system pipework. In order to reduce fouling of the cooling water pipework and condenser tubes the plant is equipped with the systems and equipment necessary to inject a biocide, sodium hypochlorite, into the intake water.

At the time of writing, no dosing is carried out. Trials have taken place in the past and found the benefits to be negligible. Centrica SHB wishes, however, to retain the option to dose should it become necessary. Section 4 discusses cooling water dosing and subsequent impacts on the aquatic environment in detail.

2.1.10 Closed Cooling Water System

The closed cooling water (CCW) system absorbs waste heat from various consumers and transfers the heat load to the secondary cooling water (from the main cooling water circuit) via the CCW heat exchanges. The water in the CCW system is treated with an inhibitor (Corsheild) to protect against corrosion.

The CCW system provides cooling water to the following consumers:

- ST generator coolers.
- ST lube oil cooler.
- ST seal oil cooler.

- GT generator air coolers.
- GT lube oil coolers.
- Sample coolers for the feed water system.
- Sample coolers for boilers.
- Boiler circ pump.

The CCW system consists of the following components:-

- 2x 100% intercoolers.
- 3x 50% CCW pumps.
- 2x 100% H_2 booster pumps.
- 1x 100% gravity operated head tank.
- 1x molybdate dosing equipment.
- 1x H_2 separator.

A head tank provides the necessary buffer volume to meet expansion changes in the CCW system. The head tank performs the following functions:

- Allows for CCW volume differences for changes of temperature from 10-55°C.
- Provides a CCW reserve for losses of water.
- Maintains consistent system pressure.

2.1.11 Water Treatment Plant

The main purpose of the Water Treatment Plant (WTP) is to purify the raw water received on site from the Elsham Industrial Water supply to make it suitable for use in the process. This in turn minimises scaling, corrosion and fouling in the power plant's system components.

Each phase has its own WTP. The plant operates as a batch process.

Phase 1 has two streams and the WTP comprises the following components:

- 2 x 100% Carbon Filters
- 2 x 100% Cation Exchange Units
- 2 x 100% Anion Exchange Units
- 2 x 100% Cation Polishing Units
- Sulphuric Acid tank and injection equipment

- Sodium Hydroxide tank and injection equipment
- Effluent tank
- 2 x 100% Effluent discharge pumps
- 2 x 100% Raw water pumps
- 2 x 100% Regeneration pumps

Phase 2 has only one stream and hence has only half of the components as listed above.

The raw water supply naturally contains impurities, which can be divided into the following types:

- **Dissolved Solids:** principally calcium, magnesium, sodium, chloride, bicarbonate, sulphate, silica and iron
- **Dissolved Gases:** principally oxygen, carbon dioxide, nitrogen and sulphur dioxide
- **Suspended Solids:** dust/dirt, contaminants such as oil, biological matter such as algae, fungi and bacteria

The water treatment plant removes these impurities as follows:-

The raw water is taken from the raw water tank situated outside of the WTP building and pumped through the carbon filter, which removes any dissolved organics and chlorine present. Any suspended solids are also removed at this stage.

The filtered water flows through the cation exchange unit, which removes positively- charged salts such as calcium, magnesium and sodium.

The water then passes through the anion exchange unit, which removes negatively- charged salts such as silica, carbonates, chlorides and sulphates.

This purified water is finally passed through the cation-polishing unit removing any remaining sodium salts.

The water is now in its most purified state and is fed into the demineralised (‘demin’) water tank where it is stored for use in the process as required.

Demineralised water is produced by the WTP at an approximate rate of 25 m^3/hr until a total batch volume of 180 m^3 has passed through or if the conductivity exceeds 0.2 µS/cm. At this point the anion and cation units are exhausted. This stream now begins a regeneration (‘regen’) cycle whilst the second stream enters service. Sulphuric acid is used to regenerate the cation units and sodium hydroxide regenerates the anion units. The regen process takes approximately 1 hour. The effluent produced by this regeneration stage is transferred to the effluent tank where it is neutralized and transferred to waste water.

At South Humber Bank the Phase 1 WTP has 2 streams, which are normally run one at a time (duty-standby), although they can be run together if the process requires it.

The water treatment plant is normally run fully automatically in duty/standby mode. Overall control is provided by *Procontrol* from the main control room but, subject to correct signals, the WTP runs as a stand-alone unit controlled by its own self-contained programmable logic controller.

2.1.12 Auxiliary Boiler

An gas oil fired auxiliary boiler is present on site. Its purpose is to provide steam to the steam distribution system to start up the first CCGT module (can be either Phase 1 or Phase 2) after the extremely rare event of both CCGT modules being completely shut down. Once one CCGT module is running, the auxiliary boiler is no longer required as the Phase 1 – Phase 2 interconnection (see Section 2.1.8.11) can be used to start the other module.

The auxiliary boiler is a *Thermax* twin furnace, three pass, multi-tubular, package shell boiler, supplied by Cochran Boilers Ltd. It is a relatively modern unit, built in 1996, and is fitted with low NOx burners of the rotary cup type.

Optimum combustion and low emissions are achieved by the rotary cup and air atomisation systems, which produce a particularly fine and homogenous spray of fuel, and the combustion air supply system, where a precision air guidance and distribution system provides controlled combustion in staged air streams.

The fuel supply for the auxiliary boiler is from two storage tanks situated adjacent to the auxiliary boiler house. They each have a capacity of 30,000 litres and are bunded to protect against spills, etc. The Application Site Report (Appendix A) contains more detail. Ultra low sulphur gas oil (sulphur content less than 0.005% by mass) is used.

2.1.13 Waste Water System

The waste water system can be divided into the following systems:

- **Surface Water Drains**: This drainage system is a common network around the site with oil separators situated inline at various higher risk positions. This network then leads to either the west effluent basin, the east effluent basin or the main cooling water pump house basin from where it is pumped into the main cooling water (MCW) return line.
- **Foul Water Drains:** This drainage system is fed from the admin / workshop block to a pumped catchment tank. Here the installation has the

capability to pump the foul water on to the electrical building where it would then enter two foul water treatment units, the first located to the west of the National Grid Gas Compound and the second to the north of the auxiliary boiler house. Here the waste would be macerated and biologically treated. This waste product would then be fed into the east effluent basin and diluted before being pumped into the MCW outlet line. The installation's IPC authorisation permits this process, subject to certain discharge limits. However, at the current time Centrica SHB Ltd chooses not to treat and discharge the foul water. Instead it is removed from the catchment tank by an external contractor to be processed off-site. Sections 2.5 and 2.6 discuss this further.

- **HRSG Blowdown Drains:** Water from the HRSG blowdown tanks is fed into the east effluent basin where it is cooled, using water extracted from the MCW inlet line.
- **Oily Water Drains:** This drainage system is connected to areas of the site where there is a greater risk of oil entering the site drains such as transformer bunds and oil tank bunds. The site transformer oily water drains are first led into the oil retention tank, located just west of the ST transformer, where any major spillages can be contained. The water is then pumped through a Class 1 oil separator before entering the west effluent basin. The remaining oily drains are led through an oil separator before entering the east effluent basin.
- **Effluent Pumped Main:** The wastewater from the east / west basins is transferred automatically to the MCW return line and discharged to the Humber Estuary.

The system is essentially fully automated. The dual pumps from the effluent basins are set to automatic duty / standby operation as are the ST building and MCW valve pit sump pumps.

The effluent basins all have *Stormceptor* bypass oil separator units fitted prior to them to prevent any ingress of oil. The basins are checked visually, for signs of oil contamination, as part of routine plant checks. If oil is found then the relevant basin's pumps are switched to manual to prevent further discharge.

The east effluent basin also has an 'oil on water' detection device installed which issues an alarm in the main control room. On receipt of this alarm the basin is checked locally.

The oil separators are routinely checked by the maintenance department and emptied as necessary. They are fitted with high level alarms, issued to the main control room

An alarm is also issued in the main control room in the event of a high level in the transformer oil retention tank. In the event of such an alarm, an investigation is initiated and if found to be necessary, much of the oil can be removed from the surface using an approved external contractor. The remaining water is pumped through the Class 1 oil separator, which also contains a coalescer (used for the separation of smaller globules of oil), and is fed into the east effluent basin.

Surface water is fed through oil separators manufactured by SPEL Products prior to entering the relevant basins. These separators do not issue alarms in the main control room but are checked routinely by the maintenance department.

On site the following oil separators are fitted to the following drains:

- SPEL *STORMCEPTOR* BYPASS SEPARATOR
    - Surface water drains located next to east basin
    - Surface water drains located next to west basin
    - Surface water drains located next to MCW basin
- SPEL OIL SEPARATOR CLASS 2
    - Surface water drains from auxiliary boiler house
    - Surface water drains from workshop area
    - Surface water drains from National Grid area
- SPEL OIL SEPARATOR CLASS 1 (a 2-chamber coalescer unit)
    - Water fed from the oil retention tank next to the west basin

2.1.14 Other Activities (Site Support)

Support services include workshops and a small on-site laboratory for analytical services. Temporary buildings are used as required for contractors during maintenance works.

2.1.15 Storage and Handling of Raw Materials

2.1.15.1 Solid Materials

No bulk solid raw materials are used at the installation.

2.1.15.2 Liquid Materials

The liquid materials used on site in bulk quantities are detailed in Table 2.5. The techniques used to prevent pollution from their storage and handling are detailed in the accompanying Application Site Report.

2.1.15.3 Gaseous Materials

The only potentially polluting gaseous materials used are natural gas and sulphur hexafluoride. Natural gas is the primary fuel and all gas systems are monitored to identify gas leaks and minimise fugitive releases. Sulphur hexafluoride is used in closed systems and is not released under normal operation.

2.1.16 Primary Measures for the Control of Oxides of Nitrogen

2.1.16.1 Types of Combustion Plant at the Installation and Primary NOx Controls

Table 2.2 details the combustion plant at South Humber Bank and the primary NOx controls.

Table 2.2: Combustion Plant and Primary NOx Controls

Unit	Fuel	Thermal input (MWth)	Release point (1)	Primary NOx control technique
GT11(2) gas turbine	Natural gas	491	A2	Dry low NOx burners
GT12 gas turbine	Natural gas	491	A2	Dry low NOx burners
GT13 gas turbine	Natural gas	491	A1	Dry low NOx burners
GT21 gas turbine	Natural gas	491	A3	Dry low NOx burners
GT22 gas turbine	Natural gas	491	A3	Dry low NOx burners
Auxiliary boiler	Gas oil	42	A4	Low NOx burners
Phase 1 emergency generator	Gas oil	1.7(3)	A5	None
Phase 2 emergency generator	Gas oil	1.7(3)	A6	None
Phase 1 back up firewater pump	Gas oil	0.75(4)	A7	None
Phase 2 back up firewater pump	Gas oil	0.65(4)	A8	None

(1) Refer to Figure 3.1 / Table 3.3

(2) The turbines are referred to as "GT*XY*" where *X* is the phase number (1 or 2). *Y* is the turbine's sequential number (starting with the southernmost unit and increasing to the north) within the phase.

(3) The thermal input of the emergency generators is estimated based on known output capacity of 500 kWe and assumed efficiency of 30%.

(4) The thermal inputs of the firewater pumps are estimated based on known output capacities of 225 kW and 195 kW for the Phase 1 and 2 units respectively, and assumed efficiencies of 30% for both units.

The following paragraphs provide the other information prompted for in the combustion sector application form.

The typical composition of the natural gas supplied at the station is as follows:

Table 2.3: Typical Fuel Gas Composition

Component	Molar %	Mass %
Methane	89.4	79.2
Ethane	5.40	9.0
Propane	1.47	3.6
Butane	0.68	2.2
Carbon dioxide	1.55	3.8
Nitrogen	1.51	2.3
Total carbon content	-	72.31 (CO_2 factor therefore 2.65 kg/kg)

Although the natural gas combusted at South Humber Bank has negligible sulphur content when extracted, it is odorised with very small amounts of sulphurous compounds (tertiary butyl mercaptan 78% and dimethyl sulphide 22%, with a dosing rate of 6 kg / million m^3 of gas, according to National Grid Gas). This leads to very low concentration emissions of sulphur dioxide in the GT exhausts. Based on a mass balance calculation using 2002 gas use this gives an annual sulphur dioxide emission of 13 tonnes. The gas is odorised for onsite safety reasons and is supplied by National Grid Gas from the adjoining compound and odorisation plant. A separate PPC permit application for the odorisation of gas has been prepared by National Grid Gas and accompanies this permit application.

The average higher heating value (gross calorific value) of the gas is 39.6 MJ/sm^3. The typical density is 0.81 kg/Nm^3.

The NOx factor for natural gas use varies with load and operating regime. Based on total emissions and total gas use 2001-2004 the average NOx factor is 2.60 kg/t.

There are no cooling towers at South Humber Bank.

The installation will be subject to the Large Combustion Plant Directive and all parts will be classed as 'new' plant for the purposes of that instrument.

2.1.17 Primary Measures for the Control of Other Pollutants

2.1.17.1 Carbon Monoxide and Volatile Organic Compounds

Carbon monoxide and volatile organic compounds are produced as a result of incomplete combustion. Since incomplete combustion significantly affects the efficiency of the plant, it is vital to avoid. Numerous instrumentation and control techniques monitor various parameters associated with ensuring complete combustion. Their effectiveness is demonstrated by the consistently very low levels of carbon monoxide emissions measured by the continuous emissions monitoring system. Section 3.1 details these emissions and compares them to benchmarks.

2.1.17.2 Sulphur Dioxide

The natural gas fired at South Humber Bank has a very low sulphur content, resulting in annual emissions of approximately 10-15 tonnes. The operator will investigate opportunities and implications associated with the expansion of gas detection systems onsite, which have the potential to eliminate the need for odorisation of the gas and hence releases of sulphur dioxide, since almost all of the sulphur in the gas is from the odorant added. The lowest possible level of odorant is currently metered into the natural gas supply at present that conforms to appropriate safety requirements to minimise the current release of sulphur dioxide from the site.

For the small amount of fuel oil use (approximately 25 tonnes per year), ultra low sulphur gas oil is used. This has a sulphur content of less than 0.005% by mass, thus resulting in maximum emissions of approximately 1.25 kg from its use, which is considered negligible.

2.1.17.3 Particulate Matter

Natural gas burns very cleanly in gas turbines and produces negligible amounts of particulate matter. Similarly the gas oil used in the auxiliary boiler and small engines is highly refined and does not result in particulate emissions of any significant quantity.

2.2 Emissions Control and Abatement

2.2.1 Abatement of Point Source Emissions to Air

There are no 'end of pipe' abatement techniques to control emissions at South Humber Bank.

The only such technique applicable to gas turbines is Selective Catalytic Reduction (SCR).

The retrofitting of SCR at South Humber Bank would require a major redevelopment of the HRSGs and GT exhaust systems. This is because the original design did not foresee the need to leave space for SCR. Section 7.5.4 of the BREF Note for Large Combustion Plant states:

SCR retrofitting is technically feasible but not economical for existing CCGT plants if the required space in the HRSG was not foreseen in the project and is therefore not available.

('*available'*, in this context, is as per the legal definition of Best Available Technique (BAT)).

SCR has other drawbacks, such as a slight reduction in plant efficiency and the risk of 'ammonia slip'. The issues associated with SCR are detailed in the BREF note.

Centrica believes that SCR is self evidently not BAT in the case of South Humber Bank and therefore a detailed cost-benefit analysis has not been carried out.

2.2.2 Abatement of Point Source Emissions to Surface Water and Sewer

There are no emissions to sewer at South Humber Bank.

The waste water system is described in Section 2.1.13 and also in the accompanying Application Site Report. They describe how a range of oil-water separators is employed to prevent hydrocarbon contamination entering the discharge.

The only other abatement technique associated with emissions to water are the biological treatment units on the foul water drain system. As detailed in Section 2.1.13 these are currently not used. Instead, foul water is collected by a licensed contractor and tankered off-site for treatment. Due to the scales involved, treatment at a main sewage treatment works is almost certain to result in a cleaner discharge than could be achieved by on-site treatment.

2.2.3 Abatement of Emissions to Groundwater

All PPC permits are subject to compliance with components of the Groundwater Regulations 1998 (Statutory Instrument No. 2746). The regulations relate to direct or indirect discharges of ‘List I’ and ‘List II’ substances, as defined by the regulations.

There will be no direct or planned indirect discharge of List I or II substance during operation of SHB.

In order to minimise the risk of a release of a potentially contaminating substance the onsite control techniques are:

- Appropriate use and storage of substances;
- Managed drainage system with interceptors
- Spill kits located close to the storage and use of hazardous materials;
- Consideration of Listed substance as part of onsite procurement;
- Periodic inspection and maintenance of onsite systems; and
- Training and safety awareness of handling materials onsite.

The Groundwater Regulations aim to prevent entry of List I substances into groundwater and prevent groundwater pollution by List II substances. To achieve this, the regulations require that the direct or indirect discharge of List I or II substances must be subject to prior investigation and authorisation. The regulations also allow notices to be served to control activities that might lead to an indirect discharge of List I substances or groundwater pollution by an indirect discharge of substances in List II.

‘Direct discharge’ is defined as the introduction into groundwater of any List 1 or II substance with percolation through the ground or subsoil.

‘Indirect discharge’ is defined at the introduction into groundwater of any List I or II substance after percolation through the ground or subsoil.

Of the List I substances, only mineral oils and hydrocarbons (as lubricants and gas oil) are expected to be present in potentially mobile states. Trace quantities of mercury and cadmium may be detectable within some of the chemical reagents used on site.

List II substances by their nature tend to accumulate in water. A number of compounds will be present within the deionisation wastes and water treatment chemicals in extremely low concentrations.

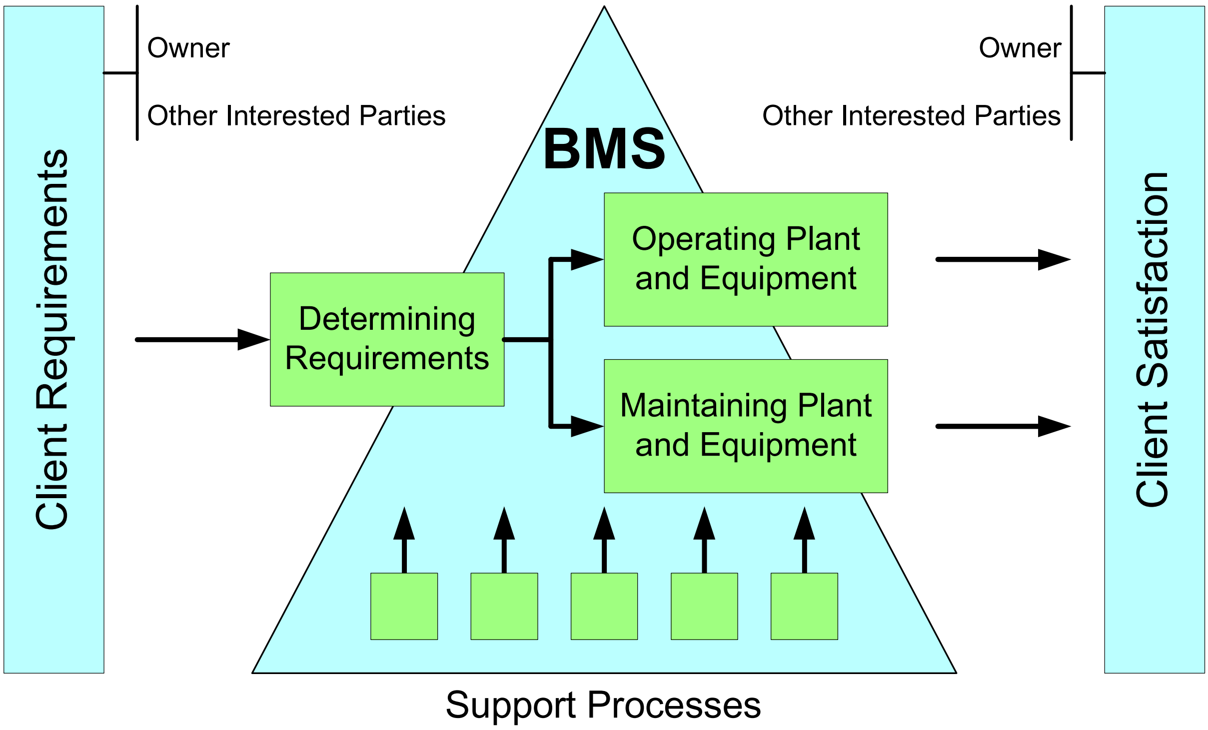
An Application Site Report (ASR) has been prepared to assess the risk of contamination and compliance with the Groundwater Regulations and describe the controls that are in place at South Humber Bank to reduce the risks. The ASR is attached as Appendix A.

2.3 Management Techniques

2.3.1 Introduction to Centrica SHB's Management Systems

Centrica SHB Limited (CSHB) operates a business management system (BMS). It provides a formal framework for South Humber Bank policies and the means of achieveing them. The BMS is documented through a manual and a range of procedures which cover quality, environment, health and safety, and human resources management. Its structure is outlined below in Figure 2.1.

Figure 2.1: Business Management System Structure



The environmental management element is entitled Safeguarding the Environment. The CSHB environmental management system is certified to ISO 14001 and is also registered with the Eco-Management and Audit Scheme (EMAS).

Centrica SHB's environment policy states the company's commitment to minimising its environmental impacts, devising an environmental action programme, preventing pollution and complying with relevant legislation. Implementation of the environmental policy is the responsibility of the operating team led by the General Manager. The Board of Directors sets out the measures the company will take to maintain and continually improve its environmental performance. The EMS employed at South Humber Bank is considered to represent BAT.

The BMS contains 12 procedures directly under the Safeguarding the Environment category. These procedures are as follows:

SHB-A8-2035	Safeguarding the Environment
SHB-A8-2036	Environmental Objectives and Targets
SHB-A8-2037	EA Authorisation Compliance System
SHB-A8-2038	Communication with EA and Other Interested Parties
SHB-A8-2039	Assessment of Environmental Effects
SHB-A8-2040	Control of Waste
SHB-A8-2041	Register of Environmental Legislation, Regulations and Other Policy Requirements
SHB-A8-2042	Environmental Awareness
SHB-A8-2044	Maintenance of Environmental Instrumentation
SHB-A8-2129	Releases of Water
SHB-A8-2130	Emissions to Atmosphere
SHB-A8-2171	Oil/Chemical Spillage Control

Each is a written procedure which details its scope, purpose and who is responsible for its implementation as well as outlining the procedure itself. There are also a series of forms relating to the procedures in this category.

Procedure SHB-A8-2039 ensures that the environmental effects of the activities at South Humber Bank are assessed. Significant environmental effects are then managed to minimise the impact on the environment. They also form the basis of objectives and targets to improve environmental performance.

Environmental objectives and targets are established using procedure SHB-A8-2036. The procedure also ensures that there is a programme for implementation and that monitoring takes place.

As required by EMAS, an annual environmental statement is available to stakeholders and other interested parties reporting on the environmental performance of the power station. The statement also makes the environmental policy, objectives and targets publicly available.

The following environmental performance information is given in the annual statement:

- natural gas consumption;
- electricity exportation;
- water abstraction and return to the River Humber, as well as mains and industrial usage;
- flue gas emissions;
- waste and recycling; and
- complaints, incidents and compliance.

External auditing of environmental performance is undertaken on an annual basis in order to achieve and retain both ISO14001 certification and EMAS registration. Auditing of the BMS, including the environment element, is undertaken as defined in procedure SHB-A8-2133 (Auditing the BMS).

2.3.2 Operations

The Operations Basic Training Manual gives an overview of the plant and explains the process that takes place at the power station (in association with process drawings). The manual is intended to be useful to both operations and maintenance staff. Reference is also made to operations and maintenance manuals, the operations handbook and other instructions.

The introduction to the manual gives a general plant overview, which describes the components of the plant and gives a basic process description. There are then a further seven modules giving more detail. The modules are:

MODULE 1..KKS designation* and P&ID

MODULE 2..Gas Turbine

MODULE 3..Heat Recovery Steam Generator

MODULE 4... Water Steam Cycle

MODULE 5...Steam Turbine

MODULE 6...Balance of Plant

MODULE 7... Electrical

**The KKS designation refers to the system used to give a reference number to all plant components throughout the station.*

Each of these areas of plant is introduced in the respective module and then a breakdown of the process and systems involved is given.

Within the BMS operations are covered by procedure SHB-A8-2009 (Operating Plant). Procedure SHB-A8-2035 (Safeguarding the Environment) provides the link between site operations and the environment by allocating responsibilities to the Operations Manager. These responsibilities are:

- Implement the requirements of the environment plan, which are within his area of control.
- Assign responsibilities where required to progress objectives.
- Review the progress of objectives, which relate to his area.

- Report internally and also externally (if required) any environmental incidents.
- Discuss with the Station Chemist any recommendations raised from assessments on environmental effects within his area of control.

The Operations Manager also acts as Chairman of the Health, Safety and Environment Forum meetings for the power station.

The following procedures are also closely related to managing the environmental impacts of operations:

SHB-A8-2040	Control of Waste
SHB-A8-2044	Maintenance of Environmental Instrumentation
SHB-A8-2129	Releases of Water
SHB-A8-2130	Emissions to Atmosphere

Procedure SHB-A8-2044 in conjunction with procedures SHB-A8-2129 and SHB-A8-2130 ensure that emissions and environmental impacts are monitored and managed.

If process or engineering change needs to occur at the installation this is covered by procedure SHB-A8-2108 (Engineering Change Management). This procedure is also used for design, construction and review of new facilities and other capital projects. Budget considerations and the financial procedures to be satisfied when considering annual site budget planning are included in procedure SHB-A8-2108.

The decommissioning of South Humber Bank Power Station has been considered. The necessary works and cost of returning the site to either brown or greenfield condition has been assessed.

2.3.3 Maintenance

South Humber Bank runs a maintenance management system called *PowerMaint*, which is used to plan, control and record the maintenance of plant and equipment. Maintenance activity includes:

- Routine maintenance, planned outage work and corrective maintenance;
- Maintenance of equipment, tools and appliances;
- Modifying existing plant and apparatus, introducing new items of equipment;
- Calibration of plant instrumentation, test equipment and testing and inspection; and

- Permanent site staff are responsible for the specification, procurement, management and supervision of contract labour to carry out planned outage, routine and breakdown maintenance.

Daily planning meetings are held at the site, where maintenance issues are discussed.

There are a number of BMS procedures relevant to maintenance at South Humber Bank.

SHB-A8-2014	Maintenance Management
SHB-A8-2015	Maintenance Work
SHB-A8-2044	Maintenance of Environmental Instrumentation
SHB-A8-2108	Engineering Change Management

The maintenance system and procedures ensure that plant failure resulting in an impact on the environment is unlikely to occur.

2.3.4 Competence and Training

There are a series of procedures within the BMS to ensure that staff are fully competent and well trained. These are

SHB-A8-2042	Environmental Awareness
SHB-A8-2089	Inducting Employees
SHB-A8-2090	Training and Personal Development
SHB-A8-2091	Maintaining Personnel Records
SHB-A8-2138	Training Needs Analysis
SHB-A8-2140	Personal Development Review

All training needs are assessed by a manager and recorded in the training records system, as described in procedure SHB-A8-2090. The need for refresher training is reviewed at least annually and if there are any changes, in legislation or working practices for example.

The Environmental Awareness procedure (SHB-A8-2042) details a comprehensive process for making both visitors and staff at South Humber Bank aware of environmental issues at the site. Everyone, visitors and staff, must be site inducted, read a small booklet and record that the induction has been carried out. All staff are issued with an Envirocard giving details of emission limits and information on the use of chemicals.

All CSHB staff are given training in:

- EMS, including the policy statement;
- Environmental effects evaluation;
- Site environmental awareness; and
- ISO 14001.

All operations and maintenance staff receive the following additional training:

- Environmental compliance
- Calibration of environmental instrumentation
- Disposal of industrial/special waste
- Environmental improvement programme
- Action on receipt of complaint
- Inventory of environmental legislation
- Management of noise control
- Procedure following accidental spillage of chemicals and oils
- Communications with the EA
- Storage of hazardous substances

Any staff working in procurement will also be given further training in purchasing green materials, disposal of waste materials and dealing with contractors. They will also be guided by procedures SHB-A8-2113 (Procurement Management) and SHB-A8-2114 (Pre-qualification), which refer to environmental considerations and impact during the vendor selection and purchasing process.

This comprehensive training system ensures that everyone on the site (including contractors) is aware of the potential environmental impacts under normal and emergency conditions. The importance of adhering to permit conditions, how to report deviations from the permit and take action following accidents is also understood.

2.3.5 Accidents, Incidents and Non-Conformance

The CSHB procedures associated with the accidents, incidents and non-conformance are:

SHB-A8-2022	Investigating Plant Failure
SHB-A8-2023	Maintaining Site Control
SHB-A8-2024	Emergency Plan
SHB-A8-2025	Complaint from a Member of the Public

SHB-A8-2037	Environmental Authorisation Compliance System
SHB-A8-2038	Communication with Environment Agency and Other External Interested Parties
SHB-A8-2059	Investigating and Reporting Accidents or Incidents
SHB-A8-2104	Maintenance Management
SHB-A8-2128	Non-Conformance and Preventative and Corrective Action
SHB-A8-2133	Auditing the Business Management System

Procedure SHB-A8-2024, in particular, ensures identification of the likelihood and consequences of accidents. It also ensures there are actions to prevent accidents and mitigate any consequences.

Ensuring compliance with emissions limits is managed through procedure SHB-A8-2037. Whilst, non-conformances are dealt with by procedure SHB-A8-2128, as are preventative and corrective actions. Investigating and reporting accidents or incidents are covered by procedure SHB-A8-2059.

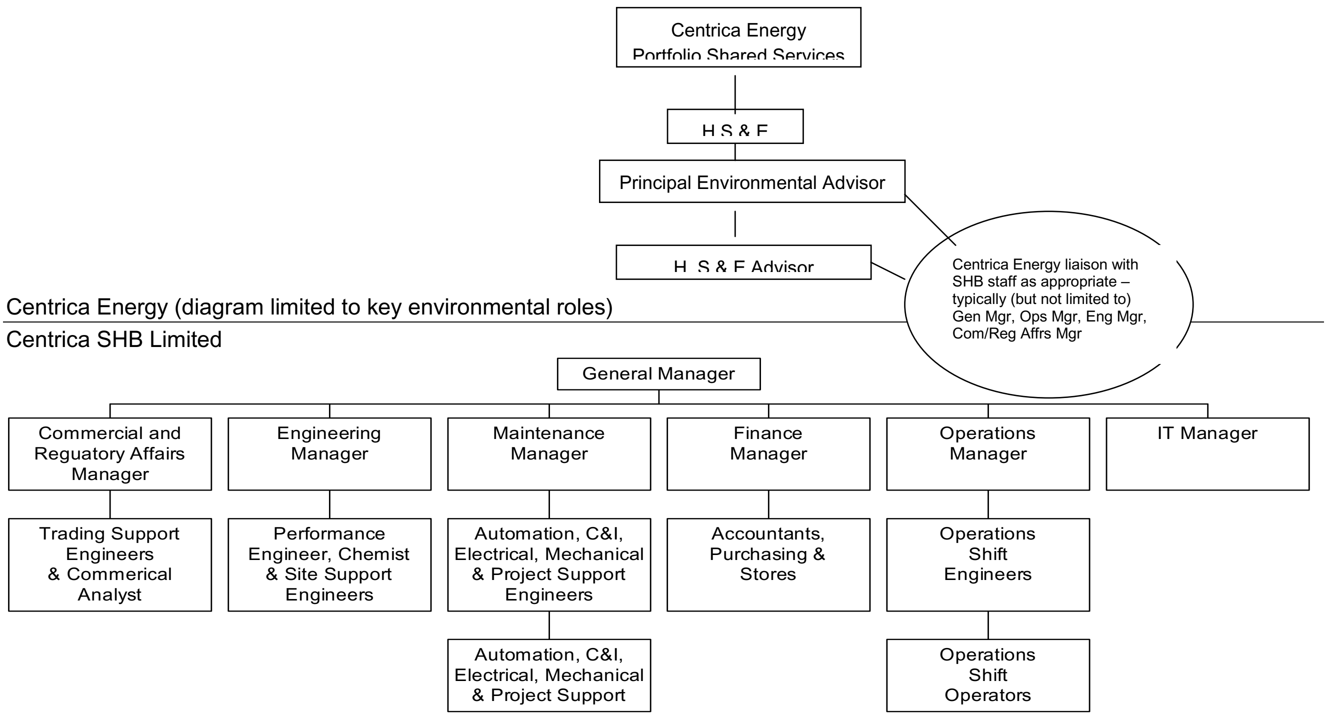
Any complaints from the public are dealt with via procedure SHB-A8-2025. Any dialogue with the Environment Agency with regard to operating procedures and emission limits is managed by procedure SHB-A8-2038.

2.3.6 Organisation

Centrica SHB Limited is 100% owned by Centrica plc, as of September 2005. Power generation is managed under the Centrica Energy business area. South Humber Bank Power Station General Manager reports to the Centrica Asset Manager Power Generation and Centrica Shared Services.

South Humber Bank has an on-site management team of seven including the General Manager (see Figure 2.2). The General Manager, Operations Manager, Maintenance Manager and Commercial and Regulatory Affairs Manager all have specific responsibilities for safeguarding the environment in the BMS, which are outlined in Section 2.3.6.1

Figure 2.2: SHB / Centrica Energy Organisational Structure



2.3.6.1 Safeguarding the Environment Responsibilities at SHBPS

General Manager

- Establishes the environmental policy
- Provides adequate financial resources to enable the needs of the EMS to be met
- Agrees environmental improvement targets
- Arranges training for staff
- Assigns environmental duties to staff
- Reports on a monthly basis on aspects of the BMS
- Oversees the development, review and updating of procedures and work instructions
- Ensures monitoring of progress towards achieving environmental improvement targets
- Ensures suitable audits are conducted to a planned programme
- Ensure the register of environmental legislation is maintained, reviewed and updated

Operations Manager

- Implementation and operation of the BMS by Operations staff
- Reports to the Plant Manager as necessary on the operation of the EMS, including collation and return of data
- Ensures monitoring of progress towards achieving environmental improvement targets
- Monitoring environmental incidents and reporting enforcing authority
- Advising management on environmental training
- Reviews internal reports on environmental incidents and take necessary action
- Maintaining the register of environmental legislation and advising management of changes
- Auditing progress on agreed targets and objectives and reporting progress to the Plant Manager

Maintenance Manager

- Implementation and operation of the BMS by maintenance personnel

- Ensures monitoring of progress towards achieving environmental improvement targets
- Ensures that selection of suppliers and contractors includes consideration of environmental concerns and the suppliers' environmental qualifications

Commercial & Regulatory Affairs Manager

- Acts as system coordinator for the BMS
- Management representative for ISO 9001 management systems
- Implementation and operation of the BMS by finance and administration personnel
- Maintenance of training records

Station Chemist

- Sampling and monitoring effluent discharges
- Maintenance of records

In addition to onsite personnel, environmental support is also provided by the Portfolio Shared Services function of Centrica Energy.

The **Portfolio Shared Services** cover areas of health and safety, environment and business services and are responsible for:

- Providing updates on new and pending legislation
- Producing legislative briefs interpreting the requirements of new legislation
- Producing policies and standards to ensure that all power assets implement new requirements into their BMS in a consistent manner
- Providing support to the power assets and assisting with the resolution of particular issues
- Assisting the power assets in developing and delivering improvement targets and objectives
- Ensuring compliance with legal and company standards through audits and reviews

Key individuals include the principal environmental advisor and the regional H, S & E advisor.

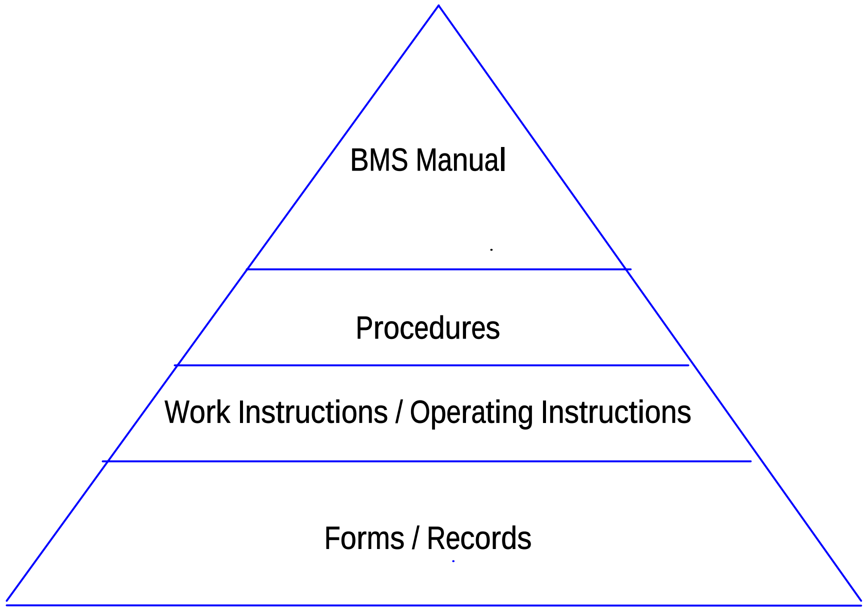
The **Principal Environmental Advisor** is responsible for:

- Defining Environmental Policy and Standards for adoption at the station.
- Providing support and guidance across all environmental issues.

The **HS&E Advisor** is responsible for providing support and guidance across all environmental issues.

The BMS Coordinator is the Trading Support Engineer who manages and controls documents to ensure that the structure of the BMS is maintained. The BMS document hierarchy is shown in Figure 2.3.

Figure 2.3: BMS Document Hierarchy



BMS Manual	defines the structure of all the management systems onsite and incorporates the EMS
Procedures	describe how processes involving individuals, departments or organisations operate
Work instructions	describe how an individual(s) undertake a task
Operating instructions	describe how an activity within the process is performed
Forms	documents that capture data
Records	Forms and other documents that retain data and provide evidence of implementation of the BMS

This document management system ensures that all records relating to environmental management at South Humber Bank are traceable and retrievable. Environmental policies, roles and responsibilities, targets, procedures, results of audits and reviews are kept within the system.

Now that South Humber Bank is completely owned by Centrica, a review of the BMS will be undertaken during 2006. This will ensure consistency and integration with other Centrica Energy assets.

2.4 Materials Inputs

The general technical guidance requires consideration of the following information in relation to material and water usage:

- Composition;
- Quantities used;
- Fate;
- Environmental impact;
- Practicable alternatives that may have a lower impact; and
- Waste minimisation.

The key raw materials used in the operation of the CCGT are:

- Natural gas;
- Gas Oil;
- Water; and
- Chemicals (water treatment, cleaning, lubrication and others).

Figure 2.4 shows the locations of raw material storage at SHBPS, and Table 2.5 provides a more detailed inventory of raw materials in use at the site.

2.4.1 Raw Material Selection

The raw materials used at SHBPS are outlined in Table 2.5. The table details the material, its function at the installation, its chemical composition, quantities used, the fate of the material within the installation, potential environmental impact, any alternatives with lower environmental impact and why these are not used.

SHBPS's health, safety and environment policy states that they ensure that chemicals and natural resources are used with increasing care and efficiency. This is supported by procedures SHB-A8-2041 (Register of Environmental Legislation, Regulations and Other Policy Requirements) and SHB-A8-2039 (Assessment of Environmental Effects). In drawing up and maintaining the register of environmental legislation the Station Chemist will be aware of statutory requirements regarding materials use so the site can operate accordingly. Updating the register of environmental effects regularly will allow the site's environmental impact to be reviewed and consequently material use can be re-evaluated.

SHBPS is certified under ISO 9001, the international standard for Quality Management Systems, and the business management system (BMS) operated by the site incorporates quality management. The quality policy states that quality will be paramount in all aspects of the site's activities.

High quality raw materials are purchased to minimise emissions to the environment. This includes the use of low mercury and cadmium water treatment chemicals and ultra low sulphur gas oil to minimise releases of sulphur to atmosphere.

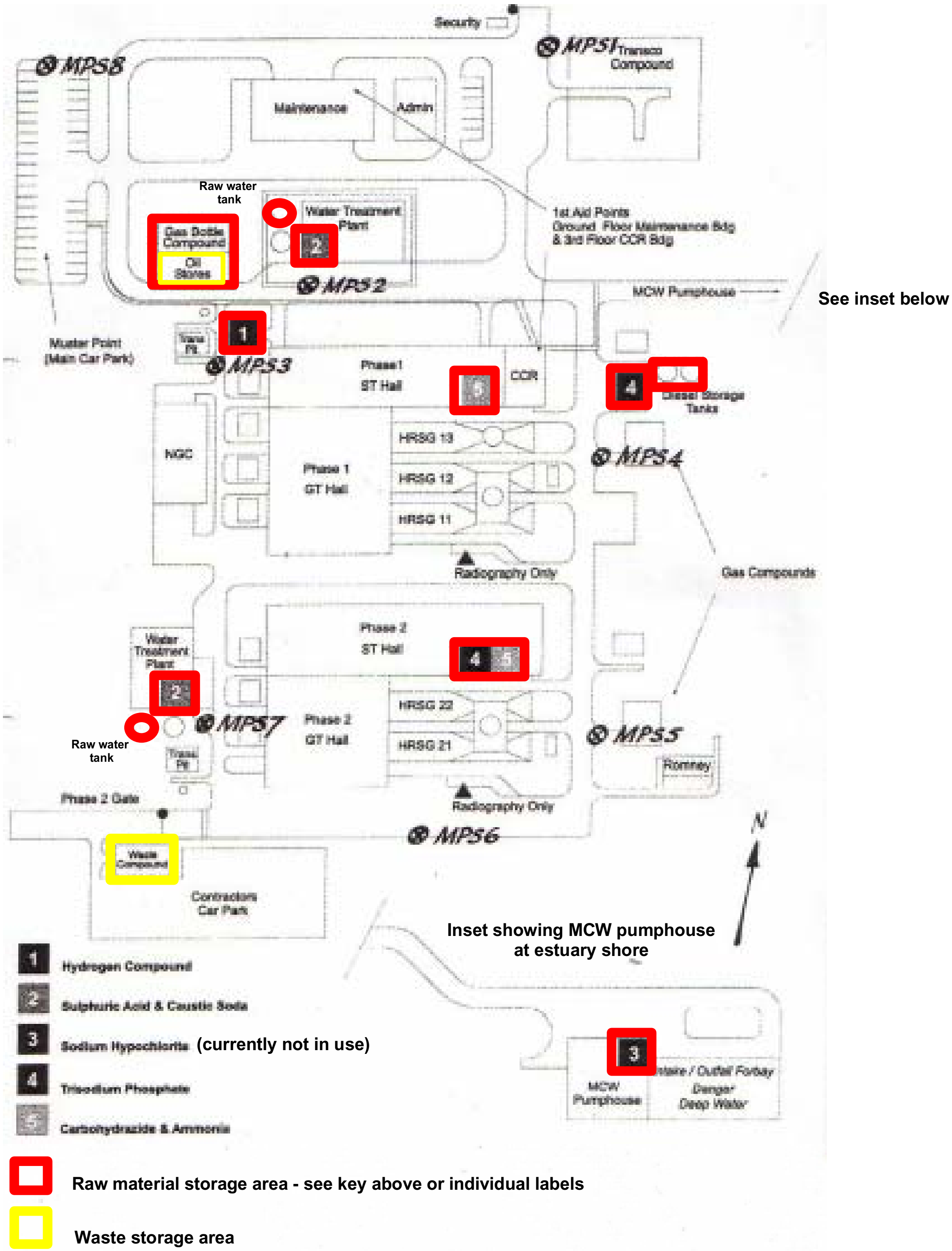
There are procedures in place for the receipt of particular materials and also generally:

SHB-A8-2127	Receipt of Chemicals (Sulphuric Acid and Caustic Soda)
SHB-A8-2032	Receipt of Chemicals (Sodium Hypochlorite)
SHB-A8-2033	Receipt of Chemicals in IBCs
SHB-A8-2034	Receipt of Gas Oil
SHB-A8-2169	Receipt of Gases in Pressurised Cylinders
SHB-A8-2124	Material Management

These procedures along with procedures SHB-A8-2113 (Procurement Management) and SHB-A8-2149 (Procurement – General Conditions) ensure materials are quality controlled and only those of a high standard are used at the installation.

Table 2.5 does not identify any materials currently being used that have less polluting options at this time. There is therefore no perceived requirement for longer-term studies into alternative or material substitutions at present, other than the ongoing management of quality driven by the BMS.

Figure 2.4: Storage Locations for Raw Materials



2.4.2 Water

A water use efficiency audit has not been undertaken at South Humber Bank Power Station during the last two years. An audit will take place within two years of the permit being issued.

Flow diagrams and water mass balances for the installation will be used to identify opportunities for maximising re-use and minimising use of water. This will include considering cleaning and other domestic uses as well as the industrial process itself. Water-efficiency objectives will be established and included in a timetabled plan for implementing water reduction improvements agreed with the Environment Agency.

As part of the improvement conditions of the site's IPC authorisation, a desktop review was carried out in 2004 to review the options for minimisation of cooling water volumes used across the process. It concluded that there are likely negative impacts on both operations and the environment of reducing cooling water flow and therefore the study was not taken further, in agreement with the Environment Agency. Any water efficiency audit is therefore likely to concentrate on HRSG feedwater use and other areas of the site.

Table 2.4: Incoming Water Sources and Annual Quantities

Source	Quantity m^3 (2004)
Anglian Water	482,252
Humber Estuary	747,354,700
TOTAL	**747,836,952**

2.4.3 Chemicals

All chemicals are stored in dedicated areas away from areas of vehicle or mechanical activity. The chemicals are stored in suitable containers, within controlled areas and bunded where appropriate. Spill control and containment equipment is located at nearby appropriate locations and staff trained in its use. All chemicals are stored in accordance with the Control Of Substances Hazardous to Health Regulations.

Table 2.5: Raw Material Inventory and Fate

Raw material	Function	Chemical nature/ compositi on	Annual quantity used	Addition point	Fate % (product, effluent, waste, air)	Risk classificati on	Environmental impact potential	Alternatives (and reasons for their non-use)
Natural gas	Combustion in gas turbines	Hydrocarbo n mixture. See Table 2.3	2000 – 1.40 M tonnes 2001 – 1.01 M tonnes 2002 – 1.16 M tonnes 2003 – 0.92 M tonnes 2004 – 1.32 M tonnes If installation was operated continually at full load it would use approximately 1.6 M tonnes	Gas turbines	Combustion with some emissions to air	R12 Extremely flammable	Production of greenhouse gases and therefore contributing to global warming	None – key raw material
Raw water (Elsham Industrial Supply)	Boiler feed water	H_2O	2001 – 414,030 m^3 2002 – 229,189 m^3 2003 – 237,338 m^3	Water treatment plant	Cooling water outfall	None	Can mobilise other contaminants	None
Potable water	Domestic uses	H_2O	2001 – 5,121 m^3	Mains water supply	Septic tanks and then removed off-site	None	Can mobilise other contaminants	None

Raw material	Function	Chemical nature/ compositi on	Annual quantity used	Addition point	Fate % (product, effluent, waste, air)	Risk classificati on	Environmental impact potential	Alternatives (and reasons for their non-use)
Sulphuric Acid	Regenerant for water treatment plant units and effluent buffering	H_2SO_4	438 tonnes Stored 2 x 17 tonnes max	Phase 1 and 2 water treatment plants	Mostly converted through the regeneration process to mineral sulphates, pH buffered if necessary and emitted to main cooling water outfall into the Humber Estuary	R21 R22 R35 R36 R37 R38 R49 Harmful Corrosive	A spill may affect surface water and groundwater quality and contaminate the ground.	Other acids, such as hydrochloric acid, have the same function and potential environmental impact
Sodium hydroxide solution (caustic)	Regenerant for water treatment plant units and effluent buffering	NaOH	840 tonnes Stored 2 x 23 tonnes max	Phase 1 and 2 water treatment plants	Mostly converted through the regeneration process to sodium salts, pH buffered if necessary and emitted to main cooling water outfall into the Humber Estuary	R35 Harmful Corrosive	A spill may affect surface water and groundwater quality and contaminate the ground	Other bases but they have the same function and potential environmental impact

Raw material	Function	Chemical nature/ compositi on	Annual quantity used	Addition point	Fate % (product, effluent, waste, air)	Risk classificati on	Environmental impact potential	Alternatives (and reasons for their non-use)
Gas oil	Fuel for auxiliary boiler and emergency generators	Hydrocarbo n	30,000 litres Stored as auxiliary boiler tanks 60,000 litres, emergency diesels 2,200 litres, fire diesel pumps 745 litres	Phase 1 auxiliary boiler and emergency generators	Combusted with some emissions to air	R10 Flammable	Combustion gases have potential impact on air quality. A spill may affect surface water and groundwater quality and contaminate the ground	Other fuels have same function and potential environmental impact. Liquid fuel provides essential diversity of supply for boiler. Lowest available sulphur content for diesel already purchased.
Ammonia solution	Optimising pH range of boiler and steam entrainment system	NH_3 (aq) solution 10%	15 tonnes Stored as 4 x 1000L	Boiler feedwater at 0.7 ppm as required to maintain pH level	Entrained within steam system and lost to atmosphere and via blowdown water from HRSG's	R20 R21 R22 R34 R36 R37 R38 R41 Harmful Corrosive	A spill may affect surface water and groundwater quality and contaminate the ground	Other pH buffers have the same function and environmental impact potential
Carbohydrazi de	Optimising oxygen levels and pH range of boiler and steam entrainment system	CH_6N_4O 10% solution	8 tonnes Stored as 4 x 1000L 10% solution	Boiler feedwater at 0.07 ppm as required to maintain low feedwater oxygen levels	Entrained within steam system broken down to CO_2, N_2, water and lost to atmosphere and via blowdown water from HRSG's	R5 R36 R37 R38 Irritant Explosive	A spill may affect surface water and groundwater quality and contaminate the ground	Other strong reducing agents have the same functions and potential environmental impact

Raw material	Function	Chemical nature/ compositi on	Annual quantity used	Addition point	Fate % (product, effluent, waste, air)	Risk classificati on	Environmental impact potential	Alternatives (and reasons for their non-use)
Di / trisodium phosphate	Optimising pH range of boiler HRSG circuits and system	HNa_2PO_4 / Na_3PO_4 $12H_2O$	100 tonnes Stored as 2 x 8 tonnes 10% solution	HRSG boiler drums to buffer pH levels and convert contaminan ts to stable forms	Entrained within HRSG systems and blown down to main cooling water system	R36 R37 R38/ R34 R36 R38 Corrosive	A spill may affect surface water and groundwater quality and contaminate the ground	Other pH buffers have the same function and environmental impact potential
Molybdate	Minimising corrosion of closed circuit cooling system. Forms protective passivation coating on bare ferrous metal	30% solution	2 tonnes Stored as 2 x 1000L 30% solution	Closed cooling system return pipe	Converted within closed cooling process. Drained to main cooling system on maintenance of CCW system			Molybdate is considered an effective, environmentally acceptable alternative to chromate treatment. Unlike many other transition elements, molybdenum exhibits low or even negligible toxicity.

Raw material	Function	Chemical nature/ compositi on	Annual quantity used	Addition point	Fate % (product, effluent, waste, air)	Risk classificati on	Environmental impact potential	Alternatives (and reasons for their non-use)
Sodium hypochlorite	Biocide control of cooling water system but chemical dosing currently suspended at SHB	NaOCl	15 tonnes Stored as 4x 50T tanks	Injected via pipe run into cooling water intake	Converted to chloramines, absorbed by organic and inorganic materials. Current Limits of total chlorine on outfall constrain dosing regime	R20 R21 R22 R34 R41 Harmful Corrosive	A spill may affect surface water and groundwater quality and contaminate the ground	Other liquid bleaches have the same function and environmental impact potential
Carbon dioxide	Fire fighting system in GTs	CO_2	Only used in emergency Stored as 4 x banks (11 cylinders each)	GT enclosures	Lost to atmosphere if used	Stable	Greenhouse gas so contribution to global warming	CO_2 used because of electricity generation
Hydrogen	Cooling phase 1 generator	H_2	5310 kg Stored as 10 x banks (11 cylinders each)	Phase 1 generator cooling point	Lost to atmosphere if leaks	R12 Highly flammable	Increased levels will increase risk of explosion	None
Sulphur hexafluoride	Insulating high voltage switchgear	SF_6	45 kg Not stored on site	Phase 1 and 2 switchgear SF6 nozzles	Lost to atmosphere if leaks	Stable Non-flammable	Potent greenhouse gas	None but alarm system in place so any releases are quickly controlled
Nitrogen	Purging gas lines	N_2	997 kg Stored as 10 x banks (11 cylinders each)	Gas purging points	Lost to atmosphere	Stable Non-flammable	Only very large releases would increase atmospheric levels	None

Note: Across the Centrica-owned facilities a number of different treatment chemicals are used for boiler feedwater treatment including hydrazine, carbohydrazide etc. The choice of chemicals is largely dependent upon the technical characteristics of the plant and the recommendations of the equipment suppliers.

2.5 Waste Handling and Storage

Electricity production using combined cycle gas turbine technology has low waste generation potential. Waste streams are principally confined to the following:

- Solid wastes generated during maintenance and repair of the station (packing materials, scrap metal);
- Waste lubrication oils
- Tank, interceptor and water treatment sludge;
- Screenings from cooling water intake;
- Replaced air filters;
- Chemical waste, e.g. from turbine wash;
- Sewage / foul water from the septic tanks;
- Office waste; and
- Empty containers.

Relatively limited quantities of wastes are produced at SHB and in aggregate do not typically exceed 1,000 tonnes per annum. The majority of the wastes generated onsite are relatively inert and necessary for the continued operation of the facility. Waste is segregated wherever possible and stored in dedicated areas to maximise recovery and recycling potential (see Section 2.6). The BMS for the site maintains a commitment to further identify and minimise sources of waste though due to the limited quantity of waste generated, further minimisation opportunities are considered to be limited.

2.5.1 Waste Storage

Waste storage containers are colour coded as follows:

1100kg Wheelie bins

General Waste	Grey
Oily Waste	Red
Chemical Waste	Blue
Waste Paper	Green

150 Litre Wheelie Bins

General Waste	Dark Grey bin with Grey liner
Blue Label Chemical Waste	Yellow bin with blue liner

Oil Waste	Metal bin with Red liner
Waste Paper	Blue bin with green liner
Skips	
General Waste	Grey
Oily Waste	Red
Chemical Waste	Blue
Waste Paper	Green

Solid waste is collected and stored temporarily on site in a number of different locations, as detailed in Table 6.1 of the current IPC authorisation. Ultimately all wastes are transferred to the waste compound where they are stored awaiting removal off-site by licensed waste disposal contractors when full.

The area is routinely inspected and the contents of the skips checked prior to off-site disposal.

2.6 Waste Disposal

Wastes are segregated and stored in skips in a dedicated concrete storage area onsite. The area has independent drainage equipped with an interceptor. All wastes disposed are recorded as a component of the site BMS and to meet the requirements of the Environment Agency's Pollution Inventory reporting. There are stringent guidelines within the IPC authorisation for the site regarding the quantities of waste materials to be stored onsite. The site is registered as a hazardous waste producer.

There is no on-site disposal of wastes and the site does not operate as a waste disposal facility. All solid wastes are removed by registered waste disposal contractors and are either disposed of within licensed waste disposal facilities or recovered if possible. Records of all waste transfers off-site are maintained on site.

Table 2.6 details the site's waste production in 2004 and the modes of disposal or recovery of the waste.

Table 2.6: Waste Transfers in 2004

EWC Code	EWC Description	Waste production (tonnes) and modes of disposal / recovery					
		R3 Recycling of organic substances	R1 Use as fuel	R9 Oil re-refining	D1 Disposal to landfill	R5 Recycling of inorganic materials	R4 Recycling of metals/ metallic compounds
11 01 11	Aqueous rinsing liquid containing dangerous substances	18.0					
13 02 06	Synthetic engine, gear and lubricating oils		6.3	12.4			
15 02 02	Absorbents, filter materials, wiping cloths, protective clothing contaminated by dangerous substances				1.26		
15 02 03	Absorbents, filter materials, wiping cloths, protective clothing not contaminated by dangerous substances					BRT	
16 02 14	Discarded equipment not containing hazardous substances				0.2		
16 06 01	Lead batteries						1.1
17 04 07	Mixed metals						BRT

EWC Code	EWC Description	Waste production (tonnes) and modes of disposal / recovery					
		R3 Recycling of organic substances	R1 Use as fuel	R9 Oil re-refining	D1 Disposal to landfill	R5 Recycling of inorganic materials	R4 Recycling of metals/ metallic compounds
17 06 04	Insulation materials not containing dangerous substances			BRT			
19 09 01	Solid waste from primary screening or filtration	105.5					
20 01 21	Fluorescent tubes and other mercury-containing waste					0.0060	
20 03 01	Mixed municipal waste				26.0		
20 03 04	Septic tank sludge	1208.0					

(Source: Pollution Inventory reporting form, 2004

EWC = European Waste Catalogue (established by Commission Decision 2000/532/EC)

Disposal /recovery codes as per Annex IIa/IIb of European Waste Directive (75/442/EEC)

Table 2.6 shows that only 27 tonnes (2%) of the total waste production of 1,379 tonnes was landfilled. The remaining 98% was recycled. This is an improvement on the 2003 figure of 92% and a significant step towards Centrica's goal, driven by the BMS, of 100% recycling.

2.7 Energy

The primary purpose of operations at SHBPS is to transform chemical energy into electrical energy. The principal energy source at SHBPS is natural gas. The details of site primary energy usage during 2002 to 2004 are indicated in Table 2.7. Sankey diagrams for the current operation (based on 2004) are presented in Figures 2.7 and 2.8. The Sankey diagrams identify the energy flows through the process. The width of bars presented in the diagrams, are proportional to the relative energy input to the site and subsequent outputs.

Table 2.7: Main Energy Inputs and Outputs at SHBPS, 2004.

Energy Input or Output Type	Yr 2004
Natural gas use GT11 (GJth gross)	10,044
Natural gas use GT12 (GJth gross)	12,624
Natural gas use GT13 (GJth gross)	13,420
Natural gas use GT21 (GJth gross)	10,850
Natural gas use GT22 (GJth gross)	13,406
Total fuel gas used (GJth gross)	60,345
Total fuel gas used (GWhr, gross)	**16,762**
Phase 1 electricity produced (GWhr, net)	4,802
Phase 2 electricity produced (GWhr, net)	3,734
Total electricity produced (GWhr, net)	**8,536**
Efficiency %	50.9
Total natural gas used (tonnes)	1,227,893

A key consideration for power stations is the efficiency at which the transformation to electrical energy is undertaken. Efficiency is dependent on many factors including the design of the plant, maintenance of equipment, the operational regime and the ambient conditions (temperature and barometric pressure).

SHBPS has a commitment to monitoring and recording efficiency. Efficiency represents a key measure of performance for the operators of the site.

The operational regime that the station is required to follow is generally determined by market demands with gas turbine power stations fulfilling an important role in meeting electricity demand at peak times. Many other types of power station (for example coal, nuclear and wind) lack the ability to change production rapidly to match the demand of the electricity grid and meet consumer requirements.

Typically the station achieves approximately 51% thermal efficiency on an annual basis. This includes many start-ups that reduce the efficiency in the operation. The nominal full load thermal efficiency is 54.7% at 12°C, 1.013 bar. This efficiency relates to continuous operation without the efficiency penalties incurred during start-ups.

During start-up operations greater fuel energy is lost as heat from the stack compared with continuous operation. Auxiliary equipment also factors into operational energy usage. Auxiliary equipment allows for rapid starts to meet demand. Its operation also allows the station to meet network demands more efficiency since the duration of the start-ups are reduced.

The condenser heat dump represents the other major waste energy loss from the site. The steam cycle (HRSG, steam turbine and the condenser) produces high-energy steam for expansion in the steam turbine. This steam can only be expanded to the point where it starts to condense (transforming from water vapour to liquid water) since the steam turbine blades would be damaged by liquid water. The wet steam is then transferred to the condenser, which removes the latent heat. This heat must be removed to produce liquid water, which can be pumped at high pressure back to the boiler (it is impossible to pump steam). The condenser releases a large quantity of low quality (i.e. low temperature) heat to the cooling water.

The power output of the station is heavily dependent on the temperature of the air entering the gas turbine for two reasons:

- Air density decreases with rising temperature. The turbine can operate with a limited volume of air but the power output is related to the mass of air passing though the turbine; and,
- Operating temperature (i.e. the combustion temperature) is more or less fixed. Its ability to expand the air as a working fluid is reduced as the ambient temperature increases. All thermal power stations are limited by the maximum difference in temperatures that can be generated in the process.

Periods of greatest national grid electricity demand tend to coincide with colder climatic conditions. Due to the broad distribution of the national electricity grid, optimal efficiency conditions may not correspond directly with temperatures experienced at SHBPS.

It is difficult to economically utilise any waste heat energy since it is not produced all of the time (only while the station is operational) and it is of low temperature, which would necessitate large heat transfer surfaces. Community / industrial heating schemes only tend to be economically viable when large, constant sources of waste heat can be found near a user, which is not the case at SHBPS. No combined heat and power (CHP) opportunities are considered to exist at SHBPS or indeed any of the Centrica Energy assets.

The Sankey diagram presented show the major flows of energy within the plant. CCGT power stations are complex in nature and many of the more minor energy flows are not presented within the diagrams.

Energy audits are unlikely to dramatically increase the overall efficiency of the facility since this is largely limited by the design of the plant and its operational demands. The station uses approximately 0.8% of its gross electrical production within the site. The majority of this energy is utilised in major essential equipment: pumps (for water abstraction from Humber Estuary), feed water pumps and other cooling equipment (largely auxiliary fans and pumps). Conventional energy efficiency measures are unlikely to yield large improvements since major energy use on site is tightly controlled as a function of plant operation and maintenance.

The site evaluates potential energy efficiency improvements and has carried out the following improvements since commissioning:

- Three year maintenance cycle optimises gas turbine efficiency;
- Gas turbine ignition sequence optimised reducing failed starts (thus minimising gas released to atmosphere).

The station is a participant in the European Union Emission Trading Scheme (EU ETS), which encourages energy efficiency improvements by essentially placing a cost on carbon dioxide emissions. Energy efficiency is principally determined by the design of the plant. As part of a detailed Best Available Technique evaluation contained in Section 5 of this application, energy efficiency (and resulting effects on abated environmental emissions of carbon dioxide) has been considered as an integral component of the assessment to evaluate options to minimise emissions of NOx.

There is currently no system to accurately break down on-site energy usage. Energy usage is recognised as an area in which the station's environmental impacts can be optimised. Objectives and targets are set in order to control and reduce, where possible, these effects. Efficient use of energy by staff is encouraged by poster campaigns and environmental awareness training.

Figure 2.5: Sankey Diagram Illustrating Design (Nominal) Major Energy Flows

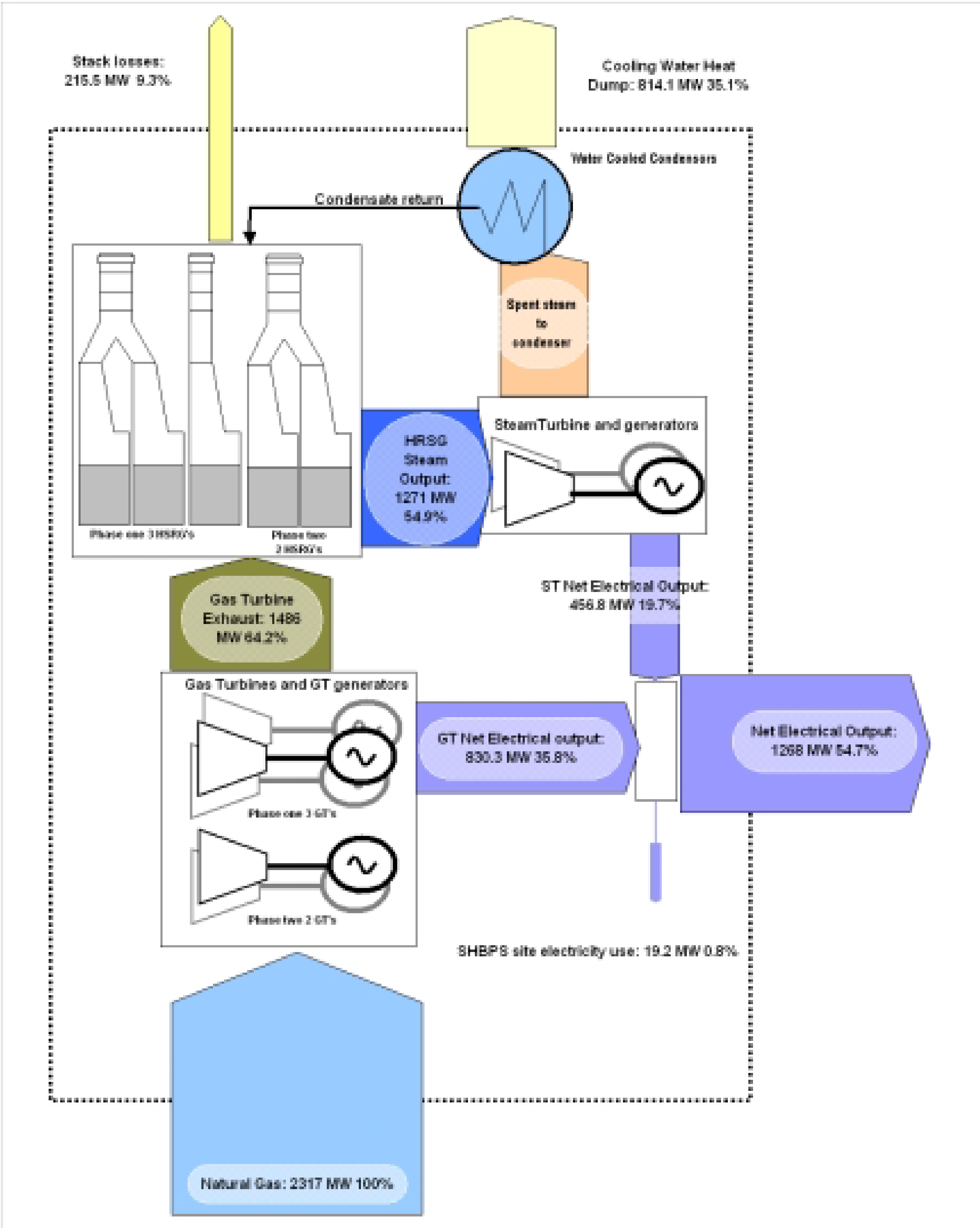
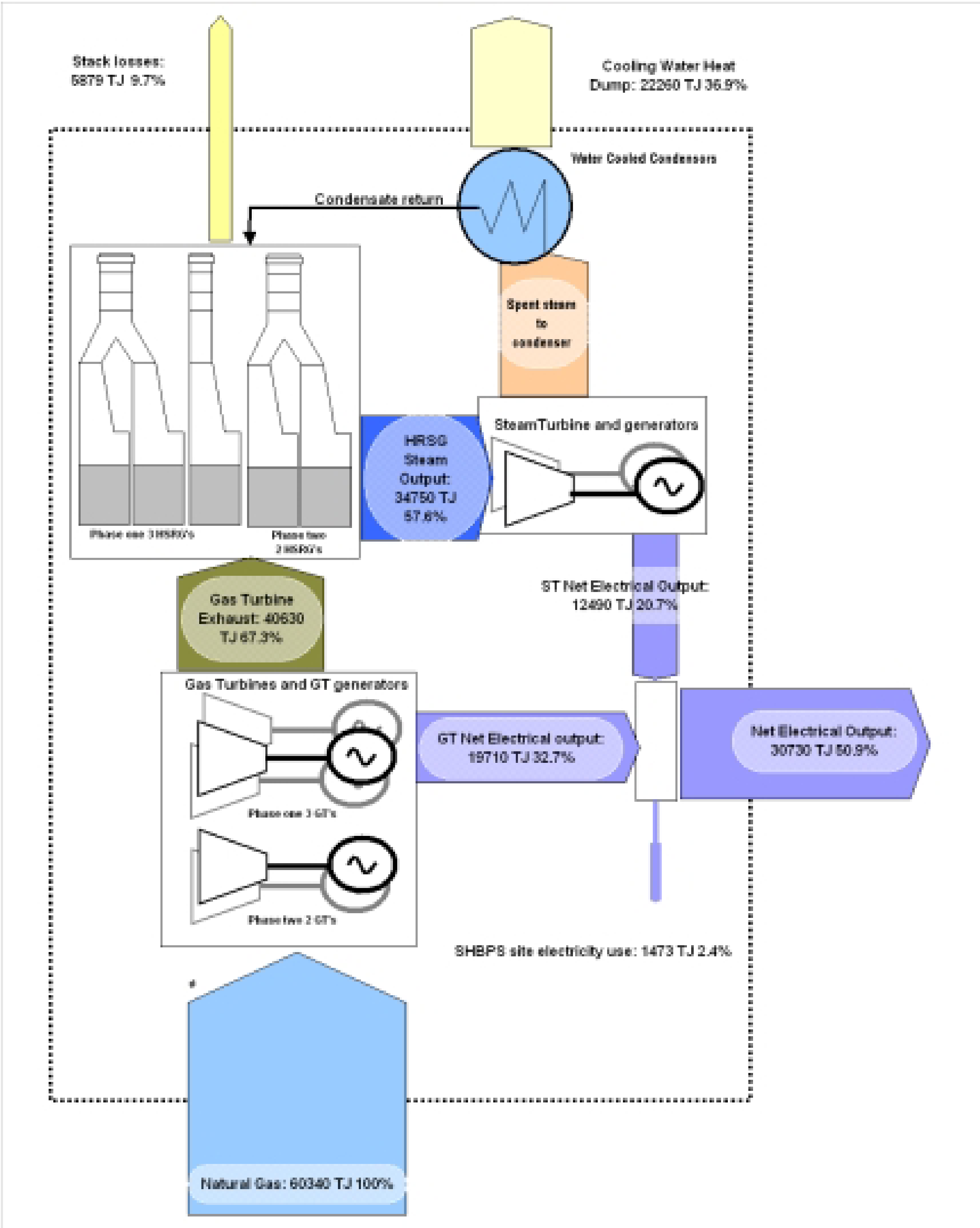


Figure 2.6: Sankey Diagram Illustrating 2004 Major Energy Flows



2.8 Accidents and their Consequences

This section covers general areas of any installation operations that have the potential for accidental emissions. Accidents in this context include any abnormal operation, which may increase emissions.

Accidents and incidents, which fall under 'Indicative BAT requirements for accidents and abnormal operations' of the IPPC Sector Guidance Note for Combustion Activities, include, the following scenarios:

- Transfer of substances (e.g. filling or emptying of vessels);
- Overfilling of vessels;
- Emissions from plant or equipment (e.g.. leakage from joints, over-pressurisation of vessels, blocked drains);
- Failure of containment (e.g. physical failure or overfilling of bunds or drainage sumps);
- Failure to contain firewater;
- Wrong connections made in drains or other systems;
- Incompatible substances allowed to come into contact;
- Unexpected reactions or runaway reactions;
- Release of an effluent before adequate checking of its composition;
- Failure of main services (e.g. power, steam, cooling water);
- Operator error;
- Vandalism

Justification of compliance with indicative BAT requirements is presented in the Accident Matrix (Table 2.8) and is not limited to the areas listed above.

Table 2.8: Accident Matrix

Accident Scenario Description		Likelihood of Occurrence (High/medium/low)	Consequences of Occurrence	Actions Taken Or Proposed To Minimise Chances Of It Happening	Actions Planned If the Event Does Occur
1	Transfer of substances (i.e. natural gas, gas oil, treatment chemicals) - e.g. filling or emptying of vessels	Low	Potential local contamination of ground, air, surface water or groundwater	Fill points located within bunds Dry-break couplings for liquid transfers Planned preventive maintenance Operator training Surface water drain system routed to interceptors	Enact Emergency/Accident Management Plan Use of spill kits and trained personnel
2	Overfilling of vessels (e.g. water treatment chemicals, gas oil, waste containers)	Low	Local contamination of ground, potential contamination of air, surface water or groundwater	High-level alarms, overfill protection devices Management of stock level Tanks contained in bunds	Enact Emergency/Accident Management Plan Use of spill kits and trained personnel
3	Emissions from natural gas system (e.g. leakage from joints, over-pressurisation)	Low	Potential contamination of air, fire, explosion	Planned preventive maintenance of critical equipment - list Gas isolation valve Operator training	Enact Emergency/Accident Management Plan

Accident Scenario Description		Likelihood of Occurrence (High/medium/low)	Consequences of Occurrence	Actions Taken Or Proposed To Minimise Chances Of It Happening	Actions Planned If the Event Does Occur
4	Emissions from plant/equipment, gas oil and demin plant (e.g. leakage from joints and pumps, over-pressurisation)	Low	Local contamination of ground, potential contamination of air, surface water or groundwater	Staff Training and Emergency Procedures Planned preventive maintenance of critical equipment	Inform EA Enact Emergency/Accident Management Plan
5	Failure of containment (e.g. physical failure or overfilling of bunds/drainage sumps)	Low	Local contamination of ground, potential contamination of drains and interceptors	Weekly check on condition of tanks, bund and pipework in accordance with relevant good practice Areas of hard standing slope towards surface water drains (routed to interceptors). Interceptor can be isolated	Remediation of local environment Use of spill kits and trained personnel
6	Failure of interceptor(s)	Low	Local contamination of ground/groundwater	Routine inspection of and maintenance of oil interceptors, including periodic clean out	Inform EA Pump out Interceptor.
7	Failure to contain firewater (see also scenario 17)	Low	Local contamination of drains and interceptors and loss of contaminated firewater to controlled water	Report on assessment of firewater run-off Minimisation of inventory of hazardous materials Onsite containment and use of CO2 based systems	Enact Emergency/Accident Management Plan
8	Wrong connections made in drains or other systems	Low	Contamination of interceptors/foul drains/storage tanks See (9) also	Clear labelling of tanks and pipework Operator training and procedures	Inform EA Clean up contaminated areas. Rectify fault.

Accident Scenario Description		Likelihood of Occurrence (High/medium/low)	Consequences of Occurrence	Actions Taken Or Proposed To Minimise Chances Of It Happening	Actions Planned If the Event Does Occur
9	Incompatible substances allowed to come into contact	Low	Dependent on materials	Substances contained in bunded-tanks and stored in designated storage areas in accordance with COSHH regulations.	Use of spill kits and trained personnel
10	Deviations in operating conditions	Medium	Breach of Authorisation	Operator training Process monitoring/alarms/protection systems	Inform EA DCS system alarms. Controlled shutdown in extreme circumstances
11	Failure of mains services (e.g. power, steam, cooling water)	Low	Potential breach of authorisation	Safe shut-down procedures Significant inventory of raw water, demineralised water, fire water and alternative fuel maintained onsite	Investigate failure before restarting plant
12	Operator Error	Low	Potential plant shut-down, failure of emissions control systems	Operator training Process monitoring/alarms/protection systems	Take immediate remedial action and provide suitable retraining if necessary

Accident Scenario Description		Likelihood of Occurrence (High/medium/low)	Consequences of Occurrence	Actions Taken Or Proposed To Minimise Chances Of It Happening	Actions Planned If the Event Does Occur
13	Vandalism	Low	Potential disruptions to operations	24/7 365-days/year security provided by plant operatives and contract security personnel only in outages CCTV coverage of entrance & site Site perimeter fence & intruder alarms Site access control and terrorist threat procedures Vulnerable equipment and areas of site secured e.g. tank drain valves locked closed	Review damage caused and carry out appropriate repairs Enact Emergency/Accident Management Plan
14	Waste Storage Failure	Low	Litter, contaminated land	Secure storage, containment e.g. sealed floors	Daily site inspection under EMS. Controlled work procedures for operators and contractors Operating procedures
15	Emissions Abatement Plant failure i.e. Dry Low NOx burner system	Low	Release of unabated combustion gases to air	Back up CEMS unit is used in the event of main CEMS failure -	Shut down plant in controlled fashion Inform EA

Accident Scenario Description		Likelihood of Occurrence (High/medium/low)	Consequences of Occurrence	Actions Taken Or Proposed To Minimise Chances Of It Happening	Actions Planned If the Event Does Occur
16	Failure of demineralisation plant e.g. power failure, reagent shortage, blockage of dosing line(s)	Low	Potential plant shut-down	Significant contingency storage of demineralised water Planned preventive maintenance Routine analysis, continuous monitoring	Urgent repair of demin system, possibility of hiring a package demin system in extreme cases? -
17	Failure of wastewater treatment system e.g. reagent shortage, blockage of dosing line(s)	Low	Release of contaminated water to sewer and breach of trade effluent consent	The wastewater treatment is limited to temperature and pH control. pH correction is carried out in a number of independent steps. Failure of one step would not necessarily lead to out of spec wastewater Planned preventive maintenance of critical equipment i.e. dosing pump(s) etc. Routine analysis, continuous monitoring of wastewater.	Isolate out of spec wastewater until problem can be rectified – site to comment

Accident Scenario Description		Likelihood of Occurrence (High/medium/low)	Consequences of Occurrence	Actions Taken Or Proposed To Minimise Chances Of It Happening	Actions Planned If the Event Does Occur
18	Fire	Low	See 7	Inventory of flammable material minimised where practical and appropriately stored away from sources of ignition No ignition sources on personnel whilst in hazardous areas Permit to work system in place to identify and manage risk. Particularly associated with hot work. Fire detection and suppression systems installed (e.g. CO2 within Gas turbine building, hydrants external to buildings, portable fire extinguishers)	Enact Accident management plan.

2.9 Noise and Vibration

Potential noise sources, noise attenuation in place and resulting ambient noise levels are described in Section 4 and Appendix C. Appendix C includes a detailed noise monitoring assessment.

2.10 Monitoring Techniques

2.10.1 Monitoring of Emissions to Air

2.10.1.1 Description of the Continuous Emissions Monitoring System

South Humber Bank Power Station is equipped with a Continuous Emissions Monitoring System (CEMS), installed by ABB, model MCS 100 CD. It measures the concentration of carbon monoxide (CO) and oxides of nitrogen (NOx) in the gas turbine exhaust gases, as well as other parameters such as the oxygen concentration to enable reporting at reference conditions.

The system consists of a system cabinet and associated sampling units. The exhaust gas from each gas turbine is monitored individually. The sampling units transport the turbine exhaust gas sample to the analytical system. A gas transfer pump continually extracts the gas from a 'cross' formation of fixed tubes in the GT exhaust – with 8 x 2 mm points in each leg of the cross (32 total) - via a locally mounted heated filter. Before entering into the gas transfer pump the gas is dried in a two-stage cooler. After passing through this cooler, the sample gas passes through a second filtration stage and a floating element flowmeter into the sample cell of the photometer. The gas filter and sample lines are heated electrically to prevent condensation and protect against corrosion. The sample gas and the condensate are directed separately to vents on the side wall of the system cabinet. Zero and test gases are supplied directly to the photometer after the gas cooler.

All operating variables that are important to the reliable operation of the system, such as temperature control loops, gas flow rate and the photometric function are continuously monitored. In the event of a malfunction the system is automatically switched to standby and the control room is alerted by the DCS system.

The multi-gas analyser unit incorporates a Siemens Oxymat 5E oxygen analyser, which works on the paramagnetic principle, NOx analysis is achieved by a sensor, which employs non-dispersive infrared spectroscopy. CO analysis is also by non-dispersive infrared spectroscopy.

2.10.1.2 Maintenance and Calibration of the Continuous Emissions Monitoring System

A fully automated maintenance and calibration programme is in place to ensure reliable and accurate operation of the CEMS. The programme comprises:

- Automatic zero check and sample line purge every 24 hours
- Work order cards raised by the maintenance database as follows:
    - System calibration every 8 weeks (manufacturer recommendation is every 12 weeks)

- o Minor service every 26 weeks
- o Major service every 52 weeks
- o The 'crosses' of fixed tubes in the exhaust duct, which contains the extraction points, are inspected twice per year during 'B' inspections of the turbines.

Competent, trained personnel carry out calibration. Test gases are supplied with certificates of conformity and renewed every three months.

All gas certificates are archived, work carried out is reported into the maintenance database and calibration certificates are archived both electronically in as hard copies.

2.10.1.3 Conformance of the Continuous Emissions Monitoring System to International Standards

For NOx measurement, the following requirements of the applicable standard ISO 10849 are met:

- The measurement technique is non-dispersive infrared spectroscopy – stated as a suitable method
- Sample handling is compliant with the requirements
- Performance is better than 2% of the selected range of the analyser
- Cross-interference to the gas mixture is less than 4% as required by the standard.

For oxygen and carbon monoxide measurement, the requirements of ISO 12039 are met:

- The measurement techniques are paramagnetic for oxygen and non-dispersive infrared spectroscopy for CO, both recommended in the standard as suitable methods.
- Sample handling is compliant with the requirements

With regard to the sampling planes / points and access thereto, the requirements of BS 13284-1:2002 for location of sample plane, angle of gas flow, division of sample plane, provision of access, etc are all met.

2.10.2 MCERTS

The Environment Agency developed the Monitoring Certification Scheme (MCERTS) to ensure the suitability and quality of monitoring data. MCERTS covers the product certification of monitoring systems, the competency certification of personnel, the accreditation of laboratories and the provision of third party inspection services.

The analysers at South Humber Bank are not certified under the MCERTS scheme, though updated versions of the analysers do hold certification

Centrica Energy has held pre-application discussions with the Environment Agency regarding the application of MCERTS Standards.

A review will be carried out by Centrica Energy to appraise all air emission monitoring carried out onsite for compliance with the MCERTS quality assurance scheme. This includes both installed continuous emission monitoring equipment (CEMS) and verification testing such as parallel monitoring of the CEMS equipment using appropriately qualified staff and procedures. Such a review will be carried out by January 2007.

Annual validation testing of CEMS equipment installed on combustion equipment (initially for equipment with a thermal input rating of greater than 50MW) will be carried out in accordance with British Standard EN14181 and guidance provided in the Environment Agency's technical guidance note M20[(1)]. This validation testing is also known as the Annual Surveillance Test (AST) that demonstrates each installed monitor is operating correctly and reading accurately through appropriate calibration. The AST will be carried out by a third party stack-testing organisation approved under the MCERTS scheme. Day-to-day calibration of equipment will continue to be carried out using trained in-house staff.

The Environment Agency has agreed as part of pre-application discussions that where existing CEMS equipment is not MCERTS approved, such equipment can continue to be used until end-of-life provided it is serviceable and meets the Quality Assurance Level 2 (QAL2) test requirements identified in EN14181 and Guidance Note M20. The QAL2 tests identify whether installed equipment measures emissions within defined limits of error or uncertainty. All CEMS equipment will undertake a QAL2 test within six months of the issue of a PPC permit or as part of scheduled bi-annual parallel monitoring surveys, whichever is sooner. QAL 2 tests will be repeated every five years as a minimum.

Any future CEMS equipment installed will meet QAL1 requirements and have a MCERTS product certification demonstrating the installed equipment is 'fit for purpose'.

The MCERTS review will also assess the requirement or otherwise on the installation of flow and temperature monitors on stacks.

It is recognised that MCERTS requirements also apply to effluent and water flow meters and the same commitments apply.

[1] Technical Guidance Note M20, Version 1, Sept 2005, Environment Agency – 'Quality assurance of continuous emission monitoring systems - application of BS EN 14181 and BS EN 13284-2'.

2.10.3 Monitoring of Water Discharges

The following parameters related to the cooling water are continuously monitored:

- pH
- Residual chlorine (redundant at the moment as no dosing is carried out)
- Temperature before and after condenser
- Total flow (measured as the product of hourly average flows and hours run)

Readings are fed to the DCS and alarms that register in the control room are provided on key parameters, particularly those controlled by the IPC authorisation.

In addition, the quantities of raw water from the Elsham industrial supply and potable water from the mains are also metered.

2.11 Site Closure

The lifetime of the plant is currently anticipated to be of the order of 30 years. The site was commissioned in the late 1990s. In considering the consequences of the closure or surrender of a site, reference will be made to the Application Site Report submitted in parallel with this IPPC application (see Appendix A). Consideration will be given to the subsequent site use after IPPC application with regard to site expansion or contraction in subsequent years.

An inventory of assets to be decommissioned will be produced followed by consideration of the need for risk assessments, site supervision / management and full adherence to Construction Design and Management Regulations (and or subsequent superseding regulations).

Reference will be made to the site asbestos surveys required under asbestos regulations and subsequent surveys / maintenance before decommissioning is started. Surveys have identified that only small quantities of asbestos are present onsite in ‘jointing’.

Disconnection of site services, whether partial or complete will be considered before dismantling work commences on site.

Equipment, where possible, will be decontaminated on site, followed by inspection and if necessary further decontamination once the equipment has been removed from position and before it has been removed from site. Despatch of equipment from site, whether as a saleable asset or as scrap, will be accompanied by a Certificate of Decontamination. All equipment containing chemicals will be drained with the chemical stored in appropriate containers and removed offsite to reduce the potential for spillage.

Dismantling of equipment shall be subject to the same conditions and control of works as required by relevant HS&E legislation. Work will be conducted under permits to work and also certificates of safety if deemed necessary by the working environment.

Inspection will be required to ascertain the need for remediation works on the site. The survey shall be as comprehensive as required by current regulations at the time of site (operational) closure.

The site will be left in a safe state. Trenches, pits and excavations will be made safe by suitable back-fill, or access denied by fencing coupled with adequate regular site inspections until responsibility for the site has been transferred to the new owners.

A full surrender site report shall accompany the surrender of the site licences to the relevant regulatory bodies and consultees.

The time period between operational site closure, site clearance and site remediation can be protracted. Provision will be made to regularly inspect the site and buildings for safety during this period as the company will still have a duty of care to ensure the safety of the site until such time as responsibility for the site has been transferred.

A site closure plan will be developed and submitted to the Environment Agency within two years following the issue of a PPC permit. The plan will document the residual materials with the potential to cause contamination and the steps that will be undertaken to eliminate pollution risk and return the site to the baseline condition established as part of the ASR and any subsequent reference data identified following the development of the Site Protection and Monitoring Plan.

2.12 Installation Issues

The South Humber Bank installation includes the gas odorisation plant operated by National Grid Gas plc (the subject of a separate permit application) as well as the power station operated by Centrica SHB Ltd (CSHB).

There is little potential for the odorisation plant to cause pollution and virtually no potential for the two parts of the installation to 'interact' adversely such that pollution is caused or risked.

There are self-evidently no opportunities for most of the installation-wide techniques and issues discussed in the guidance note such as:

a) using waste or emissions from one part of the installation as feedstock for the other

b) the combining of wastes or emissions to justify greater abatement

c) economies of scale e.g. to justify a CHP plant

Nevertheless, CSHB and the wider Centrica Energy organisation have a long-standing co-operative relationship with National Grid Gas and its parent. The historic links between the two companies (both having roots in the old British Gas) and the interdependencies facilitate collaboration and co-operation.

The odorisation plant is normally unmanned and operates automatically. National Grid Gas attends site only to carry out routine maintenance and checks.

CSHB therefore has an informal role in visually monitoring the odorisation plant for obvious signs of abnormal operation, faults, deterioration, etc. This does not imply that National Grid Gas relies on CSHB in the maintenance and operation of the odorisation plant in any way, merely that any apparent abnormality detected by CSHB staff would not go unreported just because CSHB does not own or operate the plant. This would not be in keeping with the strong HSE culture within CSHB and Centrica Energy.

Any leak of odorant would be immediately apparent due to its strong, distinctive odour. This would be immediately reported to National Grid Gas by CSHB. An extensive network of gas detectors is in place around the site and the activation or otherwise of alarms linked to these would be the primary means of differentiating a leak of odorant from a leak of gas.

3 EMISSIONS

This section describes the emissions and associated pathways emitted from SHBPS. The principal pathways for emissions are illustrated below in Table 3.1.

Table 3.1: Potential Release Routes for Gas Turbines

SOURCE RELEASES To: Air (A) Water (W) Land (L)	Substances					
	Particulate Matter	Oxides of Sulphur	Oxides of Nitrogen	Oxides of Carbon	Organic Compounds	Acids / alkalis / salts etc
Gas turbine exhaust	A	A	A	A	A	
Fuel storage and handling					AWL	
Water treatment						W
Boiler blow down						W

Taken from the IPPC Technical Guidance Note for the Combustion Sector – Consultation Draft 30.03.05 Page 12

3.1 Emissions to Air

The primary air pollutants of concern from gas turbine engines with the potential to impact on human health are nitrogen oxides (NOx) and carbon monoxide (CO) (*US EPA AP42*). Sulphur dioxide (SO_2), particulate matter (PM_{10}) and organic compounds are also released in minor quantities during start-up when the gas oil-fuelled auxiliary boiler is used to supply steam and in the event of an emergency where the diesel generator is used to supply electricity to essential on site users. In common with all combustion processes burning fossil fuels, the principal emission with global warming potential is carbon dioxide (CO_2).

A comparison of current emission performance with emission benchmarks identified in the current IPC authorisation and the latest version of sector guidance (consultation draft) issued by the Environment Agency is presented in Table 3.2. The location of potential release points is illustrated in Figure 3.1 and the description of these emission points is provided in Table 3.3. Release points A1 to A4 are subject to specific emission limits under the current IPC authorisation. This authorisation and accompanying variation notes has been updated to incorporate the requirements of the Large Combustion Plant Directive (LCPD).

Table 3.2: Historical Measured Air Pollutant Concentrations and Benchmarks

Pollutant	2004 CEMS*		IPPC Sector Guidance Note** (mg/m^3)	Current IPC condition
	Median	95%ile		
PM	N/A	N/A	5	No condition
SO_2	N/A	N/A	10	No condition
NO_x	61.5	73.3	75	80
CO	N/A	N/A	100	No condition
CH_4	N/A	N/A	N/A	No condition

* Based on all hourly average values in 2004 for the five gas turbines excluding indicated start-up and shutdowns

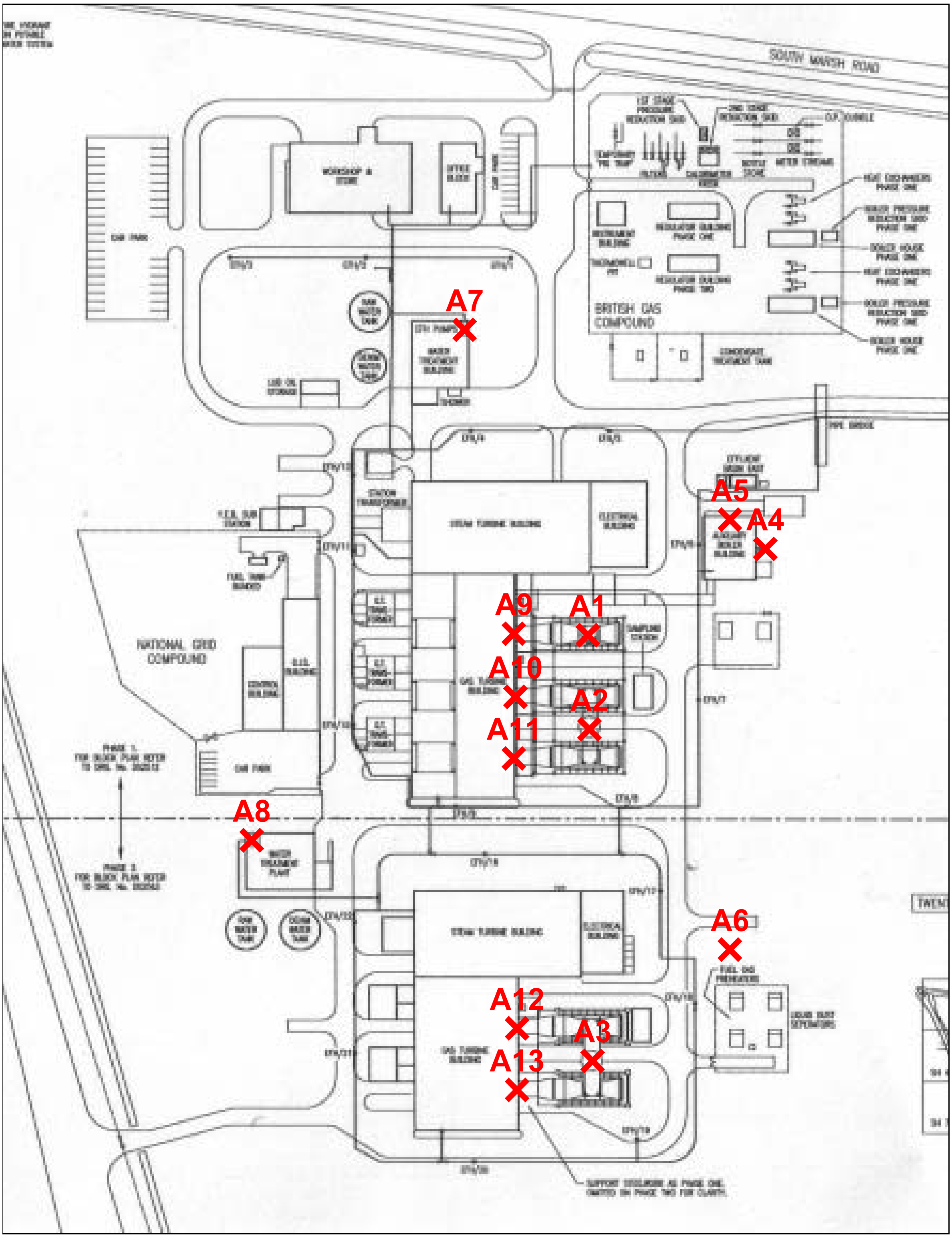
** Daily averages based on continuous monitoring during the period of operation. Large Combustion Plant Directive requirements specifically exclude start-up and shutdown periods.

Table 3.3: Release Points for Atmospheric Emissions

Emission pt ref		Emission Point Description
New	IPC(2)	
A1	T2	GT13 (1) gas turbine stack
A2	T1	GT11 & GT12 gas turbine stack
A3	T3	GT21 & GT22 gas turbine stack
A4	AB1	Auxiliary boiler exhaust
A5	D1	Phase 1 emergency diesel generator exhaust
A6	D2	Phase 2 emergency diesel generator exhaust
A7	F1	Phase 1 back up diesel firewater pump exhaust
A8	F2	Phase 2 back up diesel firewater pump exhaust
A9	NG1	Fuel gas vent from gas turbine 13 supply
A10	NG2	Fuel gas vent from gas turbine 12 supply
A11	NG3	Fuel gas vent from gas turbine 11 supply
A12	NG4	Fuel gas vent from gas turbine 22 supply
A13	NG5	Fuel gas vent from gas turbine 21 supply

(1) The turbines are referred to as "GT*XY*" where *X* is the phase number (1 or 2). *Y* is the turbine's sequential number (starting with the southernmost unit and increasing to the north) within the phase.
(2) Emission point references as per Table 2.1 in current IPC authorisation

Figure 3.1: Location of Release Points to Air



The mass emissions of the principal emission components to air during 2004 are summarised in Table 3.4. The table includes the derivation of emission indicators and an extrapolation of the emissions that would be emitted if the power station operated in a continuous base load mode.

Table 3.4: 2004 Annual Mass Emissions

Emitted compound		2004* total (tonne)	kg / MWhr**	g / MJ_{th}	kg / GT operating hour	2004*** factored continuous (tonne)
Particulate Matter	PM	181	0.033	0.003	4.56	190
Sulphur dioxide	SO_2	15	0.011	0.001	1.52	633
Nitrogen oxides NO and NO_2	NOx (as NO_2)	3,265	0.60	0.075	82.3	3,427
Nitrous oxide	N_2O	181	0.03	0.003	4.56	190
Carbon dioxide	CO_2	3,482,373	635.95	52.17	87781	3,655,205
Carbon monoxide	CO	14,000	2.56	0.232	353	14,695
Total global warming emissions	CO_{2eq}	3,489,324	587.61	53.32	81110	3,662,513
Methane	CH_4	331	0.06	0.006	8.35	348
Non-methane Volatile Organic Compounds)	NMVOCs	274	0.05	0.005	6.90	288

* 2004 total emissions are based on Pollutant Inventory returns (CO_2 and NO_x) for calendar year 2004, SO_2 emissions calculated from mass balance method based on known dosing rate of odorantinto the fuel gas. CO emissions calculated from CEMS data. Particulate Matter and methane were estimated using US EPA AP-42 Emission factors.

** MWhrs sent out as electricity.

*** Factored up for 8328-hour operational year based on current operation hours. This is intended to provide an indication of annual emissions associated with continuous operation assuming two weeks for maintenance.

Releases of specific emission components are discussed in greater detail in the following sections.

3.1.1 Oxides of Nitrogen

Oxides of nitrogen, or NOx, is used to describe a combination of two compounds consisting of nitrogen and oxygen: Nitric oxide (NO) and nitrogen dioxide (NO_2). Only NO_2 can have potential health effects at concentrations experienced in ambient air. Nitrogen oxides contribute to acid rain and nutrient enrichment and are precursors to low level ozone formation.

Nitrogen oxide formation in combustion plant occurs by three fundamentally different mechanisms:

- **Thermal NOx** is the principle mechanism of concern in gas turbine operation and arises from the thermal dissociation of molecular oxygen and nitrogen in the combustion air under high temperature. The rate of thermal NO_x production is exponentially related to the combustion temperatures reached in the combustion zone of the turbines;
- **Prompt NOx** is formed by reactions between nitrogen molecules in the combustion air and hydrocarbon radicals formed in the flame during the combustion of the fuel; and
- **Fuel NOx** is formed from fuel bound nitrogen compounds that are oxidised upon combustion.

Thermal NOx is essentially responsible for all NOx formation in natural gas fired gas turbines and the major source of NOx generation in gas oil fired operation. These fuels contain insignificant quantities of fuel bound nitrogen limiting fuel NOx formation. DLN burners are used to control thermal NOx formation at SHBPS.

Figure 3.2 shows percentile ranked daily averages for GT11. This is the reference period basis used in the large combustion plant sector guidance and is different to that currently used in the IPC permitting for GT11 (emission point A2). The median value (50th percentile) of the 2004 values for GT11 was 65.3 mg/Nm^3 at 15% O_2 (dry). This emission value is well within the sector guidance value for DLN of 75 mg/Nm^3 at 15% O_2 (dry) daily average. The 95th percentile of the daily average NOx concentrations from GT11 is 79.4 mg/Nm^3 at 15% O_2 (dry) daily average.

Figure 3.2: Percentile Ranked Daily Average NOx Emission Concentrations - GT11 - 2004.

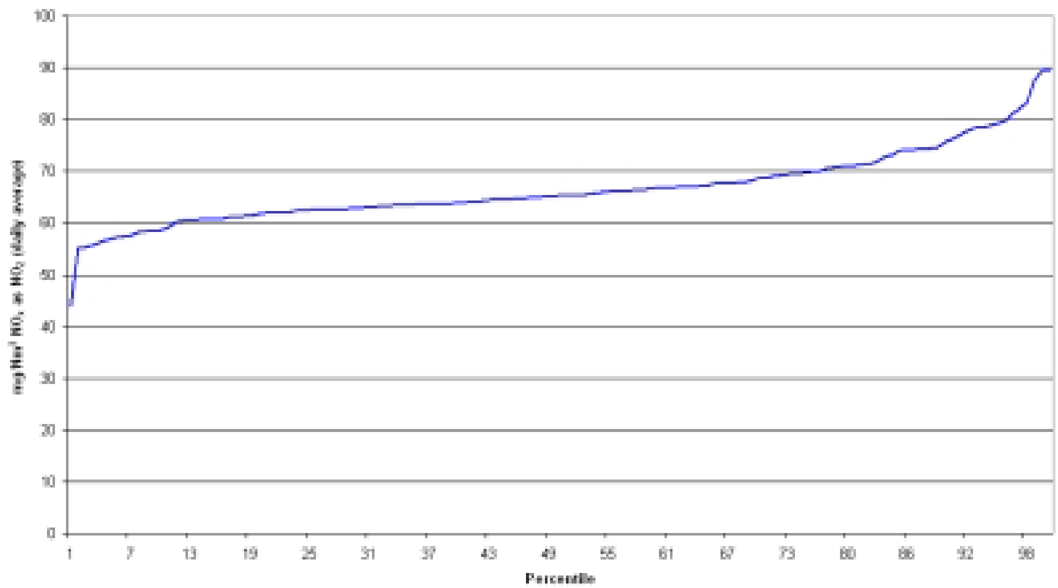


Figure 3.3 shows percentile ranked daily averages for GT12. The median value (50th percentile) of the 2004 values for GT12 (emission point A2) was 56.1 mg/Nm^3 at 15% O_2 (dry). This emission value falls inside the sector guidance value for DLN of 75 mg/Nm^3 at 15% O_2 (dry) daily average. The 95th percentile of the daily average NOx concentrations from GT12 is 64.5 mg/Nm^3 at 15% O_2 (dry) daily average.

Figure 3.3: Percentile Ranked Daily Average NOx Emission Concentrations - GT12 - 2004.

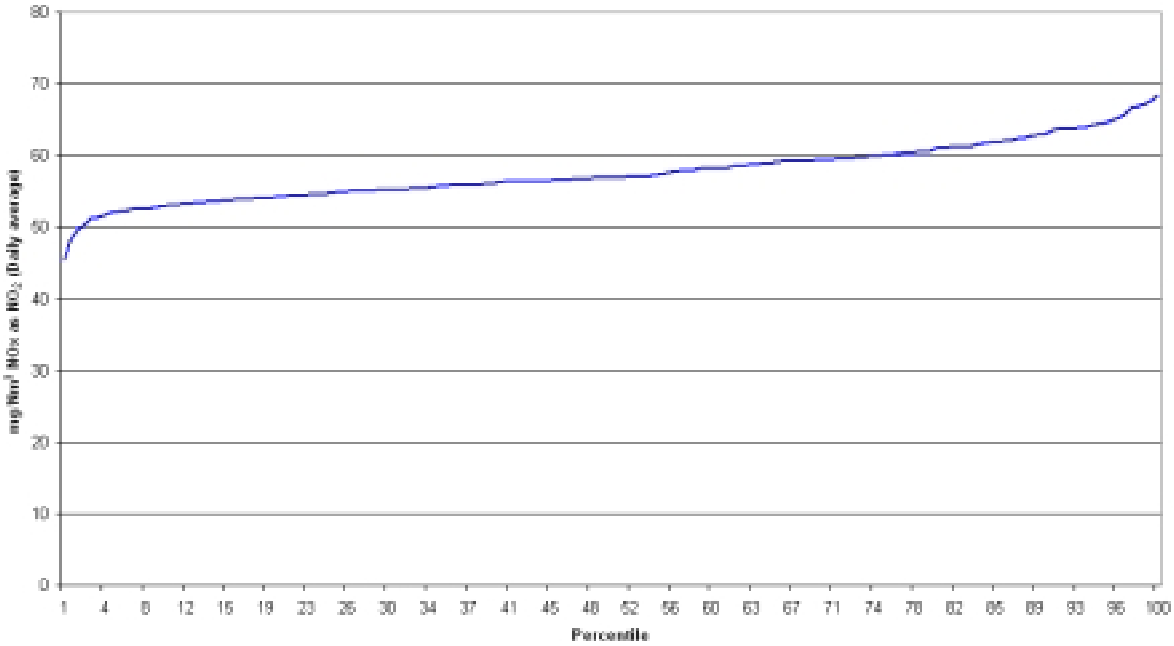


Figure 3.4 shows percentile ranked daily averages for GT13. The median value (50th percentile) of the 2004 values for GT13 (emission point A1) was 54.0 mg/Nm^3 at 15% O_2 (dry). This emission value is significantly lower than the sector guidance value for DLN of 75 mg/Nm^3 at 15% O_2 (dry) daily average. The 95%th percentile of the daily average NO_x concentrations from GT13 is 63.0 mg/Nm^3 at 15% O_2 (dry) daily average.

Figure 3.4: Percentile Ranked Daily Average NOx Emission Concentrations - GT13 - 2004

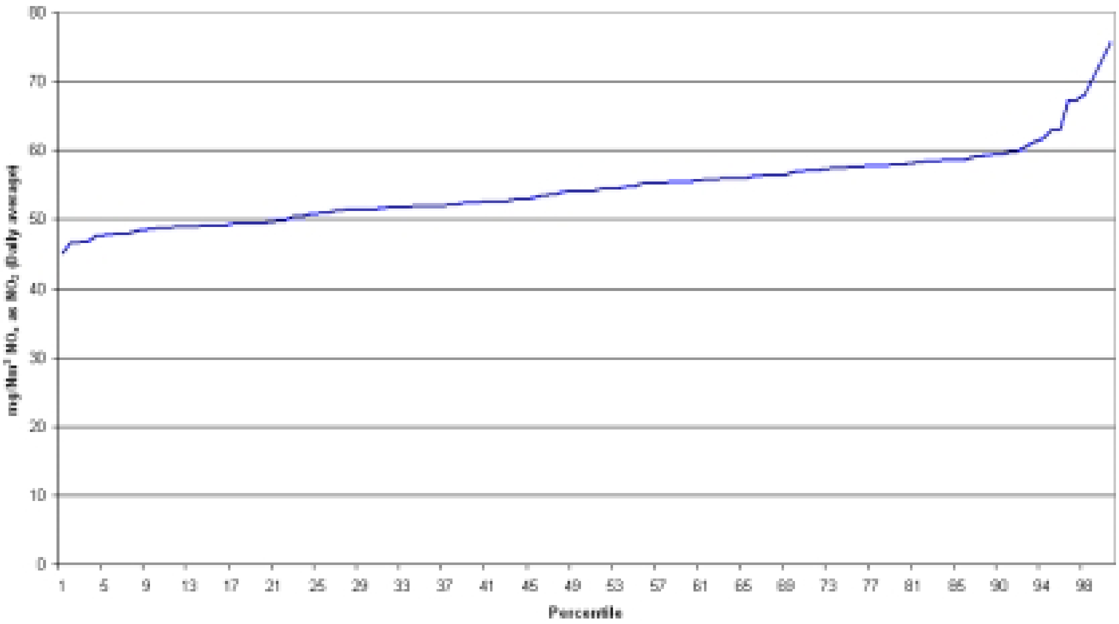


Figure 3.5 shows percentile ranked daily averages for GT21. The median value (50th percentile) of the 2004 values for GT21 was 63.6 mg/Nm^3 at 15% O_2 (dry). This emission value falls inside the sector guidance value for DLN of 75 mg/Nm^3 at 15% O_2 (dry) daily average. The 95th percentile of the daily average NOx concentrations from GT12 is 76.5 mg/Nm^3 at 15% O_2 (dry) daily average.

Figure 3.5: Percentile Ranked Daily Average NOx Emission Concentrations - GT21 - 2004

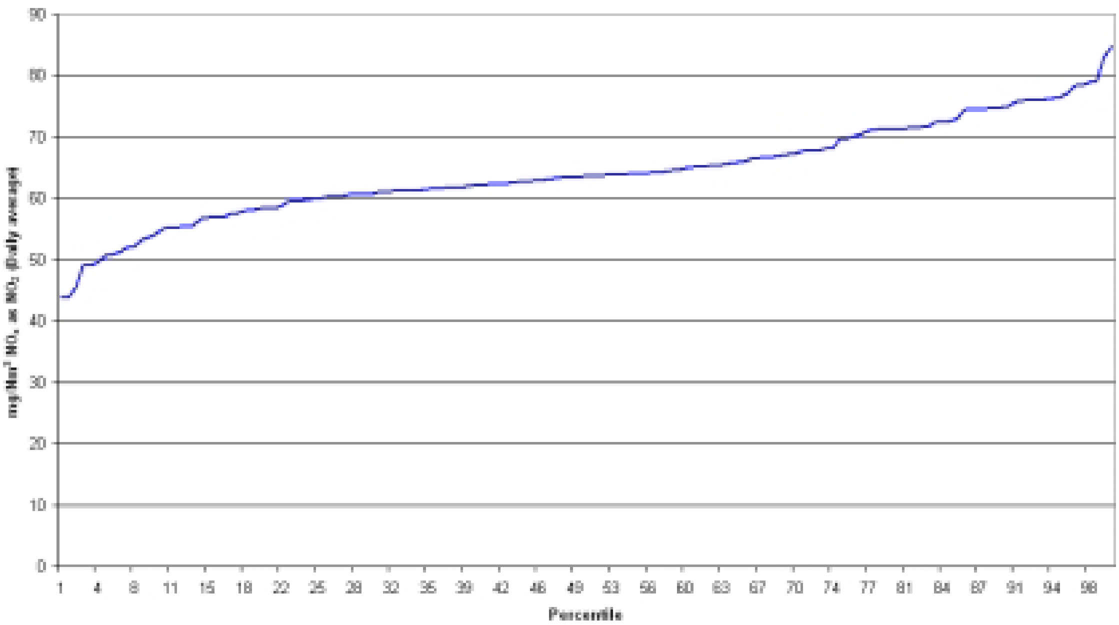
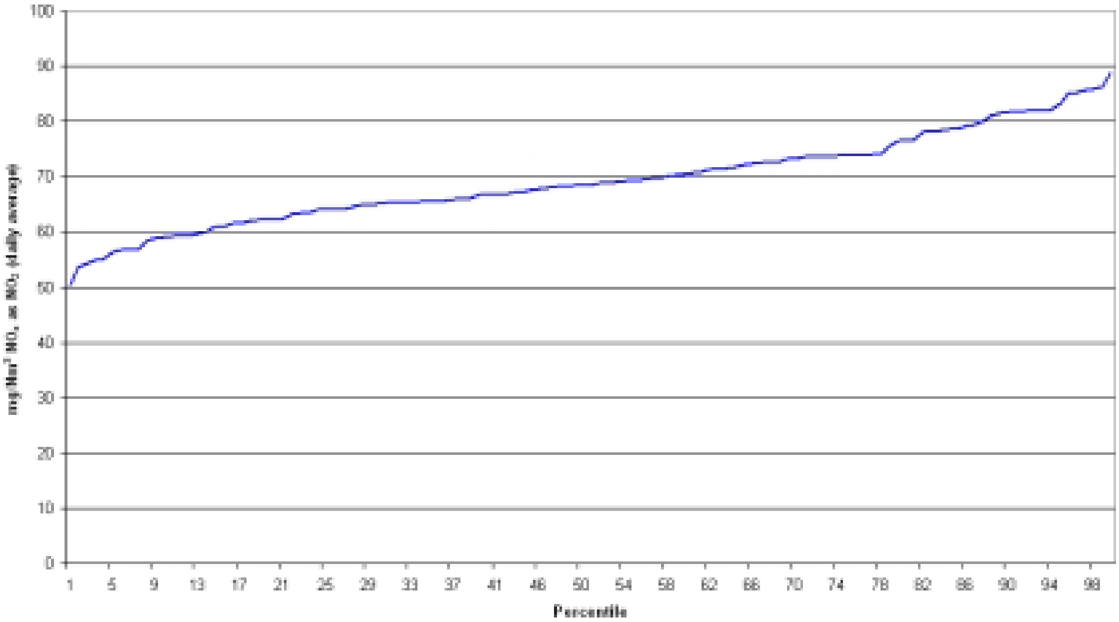


Figure 3.6 shows percentile ranked daily averages for GT22. The median value (50th percentile) of the 2004 values for GT22 was 68.4 mg/Nm^3 at 15% O_2 (dry). This emission value falls within the sector guidance value for DLN of 75 mg/Nm^3 at 15% O_2 (dry) daily average. The 95th percentile of the daily average NOx concentrations from GT22 is 83.2 mg/Nm^3 at 15% O_2 (dry) daily average.

Figure 3.6: Percentile Ranked Daily Average NOx Emission Concentrations - GT22 - 2004



The CEMS instrumentation supplies data, which are monitored by the Control Room Operator. Action is taken should a deviation that may cause an exceedance of current IPC authorisation limits for NOx emissions occur. The data is also compiled in a 24-hour daily log consisting of hourly averages. If any NOx exceedance occurs, the Operations Manager is informed.

3.1.2 Carbon Monoxide

Carbon monoxide (CO) is formed by incomplete combustion. The potential for CO emissions from gas turbines is very low in comparison to other combustion technologies since gas turbines employ large quantities of excess air beyond stoichiometric ratios and combustion takes place in very well mixed conditions. CO is measured continuously on site. Based on the arithmetic average of all hourly operational values in 2004 for the five Gas Turbines (excluding indicated start-up and shutdowns), the emission value is estimated to be 1 mg/Nm^3 at 15% O_2 (dry) and is well inside the sector guidance value for gas turbines of 100 mg/Nm^3 at 15% O_2 (dry) daily average.

3.1.3 Carbon Dioxide

CO_2 emissions are discussed further under air quality impacts in Section 4 since CO_2 is the principle emission associated with global warming potential from the facility. Emissions of CO_2 and other emissions with global warming potential were quantified in Table 3.4.

3.1.4 Organic Compounds

Emissions of organic compounds from CCGT power stations are generally very limited. Sources of organic compounds include:

- The escape of unburnt and partially burnt hydrocarbons; and,
- Emissions associated with the storage and transport of fuels.

Release estimates of organic compounds from SHBPS in 2004 are summarised in Table 3.5.

Table 3.5: Organic Compound Emissions

Compound	$g/MJ_{thermal}$	2004 emission (tonne)	Data source
Methane	0.00549	331	US EPA AP42 Emission factor
NMVOCs	0.00454	274	US EPA AP42 Emission factor
1,3 Butadiene	0.00001	0.6	US EPA AP42 Emission factor

Methane, VOCs and 1,3 butadiene are based on gas turbine emission factors from the US EPA's Compilation of Air Pollutant Emission Factors, AP42, Volume 1: Stationary Point and Area Sources, Section 3.1, Stationary Gas Turbines, 2000.

Organic compounds with the exception of methane may have associated photochemical ozone creation potential (POCP). A full POCP equivalence factor cannot accurately be defined due to uncertainty associated with the composition of NMVOC emissions. Methane does not have a direct impact on health at concentrations experienced at ambient concentrations but has a global warming potential 21 times greater than CO_2 on an equivalent molecular basis and has been considered within global warming emission estimates (as CO_2 equivalent) within Table 3.4. Emissions of 1,3 butadiene are considered negligible and will be rapidly dispersed in the air to levels well below United Kingdom (UK) Air Quality Strategy objectives. These objectives are discussed further in Section 4.

3.1.5 Particulate Matter

Particulate matter (PM) is produced in very small quantities during typical gas turbine operation. Generally particulate matter consists of small carbonaceous suspended solids formed by incomplete combustion. The nature of gas turbine combustion requires the combustion air to be largely free of particulate since it presence would erode the turbine blades which are subject to high volumes and velocities of combustion air. This restricts gas turbine operation to clean fuels such as natural gas. The turbulent high excess air operation of gas turbine combustors ensures relatively complete combustion in comparison with other combustion technologies limiting the production of particulate matter.

3.2 Odour

Gas detection systems are employed to detect the onset of leaks and gas escape. There are no sources of odour at SHBPS during normal operation.

3.3 Water

Water is essential for the operation of a combined cycle power stations and water emissions are typically associated with the following activities:

- Cooling water;
- Boiler water blow down;
- Flushing plant such as the WTP;
- Cleaning plant such as gas turbine wash;
- Site drainage including storm water runoff;
- Sewage treatment effluent; and
- Domestic use.

The majority of wastewater is discharged to the Humber Estuary (with the exception of blade wash fluid effluent which is disposed of off-site). Water is channelled via oil/water interceptors and into the west effluent basin, the east effluent basin or the bulk effluent basin from where it is pumped into the MCW return line and discharged to the Humber Estuary via an underground pipeline.

Water used in the steam cycle is continuously removed as boiler blowdown in order to prevent the gradual accumulation of contaminants within the recirculating HRSG system. This water contains some water treatment chemicals (such as ammonia, carbohydrazide and phosphates in minor quantities). Water from the HRSG blowdown tanks is fed into the east effluent basin where it is cooled, using water extracted from the MCW inlet line before being transferred automatically to the MCW return line and discharged to the Humber Estuary.

3.3.1 Releases to Surface Waters

There are various sources of wastewater at the installation including cooling water, settled solids, effluent from the WTP, HRSG blowdown, surface water drainage and domestic wastewater. However, there is a single emission point which is the cooling water outfall. Storm water runoff from the site enters either the west effluent basin, the east effluent basin or the main cooling water pump house basin from where it is pumped into the main cooling water (MCW) return line and discharged to the Humber Estuary.

Table 3.6: Releases into Surface Waters.

Emission Point Reference	Description	Waters Discharged	Receiving Water and Location
W1	Cooling water outfall	Cooling water, settled solids, water treatment plant effluent, HRSG blowdown, surface water drainage	Humber Estuary Grid reference TA 243 151

The Environment Agency regulates the discharge of effluent to the Humber Estuary. Average and maximum discharge parameters measured during 2004 and existing effluent discharge limits are summarised below in Tables 3.7 and 3.8. The summarised monthly data shows that a high level of compliance with the discharge parameters of the existing Authorisation AH4195 was achieved. It can be seen from the data that there was a discrepancy in the MCW temperature differential between line No. 1 and Line No. 2 for Phase 1 (in May, July and October, which was caused by CW pump outages and condenser maintenance during these periods.

Table 3.7: Effluent Discharge Parameters – Phase 1 – 2004

	Phase 1 Cooling Water Discharge										
	Maximum daily purge rate (Km^3/hr) Phase 1 & 2	Average daily purge rate (Km^3/hr) Phase 1 & 2	Line 1			Line 2			Maximum total oxidant as chlorine (mg/l)	Maximum pH	Minimum pH
			Average temperature before (°C)	Average temperature after (°C)	Maximum temperature difference (°C)	Average temperature before (°C)	Average temperature after (°C)	Maximum temperature difference (°C)			
Limit	99.00	99.00			8.00			8.00	0.1	<9	>6
January	89.1	88.15	5.18	9.90	5.34	5.05	9.84	5.38	0.00	7.19	7.19
February	No data	No data	5.95	12.03	8.28	5.81	12.02	9.83	0.00	7.19	7.19
March	92.92	89.66	5.90	12.08	6.92	5.77	12.08	6.99	0.00	7.19	7.19
April	91.28	86.06	9.28	14.81	6.81	9.14	14.82	7.01	0.00	7.19	5.96
May	91.70	83.99	12.61	17.18	8.94	12.46	17.22	12.24	0.00	5.96	5.96
June	91.19	70.09	16.26	25.91	14.39	16.01	25.88	14.10	0.00	5.96	5.96
July	92.32	78.62	15.57	23.70	11.37	16.51	22.58	7.49	0.00	5.96	5.96
August	90.87	86.52	18.60	25.46	7.28	18.41	20.99	6.90	0.00	5.96	5.96
September	90.55	90.06	15.46	22.32	7.16	15.29	22.05	7.05	0.00	5.96	5.96
October	92.36	87.36	11.95	18.83	9.36	11.81	18.47	8.31	0.00	5.96	5.96
November	93.76	80.97	9.64	14.88	6.60	9.49	14.62	6.39	0.00	5.96	5.96
December	89.17	83.29	6.75	12.76	6.99	6.62	12.47	6.87	0.00	5.96	5.96

Table 3.8: Effluent Discharge Parameters – Phase 2 – 2004

	Phase 2 Cooling Water Discharge										
	Maximum daily purge rate (Km³/hr) Phase 1 & 2	Average daily purge rate (Km³/hr) Phase 1 & 2	Line 1			Line 2			Maximum total oxidant as chlorine (mg/l)	Maximum pH	Minimum pH
			Average temperature before (°C)	Average temperature after (°C)	Maximum temperature difference (°C)	Average temperature before (°C)	Average temperature after (°C)	Maximum temperature difference (°C)			
Limit	99.00	99.00			8.00			8.00	0.1	<9	>6
January	89.1	88.15	4.82	11.72	7.36	4.99	11.56	6.97	0.00	7.99	7.61
February	No data	No data	No data	No data	No data	No data	No data	No data	No data	No data	No data
March	92.92	89.66	5.78	12.21	8.29	6.01	12.19	7.93	0.00	7.89	7.47
April	91.28	86.06	8.89	18.24	14.95	9.08	18.00	14.80	0.00	7.82	5.82
May	91.70	83.99	12.21	19.37	14.69	12.40	19.13	14.43	0.00	8.08	7.36
June	91.19	70.09	15.76	23.18	7.75	15.96	22.88	7.25	0.00	8.10	7.94
July	92.32	78.62	16.15	27.16	14.60	16.35	27.01	14.38	0.00	7.83	7.44
August	90.87	86.52	18.16	26.61	14.49	18.37	26.33	14.24	0.00	7.79	7.35
September	90.55	90.06	15.04	22.22	7.64	15.23	21.88	7.08	0.10	7.82	7.22
October	92.36	87.36	11.62	18.56	7.66	11.81	18.20	7.13	4.88 #	7.80	7.35
November	93.76	80.97	9.68	15.40	7.39	9.92	14.97	6.84	4.88 #	7.94	7.18
December	89.17	83.29	6.39	12.42	7.49	6.57	12.18	6.98	0.89 #	7.71	7.45

Throughout the period indicated the Phase 2 Chlorine Analyser was providing a spurious maximum signal due to sample line maintenance.

3.3.2 Releases to Groundwater

No release from the installation is made directly to groundwater.

3.3.3 Releases into Sewer

No releases from the installation are discharged into any public sewer.

3.3.4 Releases for Off-Site Disposal

The generation of gas turbine wash water is dependent upon the frequency of turbines washes. These are scheduled to effectively manage turbine wear (deposits accumulating on the turbines contribute to wear) and turbine efficiency. Licensed trade waste contractors remove waste generated from washes. Licensed contractors also remove foul water, including sludge and oil collected in the oil / water interceptors.

3.4 Noise

A detailed noise monitoring report including the identification of noise levels adjacent to principal sources of onsite noise is included in Appendix C. Noise sources are also discussed in Section 4.5.

4 IMPACTS

This section identifies the potential impact of releases from South Humber Bank Power Station on its surrounding environment.

4.1 Description of the Receiving Environment

4.1.1 Areas of Population and Residence

South Humber Bank Power Station is located to the east of the intersection of Hobson Way and South Marsh Road in an area northwest of Grimsby and east of Immingham, North East Lincolnshire. The site is within an industrial development with industrial units to the north and southeast, but has largely undeveloped, open level farmland land to the southwest. The remaining land surrounding the power station is predominantly fenland, used for cropping. The site is located on a relatively flat area. There are no residential properties within a kilometre of the site.

The nearest potentially affected locations with human occupation to the power station are industrial premises situated to the north east of the site.

- Synthomer Ltd (Organic Chemicals Process);
- Newlincs Developments Ltd (Municipal Waste Incineration),

The nearest occupied residential accommodation to the power station is at Poplar Farm, approximately 1,300 metres to the west of the power station. All other residential accommodation in the general vicinity of the power station is significantly further away than Poplar Farm,

The site and immediate surrounding land use is illustrated in Figures 1 and 2.

4.1.2 Environmental Features and Designated Sites

The Humber Estuary is situated approximately 800 m to the east of the power station. This area is designated as a Site of Special Scientific Interest (SSSI) primarily due to its large intertidal mudflats, saline lagoons and reed beds.

The closest designated area of significant ecology and nature value to the power station is the Mudflats of the River Humber. This is classified as a Ramsar site, SSSI and Special Protection Area (SPA). Part of the area is also a Nature Reserve of the Royal Society for the Protection of Birds. This is one of the countries few remaining areas of washland habitat and is nationally and internationally important as a habitat for wildfowl and wading bird populations. At its nearest point the Humber Estuary is approximately 800 m east of the main station site.

The environmental features surrounding the site were illustrated in Figure 1.3.

4.1.3 Geology

Published records for the area (Geology of England and Wales, Sheet 86, 1911) and previous logs, indicate that the site is underlain by the geological succession described in Table 4.1.

Reference to the geological records suggests that the majority of the site is underlain by Alluvium. However, these records are previous to the development of the power station, and the site is now likely to contain made ground.

Table 4.1: Underlying Geological Succession.

Strata	Description	Thickness*
Alluvium	Variable - typically mottled orange of grey brown silty to sandy clay	0.0 - 7.30m
Glacial Till	Variable – blue green to dark brown sands and clays with fine to coarse chalk gravel	7.3 - 21.45m
Upper Chalk	Cream to yellow brown moderate to highly weathered chalk with closely spaced fractures	21.45 – 82.95m

***Figures quoted are taken from Borehole No. L1. of the Mott MacDonald Investigation.**

4.1.4 Surface Water and Groundwater

There are no surface water features or controlled waters on site. However, there are drains that have been relocated to the boundary that previously cut through the central area of the site.

The River Humber is located 800 m to the northeast, flowing in a northwest to southeasterly direction.

Surface water protection features include a segregated oily water and surface water collection system across the site comprising drainage pipes and 5 interceptors.

The Alluvium beneath the site is classified as a Major Aquifer by the Environment Agency.

Groundwater beneath the site is likely to be in hydraulic continuity with local surface water drains around the boundary of the site, the fenland areas and in the surrounding farmland, unless these are clay lined across. As the site is in such close proximity to the River Humber, tidal range is expected to have an effect on groundwater levels.

4.1.5 Potential Pathways

The primary pathways by which releases from the site can potentially impact on sensitive receptors have been summarised in Table 4.2.

Table 4.2: Primary Pathways

Sensitive Receptors	Potential Impact	Potential Pathway under Normal Operation	Potential Pathway under Abnormal/Emergency Conditions
Humans	Air Quality	Discharges from gas turbine exhaust stacks and subsequent air borne dispersion	Release during fire. Discharges from gas turbine exhausts Discharge from the standby generators in the event of grid supply failure during site start up. Infrequent steam release via pressure relief valve (e.g. in event of turbine trip).
	Noise	Noise generating plant	
Birdlife and Invertebrates (SPA, RAMSAR and SSSI sites)	Air Quality	As described above	As described above
	Noise	Not considered to be significant	
Humber Estuary	Surface Water	No contaminated discharge during normal operation	Uncontained spill, which passes through interceptors.
Ground and Groundwater	Groundwater quality	No contaminated discharge during normal operation	Uncontained spill on area of open ground or loss of integrity of containment system, including underground pipework.

4.2 Air Quality Impacts

4.2.1 Air Quality Standards (Environmental Quality Standards)

Ambient air quality standards and guidelines are identified in the UK's Air Quality Strategy and came into statute under the Air Quality (England) Regulations, 2000 and subsequent amendments (February 2003). The strategy identifies air quality standards identified in the European Union Daughter Directive on Air Quality (1999/30/EC) along with recommendations made by the UK Expert Panel on Air Quality Standards where these are tighter than the EU standards.

Releases to air will occur from the operation of the gas turbines. A very high standard of emission control is in place due to the combustion of the cleanest available fossil fuel (natural gas) and the presence of a primary emission control technique (Dry Low NOx burners).

This can produce low levels of sulphur dioxide (SO_2) and particulate (PM). The air quality objectives for NO_2, SO_2 and PM are summarised below in Table 4.3.

Table 4.3: Air Quality Standards Under the UK Air Quality Strategy

Emission Parameter	Period of Exposure (Averaging Period)	Air Quality Objective (AQO)	Date to be Achieved By
NO_2	1-hour	200 µg/m^3 (not to be exceeded more than 18 times per calendar year, 99.8th percentile)	31/12/2005
	Annual Mean	40 µg/m^3	21/12/2005
SO_2	15 minute	266 µg/m^3 (not to be exceeded more than 35 times per calendar year, 99.9th percentile)	31/12/2005
	1-hour	350 µg/m^3 (not to be exceeded more than 24 times per calendar year, 99.7th percentile)	31/12/2004
	24-hour	125 µg/m^3 (not to be exceeded more than 3 times per calendar year, 99.2nd percentile)	31/12/2004
Fine Particulate Matter (PM_{10}) Provisional Stage 2	24-hour	50 µg/m^3 (not to be exceeded more than 7 times per calendar year)	31/12/2010
	Annual Mean	20 µg/m^3	31/12/2010

The Strategy also sets national objectives for NOx as NO_2 (30 $\mu g/m^3$ annual mean) and SO_2 (20 $\mu g/m^3$ annual and winter mean) for the protection of vegetation and ecosystems. Monitoring to ensure compliance with these objectives applies in areas that are:

- More than 20 km from an agglomeration; and
- More than 5 km from: industrial sources regulated under Part 1 of the Environmental Protection Act 1990 (such as South Humber Bank Power Station), motorways and built up areas of more than 5,000 people.

Although these criteria are not met, impact assessments described within this PPC permit application have however considered the above guidelines for the protection of ecosystems.

Local Authorities use the standards and objectives stated above and in Table 4.3 to review and assess air quality within their region. If exceedences are predicted to occur through the review and assessment procedure, the local authority must declare an air quality management area (AQMA) and draw up an air quality management plan to outline how air quality is to be improved to meet the objectives.

4.2.2 Effect of Emissions of NOx on Animals and Vegetation

Information is presented below sourced on the generic effects of NOx on plants, animals and ecosystems.

4.2.2.1 The Effect on Vegetation

Excessive NOx exposure beyond critical levels can reduce photosynthesis and biomass production and increases an individual plants' sensitivity to other stresses, such as frost, drought, and insect damage (direct toxic effects). At the level of ecosystems, eutrophication (a proliferation of plant life) and acidification (change in pH) are more important than toxicity as the nitrogen-enriched soil causes a reduction in biodiversity in nutrient limited habitats due to accelerated growth of nitrogen tolerant species. This could have a damaging effect on the food reserves available to waders and waterfowl that are dependant on ecosystem diversity for nourishment.

The sensitivity of plants to NOx is determined by the genetic characteristics and environmental conditions at the time of exposure. As the intake of NOx by vegetation is reliant on stomatal resistance, thus uptake increases with increasing light intensity, wind velocity and humidity. After uptake the response of the plant to the NOx uptake increases with poorer nutritional supply and lower temperatures. It must be borne in mind, that the primary impact of NOx at the concentrations found near the power station; on plants and ecosystems is through its contribution to the total nitrogen deposition in the area, not a result of direct toxicity. Large emission concentrations of NOx in conjunction with releases of sulphur can generate acidic contributions to ground and water.

The main nitrogen input into most ecosystems via surface water is much higher than atmospheric loading and atmospheric nitrogen loading is typically of minor importance. The main loading is typically derived from agricultural sources (mainly via ammonia).

Nitrogen oxides are ultimately removed from the atmosphere by either wet or dry deposition, mostly as nitrates. Nitrogen oxides can travel distances of hundreds of kilometres from source. Exposure close to a combustion source is predominantly NO, with NO_2 in the local region. Deposited nitrogen affects soil chemistry increasing the nutrient status so any additional nitrogen will have some impact.

The critical level (as guidance from the World Health Organisation) for air concentrations of nitrogen oxides is considered to be 30 $\mu g/m^3$ as an annual mean. At concentrations slightly above this critical level, growth stimulation is the dominant effect.

4.2.2.2 The Effect on Animals

Most available data is focused on plants, however it is expected that plants are the most sensitive receptors in an ecosystem and the effect on biodiversity of plant communities is a sensitive indicator of biotic effects on the whole ecosystem.

Responses to NO_2 exposure have been observed in several animal species, resulting in the conclusion that the same effects could occur in humans (however, uncertainties in respiratory tract similarities and species sensitivity currently precludes a quantitative extrapolation). In summary the major classes of effects on animals observed at exposure concentrations of less than 1880 $\mu g/m^3$ are lung structural alterations, increased susceptibility to bacterial and viral pulmonary infections in animals, a decrease in pulmonary antibacterial defences and alterations in lung metabolism. Longer exposures (of months) increase the severity of structural changes in the lungs at a given NO_2 concentration, and findings show an increase in susceptibility to infection with long-term exposure to NO_2 levels as low as 940 $\mu g/m^3$. The effects of the other nitrogen oxide compounds are unknown at present.

No information was sourced specific to the effects on birds, so the generic effects on lungs of laboratory animals is considered indicative of the potential effects of birds in the area. The area around SHBPS is noted for supporting birds and protected invertebrates. Again, no information was sourced specific to the effects on invertebrates. Invertebrates do not possess lungs, absorbing oxygen through their exoskeleton.

Controlled human exposure studies show that short term NO_2 exposure causes decreases in lung function and increased airway responsiveness and alterations in lung cells and their activity. Long-term exposure to NO_2 is associated with respiratory illness. Individuals with asthma and chronic respiratory illness are more susceptible than healthy individuals. Children between 5 and 12 years represent a subpopulation potentially susceptible to an increase in respiratory morbidity associated with NO_2 exposure.

The air quality objectives identified in Table 4.3 are designed to protect human health and, based on the limited information available, are likely to protect the health of animals including bird life.

4.2.3 Air Dispersion Modelling

Computerised dispersion modelling has been used to assess the dispersion of releases from the SHBPS to atmosphere. The impacts on air quality of emissions to atmosphere from the Centrica Killingholme Power Station has also been considered both separately and cumulatively because of its relatively close proximity to SHBPS. An extensive modelling study is also being conducted by the oil refinery adjacent to Centrica Killingholme Power Station that incorporates the power station and will be available for review as part of the refinery's PPC permit application.

Due to the presence of a number of building structures of sufficient height to cause downwash and higher ground level concentrations around the stack, the assessment was carried out using AERMOD PRIME. Unlike ADMS the model is able to account for buildings of different heights for each wind direction. For the purpose of comparison with the AERMOD PRIME model predictions, the (EA approved) ADMS v3.3 model was used for the sensitivity analysis. Predictions of maximum NO_2 concentrations made by ADMS 3.3 are significantly higher than that made by AERMOD PRIME. The reasons for this significance are not known.

The modelling took into account all appropriate factors that influence predicted air quality beyond the site boundary including the incorporation of buildings to develop a three-dimensional representation of the site.

Predicted ground level concentrations of NO_2 during gas combustion have been assessed using five years of hourly sequenced meteorological data from a representative Met Station. Only dry nitrogen deposition (via impaction on surfaces) on areas designated for their environmental importance has been considered in the modelling assessment, as is appropriate for gas turbine power stations. Deposition rates are predicted to be less than 1% of existing background concentrations (in which SHBPS contributions as an existing facility are already considered).

The maximum ground level contributions are predicted to occur within 1.5 km northeast to the South Humber Bank Power Station on the Humber Estuary. The contributions predicted in the residential areas of Stallingborough are around 20% of the maximum predicted contributions.

A summary of the maximum predicted contributions is presented in Table 4.4. Maximum predicted contributions have been classified as being ‘worst-case’ or ‘probable’. ‘Worst-case’ concentrations assume that the worst-case emission and dispersive conditions coincide consistently to produce maximum potential ground level pollutant contributions. In most instances, these worst-case conditions are continuous operation burning natural gas under either normal or start-up conditions. Continuous operation under start up conditions would never happen, but has been modeled to indicate the extreme maximum contributions that might possibly occur, although with vanishingly low probability.

‘Probable’ maximum contributions are for more typical emission conditions during normal operation. Predicted ‘probable’ NO_2 and CO concentrations are based on the emission rates and fuel usage recorded during 2004. Other ‘probable’ predicted concentrations are for continuous normal operation burning natural gas.

In Table 4.4, predicted NO_2 concentrations in the ‘plant-in-isolation’ column consider the South Humber Bank Station in isolation and estimate the maximum contribution the power station would make to ambient levels if there were no other background or significant point sources of NO_X in the vicinity of the plant. This approach uses the ADMS simplified photochemical model, but sets the background concentrations of NO_X and nitrogen dioxide to zero, and the concentrations of ozone to the total oxidative potential, which is the sum of the ozone and nitrogen dioxide concentrations from the background monitoring site. Predicted cumulative NO_2 concentrations are model predictions that use hour-by-hour background pollutant concentrations from the Humberside Airport and Waddington monitoring site. The long-term and 99.79 percentile 1-hour average concentrations calculated from the urban background pollutant input file are also given.

Table 4.4: Summary of Predicted and Accumulative Pollutant Concentrations

Averaging Period	Objective Compliance Criteria	Objective (µgm³)	Background Conc. (µgm³)	Worst Case			Most Probable		
				Plant in Isolation (µgm³)	Cumulative Conc. (µgm³)	% of Objective (µgm³)	Plant in Isolation (µgm³)	Cumulative Conc. (µgm³)	% of Objective (µgm³)
NO_2[a]									
1-Hr	99.8%	200	20.8	27.3	48.1	24.0	20.7	41.5	20.8
Annual	100.0%	40	20.8	2.4	23.2	58.0	0.7	21.5	53.8
CO									
8-Hr	100%	10,000	177	-	-	-	6.8	183.8	1.8

The full air dispersion modelling report is presented as Appendix B.

4.2.4 Human Health Impacts

The assessment has considered a range of emission conditions, including conditions when pollutant emissions and predicted contributions will be significantly higher than normal, such as the burning of natural gas during start-up conditions. The dispersion modelling results indicate that, even if worst case emission and dispersive conditions coincided consistently, predicted ground level concentration near South Humber Bank Power Station would not exceed any of the objectives for nitrogen dioxide and carbon monoxide UK Air Quality Regulations, either in isolation or in conjunction with estimated maximum background pollutant levels. Consequently the modelled pollutants emitted from the plant are unlikely to have a significant health impact on the surrounding community.

4.2.5 Emissions with Global Warming Potential

CCGT power stations such as SHBPS form an important element of the national electricity supply network. Such stations allow flexibility to meet diurnal variations and short term fluctuations in demand due to their availability and ability to start up quickly in relation to other forms of electricity supply derived from coal, nuclear and renewable based supplies.

The principal emissions with global warming potential that are emitted from SHBPS are carbon dioxide and methane. Methane has a global warming potential 21 times that of carbon dioxide on an equivalent molecular basis but is only released in minor quantities from the site. Releases of these compounds are discussed and quantified in Section 3. Due to the clean burning characteristics of natural gas and the combustion in excess air along with good fuel and air mixing, emissions of methane from SHBPS are minor in terms of overall global warming potential derived from carbon dioxide.

In contrast with other forms of power station that combust fossil fuels (and hence emit carbon dioxide), CCGT power stations typically emit half of the carbon dioxide emissions from a coal-fired power station for an equivalent electrical output. This occurs from the greater energy efficiency obtained by enabling a combined cycle operation and from the lower carbon dioxide emissions generated from combusting natural gas as the principal fuel in contrast to coal per unit of electricity produced. Oil fired power stations also produce more carbon dioxide emissions relative to natural gas CCGT plants. Electricity provided by the SHBPS CCGT hence either supports a critical function in meeting electricity demand fluctuations and ensures the stability of the national grid network or displaces electricity (and reduces global warming releases) that would otherwise be generated by oil and coal fired power stations.

Emissions of carbon dioxide from SHBPS are covered by the EU Emissions Trading Scheme via the Greenhouse Gas Emissions Trading Scheme Regulations 2005. This is the principal regulatory mechanism, as opposed to PPC, being used to reduce emissions of carbon dioxide from industrial plant within the UK and the EU.

4.2.6 Other Pathways with the Potential to Affect Air Quality

Other pathways with the potential to affect local air quality include uncontained fires on the site resulting from incidents. The fire prevention techniques to minimise accidental releases from the site are described in Section 2.8. As no toxic substances are held in significant quantity at the site and fire prevention and suppression measures are present, the potential risk of hazardous chemical fumes arising from an uncontained fire is considered to be extremely low.

Due to the combustion of fuel in excess air (of 15%) within gas turbines combined with good mixing and combustion characteristics, excellent carbon burn out of the fuel is achieved. Residual organic compounds are however emitted to air with the potential to contribute to Photochemical Ozone Creating Potential (POCP) and mass estimates are summarised in Section 3. The majority of these residual emissions relate to unburnt methane, which does not have significant POCP (value of 0.6 relative to ethylene). Certain non-methane volatile organic compounds (NMVOC) will be emitted to air that do have POCP but no quantification in POCP equivalence terms has been carried out as the composition of the NMVOC is not known. Overall releases are not considered significant in relation to other local sources including traffic and activities where solvents containing VOC are either made or used.

4.2.7 Visible Plumes

During start-up of the gas turbines and in combination with certain meteorological conditions, emissions of NO_x can contribute to a slight visible haze caused by the formation of nitrogen dioxide (NO_2). Such releases occur during operation at loads below the switchover point from diffusion to premix burner mode operation and for short durations only. Air dispersion modelling identified above has demonstrated that emissions of NOx (and NO_2) during start up do not have any significant impact on human health or ecosystems.

4.3 Surface Water and Groundwater

Only uncontaminated surface water is discharged from the site during normal operation. All flows to surface water pass through interceptors to capture any release of oils and greases. This is a final protection measure. Additional measures exist to prevent any spillage or leak of potentially hazardous material from occurring including the provision of primary and secondary containment measures. In the unlikely event of an uncontained spill, spill response procedures, equipment and supportive training are in place to ensure prompt and appropriate remedial action. A detailed impact assessment has hence not been carried out within this PPC permit application.

There are no direct releases to groundwater. Containment measures including hard surfacing, containment pits and oil/water interceptor are in place to minimise the potential for a leak into ground or groundwater. There are no underground storage tanks at SHBPS.

Recommendations to minimise the potential for surface water and ground/groundwater pollution are identified in the Application Site Report (see Appendix A).

4.3.1 Cooling Water Discharges

4.3.1.1 Description of Receiving Environment

Cooling water discharges into the Humber Estuary. The estuary is about 4 km wide in the vicinity of the site. The site is fronted by an intertidal flat, which is about 200 m to 300 m wide locally. The bed slopes down to about 5 m below lowest low water (-9 m Ordnance Datum Newlyn) some 1800 m offshore. Beyond this the bed slopes rapidly down to about –15 m ODN.

Salinity varies along the estuary due to variable freshwater inputs, but turbulent mixing is normally sufficient to prevent any significant vertical stratification at the site (i.e. the salinity and density are uniform in the vertical).

Ambient water temperatures normally vary between a minimum of about 4°C in the winter and a maximum of about 18.5°C in the summer. Again, the temperature can vary by a few degrees during a tidal cycle because of advection of the longitudinal gradient.

The tide at Immingham, 4.5 km away, is predominantly semi-diurnal (two high and two low waters per day), with mean ranges of 3.2 m on neap tides and 6.4 m on spring tides.

The tidal currents measured at the site also vary semi-diurnally as the tide flows in and out of the estuary. Currents are quite strong in the vicinity of the intake and outfall, reaching 1.2 or 1.3 m/s on spring tides and about half this on neap tides. The currents are equally strong on ebb and flood, and flow to and fro along the line of the main estuary. The turn of the tide coincides with high and low water level. Currents in the shallower water between the intake and the shore are weaker.

These tidal currents suggest that the tidal excursion, that is the distance a 'particle' of water travels between high water and low water, is some 17 km on spring tides and 8 km on neap tides.

4.3.1.2 Potential Impacts

Under current operating conditions, the potential impact on the Estuarine environment relates to the thermal content of the cooling water. The power station may also need to dose the water with sodium hypochlorite in future, which may result in potential discharges of residual oxidant (chlorine). No immediate dosing requirements however exist. The pH of the cooling water may also vary within a small range around a neutral pH.

4.3.1.3 Impact Assessment

The strong tidal currents in the vicinity of the intake and outfall provide a good dispersive environment, in which the discharges cooling water and any dissolved constituents are able to mix with a large volume of ambient water flowing past. For example, if the tidal current is 1 m/s and the water depth is 7 m (typical of the depths in the vicinity of the discharge), then an ambient discharge of 7 m^3/s flows though each metre width of the estuary. Turbulence in the tidal current promotes mixing with the discharge, and the large tidal excursion results in dispersion of the discharge over a wide area.

4.3.1.4 Thermal Discharges

A full thermal plume assessment for the site was carried out in 1992. No significant changes to the scale of the power station or the Humber Estuary are considered to have taken place since this study was carried out. It is therefore considered the study remains representative of releases from South Humber Bank Power Station today. The study identified no significant adverse impact given the estuarine conditions.

4.3.1.5 Discharges of Residual Chlorine and pH

The power station is currently permitted to discharge 0.1 mg/litre of residual oxidant as part of their current IPC authorisation. A preliminary dispersion study has been carried out by HR Wallingford to assess the impact of potential discharges of chlorine and pH should dosing of the cooling water be required in the future. It can be conservatively estimated that the chlorine concentration will reduce in proportion to the dilution of the cooling water. Evaporation and reaction of the residual oxidant however will reduce the concentration further.

The receiving water provides a dispersive environment, with large tidal range, strong currents and long tidal excursions. The discharge spreads over an elongated ellipse aligned from east-southeast to west-northwest.

The highest concentrations of residual chlorine will be found in the top 2m of the water column. In this layer the concentration of dissolved constituents is expected to be some 10% of the discharge concentration at up to about 500 – 1000 m from the discharge, dropping to about 1% or less at a distance of 1.5 km. These raised concentrations are only found intermittently, when the tide is flowing in the appropriate direction.

The average concentration drops to 10% of the discharge concentration within less than 100m of the discharge location. Concentrations of 1% of the discharge value are found at up to about 500 m east-southeast and west-northwest of the discharge over a width of 50 – 100 m.

A change in concentration of a factor of 10 would be equivalent to a change of 1 pH unit, but the discharge will change the pH in the receiving water by much less than the amount suggested by 'dilution' due to the buffering capacity of the water.

No background monitoring of chlorine or residual oxidant is carried out by the Environment Agency. The Environmental Assessment Level included in EA Guidance Document H1 for chlorine is 10 µg/litre for estuarine waters (expressed as total residual oxidant) though a higher value can be used if the pH is maintained above a pH value of 6. Excluding any background levels therefore, a discharge of 0.1 mg/litre (or 100 µg/litre) of total residual oxidant is predicted to result in average receiving water concentrations being below the EAL within less than 100 m of the discharge point. Peak concentrations are expected to be approaching or at the EAL concentration at distances of up to about 500 – 1000 m from the discharge, dropping to about 10% of the EAL or less at a distance of 1.5 km. These raised concentrations are however only predicted to occur intermittently, when the tide is flowing in the appropriate direction.

Average concentrations of residual oxidant (chlorine) will reduce to below 10% of the EAL beyond 500m of the discharge point.

A change in concentration of a factor of 10 would be equivalent to a change of 1 pH unit, but the discharge will change the pH in the receiving water by much less than the amount suggested by 'dilution' due to the buffering capacity of the water. The EAL for pH is greater than 6 and less than 8.5 for estuarine waters. The existing IPC authorisation limit is a pH of 6 to 9. A change of 1 pH unit on average will be anticipated in the cooling water within 100 m of the discharge and hence any excursion of the upper pH limit will be below 8.5 within a short distance of discharge, excluding any buffering effects.

It is considered that the existing IPC authorisation limit for releases of residual oxidant (from cooling water treatment using sodium hypochlorite giving rise to a residual chlorine component) and pH will not give rise to a significant impact on the Humber Estuary.

The preliminary water modelling report is presented as Appendix D.

4.3.1.6 Fish Impingement

The abstraction of cooling water is regulated under a separate licensing regime to PPC

As with all cooling water systems of the type installed at South Humber Bank, there is the potential for fish impingement (entrainment in the cooling water intake) to occur. The various operators of South Humber Bank have commissioned a number of studies to examine the effects of the current process and options for reduction or elimination of fish impingement, varying from fundamental changes to the design of the cooling water system to relatively minor modifications.

Fish impingement is generally of the order of 50 tonnes per year. The fish impinged are removed by a licensed contractor and are used in the manufacture of animal feed. The Institute of Estuarine and Coastal Studies at the University of Hull (2000) stated that this was unlikely to be deleterious to the overall offshore stocks. The studies have also concluded that major modifications to the cooling system are not practicable as they entail great cost, sometimes too great a risk to operation of the power station and in addition they are generally accompanied by other environmental impacts (e.g. loss of efficiency, visible plumes of water vapour, noise, etc). NEL Power (2002) concluded that "the once-through [cooling water] system at South Humber is a class leader in design and operation within the power industry". The current design of a once through system is considered to represent Best Available Technique for a power station of the scale of South Humber Bank in terms of electrical output.

4.4 Waste

SHBPS does not produce significant quantities of waste. The main source of hazardous waste is waste oils. Solid non-hazardous wastes are segregated wherever possible to maximise the opportunity for recycling and minimise the requirement for final disposal. All wastes are appropriately stored to minimise the potential for contaminated surface water run-off or impact to ground/groundwater. Appropriate Duty of Care requirements are followed. The environmental impact associated with waste generation at SHBPS is considered to be minimal.

4.5 Noise

Power stations have the potential to generate significant noise levels during operation. Noise has been successfully managed at South Humber Bank power station employing the following considerations:

- Minimisation of noise production by design
- Control of noisy activities (by employing enclosure and silencers)
- Minimal requirement for heavy transport (the fuel source is piped to the site) due to fuel and technology type
- Controlling high pressure flows such as steam and natural gas
- Appropriate zoning – the site is a significant distance from residential areas
- Ongoing monitoring and review of noise performance

A complete and detailed noise survey and report has been prepared for the site in and has been discussed with the local Environmental Health Officer. The report is included as Appendix C.

Regular monitoring and review of noise has been undertaken as required by the IPC authorisation for the site.

4.5.1 Noise Sources

4.5.1.1 Gas Turbines

There are five gas turbines installed at South Humber Bank Power Station and two steam turbines. The generation of noise from these turbines primarily results from the high mass flows of air, combustion gases and steam through the machine.

Noise from the turbines themselves is controlled by enclosure within the turbine halls. Noise from the intake and exhaust is controlled by the inclusion of silencers in the gas paths to block and attenuate the escape of noise.

4.5.1.2 Water Cooling

Many power stations also generate significant levels of noise from the cooling water by means of air-cooled condensers or cooling towers. However, at South Humber Bank this cooling function is provided by heat exchangers that do not generate any airborne noises.

4.5.1.3 Fluid Flows

There are a number of high-pressure fluids (steam, natural gas, compressed air) employed at the power station. These have the potential to generate noise due to the high velocities movement and venting to the atmosphere.

Venting of steam is necessary during start-up in order to protect the steam turbines from water ingress, but is minimised where possible and silencers are employed on significantly frequent / noise generating sources to control the production of noise.

Apart from noise generated during the venting of steam during start-up the main noise sources on the site are the Heat Recovery Steam Generators (HRSGs) and the GT air intakes. Noise from other fluid flows is not significant compared to these sources.

Acoustic attenuation has been applied or is intrinsic to the design of the stacks, air intakes and steam pressure relief valves to minimise emissions of noise from the installation.

It should also be noted that the system employed for routine testing of pressure relief valves does not require the lifting of these valves during testing. Testing can therefore be carried out without venting steam to atmosphere and associated noise emissions.

4.5.1.4 *Transport*

The nature of the fuel and technology reduces the requirement of heavy vehicular transport to the site. Deliveries are typically undertaken during daylight hours.

4.5.2 Ambient Noise Levels

A summary of the noise monitoring survey carried out in September 2005 is provided below in Table 4.5. The monitoring survey identified that noise emissions would not give rise to probable complaints and meets applicable noise standards at the nearest commercial and residential receptors. Noise emissions from the site are hence not considered to be significant, particularly in the context of its current land-use setting.

Table 4.5: Noise Receptor Information

Receptor	Location relative to SHBPS	External Noise Level	Internal Noise Level	Standard	Comments on Noise Levels
Poplar Farm	West of SHBPS	<30 dB $LA_{eq,t}$ for steady-state operation	<17 dB $LA_{eq,t}$ worst-case not measured	BS8233	Satisfactory

All figures are free-field values rounded to the nearest whole dB.

Noise level for Poplar Farm is derived from the results of measurements on the power station site – high background road traffic noise levels prevail at Poplar Farm.

Noise from the power station meets applicable noise standards at the nearest residential receptor and has no potential to affect any commercial receptors.

4.6 European Sites

The Humber Estuary Special Protection Area (SPA) and Humber Flats, Marshes and Coast (RAMSAR) are the only site designated within 10km of SHBPS under 'the Habitats Regulations' (The Conservation (Natural Habitats, etc, Regulations, 1992). The Humber Estuary and Humber Flats, Marshes and Coast can theoretically be impacted by the operation of SHBPS through;

- Long term ambient concentrations of NOx that are principally derived from background sources;
- Nitrogen deposition from releases of NOx from the gas turbine exhausts; and,
- In the case of the Humber Estuary, a discharge to surface water or groundwater, which is hydraulically connected to the designated site,
- Discharge of cooling water.

Further from the site there are no SAC, SPA or RAMSAR sites present (within 15 km of site).

The air dispersion modelling study described in Section 4.2 and Appendix B has identified that no critical loads for nitrogen deposition are exceeded at any of the European designated sites identified above though the current background level (that includes contributions from SHBPS as an existing operational facility) is within the critical load range for the Humber Estuary SPA site. Background nitrogen deposition levels include contributions from both NOx and ammonia (NH_3). The contribution from SHBPS is less than 1%.

An assessment of predicted nitrogen deposition and NOx concentrations at European designated sites is presented below in Table 4.6:

Table 4.6: South Humber Bank Nitrogen Deposition Rates In Comparison With Critical Loads for Designated Sites

Site	National Grid Reference	Reason for Designation	Habitat Classification for Assessment Purposes	Critical Load kg N/ha/yr	Current Background Deposition kg N/ha/yr	Background Above Critical Load?	Process Contribution from Dispersion Modelling kg N/ha/yr	Contribution as a percentage of critical load (lower range valve)
Humber Estuary	TA250148	SPA (UK9006111): Designated for Bird conservation. SAC (UK0030170): Annex I habitats present are the primary reason for selection; Estuaries SSSI (1009830).	Grazing marsh	20-30	22.1	Potentially	0.048	<1%
North Killingholme Haven Pits	516550 419850	SPA (UK0014782): Annex I habitats are the primary reason for selection of this site; Molinia meadows on calcareous, peaty or clayey-silt-laden soils (Molinion caeruleae), calcareous fens with Cladium mariscus and species of the caricion davallianae. Annex II species present that are not the primary reason for selection; Spined loach (Cobitis taenia), great crested newt SSSI (1006646)	Calcareous grassland	Sub-atlantic semi dry calcareous grassland: 15-25	19.0	No	<0.016	<1%

Designated site means the site has been classified as one of the following:

1. Special Protection Area (SPA).
2. Special Area of Conservation (SAC).
3. Site of Special Scientific Interest (SSSI).

Table 4.7: Comparison of Predicted Annual Average NO_x Concentration (for Year 2010) Against EU Standard for the Protection of Ecosystems

Site	National Grid Reference	Reason for Designation	Habitat Classification for Assessment Purposes	NOx Criteria for the Protection of Ecosystems ($\mu g/m^3$)	Projected NOx Background Concentration for 2010 ($\mu g/m^3$)	Existing Exceedance of EU Standard	Process Contribution from Dispersion Modelling $\mu g/m^3$)	Contribution as a Percentage of EU Standard
Humber Estuary	TA250148	SPA (UK9006111): Designated for Bird conservation. SAC (UK0030170): Annex I habitats present are the primary reason for selection; Estuaries SSSI (1009830).	Grazing marsh	30	25	No	<1	<3
North Killingholme Haven Pits	516550 419850	SPA (UK0014782): Annex I habitats are the primary reason for selection of this site; *Molinia* meadows on calcareous, peaty or clayey-silt-laden soils (*Molinion caeruleae*), calcareous fens with C*ladium mariscus* and species of the *caricion davallianae.* Annex II species present are not the primary reason for selection; Spined loach (*Cobitis taenia*), great crested newt SSSI (1006646)	Calcareous grassland	30	25	No	<0.3	<1

Source of background NOx concentration derived by NETCEN modelling data available on interactive maps at : www.airquality.co.uk. The containment measures identified previously in Sections 2.8, 4.4 and the Application Site Report (Appendix A) and suggested improvements included within this PPC permit application will ensure that a spill with the potential to impact upon the Humber Estuary is extremely unlikely.

No significant impact on a European Site is predicted to occur resulting from either normal or abnormal operation of SHBPS.

5 BAT JUSTIFICATION

5.1 Introduction

The major environmental challenges for the design and operation of a CCGT power station are (in approximate order of priority):

- Emissions of NOx to atmosphere / control of local air quality concentrations
- Energy efficiency / global warming
- Control of water quality burden

The remaining parameters listed below are considered of a lesser priority due to the nature of the activities undertaken and, in some cases, the location of the process.

- Noise, odour, fugitive emissions to air, waste, use of raw materials, nuisance issues, ozone depletion, fugitive releases to water and land.

Best Available Techniques (BAT) are explained in the Department of Environmental and Foods (DEFRA's) Integrated Pollution Prevention and Control: A Practical Guide, Edition 1, August 2000 as:

'The main basis for determining standards in IPPC under the PPC Regulations, and defined as the most effective and advanced stage in the development of activities and their methods of operation which indicates the practical suitability of particular techniques for providing in principle the basis for ELVs designed to prevent and, where that is not practicable, generally to reduce Emissions and the impact on the environment as a whole'.

(ELV – Emission Limit Value)

'Emission' in relation to a Part A Installation is explained as:

'the direct or indirect release of substances, vibrations, heat or noise from individual or diffuse sources in an installation into the air, water or land'

'Best' in relation to Techniques in BAT is explained as:

'the most effective in achieving a high general level of protection of the environment as a whole'.

'Techniques' in connection with BAT are taken to include:

'both the technology and the way the Installation is designed, built, maintained, operated and decommissioned.

Available Techniques in connection with BAT are explained as:

'those Techniques developed on a scale which allows implementation in the relevant industrial sector, under economically and technically viable conditions, taking into consideration the cost and advantages, whether or not the techniques are used or produced inside the United Kingdom, as long as they are reasonably accessible to the Operator'.

This section identifies where operations meet BAT requirements identified within the sector guidance note for combustion activities (at the time of writing was issued as a consultation draft). A summary is also provided in Appendix E of sector guidance requirements and compliance with indicative benchmarks for the attainment of BAT. This section should also be read in conjunction with the Application Site Report presented as Appendix A. Where indicative BAT requirements are not met at the present time, an outline improvement plan has been prepared in Section 6 with indicative timescales for associated actions to be carried out within.

5.2 Choice of Fuel Type

A range of fuels may be employed to generate electricity including:

- Fossil fuels such as coal, oil and gas;
- Nuclear fuels;
- Wastes and by-products including domestic refuse, sewage sludge, straw, tyres.

Agro-fuels, such as wood from short-rotation coppicing can also be used along with biofuels made or blended with vegetable oils.

Due to the nature of gas turbines, fuels that generate significant quantities of particulate and acid gases will impact on the wear and tear of turbine blades. A suitable means of delivery must also be present to ensure complete combustion and minimise emissions. For these reasons, only natural gas is used in the gas turbines at SHBPS. Natural gas is the cleanest burning commercially available fossil fuel and produces lower emissions to air than alternative fossil fuels.

The Environment Agency's Sector Guidance note states outright in its Section 2.1.2.3:

"Combined cycle gas turbine (CCGT) plant are BAT for new gas turbine installations."

Indicative BAT requirements for fuel selection have been met with gas as the primary source of fuel offering the lowest emission profile.

5.3 Cooling Method

5.3.1 Cooling of Process Stream

Alternative methods exist for condensing the steam from the steam turbine unit of a CCGT plant. These are either air-cooling or water-cooling. Both systems have advantages and disadvantages. Determination of BAT is dependant upon the impacts on the local receiving environment.

For air cooling the loss of efficiency associated with reduced temperature differential and power consumption of the fans can be significant. In addition, larger structures are usually required. For evaporative water cooling "fogging" (visible water vapour) can often occur from cooling towers and significant water consumption may also result. Return of cooling water to local rivers following condensation of the steam can have significant effects as the returned cooling water is at elevated temperature and may contain trace impurities from the power station process. All three cooling techniques are employed across the Centrica group, depending on location.

A summary of the advantages and disadvantages of the different methods of cooling are presented in Table 5.1.

Table 5.1: Environmental Aspects of Types of Industrial Cooling System

(Taken from the EC 'Reference Document on the Application of Best Available Techniques to Industrial Cooling Systems, 2000').

Cooling system type	Energy Consumption (direct)	Water requirement	Fish entrainment	Emissions to surface water		Air emissions (direct)	Plume formation	Noise	Risk		Residues
				Heat	Additives				Leakage	Micro biol (health)	
Once-through cooling (direct)	Low	++	+	++	+ (biocides)	--	--	--	++	--/low	+(1)
Once-through cooling (indirect)	Low	++	+	++	+ (biocides)	--	--	--	Low	--/low	+(1)
Open wet cooling tower (direct)	+	+	--	Low	+(3)	Low (in plume)	+	+	+	+	--/low
Open wet cooling tower (indirect)	+	+	--	Low	+(3)	Low (in plume)	+	+	Low	+	+
Open wet/dry cooling tower	+	Low	--	Low	Low(3)	--	--(5)	+	Low	?	+
Closed circuit wet cooling tower	+	+	--	--	Low	Low(4) (in plume)	--	+	Low	Low	--/low
Closed circuit dry cooling	++	--	--	--	--	--/Low	--	++	Low	--	--
Closed circuit wet/ dry cooling	+	Low	--	--	Low(3)	Low	--	Low	Low	Low	--/low

Notes:
-- none/not relevant
Low relevance below average
+ relevant
++ highly relevant

1: waste refers to sludge from water intake and from decarbonization
2: other species can also be entrained
3: biocides, antiscaling, anticorrosion
4: potentially in case of leakage
5: if properly operated no issue

In the case of the SHBPS site there is an appropriate source of water and discharge location available to enable direct use of water-cooling to be a viable proposition. Given the greater efficiency of water-cooling, scale of electricity production and locality of the Humber Estuary, water-cooling is employed as the cooling method at SHBPS. The design of the cooling system was best practice at the time of the power station's development. This has been confirmed by the independent studies discussed in Section 4.3.1.6.

The current method for cooling of the steam from the steam turbines can therefore be considered to be BAT for the installation.

5.3.2 Conditions to be Set in Permit

The existing IPC authorisation was updated in November 2004. As this is a relatively recent review, it is anticipated that the authorisation conditions will be transferred generally unmodified into any new PPC permit.

The current permitted differential temperature limit of 15°C for cooling water discharges is permitted for 96 hours of the year to allow essential maintenance of the cooling water system. Since the original IPC authorisation application was submitted prior to operation of the power station, operational experience has identified this is insufficient to control seaweed fouling in particular. It is requested that up to 200 hours be permitted to enable essential maintenance in future.

5.4 Turbine and Emission Control Technologies

SHBPS uses a combination of the cleanest available fossil fuel - natural gas and the most thermally efficient combustion technology- Combined Cycle Gas Turbine.

The major environmental challenges for CCGTs in operation relate to:

- NO_x emission levels;
- Thermal efficiency; and
- Water consumption.

Thermal efficiency can affect the quantity of raw materials (including fuel) consumed by the installation and the resulting emissions, including in particular emissions of carbon dioxide (CO_2). Releases of CO_2 are managed under the EU-ETS permitting regime.

The following section considers NO_x emissions in particular, though energy efficiency and releases of CO_2 are also considered as part of the BAT assessment.

5.4.1 NOx Control Technologies

The DLN burner technology employed is identified in the current PPC large combustion plant sector guidance as a suitable gas turbine NOx control technology.

The NOx emission levels achieved at SHBPS are significantly lower than emissions achievable in comparable thermal technologies such a coal fired electricity generation.

The use of DLN burner technology for NOx control at SHBPS are considered BAT.

5.4.1.1 Available NOx Reduction Technologies

- Steam injection;
- Selective Catalytic Reduction (SCR); and,
- Selective Non Catalytic Reduction (SNCR);

5.4.1.2 Advantages and Disadvantages of Available NOx Control Technologies

The advantages and disadvantages of available NOx control technologies are summarised in Table 5.2 below/

Table 5.2: Generic Options & Associated Advantages/Disadvantages for NOx Control

.	Advantages	Disadvantages
Steam Injection	Works with older turbine frames Works regardless of fuel type Increases turbine power rating	Decreases efficiency by 2% to 3% (US EPA) Requires significant amounts of demineralised water Can contribute to turbine wear Requires steam availability Not active during start up
Dry Low NO_x burners or turbines (DLN)	Achieves greater NOx reduction No water requirement	Difficult to retrofit – particularly on older machines Generally not applicable to liquid fuel combustion though can be used with distillate fuels – steam injection/water injection still required for dual fuel machines. Greater maintenance requirement Only works at loads greater than 50-70%. Diffusion burners will operate prior to this load

.	Advantages	Disadvantages
Selective Catalytic Reduction (SCR)	End of pipe – requires no modification to gas turbines Good reduction (80% to 95%)	End of pipe – does not stop the formation of pollution Requires large amount of space Pressure drop Limited operating temperature range Ammonia slip – introduces new pollutant Ammonia storage and handling High installation and operating cost relative to DLN and steam injection Catalyst requires time to reach operating temperature at start-up Periodic generation of catalytic metal waste requiring regeneration/disposal
Selective Non Catalytic Reduction	No advantages to use with gas turbines.	Limited reduction of 30-50% Cannot be employed on gas turbines due to residence time and temperature window requirements Ammonia slip – introduces new pollutant that can be emitted to air Ammonia storage and handling High installation and operating cost relative to DLN and steam injection

Selective non-catalytic reduction is not considered a viable option for use in gas turbines. Steam and water injection are not applicable techniques at SHBPS.

5.4.1.3 Minimising Emissions During Start-up

Start-up emission rates can be higher than full load operation. Dispersion of emissions from the facility will be reduced since the stack emissions will have reduced temperatures and velocities during start-up. Emissions will essentially be uncontrolled in the following circumstances;

- **DLN** – generally DLN systems do not control NOx formation until a load of approximately 50% is achieved. Optimal combustion control and stability is not achieved until relatively high loads are obtained; and,
- **SCR** – the catalyst must reach the required operating temperature before NOx emissions are reduced.

The dispersion modelling study undertaken to support this application has demonstrated that short-term ambient air quality guidelines can be met by the facility during start-up conditions. All of the above NOx control technologies have limitations in regards to minimising NOx emissions during start-up and regardless of the technology type employed; emissions will essentially be uncontrolled for a period of time. The modelling carried out will hence be applicable to a worst case evaluation for all technologies on the basis that NO_x emissions from the gas turbines will either be unabated or partly abated in the early stages of start-up (e.g. during the first hour). Duct burners can also be employed to raise the temperature within the HRSG though there are energy penalties associated with this option.

5.4.1.4 Qualitative Appraisal of Available NOx Control Options

A qualitative appraisal of the practicalities of introducing each of the available NOx technologies at SHBPS and the associated engineering constraints has been carried out and is summarised in Table 5.3. The qualitative assessment has reviewed the following;

- Whether options are available on the marketplace to fit the turbines currently installed;
- Whether space is present for such a retrofit;
- Can the option operate under all scenarios including continuous and non-continuous operation;
- What the resulting impacts are on output, energy efficiency and resource use;
- Are the systems compatible with downstream and upstream processes;
- Availability for dual fuel use where applicable;
- Potential impacts on plant reliability, operability and maintenance.

Table 5.3: Engineering Constraints Evaluation for NOx Control Options

Potential Constraints to Operation/Maintenance for NOx Reduction Techniques	Steam Injection	Turbine Optimisation Package	New Turbine Package	Selective Catalytic Reduction
Are options available on the market place for the turbines installed onsite?	Not BAT for turbines with DLN	Yes Series of three NOx improvement techniques announced mid 2005: Reduced Zone 1 air cooling, using modified zone 1 combustor segments. (2 of 3 zone 1 segments in GT13 fitted with modified segments with encouraging results) Fibre optic flame sensing with individual burner gas fuel adjustment. Advanced pulsation control logic – closed loop control of overall air fuel ratio using combustor pulsation as indicator of flame instability.	No GT 13E2 is Alstom's only option for this capacity. Installed/on order fleet of approx 100 machines.	Yes
Is space available to replace existing turbine or retrofit available option?		Yes		No - Requires major redevelopment of existing HRSG
Compatibility with downstream or upstream processes. What items are not compatible and why?		Yes		See impacts above on HRSG
Can option operate under all scenarios (e.g. baseload/two shifting)?		Yes		Yes

Potential Constraints to Operation/Maintenance for NOx Reduction Techniques	Steam Injection	Turbine Optimisation Package	New Turbine Package	Selective Catalytic Reduction
Impacts on net output / energy efficiency?		None envisaged		Loss of efficiency
Impacts on resource use (water, chemicals)?		None		Periodic replacement of catalyst
Can option operate with dual fuel capability?		N/A		Yes
Are any impacts on flame stability envisaged?		Zone 1 modifications – No Fibre optic flame sensing – Yes Pulsation control - Yes		None
Can operations be modified in a timely manner by the site to respond to market trading conditions (flexibility)		Yes		Yes
Foreseeable impacts on reliability		Pulsation control and fibre optic sensing may increase no of flameouts. Increased risk of leaks with fibre optic sensing, 72 additional valves with 144 additional connections required.		No significant impact envisaged

Potential Constraints to Operation/Maintenance for NOx Reduction Techniques	**Steam Injection**	**Turbine Optimisation Package**	**New Turbine Package**	**Selective Catalytic Reduction**
Foreseeable impacts on maintenance		Pulsation control and flame sensing expected to increase maintenance effort. Flame sensing will require large amount of tuning/shutdowns – may not be practical. Also increased risk of leaks – note above. HPL to seek further information from Alstom.		Increased maintenance on catalyst
Manpower constraints to operate and maintain		As above – additional effort required for pulsation control and flame sensing.		Minimal impact on operation. Increase in maintenance requirements
Downtime requirements to install equipment. Could this be carried out without significant impact on plant availability?		Zone 1 modification – major overhaul. Longer re-commissioning required for flame sensing and pulsation control.		Major refit Redesign of HRSG required to accommodate installation
Any other constraints?		None.		Risk of ammonia slip (where ammonia is produced and emitted by the catalyst) with subsequent environmental impact

5.4.1.5 Summary of BAT Assessment for NOx Control

Both the European BREF note and the UK Sector Guidance note give strong indication that dry, lean-premix low NOx burners are generally BAT for existing gas turbines and CCGT plant. The EV burners used in the GTs at South Humber Bank fit this description.

Steam injection can be considered BAT for those turbines that do not have low-NOx burner technology, but for DLN units, additional steam injection is not beneficial

The Sector Guidance Note states in its Section 2.1.2.3:

"Dry low NOx combustion should be BAT for all new gas fired turbines and is preferred to wet low NOx combustion."

The retrofitting of **Selective Catalytic Reduction** at South Humber Bank, whilst offering high reductions in NOx emissions, would require a major redevelopment of the HRSGs and GT exhaust systems. This is because the original design did not foresee the need to leave space for SCR. Section 7.5.4 of the BREF Note for Large Combustion Plant states:

SCR retrofitting is technically feasible but not economical for existing CCGT plants if the required space in the HRSG was not foreseen in the project and is therefore not available.

('*available*', in this context, is as per the legal definition of BAT).

As Table 5.2 details, SCR also has other drawbacks, such as a reduction in plant efficiency and the risk of 'ammonia slip'. These issues associated with SCR are discussed in detail in the BREF note.

A **complete new turbine package** is not an option as the GT13E2 is ABB Alstom's currently available package for the capacity installed at SHBPS.

A **combustion optimisation package** is under development by ABB Alstom and could result in NOx emissions reductions for the GT13E2 units. There are 3 independent strands to the package:

(i) Modified zone 1 combustor segments, resulting in reduced zone 1 air cooling and better flame shape.

(ii) Fibre optic flame sensing with individual burner gas fuel adjustment.

(iii) Advanced pulsation control logic – closed loop control of the overall air-fuel ratio using combustor pulsation as an indicator of flame instability.

At South Humber Bank, GT13 was fitted in August 2005 with the new zone 1 combustor segments in 2 of the 3 zone 1 segments. Initial results are encouraging based on tuning margins available. On this basis, SHBPS sees this as potentially attractive, however this is a high cost option and further study of the unit's performance is required.

The flame sensing and pulsation control logic modifications are also of interest, but there are possible drawbacks in flame stability, increasing the number of flameouts. The fibre optic flame sensing also requires 72 more valves and 144 more connections, increasing the risk of leaks.

All the modifications would require a major overhaul of the turbine being modified. The flame sensing and pulsation control logic options are likely to result in an increased maintenance effort. Flame sensing will also require extensive tuning and shutdowns.

At the moment these modification options are very new, with vendor testing only commencing in earnest in June 2005. There is insufficient data to assess their performance and potential costs at this stage. Centrica SHB is committed to ongoing review and appraisal of these options and will share the results with the Environment Agency if requested. The timescales for such a review progressing to such a stage that a conclusion can be reached as to the options' viability and attractiveness are uncertain as they are dependent on data becoming available from the vendor.

Centrica SHB has scheduled a review of the start-up sequence. This is intended to optimise the start-up sequence. This may not, however, result in a reduction in the start-up time as other factors such as start-up success rates and equipment fatigue must also be considered (any such factors entail their own environmental aspects). The results of the review will be shared with the Environment Agency if requested.

The following key points therefore summarise the BAT assessment for NOx control options:

- The existing technique used at the site – dry, lean premix low NOx burners – is generally BAT for gas turbines according to both the UK Sector Guidance Note and the European BREF note.
- Selective Catalytic Reduction is not an *available* technique as space in the HRSG / GT exhaust arrangement is not present.
- A complete new turbine package would offer no advantage.
- Modification options for the existing turbines may be BAT in the future, but are not an *available* technique at this stage as they have not been developed and tested on a scale that allows confident implementation across the sector.
- The performance of the turbines is within benchmark levels (see Section 3.1). It is worth noting that at the time of the IPC application in December 1992 the design emission concentration of the turbines was 125 mg/Nm^3. This has subsequently been reduced considerably.
- The impact of the emissions has been shown to be minor (see Section 4.1)

Centrica SHB therefore considers that the current techniques used in relation to NOx control represent BAT for the activity.

5.4.2 Control Techniques for Other Pollutants

5.4.2.1 Carbon Monoxide and Volatile Organic Compounds

Carbon monoxide and volatile organic compounds are produced as a result of incomplete combustion. Since incomplete combustion significantly affects the efficiency of the plant, it is vital to avoid. Numerous instrumentation and control techniques monitor various parameters associated with ensuring complete combustion. Their effectiveness is demonstrated by the consistently very low levels of carbon monoxide emissions measured by the continuous emissions monitoring system. Section 3.1 details these emissions and compares them to benchmarks.

5.4.2.2 Sulphur Dioxide

The natural gas fired at South Humber Bank has a very low sulphur content, resulting in annual emissions of approximately 10-15 tonnes. The operator will investigate opportunities and implications associated with the expansion of gas detection systems onsite, which have the potential to eliminate the need for odorisation of the gas and hence releases of sulphur dioxide, since almost all of the sulphur in the gas is from the odorant added. The lowest possible level of odorant is currently metered into the natural gas supply at present that conforms with appropriate safety requirements to minimise the current release of sulphur dioxide from the site.

For the small amount of fuel oil use (approximately 25 tonnes per year), ultra low sulphur gas oil is used. This has a sulphur content of less than 0.005% by mass, thus resulting in maximum emissions of approximately 1.25 kg from its use, which is considered negligible.

5.4.2.3 Particulate Matter

Natural gas burns very cleanly in gas turbines and produces negligible amounts of particulate matter. Similarly the gas oil used in the auxiliary boiler and small engines is highly refined and does not result in particulate emissions of any significant quantity.

Centrica SHB considers that the current techniques used in relation to the control of air emissions represent BAT for the activity.

5.4.3 Emission Limits to be Set in Permit

The site's IPC authorisation was updated in November 2004 to take account of requirements identified under the Large Combustion Plant Directive. Accordingly it is anticipated that the authorisation conditions identified in the IPC authorisation will be largely transferred unmodified into any new PPC permit. Centrica requests, however, that the current limit of 80 mg/Nm^3 for oxides of nitrogen excluding start-up and shut down periods is expressed as a daily average in line with PPC sector guidance. It is requested the same limits and definitions for start up and shut down conditions currently applied are also transposed into any future PPC permit.

5.5 Management Systems

The Station currently employs an Environmental Management System (part of a Business Management System) that is accredited to the ISO 14001 international standard for environmental management and registered with the European Eco-Management and Audit Scheme (EMAS). This is considered to constitute BAT for environmental management systems for the installation.

The system has been described in Section 2.3 and incorporates a wide range of documents and procedures, which are designed to achieve a high level of environmental protection and environmental performance.

5.6 Waste

The Station does not generate significant quantities of solid wastes/aqueous wastes requiring disposal off-site. Wherever possible the quantities of wastes generated on-site for disposal are minimised by a range of mechanisms including the control of impurities in raw materials brought onto the site (for example mercury and cadmium for WTP chemicals), recycling and reuse.

All wastes are segregated into appropriate waste streams for recycle, reuse, disposal as appropriate. However waste disposal when required is carried out by suitably licensed waste transfer and disposal contractors following the necessary regulatory requirements in accordance with "Duty of Care" requirements.

Opportunities for waste reduction and improved waste handling are subject to on-going review as part of the environmental management system.

The current methods employed on-site for the handling and disposal of wastes are thus considered to be BAT for the installation.

5.7 Water

5.7.1 Controlled Waters

Additional measures exist to prevent any spillage or leak of potentially hazardous material from occurring including the provision of primary and secondary containment measures. In the unlikely event of an uncontained spill, spill response procedures, equipment and supportive training are in place to ensure prompt and appropriate remedial action. The possibility of a significant spillage of material leaving the site is therefore minimised as far as is possible.

Overall, the current measures in place to prevent contamination of controlled waters can be considered to be BAT for the installation.

5.7.2 Off-site Disposal

Significant quantities of gas turbine blade washing effluent from off-line washing are not generated on-site. At present the effluent is collected by a licensed waste management company. Overall it is considered that the current systems in place for disposal are appropriate and can be considered to be BAT for the installation.

5.8 Odour

The Station does not have a history of odour complaints. Odorant is stored by National Grid in the adjoining AGI but this is a closed system (with no direct emissions to air) constructed to standards common to all odorisation plants operated in the UK gas network. Odorised gas is combusted by the power station, converting the odorous components (sulphide based) into sulphur dioxide which is not detectable at the concentrations that result. Gas detectors at the power station are present should a gas leak occur as an essential safety precaution.

Overall it is considered that the current measures in place to control odour can be considered to be BAT for the installation.

5.9 Noise

Noise emissions from the operation of the power station have limited potential to cause significant disturbance at identified sensitive receptors.

Equipment is enclosed in acoustic enclosures where necessary and routine inspection of equipment is undertaken to identify noisy equipment. Some noise is inevitable as a result of starting up and shutting down but this is minimised wherever possible by adopting standard operating procedures.

Noise has been successfully managed at SHBPS by employing the following considerations:

- Minimisation of noise production in design;
- Control of noisy activities (by employing enclosures and silencers);
- Minimal requirement for heavy transport (the fuel source is piped to the site) due to fuel and technology type;
- Controlling high pressure flows such as steam and natural gas;
- Appropriate zoning- the site is a significant distance from residential areas;

- Ongoing monitoring and review of noise performance; and
- Additional silencers installed on vents.

5.10 Raw Materials

Only relatively small quantities of chemicals for cleaning, lubrication, cooling and water-treatment purposes are stored on-site in either bulk storage tanks, IBCs or drums. The location and storage arrangements for all chemicals are designed to give protection in the event of spillages occurring. Bulk storage tanks are designed to appropriate standards, routinely inspected and bunded where necessary. Drums and IBCs are located on drip catchment trays wherever possible. Raw materials are often stored inside buildings.

Transfer areas for raw materials are designated and interceptors are available to protect against oil spillages being released to surface water run-off systems. Distribution pipework systems for chemicals are often above ground.

Overall it is considered that the existing arrangements for the storage of raw materials on-site can be considered to be BAT for the installation.

6 IMPROVEMENT PROGRAMME

The design of the installation incorporates numerous environmental protection, waste minimisation, energy efficiency and accident prevention measures along with the selection of plant that will minimise releases to air, water and the generation of noise.

The following improvements have been carried out in the past three years:

- Requalified for ISO14001 and retained EMAS registration.
- Established Monthly Environmental Forum
- Completed MCERTS training for Control & Instrumentation Technicians
- Continued Lamprey study at Cooling Water Pumphouse
- Carried out feasibility studies to reduce site water usage
- Reviewed the environmental impact of the storage and transportation of chemicals.
- Replaced site fuel oil bowser and revised on-site storage arrangements
- Installed bulk phosphate storage tanks

A number of additional improvements to the site have been identified below in order to incorporate a process of continuous improvement and ensure best available techniques are applied in accordance with the PPC permitting process:

Table 6.1: Proposed Improvement Programme

Improvement Condition Reference	Proposed Improvements	Proposed Date (from permit being granted)
SHBPS 1	Conduct review of MCERTS requirements including potential installation of flow and temperature monitors on stacks	January 2007
SHBPS 2	Review of BMS to ensure consistency with Centrica systems corporate wide	January 2007
SHBPS 3	Study to improve spill controls and update to procedures	Within six months
SHBPS 4	Develop site protection and monitoring plan including identification of inspection and integrity testing regime for containment systems and associated drains	Within two months
SHBPS 5	Reference data obtained to augment site protection and monitoring programme	Within six months
SHBPS 6	Development of Site Closure Plan	Within two years
SHBPS 7	Undertake energy, waste and water-use audit	Within two years

7 LIST OF ABBREVIATIONS

AQMA	Air Quality Management Area
ASR	Application Site Report
BAT	Best Available Techniques
BETTA	British Electricity Transmission and Trading Arrangements
BMS	Business Management System
CCGT	Combined Cycle Gas Turbine
CCR	Central Control Room
CCTV	Closed Circuit Television
CCW	Closed Cooling Water
CDM	Construction (Design and Management) [Regulations]
CEMS	Continuous Emissions Monitoring System
CEN	European Committee for Standardisation
CH_4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CMMS	Computerised Maintenance Management System
COSHH	Control of Substances Hazardous to Health
DCS	Distributed Control System
DLN	Dry Low NOx
DSEAR	Dangerous Substances and Explosive Atmospheres Regulations
EA	Environment Agency
ELV	Emission Limit Value
EMS	Environmental Management System
EMAS	Eco-Management and Audit Scheme
EP-OPRA	Environmental Protection Operator Pollution Risk Appraisal

EU ETS	European Union Emission Trading Scheme
GT	Gas Turbine
HRSG	Heat Recovery Steam Generator
HSE	Health, Safety and Environment
IBC	Intermediate Bulk Container
IPC	Integrated Pollution Control
IPPC	Integrated Pollution Prevention & Control
ISO	International Standards Organisation
LCPD	Large Combustion Plant Directive
MCERTS	Monitoring Certification Scheme of the Environmental Agency
MCW	Main Cooling Water
N_2O	Nitrous Oxide
NMVOCs	Non-Methane Volatile Organic Compounds
NOx	Oxides of Nitrogen
NTS	National Transmission System
O_2	Oxygen
OPA	Operator Performance Attribute
OPRA	Operator and Pollution Risk Appraisal
PHA	Pollution Hazard Attribute
PI	Pollution Inventory
PM	Particulate Matter
POCP	Photochemical Ozone Creation Potential
PPC	Pollution Prevention & Control
SAC	Special Area of Conservation
SCR	Selective Catalytic Reduction
SF_6	Sulphur Hexafluoride

SHB/SHBPS	South Humber Bank (Power Station)
SNCR	Selective Non Catalytic Reduction
SO_2	Sulphur Dioxide
SSSI	Site of Special Scientific Interest
SPA	Special Protection Area
ST	Steam Turbine
TDS	Total Dissolved Solids
UKAS	United Kingdom Accreditation Service
US EPA	United States Environmental Protection Agency
WTP	Water Treatment Plant