Saltfleetby Wellsites

Environmental Permit Variation EPR/JB3107XB Technical Plan

Angus Energy Weald Basin No3 Limited

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Prepared by	Checked by	Verified by	Approved by
Savhannah Rewcastle Graduate Waste Management Consultant	Caroline Braithwaite Senior Consultant	Angela Graham Associate Director	Angela Graham Technical Director

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	1	Angus Energy / Tim Hussain
	1	Angus Energy / Nick Mace

Prepared for:

Angus Energy Weald Basin No3 Limited

Prepared by:

Savhannah Rewcastle
Graduate Waste Management Consultant

AECOM Limited
12 Regan Way
Chetwynd Business Park
Nottingham NG9 6RZ
United Kingdom

T: +44 (115) 907 7000
aecom.com

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1. Report Context

1.1 Introduction

AECOM have been commissioned by Angus Energy Weald Basin No3 Limited ("the Operator" or Angus Energy) to prepare an application to vary the existing environmental permit (EPR/JB3107XB/T001) for the mining, extraction and transportation of natural gas and gas condensate from proven underground reservoirs at Saltfleetby Wellsites.

The application is being submitted to cover changes at the existing Gasfield which will facilitate the processing of natural gas to ensure it meets the quality requirements necessary to export the gas into the National Grid.

This report details the operational techniques employed at the wellsites. The report should be read in conjunction with other supporting application information.

1.2 Background

1.2.1 Existing Operations

Saltfleetby 'A' and 'B' ("SFA", "SFB") onshore production sites were established in 1999. Both wellsites produce natural gas, water and condensate with two 6" pipelines connecting the SFA and SFB wellsites. A 10" pipeline transported hydrocarbons to the nearby Theddlethorpe Gas Terminal (TGT) for processing. Gas production at the wellsites was suspended by then Operator Wingas Storage UK Ltd in 2017 due to the closure of TGT.

In November 2019, Angus Energy farmed into the licence and became the Operator of the field with the intention to restart production from the field following the installation of a new pipeline connection to National Grid transmission system (NTS). To facilitate the resumption of operations, the intention is to:

- Keep suspended three of the remaining wells (SF 5, 6 and 7) with the potential for side-tracking any one or all of them.
- Evaluate the commercial case for continued production from Saltfleetby 8 either with or without side-tracking.
- Examine the possibility of the utilising any two of the remaining wells for geothermal heat recovery; and
- Return the existing two producing wells to natural gas and associated condensate production.

1.2.2 Proposed New Operations

Since 2017, the processing operations at the nearby Theddlethorpe Gas Terminal (TGT) has ceased. Therefore, to ensure the produced natural gas can be exported into NTS, Angus Energy also intend to:

a) install natural gas and condensate processing facilities at SFB Site. This will indicatively include the modification to the existing first stage separator, a set of compressors, a passive dehydration system to remove water, a solid state Joule-Thomson valve allowing for a drop in pressure and temperature to remove heavy hydrocarbons, a condensate stabilisation tower, a new condensate storage unit, produced water storage, a metering and analysis skid, a fuel gas skid, an enclosed ground flare, and some associated pipework manifolding, comms and electrical ancillaries; and

b) install up to 750m of pipeline from the existing TGT entry point to the new NTS connection point which is beyond the scope of this permit variation and

c) Install power generation equipment to support the above facilities.

2. Operational Context

2.1 The Operator

Angus Energy is an independent onshore oil and gas development company focused on advancing its portfolio of licensed UK assets. Founded in 2009, Angus Energy is an Oil and Gas Authority (OGA) approved operator and a member of United Kingdom Onshore Oil and Gas (UKOOG) - the representative body for the UK onshore oil and gas industry.

In November 2019 Angus Energy became the 51% licence owner and operator of the field, with Saltfleetby Energy (previously WINGAS UK Limited) holding the remaining 49% at the time of writing. Angus Energy, now as operator, intends to continue production from the field following the successful reconnection to the national grid, mostly in place, with completion expected in February 2021.

The company is currently an operator in three licences in the Weald Basin in the south of England:

- Brockham oil field near Dorking in PEDL235;
- Lidsey oil field near Bognor Regis (PEDL241); and
- Balcombe oil field near Crawley (PEDL244).

2.2 Overview of Processes Covered

2.2.1 Existing Operations

The Saltfleetby Gasfield is located onshore in the UK within licence PEDL 005, east of Louth. The location of the Saltfleetby Wellsites is shown on drawing AE-GEN-001 (Application Section 10).

The 'Site' comprises:

- Saltfleetby A (SFA) wellsite which is located off Saddleback Road, close to the junction of Saddleback Road with North End Lane. SFA is quadrilateral in shape, covering an area of approximately 0.8ha and was constructed in 1996.
- Saltfleetby B (SFB) wellsite which is also located off Saddleback Road, approximately 1km northeast of the Saltfleetby A wellsite. SFB is also quadrilateral in shape, covering an area of approximately 2.3ha for both the original wellsite B and the wellsite B extension. The main SFB area was constructed in 1998 with the extension subsequently built in 2001.

Each wellsite has an existing private access point and is screened with earth mounds and mixed planting of trees and shrubs. The wellsites comprise gas wellsite infrastructure and are underlain by concrete hardstanding. SFB also has processing/utilities equipment and portacabins for control and security purposes. The current layout of the wellsites is shown in drawing AE-SFB-EPR-002-SITE-A and AE-SFB-EPR-003-SITE-B.

2.2.2 Well Design

There were originally eight wells associated with the Saltfleetby Gasfield being SF01 and SF04 on SFA and SF02, SF03 and SF05 through SF08 on SFB.

All wells were completed horizontal with intervals between 120 and 612 metres with slotted liners (except for the open hole completion of SF02) and perforations in some wells towards the heel of the completion.

Two wells SF-01 and SF-03 have been permanently plugged and abandoned. Two wells SF-02 and SF-04 will be returned to gas and associated condensate production in 2021, following commissioning of the gas processing and compression plant. Of the four remaining wells, SF-05, SF-06, SF-07 and SF-08 four will remain suspended until final reuse or abandonment decisions are made but one or more of these wells will be side-tracked to accelerate production. The well design for any sidetracked wells will be submitted to the EA in the WR11 notification.

The wells and status are set out in the table 1 below:

Table 2-1: Summary of Well Operations

Number	Name	Status	Notes
L47/16- 2	Saltfleetby 1	Abandoned (3)	Fully Abandoned
L47/16- 2Z	Saltfleetby 1z	Abandoned (3)	Fully Abandoned
L47/16- 2Y	Saltfleetby 1y	Abandoned (3)	Fully Abandoned
L47/16- 2X	Saltfleetby 1x	Abandoned (3)	Fully Abandoned
L47/16- 2V	Saltfleetby 1v	Abandoned (3)	Fully Abandoned
L47/16- 2U	Saltfleetby 1u	Abandoned (3)	Fully Abandoned
L47/16- 2W	Saltfleetby 1W	Abandoned (3)	Fully Abandoned
L47/16- 5	Saltfleetby 2	Completed – Shut-in	On production – Dec 1999 – Shut-in Dec 2017
L47/16- 6	Saltfleetby 3	Abandoned (3)	Fully Abandoned
L47/16- 6Z	Saltfleetby 3z	Abandoned (3)	Fully Abandoned
L47/16- 7	Saltfleetby 4	Completed – Shut -in	On production – Dec 1999 – Shut-in Dec 2017
L47/16- 9	Saltfleetby 5	Abandoned (1)	
L47/16- 10	Saltfleetby 6	Abandoned (2)	Abandoned after appraisal punch through
L47/16- 10Z	Saltfleetby 6z	Abandoned ()	Abandoned attempt at horizontal reservoir
L47/16- 10Y	Saltfleetby 6y	Abandoned (1)	Cemented at Westphalian reservoir
L47/16- 11	Saltfleetby 7	Abandoned (2)	Abandoned attempt at horizontal reservoir
L47/16- 11Z	Saltfleetby 7z	Abandoned (2)	Abandoned high angle appraisal penetration of reservoir section
L47/16- 11Y	Saltfleetby 7y	Abandoned (2)	Failed to produce – low flow
L47/16- 11X	Saltfleetby 7x	Abandoned (2)	Failed to produce
L47/16- 11W	Saltfleetby 7w	Abandoned (1)	Failed to produce – Cemented at Westphalian reservoir
L47/16- 12	Saltfleetby 8	Abandoned (2)	
L47/16- 12X	Saltfleetby 8x	Completed – Shut-in	
L47/16- 12Y	Saltfleetby 8y	Abandoned (2)	
L47/16- 12Z	Saltfleetby 8z	Abandoned (2)	

2.2.3 Proposed Site Changes

To enable production to restart from the gas field, the following will be required:

- Three wells (SF-05, SF-06, SF-07) will remain abandoned (1) cemented at Westphalian reservoir along with well SF-08 open to Westphalian reservoir and shut-in due to very low production rate.

The future utility of the wellbores will be assessed for reuse for production sidetracking or geothermal use.

- Return the remaining two wells (SF-02 and SF-04) to gas and associated condensate production in 2021, following commissioning of gas processing/compression facilities and a tie-in connection to the National Transmission System (NTS).
- Install new processing facilities at the SFB wellsite, being (working from the wellhead) the modification to the existing first stage separator, a set of compressors, a passive dehydration system to remove water, a solid state Joule-Thomson valve allowing for a drop in pressure and temperature to remove heavy hydrocarbons, a condensate stabilisation tower, a new condensate storage unit, produced water storage, a metering and analysis skid, a fuel gas skid, an enclosed ground flare, and some associated pipework manifolding, comms and electrical ancillaries; and
- Install up to 750m of pipeline from the existing Theddlethorpe Gas Terminal (TGT) entry point to the new NTS connection point which is beyond the scope of this permit and
- Install power generation to support the above facilities.

2.3 Plant Capacity

Analysis of individual well pressure data suggests that approximately 18 bcf of gas could be recoverable over a 10-12 year period. Additionally, ~100,000 – 180,000 bbls of condensate would also be recoverable. It should be noted however that previous volumetric calculations have resulted in GIIP values of up to 160 BCF, and as a separate Southern extension of the field has been identified which may yield approximately 6 BCF of additional resources.

Regardless of the eventually recovered resources it is intended to produce the field initially at a plateau rate of 10 MMscfd plus/minus 2 MMscfd and the duration of that plateau production period may vary according to the eventual recovered reserves and resources. The production facilities have therefore been designed based on a rate of 10 MMscfd.

2.4 Process Chemistry

There will be no chemical processing stages at the installation, the facility provides for the simple physical separation drying and compression of the abstracted natural gas to meet the requirements for transmission through the national gas grid.

The process flow for the installation is shown on drawings contained in Appendix A.

2.5 Regulatory Context

The wellsites are regulated under the Environmental Permitting (England and Wales) Regulations 2016 (as amended), namely:

- For the use of the ground flare (temporary or permanent) - Schedule 1, section 5.1, Part A (1)(a)(c): “The Burning of a Hazardous Waste Gas”.
- For the management of extractive waste, primarily associated with site workover and well abandonment – Schedule 20, “Mining Waste Operations”.
- For the management of condensate – Schedule 1, section 1.2, Part A (1)(e)(i): “Loading, Unloading, Handling or Storage of, or the Physical, Chemical or Thermal Treatment of Crude Oil”..
- For the processing of the natural gas – Schedule 1, section 1.2, Part A : “Refining of Gas Where This is Likely to Involve the Use of 1,000 or More Tonnes of Gas in a 12 Month Period”.

The directly associated activities for the wellsites include:

- Dew point control, drying, compression and custody transfer metering of the natural gas; and treatment of the associated condensate to meet sales requirements and
- Power generation using a gas-fed generator set.

3. Preparing the Site for Production

3.1 Introduction

The wellbores already exist at SFA and SFB and to bring wells back online for production and gas flowing, each well will be connected and flow directly to the pipeline via the onsite process plant.

As a contingency, each well may require a short period of operations which will involve work-over of existing wells to reinstate the flow of natural gas or a sidetrack to target a new section of the formation.

It is anticipated that wells SF05 to SF08 are the likely candidates for a sidetrack. The aim of the sidetrack(s) would be to accelerate production from the main northern lobe of the reservoir and potentially access resources in the southern extension.

3.2 Sidetrack Drilling or Work-over

A side-track or work-over will be completed using either a drilling rig or truck-mounted workover rig respectively or similar equipment.

All waste produced will be handled in accordance with the Waste Management Plan (Application Part 5) and temporary surface installation equipment will include the use of an enclosed ground flare to burn off any relatively minor volumes of gas produced as the well is circulated, tested, or brought back into operation.

In the event that a sidetrack or work-over is required, Angus Energy will confirm the estimated quantity of waste, drill fluids and well design in writing to the Environment Agency as part of the WR11 submission.

3.3 Well Treatment of Sidetrack

3.3.1 Nitrogen Lift

This may be used to aid the initial flow of gas and fluids from the wellbore to displace fluids which have been introduced during the drilling operations. A small amount of nitrogen (N_2) will be used to displace any liquids remaining in the tubing thus reducing the hydrostatic pressure to allow the well to flow. This is an inert gas which will be pumped from the surface via an inner coil tubing string in the completion tubing with returns occurring outside the inner coil back to the surface.

As the wellbore fluids, N_2 and natural gas rise to the surface they will be diverted via temporary pipework to the three-phase separator where the mixture will be separated into condensate, formation water and gas (mix of N_2 and natural gas). The condensate and produced water will be transferred to the condensate storage and the produced water storage tanks.

The gas will be managed as follows:

- Immediately following the artificial lift the gas will be primarily N_2 with small volumes of natural gas. This material will be cold vented through the flare to facilitate dispersion.
- As the lift operation progresses, the volume of natural gas will increase and N_2 levels will decrease to the point where the level won't blanket ignition. Once a suitable mix of natural gas to oxygen has been achieved the flare pilot light will ignite the waste gas stream. The flare pilot light will be continuously on and will ensure the gas is ignited as soon as it is physically possible to do so thus minimising the period cold venting will occur.

The use of N_2 is generally considered as closed loop as it is originally extracted from the atmosphere and the amount cold vented returns to the atmosphere.

3.3.2 Acid Wash

If flow from the well is impeded by debris/materials left from drilling then a dilute acid mixture (usually hydrochloric acid at 15% concentration with water) will be pumped from the surface into the well to dissolve any debris/material. The clean-up fluids pumped into the wellbore will be reverse circulated back to the surface where it will be collected in IBC containers prior to removal from the wellsites to an authorised waste facility for treatment and if possible recovery as detailed in the Waste Management Plan (Application Part 5).

4. Gas Management Plan

4.1 Gas Composition

Gas composition has been relatively stable throughout the 20 year life of the field, although as production proceeded and reservoir pressure declined the condensate production as a proportion of total hydrocarbon production has declined. The typical gas composition is summarised in table 4.1 below.

Table 4-1: Gas Composition

Component	Mole %	Component	Mole %
Nitrogen	3.43	Ethyl Benzene	0.02
Oxygen	0.00	M/P - Xylene	0.11
Hydrogen Sulphide	0.0000	O - xylene	0.02
Methane	76.96	C8 Hydrocarbons	0.90
Carbon Dioxide	2.17	C9 Hydrocarbons	0.22
Ethane	8.11	C10 Hydrocarbons	0.18
Propane	3.57	C11 Hydrocarbons	0.13
Iso-butane	0.62	C12 Hydrocarbons	0.09
Butane	1.17	C13 Hydrocarbons	0.07
Neo-pentane	0.01	C14 Hydrocarbons	0.06
Iso-pentane	0.44	C15 Hydrocarbons	0.03
Pentane	0.44	C16 Hydrocarbons	0.02
Hexane	0.53	C17 Hydrocarbons	0.01
Cyclo-hexane	0.34	C18 Hydrocarbons	0.01
Benzene	0.09	C19 Hydrocarbons	0.01
Toluene	0.22	C20 Hydrocarbons	0.02

4.2 Gas Processing (Refining)

We are expecting flow rates of 5 million standard cubic feet per day (MMscfd) initially rising, following a successful sidetrack or sidetracks to a plateau rate of 10 MMscfd which will be maintained as long as practicable and then gently declining until final abandonment of field. Final closure and abandonment of the field will be set by economic conditions at the time.

The natural gas flows readily to surface under natural reservoir pressure and gas flow from the well will be controlled by the well choke at the surface. The choke is adjustable to flow the well at different production flow rates as required and will be used to maintain the plateau rate and the decline process.

Although the gas is essentially ‘dry’, traces of water are present and accordingly a first stage 3-phase separator is installed (see below) in order to remove any free water and condensed hydrocarbons. This water will be collected, along with water from other processing equipment, and routed by pipe to a repurposed water storage tank.

4.2.1 Three Phase Separation

The existing 3-phase test separator on SFB will be re-used as a production separator and will facilitate the separation of the gas, water and condensate. The gas will enter at mid-point of the vertical vessel and liquids drop out of suspension under gravity and separates in the bottom of the vessel. There is a weir fitted to add separation of the gas condensate and water which are separately measured for level and metered before downstream processing. The gas separated is metered. There is a demister pad fitted before the gas exit nozzle at the top of the 3-phase separator, which aids removal of any liquid entrained in the gas flow exiting the vessel.

A new modulating pressure control valve will be added into the gas line exiting the separator to ensure the downstream pressure is maintained. The pressure in the separator is controlled by the choke valves. There is no pressure relief valve on the separator, it is instead equipped with a bursting disc which will burst at 105 barg and this will discharge to atmosphere from the existing vent system.

4.2.2 Gas Compression

Gas from the 3-phase production separator will flow to the new gas compression plant in order to increase the pressure of the gas for processing. Gas compression will consist of a (future) electric motor-driven booster compressor (required when the flowing wellhead pressure has declined) followed by two, gas-fired engine-driven main compressors (see specification in Appendix C) operating as two compressors in parallel. The compressors will be sufficient to raise the pressure of the gas to overcome the pressure drops in the processing plant, and result in a maximum export pressure of up to 78 barg, in order to meet the maximum NTS pipeline pressure of 75 barg. The two main compressors each comprise of two stages in series, and the compressors will be run in parallel to enable production at 5 MMscfd during periods of outage of one machine.

All compressors will be provided with knockout drums, cooling systems, lubrication oil systems and control systems, as appropriate to ensure correct and safe operation.

4.2.3 Passive Dehydration System

The gas from the outlet of the first stage of the main compressors will be at a pressure of approximately 59 barg and will be passed through two pressure vessels (absorbers) in a lead/lag configuration. The absorbers will be packed with a water absorbing material that removes most of the water from the gas. The water will be removed as a brine, via the production separator, and then on to the water storage tank.

The passive dehydration system will include two knockout drums; one before the absorbers, and the other after the absorbers, to remove any small traces of liquids from the gas.

4.2.4 Dew Point Control – Joule-Thomson Valve

Following dehydration, the pressure, and therefore the temperature, of the gas will be dropped by means of a solid-state Joule-Thomson valve. This has the effect of causing heavier hydrocarbon fractions to coalesce into liquid phase as condensate allowing them to be removed from the gas stream and passed to the condensate stabilisation tower (see below). The necessary pressure drop over the Joule-Thomson valve results in a gas pressure of approximately 20 barg and requires a second stage of compression to increase the gas to the required pipeline export pressure.

After the dew point control skid a small side-stream of gas is taken off as feed to the fuel gas system (see below).

4.2.5 Condensate Stabilisation

This will be based around a distillation tower with contraflow of heated condensate against gas to strip more volatile gaseous components out of the condensate to meet a vapour pressure allowable for condensate transportation. The effect is to draw off lower hydrocarbon fractions (ethane, propane, butane in the main) as a so-called “off-gas” stream, leaving the liquid condensate in a stable form. The stabilised condensate will be removed from SFB by road tanker for further processing by others. The condensate stabiliser off-gas will be used as fuel gas (see below).

In addition to the distillation tower the condensate stabilisation will require a feed drum/separator, a reboiler, and a condensate cooler.

4.2.6 Metering and Gas Analysis

A full suite of fiscal metering and gas analysis is being provided by Honeywell to satisfy the custody transfer and export gas quality requirements imposed by National Transmission Service.

4.2.7 Fuel Gas and Off-Gas Usage

Heavier off-gas from the condensate stabilisation process will pass to a fuel gas unit which will mix this gas with export quality gas to be supplied to the compressors and a different specification for the gas driven power generation. Some remaining off-gas will also be used to fuel the pilot light on the emergency flare. It is possible that supplementary process heating will be required. Should this be necessary a gas-fired boiler will be provided to supply the additional process heat.

4.3 Flare

4.3.1 Flare Design

The flare will be skid-mounted for ease of transport and installation. It is designed as an enclosed burner 3.3m in diameter and 10m tall. The flare specification as per that shown in Appendix D ensures combustion temperatures in excess of 800˚C and retention times in excess of 0.3 seconds can be achieved consistently across their operational range for planned activities.

4.3.2 Purpose of Flare

The flare qualifies as a safety device utilised for emergencies and planned or unplanned events. In accordance with Environment Agency guidance Angus Energy will notify the Environment Agency in advance of using the flare for planned events or notify after an unplanned event. The volume of gas burnt will be calculated.

A pilot light will be lit constantly to ensure that in the unlikely event of an emergency or process upset the gas being diverted to the flare can be immediately combusted.

There are “other scenarios” where the flare may be used such as a short term well test. The duration of the well test after drilling a side-track will be up to 3 days flaring.

4.3.3 Flare Operation

4.3.3.1 Flare Installation, Commissioning and Testing

Upon delivery, the flare manufacturer will be responsible for the safe and correct installation, commissioning and testing of the flare. The initial installation will comprise the placement and final assembly of the flare, followed by the connection of the inlet manifold, and ultimately the connection to the gas inlet line from the production area.

Following assembly and connection, the flare will undergo a staged series of commissioning tests to ensure it is configured and operating correctly for each stage of activity. These tests will cover the flare’s mechanical, electrical, pneumatic, telemetry and data recording systems to ensure each individual system is operating correctly. These tests will be undertaken prior to the commencement of production which will only commence if all tests and other requirements have been successfully completed. The records of each stage of commissioning tests will be retained and be available for inspection as part of the management system.

Following the delivery and installation of the flare, the flare manufacturer along with the Angus Energy Operational team will undertake initial training.

This training will cover;

- operational philosophy of the flaring system;
- hazards associated with the flare
- the start-up and shut down procedures; and
- routine and non-routine operational procedures plus the required data recording parameters.

Angus Energy HSE Advisor or a competent delegate will also brief the operational team regarding:

- relevant permit conditions; and
- monitoring of the flare system in accordance with the permit conditions;
- required document and record management to demonstrate ongoing permit compliance.

Further training (either refresher or initial) will be undertaken where there is a change in personnel, change to permit conditions, as a result of an inspection or audit whereby training or briefings are required, changes to the equipment or changes to onsite operational procedures.

The ongoing management of onsite staff competence in the operation of the flare will be undertaken as part of Angus Energy's management system. Angus Energy utilise competency assessment based on individuals' Skills, Knowledge, Attitude and Experience (SKATE). The records of all staff training will be retained, and be available for inspection if required.

4.3.3.2 Operational Control

The flare has been designed for simplicity and ease of operation. As such, the human involvement in the flare start up, shutdown and operational use is minimal.

The flare will only be started up initially once the competent person is satisfied that the conditions required to safely commence flow to flare has been achieved. Once these conditions have been achieved a designated member of onsite staff checks the control screen or equivalent notification protocol to ensure no alarm conditions are indicated. Once satisfied that the flare is ready for operation, the operator simply presses the 'Start' button on the flare's control panel.

When the flare is operating as a safety device it will be in a constant state of readiness. If the flare suffers a malfunction or breakdown (e.g., pilot light not operating) then operations will be paused until the flare is in a state of readiness. The evacuation of gas from the process facility will be sectioned/zoned to avoid a large contingency of natural gas being sent to the flare.

When the flare is utilised for a short term well test it will operate as and when required to manage the initial returning gas to surface. An adjustable choke at the downstream end of the separator will be used until stable gas flow rates have been achieved.

The flare will be provided with a knockout drum to intercept any condensate coming out of the vapour phase in the gas due to sudden pressure and temperature variation during emergency flaring operations. This vessel will be sized for a worst case condensate drop out.

There is no planned or expected cold venting at the wellsites.

4.3.3.3 Planned Operations

For the initial flow of wells and short term well testing, once the natural gas is introduced to the main inlet, the natural gas will ignite. The flare's automatic control system will then adjust burner capacity and available air flow into the stack to match the available gas stream until the combustion temperature target set point is achieved (typically 800˚C - 1,000˚C). This automatic adjustment typically takes several minutes to complete once stable gas conditions are achieved. It is expected that a period of 5 minutes is required for stable natural gas rates to achieve target combustion during a short term well test.

4.3.3.4 High temperature alarm

The flare has been designed to ensure consistently high temperature combustion to minimise environmental emissions. The routine combustion temperature for natural gas is typically 1,000˚C, which is in excess of the BAT requirement to achieve a combustion temperature greater than 800˚C. However, this only applies to "other scenario" operations rather than when the flare operates as a safety device. The flare will be manufactured with ceramic thermal insulation within the stack, which aids the achievement and maintenance of high temperature combustion. The thermal insulation used will be rated to a maximum of 1,265˚C. Prolonged combustion at such high temperatures can cause damage to the thermal insulation and will therefore be avoided.

The flare features a 'high temperature alarm' state within its control system. The set point for this alarm is 1,185˚C. This alarm state will be controlled by the primary thermocouple within the flare stack. In the event of a combustion temperature in excess of the target set point (typically 1,000˚C), the flare will seek to automatically adjust the available air flow to maintain the combustion temperature target set point. If the flare is unable to achieve this for any reason, and a combustion temperature of 1,185˚C is maintained for more than two minutes, an alarm state will be activated.

The activation of this alarm state will initiate a control system delay (set at 200 seconds). This period is to allow investigation of the cause of the alarm, and to carry out immediate rectification actions where possible. In the event that combustion temperature cannot be returned to optimal levels, a further alarm will be triggered. This second stage alarm state will activate the site's emergency shut down system

(ESD), which will commence an automatic flare shut down and automatically shut in the well(s). Further details of the automatic flare shut down procedure are explained below.

4.3.3.5 High pressure alarm

The flare has been designed to include gas pressure sensors at key points within the unit. Examples of such key points include the valves controlling gas access to each of the pilot lines, the support gas injection line, and on each of the three main stage burner inlet lines.

Each pressure sensor has a pressure trigger level associated with it appropriate to its particular function. An overall pressure limit is set to control the maximum pressure, and therefore flow, within the flare.

This alarm state will be controlled by the primary pressure sensor within the main burner inlet line. In the event of the gas flow pressures in excess of the target set point, an alarm state will be activated. The activation of this alarm state will initiate a control system delay (set at 90 seconds). This period is to allow investigation of the cause of the alarm, and to carry out immediate rectification actions where possible. In the event that gas flow pressures cannot be returned to nominal levels, a further alarm will be triggered. This second stage alarm state will activate the site's emergency shut down system (ESD), which will commence an automatic flare shut down and automatically shut in the well(s). Further details of the automatic flare shut down procedure are explained below.

4.3.3.6 Pilot flame failure

The flare has been designed to include multiple propane-fuelled pilot lines to ensure reliable combustion upon flare start-up. Each pilot line (there are two) features an ultraviolet flame detection sensor. The purpose of these sensors is to ensure a steady and reliable ignition flame is available prior to introducing gas into the main burner inlet of the flare.

If a stable pilot flame has not been achieved within three minutes of flare start-up, an alarm condition will be triggered. It is important to note that no natural gas from the well will have been introduced to the main burner stages in this circumstance. This alarm condition will initiate an immediate automatic flare shutdown. The location of the alarm triggered will be indicated on the flare control panel's. Investigation and rectification of the cause of the pilot flame failure and a flare reset will be required before it is possible to attempt to restart the flare.

This alarm state is controlled by the UV flame sensor on each pilot line.

4.3.3.7 Flare automatic shutdown

In the event of one (or more) of the above alarm states occurring, an automatic flare shutdown will occur. An automatic flare shutdown will also take place in the event that the 'Emergency stop' button is pressed.

Once an automatic flare shutdown is initiated, the site's ESD system will be triggered which will shut in the well(s). The inlet lines for the flare's subsidiary burner stages will immediately return to their fail-safe position of 'closed'. Over a very short period, the gas lines from the phase separator will naturally purge themselves of natural gas. Any gas remaining in the lines at the time of the automatic shutdown will still be fully combusted within the flare via the main burner first stage inlet line which operates in a fail-safe 'open' mode. This feature ensures any remaining gas is effectively combusted rather than vented. The remaining gas is purged through the system until the residual gas pressure has reduced to zero. During this process, similarly to during a planned shutdown, combustion temperature is likely to fall progressively until all remaining gas is exhausted, however this is in keeping with the permit condition as the shutdown is being conducted for safety purposes. This process will typically take place over approximately five minutes.

4.3.3.8 Recording and reporting

A record will be kept of flare usage which will include:

- Date of flaring
- Type of flaring (well test, emergency, planned or unplanned)
- Duration in minutes

- Volume of gas sent to flare
- Calculation of gas burnt and associated emissions

This record of flare usage will be kept as the site flare register and will be available for inspection by the Environment Agency.

4.3.3.9 Flare Maintenance

The flare will be maintained in line with manufacturers guidance and recommendations. Records of flare maintenance will be kept at site for inspection by the Environment Agency.

4.4 Power Generation

The new gas-fed generating package (up to 1.5 MW) will be located on mown species-poor improved grassland to the south of the screening bund in the SFB's south eastern corner. These units will be raised on small concrete pillars and screened by 3m high acoustic fencing and tree and hedgerow planting.

The generator package will comprise a range of commercially available, self-contained packages that are either skid mounted or containerised. Each new generator package will essentially include:

- gas-fed generator;
- Low level air cooler; and
- Generator control room.

During normal operations, all power required to operate the processing plant will be generated from the gas fired generation set which will be powered by well-produced natural gas.

5. Management of Fluids

5.1 Condensate Management

5.1.1 Storage Tank

The condensate will be stored in a tank with a 25 m^3 capacity. The tank will be of steel construction so as to be impermeable to the condensate and resistant to corrosion. The tank will be equipped with:

- Level detection including an overfill protection system;
- Welded or flanged connections;
- Protected against over or under pressurization; and
- Fitted with a system that can detect water building up and facilitate the draining of the water without a significant release of the condensate.

The tank will be hydro tested, or integrity tested, using clean water before initial operation to identify any leaks. The tank will be routinely inspected for thickness to ensure integrity and will be located within a bund capable of containing 110% capacity of the tank.

5.1.2 Containment Bund Capacity

The condensate tank will be sited inside a new local concrete containment bund. The design of the bund will be in accordance with CIRIA C736 Guidance and will be installed to last beyond 10 years. The bund will:

- Be constructed from concrete which will be impermeable to the condensate and is fire resistant;
- Have joint seals which are resistant to the condensate and water and will maintain a seal during thermal expansion or contraction of the bund;
- Be designed to withstand the hydrostatic head of liquid when full and equipped with a high-level alarm;
- Be constructed in a manner that ensures that the walls and floor are not penetrated by pipework, cable and instruments; and
- Be equipped with a sump to allow removal of the accumulated liquid.

In designing the bund capacity, the following parameters have been accounted for:

- The condensate maximum tank capacity is 25m^3.
- Freeboard: 100mm (unplanned events)
- Rainfall: n/a due to roof
- Height: 450mm (subtract freeboard and rainfall = 350mm)
- Length: 10,000mm
- Width: 6,000mm

Subtracting a freeboard of 100mm and 25mm for rainfall, a height of 475mm will be used in the bund capacity calculations.

To further mitigate the impact from rainfall a roof will be installed above the tank to prevent rainwater from filling the bund.

Potentially contaminated rainwater removed from the bund will be transferred through the 3-phase separator to recover any hydrocarbon and the water transferred to the produced water tank.

5.1.3 Managing Vent Arrangements

The condensate tank will be fitted with dry break coupling connection and arrangements for back venting during loading of road tankers back to the bulk storage tank for containment.

5.1.4 Ancillary Equipment and Pipework

Ancillary equipment such as pumps, filters and oil bath heaters will be located within the containment bund and will be protected against over pressurisation.

Joints in the pipework associated with the condensate storage and handling system will be sited within the containment bund where practicable.

5.2 Fluids Within Well Head & Cellar

Each well cellar will be watertight and tested before the start of operations to check for integrity. The methodology for checking cellar integrity will follow this process:

The cellar needs to be cleared of all non-fixed structures

1. The cellar is filled and left for 24 hours depth changes monitored every hour and the results noted. An evaporation container is also filled and the level marked. This is monitored for a reduction in level due to evaporation

2. The permissible drop in water level allowing for evaporation should not exceed 1/500th of the average water depth of the full cellar.

3. If the cellar is not found to be watertight then it should be drained and remedial treatment of the concrete, cracks or joints should, where practicable, be carried out from the liquid face.

4. When a remedial lining is applied to inhibit leakage at a crack it should have adequate flexibility and have no reaction with the liquid stored

5. The test should be repeated until the bund is found to be watertight.

In the event that water accumulates within the well cellar during operations, this will be pumped to the produced water tank and removed to an authorised waste treatment facility for treatment and disposal.

5.3 Produced Water Management

The overall quantity of waste produced water per day will be approximately 2-3m^3 per wellsite but may vary depending on geological conditions encountered during the lifetime of the production. Once the waste produced water reaches the surface it is not expected to undergo any significant changes due to surface conditions.

The produced water will be stored in steel tanks which are resistant to corrosion. Each tank will be hydro tested, or integrity tested, using clean water before initial operation to identify any leaks. Each tank will be routinely inspected for thickness to ensure integrity and will be located within a bund capable of containing 110% capacity of the vol of a single tank of 25% of the total volume whichever is the larger.

To prevent over filling or emergency conditions at the produced water storage tanks, shut off valves and chokes will control the amount of produced water flowing into the tanks. Furthermore, each tank will be fitted with an alarm system which monitors the levels and sight gauges. The shut off valves will be initiated at a pre-determined level to prevent off filling and spillage of the produced water.

The tank and operations will be visually inspected and monitored by site operatives. When the storage tanks require emptying this will be a manned operation. Hoses and hose fittings will be inspected to avoid detachment of hose assemblies during unloading due to mechanical failure. Standard hose clamp fittings will be used for hose fittings to ensure secure liquid-sealed connection.

It is not expected or anticipated that venting of natural gas from the produced water will occur as dissolved methane will be separated from the produced water.

6. Site Control System

6.1 Control System Philosophy

The control systems for the wellsites will be developed on the principle of minimising the impact of the facility on sensitive receptors and control arrangements are in place for control of:

- Combustion operations and associated emissions;
- Materials storage and handling and potential associated fugitive releases;
- General facility condition including housekeeping and surface water; and
- Emergency conditions

6.2 Design

All pressure containment pipework and vessels that can expect to see wellhead pressure or gas export pressures will be rated to 600 pound flange rating (1440 psi) which exceeds the maximum pressures that could be experienced due to the wells.

6.2.1 Pipework

Pipework will be designed and constructed to national industry standards (typically API 5L Grade B Schedule 80 seamless carbon steel) installed to IP Pipeline Safety Code, Part 6. Pipework is carefully chosen to provide maximum protection from all forms of damage or impact and all intersections are fitted with shut-off valves which can be used to isolate parts of the system in the event of a leak or fire. All pipelines will be inspected in accordance with a 24 monthly statutory inspection regime.

6.2.2 Pressure Vessels

Pressure vessels on the wellsites will be designed to recognised industrial standards, typically ASME VIII div.1 with 100% x-ray of welds or BSI equivalent. All pressure vessels will be inspected in accordance with statutory inspection requirements. Notified body to confirm conformity with Pressure Systems regulations.

6.3 Control System

6.4 Protection During Abnormal Operations

6.4.1 General Protection Measures

During abnormal operational conditions (e.g. plant start-up, shut-down, maintenance, workovers etc) the plant is closely supervised, with tasks undertaken in accordance with written procedures and records kept of the work undertaken. Additional monitoring checks may be undertaken to ensure effective running of the plant and equipment as per Company operating procedures.

6.4.2 Environmental Protection Plan

The Company will prepare and maintain an Emergency Plan for the wellsites which will summarise, inter alia:

- the containment measures on each wellsite in the event of a major fire;
- listing times to reach perimeter ditch capacities; and
- any tertiary containment measures or emergency measures required to contain firewater runoff.

6.4.3 Venting and Emergency Relief Provision

The wellsites will be protected by a number of vents and emergency relief valves and the Angus Energy maintenance department will maintain a register to ensure they are regularly inspected and serviced in accordance with a planned maintenance programme.

These relief systems will be compartmentalised and controlled to ensure that pressure relief is controlled within the capability of the system and the emergency flare

In addition to the specific pressure relief provisions, other fugitive VOC emissions from the general operation of production plant is minimised by regular inspection and servicing as part of the daily inspection regime and planned maintenance schedule. In addition, procedures are in place to manage any incidents or emergencies that may occur on site.

6.4.4 Emergency Shutdown System

The wellsites have emergency protection via a variety of hydraulically and pneumatically operated emergency shutdown (ESD) valves with a pneumatic shutdown panel and various high pressure pilots and ESD buttons. This enables the plant to be shut down quickly and safely in the event of an emergency.

6.4.5 Actions During Abnormal Events

Although the instrument control system is designed to ensure safe operation of the installation, including instigating emergency action to safely shutdown the plant, there are potential situations that may arise when further action must be taken to prevent spillage or unplanned emissions:

a) Mechanical failure,

   In the event of major mechanical failure of plant, equipment or pipelines the emergency shutdown system (ESD) will safely shut down the plant. If any gas leakage occurs as a result of the failure or shutdown, action will be taken in accordance with operating procedures

b) Serious leakage or fire

   In the event of a fire at the installation, site personnel follow the procedures identified within the site emergency plan which include initial containment of firewater and subsequent removal from the wellsites by tanker.

c) Well head maintenance

   On occasion it will be necessary to service or maintain the well head equipment. These activities will be undertaken in accordance with written company procedures and by competent, trained, operatives to ensure that the potential for gas release from the well is minimised.

7. Site Utilities

7.1 Site Offices and Welfare

The original north easterly part of the SFB wellsite comprises an open parking area surfaced with asphalt. West of the car park is a fenced compound containing an open engineered platform with a number of offices and welfare.

7.2 Energy

The wellsites currently draw power from the National Grid with a small diesel fuelled generator as a back-up which is only used in the event of a power cut from the grid.

Following the wellsites being brought back into production operations, power requirements for the new processing plant will be met by onsite generation via a new gas-powered engine (up to 1.4MW).

7.3 Water

There are three water abstractions boreholes, one for each of the 3 sites comprising the Saltfleetby gasfield facilities. Cumulative maximum abstraction is estimated at 150 cubic meters per year, based on historic usage.

7.4 Surface and Foul Water Drainage

Surface water will be managed as follows:

- Both the SFA and SFB wellsites included the diversion of existing field drains as part of the initial phase of construction. SFB Extension wellsite did not include the diversion of field drains but instead incorporated these into the design of the wellsite.

- The Saltfleetby wellsites were constructed such that it provides containment for operations that take place therein. Each wellsite was constructed using a HDPE impermeable membrane which lines the active areas of the wellsites including the perimeter ditches. The purpose of the impermeable membrane is to capture any surface run-off liquids, such as rainwater, but also capture any spillages incurred onsite and contain them within the site perimeter ditches, ensuring environmental harm is averted and any spillages can be rectified onsite.

- Connected to the perimeter ditch at each wellsite is a Class-1 SPEL oil interceptor which is kept isolated during normal operations. The purpose of the interceptor is to enable the discharge of clean surface run-off water (after testing) from the wellsites during hydrocarbon production. The existing containment ditches are regularly assessed to ensure they retain integrity, if it is evident that the performance of the HDPE impermeable membrane has been compromised, remedial work will be undertaken to reinstate integrity prior to discharge operations commencing onsite. An isolation valve is located upstream from the interceptor.

- Surface water from western side of the overall SFB site flows overland to the west and is captured by an open drain adjacent to the land bund. Any surface water not collected by the drain is discharged to filter drain with perforated pipe circling the perimeter of the site to the north, east and south which conveys runoff to the northeast corner, where a penstock valve limits the discharge to the equivalent greenfield runoff rate prior to discharge via a Class 1 oil interceptor to the LMDB land drain.

- Runoff within the eastern part of the overall SFB site flows overland to a filter drain containing perforated pipe circling the perimeter of the part of the site. The pipe flows to the northwest corner where a penstock valve limits discharge from the filter drain to the equivalent greenfield runoff rate. Flows are then discharged to the central LMDB land drain via a Class 1 oil interceptor.

- Interceptors at both SFA and SFB are kept isolated during normal operations and surface runoff will collect in the perimeter drain. The interceptors are only opened to allow discharge of surface water from the drain once the collected water has been sampled and tested to confirm it is free from contamination.

7.4.1 Foul Water

There are no discharges to sewer from the site operations. Sewage from welfare facilities will be collected separately in septic tank which will be routinely emptied by a waste contractor who will collect any sewage by vacuum tanker and transport it to an EA approved offsite treatment plant.

7.5 Firewater System

Although Angus Energy maintains a fire water tank (capacity 50,000 litres), any fire at the installation will be managed by the local fire brigade using their specialist fire-fighting materials and equipment. Major fires and subsequent firewater accumulations will be managed in accordance with the Angus Emergency Plan

The wellsites are underlain by an impermeable membrane and surface water flows are directed to the membrane lined perimeter drain.

Dependant on the location of the fire, firewater will be collected within containment bunds or in well cellars which provide sufficient containment to hold the first flush (i.e. potentially the most contaminated) of firewater to allow for removal by road tanker for subsequent disposal.

If significant quantities of firewater are used then the water would run to the perimeter containment ditch that surrounds the installation. The site interceptors are kept isolated at all times thus preventing accumulated firewater in the drain leaving the site.

The firewater will be sampled and analysed for contaminants and arrangements made to remove the accumulated water by road tanker to an appropriately licensed facility for treatment and disposal.

7.6 Site Security

SFA is accessed via tall gates and an industrial security fence is erected around the perimeter of the wellsite and an earth bund which is approximately 2m in height surrounds the majority of the wellsite. Trees and shrub vegetation has been established on the bund.

SFB is quadrilateral in shape, covering an area of approximately 2.3ha for both the original SFB wellsite and the SFB extension. An earth bund surrounds the north, west and south sides of the site. Access to the wellsite is gained from Saddleback Road, along a Tarmac access track leading to a bridge over the eastern boundary drain. The entrance is secured by an entry control barrier. The surrounding area is primarily arable farmland.

SFB is permanently manned with a security officer with security cameras routed to a control panel from both sites.

8. Monitoring

8.1 Baseline Monitoring

8.1.1 Current Baseline

A site investigation was completed during February to April 2011 by Atkins. This investigation included a desk top review of prior ground investigations and also included sampling from SFA, SFB, the access road between the wellsites and the route of the gas pipeline to Theddlethorpe.

The conclusion of this investigation is presented in section 3.3.6 of the Site Condition and Baseline Report (Application Part 7) with the summary and sampling results presented in Appendix C of the Site Condition and Baseline Report.

8.1.2 Monitoring During Operational Life

The monitoring and recording of relevant information throughout the operational life of the facility is defined within the Integrated Management System (see section 7 of the Management Plan, Application Part 3). This includes ensuring relevant records are retained with respect to activities or events that could impact the condition of land and groundwater, including:

- Drilling activities including workover or sidetrack activities;
- Well stimulation including acid washing;
- surface spillage,
- well shaft leaks,
- seismic events,
- containment failure,
- site remediation undertaken,
- borehole monitoring being carried out,
- well suspension periods, well capping & abandonment and
- fugitive/other emissions.

8.2 Waste Monitoring

Waste will be managed in accordance with the site Waste Management Plan (Application Part 5) and the Angus Energy Waste Consignment Procedure and will include appropriate sampling and maintenance of records including:

- Details of the processes producing the specific waste streams;
- Sampling and analysis of produced waters, flow back fluids, drill cutting and other waste materials where analysis is required to confirm the composition of the waste. In respect of any flow back fluids, each consignment will be sampled prior to disposal and a reference sample retained by the site;
- Details of the quantity of the individual waste streams including details of any waste gas/vapours which are combusted;
- Details of the properties of each waste type including the specific handling requirements;
- Ensuring the wastes are correctly classified and allocated the appropriate EWC code
- Selection of the appropriately licensed waste carrier and waste treatment facility. This will include periodic checks through compliance audits; and

- Completion of the relevant waste transfer note or hazardous waste consignment note and retention of the producer's copy on site.

8.3 Radioactive Substances Monitoring

The management of wastes containing naturally occurring radioactive materials (Norm) at the wellsites are managed in accordance with the site's RSR permit (NB3494DA) and the site is supported by an independent Radiological Protection Adviser (RPA).

8.4 Air Emissions

8.4.1 Point Sources

Point source emissions to air on site are summarised in the table below:

Table 8-1: Point Source Release To Air

Point Reference	Plant Source	Emission Limit	Monitoring	Frequency
A1 Flare	Oxides of nitrogen	-	As approved in writing by the EA under PO1	Monthly
	Carbon monoxide	-		
	Carbon Dioxide	-		
	Total VOC	-		
	Benzene	-		
	Toluene	-		
	Ethyl benzene	-		
	M-xylene	-		
	P-xylene	-		
	O-xylene	-		
	Hydrogen Sulphide	-		
	Hydrocarbons C1 – C15	-		
A2 Compressor Gen No 1	Oxides of nitrogen	95 mg/Nm^3	In accordance with EA TGN M5. All limits are at a temperature of 273.15 K, a pressure of 101.3 kPa and after correction for the water vapour content of the waste gases at a standardised O_2 content of 15%.	Every 3 years
A3 Compressor Gen No 2	Oxides of nitrogen	95 mg/Nm^3		Every 3 years
A4 Power Generator	Oxides of nitrogen	95 mg/Nm^3		Every 3 years

Monitoring will be completed:

- When the flare is first brought into use;
- For the generators, monitoring will be first completed within 4 months of the date of permit issue or the date when the MCP is first brought into operation, whichever is later;
- During normal operations and shall exclude periods of start up or shut down.

Records will be retained of all sampling and analysis including records of calibrations, examinations, tests, surveys or evaluations made on the basis of such data.

8.4.2 Fugitive Releases

Angus Energy will implement the Leak Detection and Repair Plan (LDAR) which was submitted to the EA under IC No 1. This basically comprises:

- Steady state monitoring which uses site personnel's visual, olfactory or audible senses to detect leaking components and equipment.

- Snoop Test (Bubble Leak Testing) which will use a liquid to detect the presence of a leak.

Gas monitors will be used to estimate the level of emission associated with any leak detected.

As per the submitted LDAR plan, the formal leak detection inspection schedule operates on a monthly frequency, however, additional monitoring can be implemented in the event that a variation in flow rate or temperature on key plant and pipework indicates there may be a problem.

8.4.3 Vent Releases

The wellsite systems are set to direct gas to the flare for combustion as part of the emergency/safety arrangements for the site. Therefore condensate/produced water tanks will only vent in an emergency (indicated by valve blow out). Such events would be logged including details of the date/time of the event, the duration and the estimated volume of the release which would be notified to the EA in accordance with the site permit requirements.

8.5 Ambient Monitoring

The Operator will undertake ambient monitoring in accordance with schedule S3.3 of the environmental permit which requires:

Table 8-2: Ambient Monitoring

Parameter	Location	Frequency	Method
Oxides of Nitrogen	4 locations shown on the commissioning monitoring site plan in Appendix 3 of the Flare Appraisal and Design Report (WSUKL/SFB/7X/EA/WC/FAD-001 Rev 2	Monthly	Diffusion tubes as per BS EN 13528 (parts 1 – 3 2002/3)
Sulphur Dioxide		Monthly	Diffusion tubes as per BS EN 13528 (parts 1 – 3 2002/3)
Carbon Monoxide		Monthly	Spot sampling
Methane		Monthly	Spot sampling
Non-Methane VOCs		Monthly	ISO 16017 or EN 1466 or EN 13528

8.6 Noise Monitoring

The Operator will complete monitoring in accordance with BS4142: 2014 to demonstrate compliance with the site planning conditions.

8.7 Groundwater

There are no monitoring boreholes on site.

8.8 Surface Water

Surface water discharges and sampling will be undertaken in accordance with the Surface Water Plan submitted to the EA under IC No 4 only when necessary. Sampling will take place at the grid references detailed below.

Table 8-3: Surface Water Monitoring Locations

Wellsite	Discharge Point	Upstream Sampling Point	Downstream Sampling Point
Saltfleetby A	TF 41475 90838	TF 41435 90824	TF 41498 90841
Saltfleetby B	TF 42518 91366	TF42492 91269	TF 42523 91393
Saltfleetby B Extension	TF 42529 91364	TF42492 91269	TF 42523 91393

A list of surface water monitoring parameters to be analysed are detailed below in Table 8.6 below.
Table 8-4: Surface Water Monitoring Parameters

Monitoring Parameters	
pH	Electrical Conductivity
Total Suspended Solids	Biochemical Oxygen Demand
Turbidity	Alkalinity (Total, Bicarbonate)

Monitoring Parameters	
Hardness	Mercury (Total Hg)
Cadmium (Total Cd)	PAH 16MS including:
Sulphate	Naphthalene
Sulphur	Acenaphthylene
Chloride	Acenaphthene
Sodium	Fluorene
Nitrate	Phenanthrene
Calcium	Anthracene
Magnesium	Fluoranthene
Potassium	Pyrene
Aluminium	Benzo[a]anthracene
Iron	Chrysene
Manganese	Benzo[bk]fluoranthene
Zinc	Benzo[b]fluoranthene
Benzene	Benzo[k]fluoranthene
Toluene	Benzo[a]pyrene
Ethel Benzene	Indeno[1,2,3-cd]pyrene
p/m-Xylene	Dibenzo[a,h]anthracene
o-Xylene	Benzo[ghi]perylene
MTBE	Total (USEPA16) PAHs

8.9 Water Abstraction Monitoring

Angus Energy has three abstraction boreholes located on SFA, SFB and SFB extension areas for the provision of water for the site. The volume of water abstracted is recorded.

8.10 Process Monitoring

The wellsites will be operated under an automatic control system which has been designed with typical process safety features and process logic controls. This means that any faults or anomalies will cause the process to automatically trip and shut-down the site using the Emergency Shut Down system (ESD).

In relation to the flare, process monitoring will be completed in accordance with Schedule S3.4 of the environmental permit and will comprise:

Table 8-5: Process Monitoring

Parameter	Limit	Monitoring Frequency	Monitoring Standard
Gas feed rate	5,000 Nm^3/hour at 273K and 101.3 kPa reference conditions	Continuous	As approved in writing with the EA
Combustion temperature	> 800 ^{o}C	Continuous	BS 1041-4: 1992
Video feed with screen time display of flare		Continuous while in operation	As approved in writing with the EA

9. Site Completion

9.1 Well Abandonment

Following the permanent cessation of all operations the wells will be abandoned in line with:

- Borehole Sites and Operations Regulations 1995;
- Petroleum Exploration and Development Licence; and
- OGUK Guidelines for Decommissioning of Wells or whichever best practice is in force at the time.

The well cellar, any impermeable areas and wellsites perimeter drains will be emptied of fluids and any potentially contaminated material removed and disposed of at an appropriately licenced facility. The current best practice approach is to seal any permeable layers within the well, permanently fill rest of the well with cement between 2 cement plugs (lower plug at level to prevent fluids from the reservoir migrating to formations above, adequate isolation of the main section of the well and removing the well head and surface valve arrangements will be removed and the well casing cut off not less than 1.8m below the finished ground level, a metal plate welded on top and a concrete cap placed on top of the plate.

Once abandonment is complete the closed wells will be inspected by an independent well examiner and the HSE prior to the site being reinstated back to its pre-operative state.

9.2 Site Clearance

All plant and above ground hardware such as valves and pipes will undergo general cleaning by a specialist contractor and be removed from the site. Any further potentially hazardous materials will also be disposed of appropriately and all pipes, cables, ducting and similar items will be disconnected and removed.

In appropriate weather conditions all concrete installation will be broken up and removed along with the aggregate surfacing the operational areas. Wherever practical any lifted materials will be re-used elsewhere or recycled. The underlying impermeable membranes will then be removed and disposed of to an appropriately licenced facility.

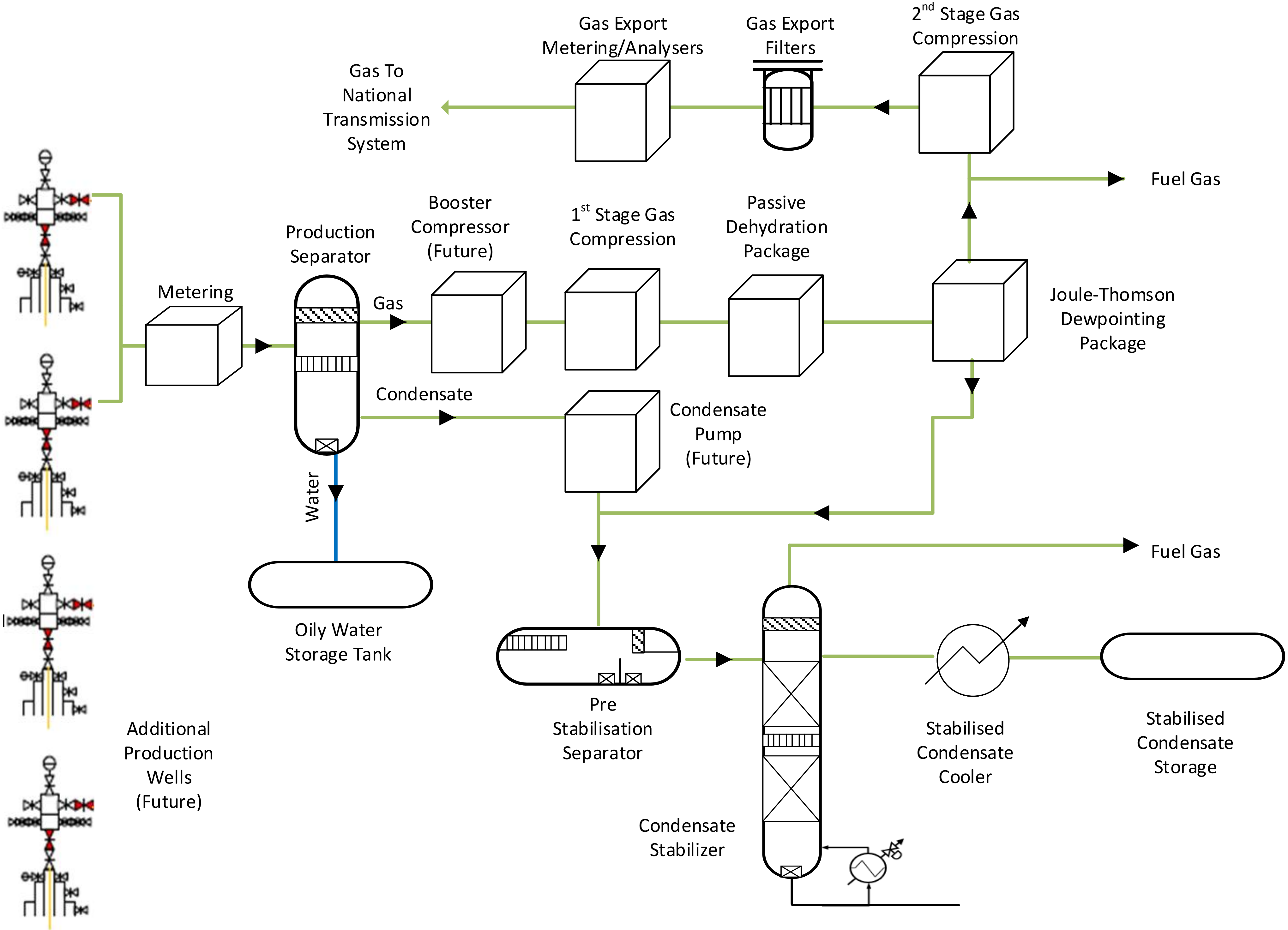
Any cables and pipes remaining below the lining level will be excavated and removed. The voids remaining from the removal of the well cellars and pipework will be in-filled with soils recovered from the site bunds, which shall be laid in layers of not more than 200mm.

Following the removal of all plant from the site, and prior to the laying of soils, an appropriate land quality investigation shall be undertaken to ensure that no contaminants are present and that the underlying ground is in a suitable condition to support the re-establishment of forestry. Any contaminated materials identified shall be dealt with appropriately, either through on-site remediation or by removal from the site and disposal at an appropriately licenced facility.

9.3 Site Restoration

The design life of the plant would be 12-16 years. At this point, all wells would be abandoned and the Saltfleetby A and B wellsites would be restored. A scheme would be agreed with the relevant landowners 12 months before the restoration programme was due to begin although the intention would be to return part of the Sites to coastal grazing marsh in consultation with the Lincolnshire Wildlife Trust, and include improved biodiversity measures to provide net gains for biodiversity.

Appendix A Process Flow Charts



Gas Export Metering/Analysers
Gas Export Filters
2nd Stage Gas Compression
Gas To National Transmission System
Fuel Gas
Booster Compressor (Future)
1st Stage Gas Compression
Passive Dehydration Package
Production Separator
Metering
Gas
Joule-Thomson Dewpointing Package
Condensate
Condensate Pump (Future)
Water
Fuel Gas
Oily Water Storage Tank
Pre Stabilisation Separator
Stabilised Condensate Cooler
Stabilised Condensate Storage
Additional Production Wells (Future)
Condensate Stabilizer

Appendix B Condensate Generator Specification

G3516

GAS ENGINE TECHNICAL DATA

CATERPILLAR®

ENGINE SPEED (rpm):	1400
COMPRESSION RATIO:	8
AFTERCOOLER TYPE:	SCAC
AFTERCOOLER - STAGE 2 INLET (°C):	54
AFTERCOOLER - STAGE 1 INLET (°C):	94
JACKET WATER OUTLET (°C):	99
ASPIRATION:	TA
COOLING SYSTEM:	JW+OC+1AC, 2AC
CONTROL SYSTEM:	ADEM3
EXHAUST MANIFOLD:	ASWC
COMBUSTION:	LOW EMISSION
NOx EMISSION LEVEL (g/bhp-hr NOx):	0.5

RATING STRATEGY:	LOW NOX UPGRADE
APPLICATION:	GAS COMPRESSION
RATING LEVEL:	CONTINUOUS
FUEL:	NAT GAS
FUEL SYSTEM:	HPG IMPCO WITH AIR FUEL RATIO CONTROL
FUEL PRESSURE RANGE(kPag): (See note 1)	276-310
FUEL METHANE NUMBER:	80
FUEL LHV (MJ/Nm3):	35.64
ALTITUDE CAPABILITY AT 25°C INLET AIR TEMP. (m):	1737

RATING		NOTES	LOAD	100%	75%	50%
ENGINE POWER	(WITHOUT FAN)	(2)	bkW	999	749	500
ENGINE EFFICIENCY	(ISO 3046/1)	(3)	%	31.0	29.8	28.6
ENGINE EFFICIENCY	(NOMINAL)	(3)	%	30.5	29.2	28.1

ENGINE DATA						
FUEL CONSUMPTION	(ISO 3046/1)	(4)	MJ/bkW-hr	11.59	12.08	12.57
FUEL CONSUMPTION	(NOMINAL)	(4)	MJ/bkW-hr	11.82	12.31	12.82
AIR FLOW (0°C, 101.3 kPa)	(WET)	(5) (6)	Nm3/bkW-hr	5.11	5.29	5.34
AIR FLOW	(WET)	(5) (6)	kg/bkW-hr	6.60	6.83	6.90
FUEL FLOW (0ºC, 101.3 kPa)			Nm3/hr	331	259	180
COMPRESSOR OUT PRESSURE			kPa(abs)	311	270	205
COMPRESSOR OUT TEMPERATURE			°C	176	151	113
AFTERCOOLER AIR OUT TEMPERATURE			°C	58	56	54
INLET MAN. PRESSURE		(7)	kPa(abs)	265	217	149
INLET MAN. TEMPERATURE	(MEASURED IN PLENUM)	(8)	°C	60	58	55
TIMING		(9)	°BTDC	33	33	33
EXHAUST TEMPERATURE - ENGINE OUTLET		(10)	°C	511	514	515
EXHAUST GAS FLOW (0 °C, 101.3 kPa)	(WET)	(11) (6)	Nm3/bkW-hr	5.45	5.64	5.71
EXHAUST GAS MASS FLOW	(WET)	(11) (6)	kg/bkW-hr	6.86	7.10	7.18

EMISSIONS DATA - ENGINE OUT					
NOx (as NO2)	(12)(13)	g/bkW-hr	0.67	0.67	0.67
CO	(12)(14)	g/bkW-hr	4.09	4.12	4.02
THC (mol. wt. of 15.84)	(12)(14)	g/bkW-hr	6.10	6.74	7.04
NMHC (mol. wt. of 15.84)	(12)(14)	g/bkW-hr	0.92	1.01	1.06
NMNEHC (VOCs) (mol. wt. of 15.84)	(12)(14)(15)	g/bkW-hr	0.61	0.67	0.70
HCHO (Formaldehyde)	(12)(14)	g/bkW-hr	0.38	0.75	0.79
CO2	(12)(14)	g/bkW-hr	713	738	754
EXHAUST OXYGEN	(12)(16)	% DRY	8.5	8.4	8.0
LAMBDA	(12)(16)		1.62	1.61	1.56

ENERGY BALANCE DATA					
LHV INPUT	(17)	kW	3281	2563	1781
HEAT REJECTION TO JACKET WATER (JW)	(18)(26)	kW	742	633	498
HEAT REJECTION TO ATMOSPHERE	(19)	kW	93	78	62
HEAT REJECTION TO LUBE OIL (OC)	(20)(26)	kW	111	94	74
HEAT REJECTION TO EXHAUST (LHV TO 25°C)	(21)(22)	kW	1082	845	569
HEAT REJECTION TO EXHAUST (LHV TO 177°C)	(21)	kW	720	564	383
HEAT REJECTION TO A/C - STAGE 1 (1AC)	(23)(26)	kW	158	85	19
HEAT REJECTION TO A/C - STAGE 2 (2AC)	(24)(27)	kW	81	64	43
PUMP POWER	(25)	kW	15	15	15

CONDITIONS AND DEFINITIONS

Engine rating obtained and presented in accordance with ISO 3046/1. (Standard reference conditions of 25°C, 100 kPa barometric pressure.) No overload permitted at rating shown. Consult the altitude deration factor chart for applications that exceed the rated altitude or temperature.

Emission levels are at engine exhaust flange prior to any after treatment. Values are based on engine operating at steady state conditions, adjusted to the specified NOx level at 100% load. Tolerances specified are dependent upon fuel quality. Fuel methane number cannot vary more than ± 3.

For notes information consult page three.

FUEL USAGE GUIDE

CAT METHANE NUMBER	14	20	25	30	35	40	45	50	55	60	65	70	75	80	100
SET POINT TIMING	24	24	24	24	24	24	25	26	27	28	29	30	31	33	33
DERATION FACTOR	0.50	0.65	0.78	0.90	0.93	0.97	1	1	1	1	1	1	1	1	1

ALTITUDE DERATION FACTORS AT RATED SPEED

INLET AIR TEMP °C	0	250	500	750	1000	1250	1500	1750	2000	2250	2500	2750	3000
50	1	1	1	0.97	0.92	0.88	0.84	0.81	0.77	0.74	0.71	0.68	0.65
45	1	1	1	1	0.97	0.92	0.88	0.84	0.81	0.78	0.74	0.71	0.68
40	1	1	1	1	1	0.96	0.92	0.88	0.85	0.81	0.78	0.75	0.72
35	1	1	1	1	1	1	0.95	0.91	0.88	0.84	0.81	0.78	0.75
30	1	1	1	1	1	1	0.98	0.94	0.90	0.87	0.83	0.80	0.77
25	1	1	1	1	1	1	1	1	0.95	0.91	0.88	0.84	0.81
20	1	1	1	1	1	1	1	1	0.98	0.93	0.90	0.86	0.83
15	1	1	1	1	1	1	1	1	1	0.96	0.92	0.88	0.85
10	1	1	1	1	1	1	1	1	1	0.98	0.94	0.90	0.87

ALTITUDE (METERS ABOVE SEA LEVEL)

AFTERCOOLER HEAT REJECTION FACTORS (ACHRF)

INLET AIR TEMP °C	0	250	500	750	1000	1250	1500	1750	2000	2250	2500	2750	3000
50	1.29	1.34	1.38	1.42	1.47	1.51	1.56	1.60	1.60	1.60	1.60	1.60	1.60
45	1.23	1.27	1.31	1.36	1.40	1.45	1.49	1.54	1.54	1.54	1.54	1.54	1.54
40	1.17	1.21	1.25	1.29	1.34	1.38	1.42	1.47	1.47	1.47	1.47	1.47	1.47
35	1.10	1.14	1.19	1.23	1.27	1.31	1.36	1.40	1.40	1.40	1.40	1.40	1.40
30	1.04	1.08	1.12	1.16	1.20	1.25	1.29	1.33	1.33	1.33	1.33	1.33	1.33
25	1	1.02	1.06	1.10	1.14	1.18	1.22	1.26	1.26	1.26	1.26	1.26	1.26
20	1	1	1	1.03	1.07	1.11	1.15	1.19	1.19	1.19	1.19	1.19	1.19
15	1	1	1	1	1.01	1.05	1.09	1.13	1.13	1.13	1.13	1.13	1.13
10	1	1	1	1	1	1	1.02	1.06	1.06	1.06	1.06	1.06	1.06

ALTITUDE (METERS ABOVE SEA LEVEL)

MINIMUM SPEED CAPABILITY AT THE RATED SPEED'S SITE TORQUE (RPM)

INLET AIR TEMP °C	0	250	500	750	1000	1250	1500	1750	2000	2250	2500	2750	3000
50	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050
45	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050
40	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050
35	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050
30	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050
25	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050
20	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050
15	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050
10	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050

ALTITUDE (METERS ABOVE SEA LEVEL)

FUEL USAGE GUIDE:

This table shows the derate factor and full load set point timing required for a given fuel. Note that deration and set point timing adjustment may be required as the methane number decreases. Methane number is a scale to measure detonation characteristics of various fuels. The methane number of a fuel is determined by using the Caterpillar methane number calculation.

ALTITUDE DERATION FACTORS:

This table shows the deration required for various air inlet temperatures and altitudes. Use this information along with the fuel usage guide chart to help determine actual engine power for your site. The derate factors shown do not account for the external cooling system capacity. The derate factors provided assume the external cooling system can maintain the specified cooling water temperatures at site conditions.

ACTUAL ENGINE RATING:

To determine the actual rating of the engine at site conditions, one must consider separately, limitations due to fuel characteristics and air system limitations. The Fuel Usage Guide deration establishes fuel limitations. The Altitude/Temperature deration factors and RPC (reference the Caterpillar Methane Program) establish air system limitations. RPC comes into play when the Altitude/Temperature deration is less than 1.0 (100%). Under this condition, add the two factors together. When the site conditions do not require an Altitude/Temperature derate (factor is 1.0), it is assumed the turbocharger has sufficient capability to overcome the low fuel relative power, and RPC is ignored. To determine the actual power available, take the lowest rating between 1) and 2).

1) Fuel Usage Guide Deration
2) 1-((1-Altitude/Temperature Deration) + (1-RPC))

AFTERCOOLER HEAT REJECTION FACTORS(ACHRF):

To maintain a constant air inlet manifold temperature, as the inlet air temperature goes up, so must the heat rejection. As altitude increases, the turbocharger must work harder to overcome the lower atmospheric pressure. This increases the amount of heat that must be removed from the inlet air by the aftercooler. Use the aftercooler heat rejection factor (ACHRF) to adjust for inlet air temp and altitude conditions. See notes 26 and 27 for application of this factor in calculating the heat exchanger sizing criteria. Failure to properly account for these factors could result in detonation and cause the engine to shutdown or fail.

MINIMUM SPEED CAPABILITY AT THE RATED SPEED'S SITE TORQUE (RPM):

This table shows the minimum allowable engine turndown speed where the engine will maintain the Rated Speed's Torque for the given ambient conditions.

NOTES:

1. Fuel pressure range specified is to the engine fuel pressure regulator. Additional fuel train components should be considered in pressure and flow calculations.
2. Engine rating is with two engine driven water pumps. Tolerance is ± 3% of full load.
3. ISO 3046/1 engine efficiency tolerance is (+)0, (-)5% of full load % efficiency value. Nominal engine efficiency tolerance is ± 3.0% of full load % efficiency value.
4. ISO 3046/1 fuel consumption tolerance is (+)5, (-)0% of full load data. Nominal fuel consumption tolerance is ± 3.0% of full load data.
5. Air flow value is on a 'wet' basis. Flow is a nominal value with a tolerance of ± 5 %.
6. Inlet and Exhaust Restrictions must not exceed A&I limits based on full load flow rates from the standard technical data sheet.
7. Inlet manifold pressure is a nominal value with a tolerance of ± 5 %.
8. Inlet manifold temperature is a nominal value with a tolerance of ± 5°C.
9. Timing indicated is for use with the minimum fuel methane number specified. Consult the appropriate fuel usage guide for timing at other methane numbers.
10. Exhaust temperature is a nominal value with a tolerance of (+)35°C, (-)30°C.
11. Exhaust flow value is on a 'wet' basis. Flow is a nominal value with a tolerance of ± 6 %.
12. Emissions data is at engine exhaust flange prior to any after treatment.
13. NOx values are the maximum values expected under steady state conditions.
14. CO, CO2, THC, NMHC, NMNEHC, and HCHO are the maximum values expected under steady state conditions. THC, NMHC, and NMNEHC do not include aldehydes. An oxidation catalyst may be required to meet Federal, State or local CO or HC requirements.
15. VOCs - Volatile organic compounds as defined in US EPA 40 CFR 60, subpart JJJJ
16. Exhaust Oxygen tolerance is ± 0.5; Lambda tolerance is ± 0.05. Lambda and Exhaust Oxygen level are the result of adjusting the engine to operate at the specified NOx level.
17. LHV rate tolerance is ± 3.0%.
18. Heat rejection to jacket water value displayed includes heat to jacket water alone. Value is based on treated water. Tolerance is ± 10% of full load data.
19. Heat rejection to atmosphere based on treated water. Tolerance is ± 50% of full load data.
20. Lube oil heat rate based on treated water. Tolerance is ± 20% of full load data.
21. Exhaust heat rate based on treated water. Tolerance is ± 10% of full load data.
22. Heat rejection to exhaust (LHV to 25°C) value shown includes unburned fuel and is not intended to be used for sizing or recovery calculations.
23. Heat rejection to A/C - Stage 1 based on treated water. Tolerance is ±5% of full load data.
24. Heat rejection to A/C - Stage 2 based on treated water. Tolerance is ±5% of full load data.
25. Pump power includes engine driven jacket water and aftercooler water pumps. Engine brake power includes effects of pump power.
26. Total Jacket Water Circuit heat rejection is calculated as: (JW x 1.1) + (OC x 1.2) + (1AC x 1.05) + [0.95 x (1AC + 2AC) x (ACHRF - 1) x 1.05]. Heat exchanger sizing criterion is maximum circuit heat rejection at site conditions, with applied tolerances. A cooling system safety factor may be multiplied by the total circuit heat rejection to provide additional margin.
27. Total Second Stage Aftercooler Circuit heat rejection is calculated as: (2AC x 1.05) + [(1AC + 2AC) x 0.05 x (ACHRF - 1) x 1.05]. Heat exchanger sizing criterion is maximum circuit heat rejection at site conditions, with applied tolerances. A cooling system safety factor may be multiplied by the total circuit heat rejection to provide additional margin.

FREE FIELD MECHANICAL & EXHAUST NOISE

SOUND PRESSURE LEVEL (dB)

			Octave Band Center Frequency (OBCF)								
100% Load Data			**dB(A)**	**63 Hz**	**125 Hz**	**250 Hz**	**500 Hz**	**1 kHz**	**2 kHz**	**4 kHz**	**8 kHz**
Mechanical Sound	Distance from the Engine (m)	1.0	98.1	93.8	95.3	91.5	90	93.1	92.8	88.8	83.2
		7.0	88.5	84.2	85.7	81.9	80.4	83.5	83.2	79.2	73.6
		15.0	83.2	78.9	80.4	76.6	75.1	78.2	77.9	73.9	68.3
Exhaust Sound	Distance from the Engine (m)	1.0	113.5	102.9	105.5	109.5	105.6	106.9	106.6	107.1	104
		7.0	100.1	88.1	94.6	94.9	91.6	94.3	93.2	93.8	89.1
		15.0	93.5	81.5	87.9	88.2	84.9	87.6	86.6	87.2	82.5

SOUND PARAMETER DEFINITION:

Data Variability Statement:

Sound data presented by Caterpillar has been measured in accordance with ISO 6798 in a Grade 3 test environment. Measurements made in accordance with ISO 6798 will result in some amount of uncertainty. The uncertainties depend not only on the accuracies with which sound pressure levels and measurement surface areas are determined, but also on the 'near-field error' which increases for smaller measurement distances and lower frequencies. The uncertainty for a Grade 3 test environment, that has a source that produces sounds that are uniformly distributed in frequency over the frequency range of interest, is equal to 4 dB (A-weighted). This uncertainty is expressed as the largest value of the standard deviation.

Appendix C Flare Specification

UFQ1715 UF10-2500 High Temperature Stand Alone Flare Specification

Customer		
Customer's reference		
Our Reference No.		
Machine type	**UF10-2500** – 2500 Nm^3h^{-1} Stand Alone High Temperature Enclosed Flare	
Turndown Ratio	**5:1**	
Turndown Ratio Nm3hr	**500 Nm3hr**	
Number of Machines	**TWO**	
Total Capacity Nm3hr	**5000 Nm3hr**	
Design CH^4 Destruction efficiency	**99.97%**	
Visible Flame / Smoke	**None. Flame is Total Enclosed with Cyclonic Burner Technology**	
Plant Design noise at 1 metre distant free field conditions	**<70 dBA@1m**	
Maximum design emissions Normalised at 0°C, 101.3 k Pa and 3% O2: Compliant with EA Guidance Note LFTGN 05	Carbon monoxide (CO)	50 mg/m3
	Oxides of nitrogen (NOx)	150 mg/m3
	Total VOC's	10 mg/m3
	NMVOC's	5 mg/m3
Use environment	Site in open air with restricted access and supervised by trained personnel.	
Hazardous area classification in compliance with ATEX	Zone 2 in sphere 200 mm radius around all positive gas pipe connections	
Operation	Unattended Intermittent use	
Media	Methane 96%	
Delivery Pressure	80 to 120 mbarg	
Design Combustion temperature	1000°C (Refractory Lined)	
Minimum retention time	> 0.3 seconds	
Control system: Uniflare standard with weather protection roof		

Uniflare Limited
Unit 19
Runway Farm Technical Park
Honiley Road
KENILWORTH
CV8 1NQ, ENGLAND
T: + 44 1676 529118 F: + 44 1676 529119
Registered in England Number 05689034

PLC: Siemens S7 range Controls: Start/stop button Emergency stop button	Vent / Flare selector switch Local/Remote control selector switch Lamp test button Reset button Panel isolator
Activity Indicators: Panel on Pilot Valve 1 Open Pilot Valve 2 Open Flame on Burner valve 1 open Burner valve 2 open Flare temp °c PID adjust & display	Shutdown Indicators: Flare high temp Flame fail Pilot flashback Burner flashback Emergency stop shutdown Remote Signals Flare Start Flare Stop Flare Fault Remote Emergency Stop Facility
Frame hot dip galvanised to ISO 1460	
Output signals to main plant system to include all flare I/O and digital signals	

Uniflare Limited
Unit 19
Runway Farm Technical Park
Honiley Road
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