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DY Oldhall Energy Recovery Limited

Heat and Power Plan

ENGINEERING + CONSULTING

Document approval

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Management summary

DY Oldhall Energy Recovery Limited (herein referred to as Doveryard) is proposing to build an Energy Recovery Facility (ERF, the Facility), and associated infrastructure, to process non-hazardous waste derived fuel. The Facility will be located on land to the south of Murdoch Place within the Oldhall West Industrial Estate in North Ayrshire, approximately 2.3 km south-east of Irvine.

The Facility will have a nominal design capacity of approximately 22.8 tonnes per hour (tph) of pre-processed waste, at a design NCV of 10.5 MJ/kg. Assuming an availability of 8,000 hours per annum, this equates to a design capacity of approximately 182,400 tonnes per annum (tpa). However, it is acknowledged that the planning permission for the Facility currently limits the capacity to 180,000 tpa.

The Facility will be designed to generate approximately 19.3 MW_e of electricity (when operating in fully condensing mode), approximately 2.0 MW_e of which will be used to supply the site parasitic load and the balance exported to the local grid. It is proposed to develop the Facility as Combined Heat and Power (CHP) enabled with the capability to export heat to local heat consumers, subject to technical and economic viability.

Fichtner Consulting Engineers Ltd (Fichtner) has been engaged by Doveryard to produce a Heat and Power Plan to support a PPC permit application for the Facility. Scottish Environment Protection Agency (SEPA) Thermal Treatment of Waste Guidelines (TTWG) 2014 require that all new thermal treatment plants must ensure that the recovery of energy from waste takes place with a high level of efficiency. For facilities processing over 70,000 tpa of fuel, the facility must meet or exceed a Quality Index (QI) of 93 or an indicative overall plant efficiency of 35%. For the heat network identified within this report, the Facility is able to achieve above an indicative overall plant efficiency of 35 %. We therefore consider that the TTWG energy recovery targets are met.

Fichtner has investigated whether there could be any existing buildings and/or developments within a 15 km radius that could potentially connect to the network. The adjacent GlaxoSmithKline (GSK) facility is a large heat user with a high potential demand for saturated steam, which can be supplied by exporting steam at a suitable pressure from the Facility. Initial discussions with GSK indicate that a demand of approximately 81,421 MWh per annum can be met by the Facility, in the form of 10 bar(g) steam. This translates into an estimated steady state demand of 9.29 MW_{th}.

The heat network will be developed on the basis of well proven and highly efficient technology, which is designed to supply heat that meets the requirements of end consumers while minimising the impact on power generation. Steam will be extracted from the steam turbine via dedicated extraction point(s) and heat transferred, via an above-ground steam pipeline, to a steam-steam heat exchanger on the GSK site. The condensed steam will be returned to the Facility through an insulated above ground hot water pipeline for reheating. The location for the heat exchanger has not yet been agreed with GSK.

Under Article 14 of the Energy Efficiency Directive, a cost-benefit assessment (CBA) of opportunities for CHP is required when applying for a PPC Permit. The costs and revenues associated with the construction and operation of the proposed heating network has been undertaken. This has been entered into a CBA in accordance with the draft Article 14 guidance document issued by the Environment Agency. The results of the CBA indicate that the nominal project internal rate of return and net present value (before financing and tax) over 33 years are 18.4% and £0.28 million. Therefore, it is considered that the proposed heat network yields an economically viable scheme in its current configuration. However, the economic feasibility of the scheme will be reassessed in the future when there is further certainty regarding heat loads and taking into consideration any subsidies that might be available at that time which support the export of heat.

We consider that implementation of the heat network should be achievable within SEPA's recommendation of up to 7 years starting on cessation of commissioning of the Facility. Doveryard has agreed to implement an action plan to ensure that the identified heat demand can be secured and the Facility achieves the requisite level of heat export capacity.

Contents

1 Introduction

DY Oldhall Energy Recovery Limited (Doveryard) is proposing to build an Energy Recovery Facility (ERF, the Facility), and associated infrastructure, to process non-hazardous waste derived fuel. The Facility will be located on land to the south of Murdoch Place within the Oldhall West Industrial Estate in North Ayrshire, approximately 2.3 km south-east of Irvine.

The Facility will be fuelled by incoming municipal and commercial & industrial non-hazardous waste, that has been pre-processed to remove recyclates.

The Facility will have a nominal design capacity of approximately 22.8 tonnes per hour (tph) of pre-processed waste, at a design NCV of 10.5 MJ/kg. Assuming an availability of 8,000 hours per annum, this equates to a design capacity of approximately 182,400 tonnes per annum (tpa). However, it is acknowledged that the planning permission for the Facility currently limits the capacity to 180,000 tpa.

The Facility will be designed to generate approximately 19.3 MW_e of electricity (when operating in fully condensing mode), approximately 2.0 MW_e of which will be used to supply the site parasitic load and the balance exported to the local grid. It is proposed to also export low grade heat to local heat consumers, subject to technical and economic viability.

This document forms a Heat and Power Plan in support of the PPC Permit application for the Facility. Local heat consumers have been identified and the technical and economic feasibility of including these in a CHP network has been assessed.

1.1 Background

Scottish Environment Protection Agency (SEPA) Thermal Treatment of Waste Guidelines (TTWG) 2014 stipulate that all new thermal treatment plants must ensure that the recovery of energy from waste takes place with a high level of energy efficiency. To comply with the TTWG, it is recommended that information is supplied in the form of a robust and credible Heat and Power Plan. This document provides evidence to demonstrate compliance with the requirements of the guidelines.

In addition, the UK government's CHP strategy, as required by Article 14 of the Energy Efficiency Directive, requires a cost benefit analysis (CBA) of CHP opportunities to be carried out for certain types of combustion facilities. In the absence of guidance from SEPA, this document includes a CBA in line with the EA's draft guidance on CBA for combustion installations. However, for the purposes of the PPC application, it is understood that the regulated activity being applied for is waste incineration activity.

1.2 Objective

Fichtner has been commissioned by the Applicant to assess the feasibility of supplying heat from the Facility to local consumers. The principle objectives of this study are as follows.

1. Prepare a Heat and Power Plan in line with the requirements of SEPA's TTWG 2014, which will support a PPC permit application.
2. Provide a description of the proposed facility and heat export infrastructure.
3. Assess the waste to be treated and its energy value.
4. Identify potential heat consumers from a desktop survey, as required by SEPA's TTWG.
5. Calculate the heat network capacity based on likely heat consumers.

6. Provide evidence of compliance with the energy recovery targets provided in Annex 1 of SEPA's TTWG 2014.
7. Produce provisional pipe routing drawing from the Facility to the likely heat consumers.
8. Conduct an economic assessment feeding into the CBA as required under Article 14 of the Energy Efficiency Directive.

1.3 The location

The site is a 1.43 ha parcel of land located on Murdoch Place, Oldhall West Industrial Estate, Irvine, North Ayrshire, KA11 5AR [redacted]

A site location plan and Installation boundary drawing are presented in Appendix B.

2 Conclusions

2.1 Technical solution

The Facility includes a single waste treatment/energy recovery line, waste reception, waste storage, water, auxiliary fuel and air supply systems, boilers, facilities for the treatment of exhaust gases, on-site facilities for treatment or storage of residues and waste water, flues, stack, devices and systems for controlling operation of the CHP plant, recording and monitoring conditions.

The Facility has been designed as a CHP plant and will have capacity to provide heat to the identified potential heat consumers and to supply power to the National Grid. The turbine has been designed to generate up to 19.3 MW_e of electricity. The Facility will have a parasitic load of approximately 2 MW_e. It is proposed to export heat to local potential heat consumers, subject to technical and economic viability.

The Facility has been designed to thermally treat residual waste with a range of net calorific values (NCVs). The nominal design capacity of the thermal treatment line is approximately 22.8 tonnes per hour of waste, with an average NCV of 10.5 MJ/kg. The Facility will have an assumed availability of approximately 8,000 hours per annum. On this basis, the Facility will have a nominal design capacity of approximately 182,000 tonnes per annum.

A number of arrangements for heat recovery and export are available. Given the requirements of the end consumers (discussed subsequently), flexibility in terms of export temperatures and capacity, and the associated environmental benefits, steam extraction from the turbine is considered the most favourable solution. Heat will be transferred to a consumer heat exchanger through an insulated live steam pipeline, with the condensate being returned to the Facility for reheating. This technology is well proven.

2.2 Power export

To export electricity from the Facility it is necessary to provide a connection to the local electricity distribution network. Doveryard are looking for a 25 MW_e grid connection capacity offer, which would accommodate the maximum electrical output from the Facility.

2.3 Waste to be treated

The waste to be treated comprises 180,000 tpa of non-hazardous residual waste with an average net calorific value (NCV) of 10.5 MJ/kg. However, the relevant environmental assessments and this heat plan have been undertaken assuming a design capacity of approximately 182,400 tpa.

2.4 Heat export capacity

Based on knowledge of similar facilities (in terms of capacity and fuel specification) and the outline design proposed, it should be technically possible to export up to approximately 10 MW_{th} from the Facility. However, a higher heat export capacity will have an adverse impact on power export and power efficiency. Therefore, the heat network will need to be designed to take into account the estimated local demand and economic returns resulting from power generation.

Steps will be taken during the design phase to ensure that the lower heat network demand seen in the initial stages of network operation can be met with reasonable efficiency, as well as providing scope for increasing the export capacity at later stages if feasible additional demand is identified.

2.5 Potential heat consumers

A review of the potential heat demand within a 15 km radius of the Facility has been undertaken in accordance with the requirements set out in Section 2 of the EA's draft Article 14 guidance. Physical constraints imposed by local infrastructure and topology have a significant impact on which consumers can viably be connected. Both river and rail crossings exist in the area surrounding the Facility and may present obstructions to connect some consumers. Engineering a bridge crossing will likely require detailed structural assessments and the consent of the bridge owner. Trenching in road crossings will require traffic management and permission from the highway authority. Following screening of potential heat consumers, the identifying existing heat demands has centred on nearby industrial and commercial users, as the benefits of providing heat to large nearby premises is generally more financially viable than supply to multiple smaller consumers at further distances.

Two large heat consumers (point heat demands greater than 5 MW_{th} as defined by the UK CHP Development Map) have been identified within the specified 15 km search radius, both within approximately 1.5 km of the Facility. One large consumer – the Caledonian Paper Mill – has been discounted, as review of satellite imagery showed this consumer already has an extensive system in place. Additionally, the large demand is several times larger than the maximum Facility export.

The second large heat consumer – GlaxoSmithKline, GSK – is approximately 770 m from the Facility. GSK has expressed interest in exploring the option of a heat network connection, which would reduce both their site carbon emissions and fuel use. Doveryard has been in advanced discussions with GSK, and therefore the heat network considered in this Heat and Power Plan has been built around this large heat consumer.

GSK requires heat in the form of saturated steam, and as a large heat consumer is many times larger than estimates of nearby demand that can be met by a hot water network. As such, hot water demands have been discounted in favour of the GSK steam demand.

Based on information provided by Doveryard, the heat demand of the preferred heat consumers has been estimated. The GSK site is expected to require a comparatively stable demand of 9.29 MW_{th} at their side of the steam to steam heat exchanger, with an annual heat demand of 81,421 MWh/annum.

2.6 Economic assessment

As a new electricity generation installation with a total aggregated net thermal input of more than 20 MW, the Facility and its potential CHP opportunities are subject to a cost benefit assessment (CBA) when applying for a PPC permit. This is a requirement under Article 14 of the Energy Efficiency Directive.

The costs and revenues associated with the construction and operation of the proposed heat network have been considered. These values have been inputted into the CBA template provided by the EA. The CBA takes account of heat sales income and assume no fiscal benefits. It also considers the lost revenue due to reduced electricity generation caused by diverting energy to the heat export circuit and costs associated with operating a back-up boiler. It does not consider the costs associated with the Facility.

The results of the CBA indicate that the nominal project internal rate of return and net present value (before financing and tax) over 33 years are 18.4 % and £0.28 M respectively. We therefore consider that the proposed heat network possibly yields an economically viable scheme in its current configuration.

It should be noted that the draft EA guidance calculation spreadsheet makes fixed assumptions about a project which are not appropriate for this project. The standard CBA calculation only considers the costs associated with the heat supply infrastructure rather than the full project costs. This has the effect of producing artificially high rates of return. The economic case for the Facility relies on both heat and power revenues to produce a rate of return acceptable to Doveryard for the whole project and not just the heat supply infrastructure.

2.7 Energy efficiency measures

The TTWG[1] 2014 sets out the approach of SEPA to permitting thermal treatment of waste facilities. SEPA expects that new waste thermal treatment plants achieve a minimum level of energy recovery. In order to demonstrate compliance, facilities processing over 70,000 tpa of fuel must meet or exceed a QI of 93 or an indicative overall efficiency of 35%.

Based on a Z factor of 4.75 (assuming steam extraction at a pressure of 14 bar(a) which is sufficient to meet the needs of the identified consumer), the Facility will achieve a QI of 67.3 and an indicative overall efficiency of 35.1 %, for the average heat load export case. It is technically possible for the Facility to export at least this amount of heat. As a result of operating in CHP mode, net power export will be reduced from 17.3 MW_e to 15.3 MW_e. Recent changes to CHPQA guidance (released in December 2018) now mean that the proposed heat network would achieve a lower QI under the average heat load exported to the proposed network than would have been achieved with the guidance in force when the TTWG was first published. However, the proposed heat network still achieves the overall efficiency threshold of 35 % to comply with SEPA's efficiency requirements.

There is no reason (within the scope of this review) to suggest that the heat network outlined in this Heat and Power Plan cannot be implemented within SEPA's recommendation of up to 7 years starting on cessation of commissioning of the Facility. It is understood that the final implementation timescale will be agreed with SEPA when there is more certainty over the developments. Doveryard has agreed to implement an action plan to ensure that the identified heat demand can be secured and the Facility achieves the requisite level of heat export capacity.

[1] SEPA Thermal Treatment of Waste Guidelines 2014, May 2014.

3 Legislative requirements

The TTWG[2] sets out the approach of SEPA to permitting thermal treatment of waste facilities. SEPA guidance states that any permit authorising the incineration of waste contains "conditions necessary to ensure the recovery of energy takes place with a high level of energy efficiency". To comply with the guidelines, it is recommended that information is supplied in the form of a robust and credible Heat and Power Plan.

SEPA requires that new waste thermal treatment facilities achieve a minimum level of energy recovery. As a consequence, any Heat and Power Plan for a new waste thermal treatment plant is required to demonstrate that it can achieve at least 20 % (gross calorific value basis) energy recovery as electricity only, electricity and heat, heat only or as exported fuel (energy) equivalent on commissioning.

The design and construction of the Facility must provide for the available floor space / infrastructure / facilities to allow for the installation of additional energy recovery equipment, such as heat exchange and / or heat pump systems. A point of connection to allow steam / hot water to be taken to a heat recovery system will be required; for example, in the case of high efficiency electricity generating steam turbines, suitably designed steam off takes should be installed to provide high quality heat for use in an appropriate heat network.

The Heat and Power Plan must be maintained, implemented and reviewed on an annual basis. SEPA has a duty to ensure compliance if these conditions are not met.

The QI value is to be estimated and calculated in accordance with the relevant Combined Heat and Power Quality Assurance (CHPQA) method for the relevant type of thermal treatment facility and fuel type. The calculation must demonstrate that as a minimum the QI or efficiency values meet the energy recovery targets provided in Annex 1 of TTWG.

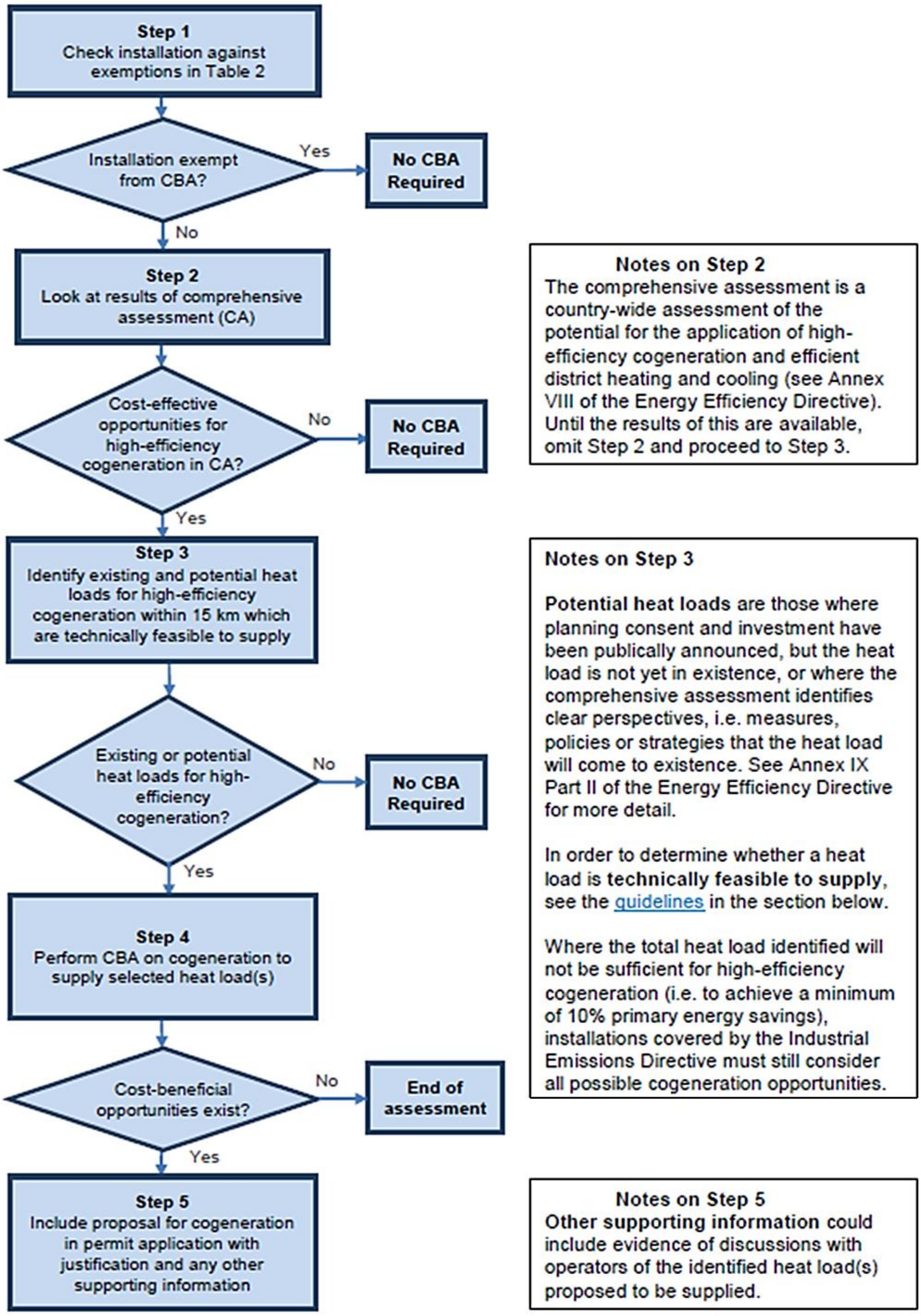
From 21st March 2015, operators of certain types of combustion installations are required to carry out a cost-benefit assessment (CBA) of opportunities for CHP when applying for a PPC permit. This is a requirement under Article 14 of the Energy Efficiency Directive and applies to a number of combustion installation types. As new electricity generation installation with a total aggregated net thermal input of more than 20 MW, the Facility will be classified as an installation type 14.5(a).

In April 2015, the EA issued draft guidance on completing the CBA, entitled '*Draft guidance on completing cost-benefit assessments for installations under Article 14 of the Energy Efficiency Directive*'[3]. The following methodology describes the process that must be followed for type 14.5(a) and 14.5(b) installations. The CBA is presented in Section 8.

[2] SEPA Thermal Treatment of Waste Guidelines 2014, May 2014.

[3] Draft guidance on completing cost-benefit assessments for installations under Article 14 of the Energy Efficiency Directive, V9.0 April 2015

Figure 1: CBA methodology for type 14.5(a) and 14.5(b) installations



4 Description of the facility technology and heat network

4.1 The facility

The main activities associated with the Facility will be the combustion of incoming non-hazardous waste to raise steam and the generation of electricity in a steam turbine/generator.

The Facility includes one waste incineration line, waste reception hall, main thermal treatment process, turbine hall, on-site facilities for the treatment or storage of residues and wastewater, flue gas treatment, stack, boiler, devices and systems for controlling operation of the waste incineration plant and recording and monitoring conditions.

In addition to the main elements described, the Facility will also include weighbridges, water, auxiliary fuel and air supply systems, site fencing and security barriers, external hardstanding areas for vehicle manoeuvring, internal access roads and car parking, transformers, grid connection compound, firewater storage tanks, offices, workshop, stores and staff welfare facilities.

The Facility will have a gross electrical output of up to 19.3 MWe, (design when operating in fully condensing mode), with a parasitic load of approximately 2 MW_e with the balance exported to the local grid. Therefore, the Facility will export approximately 17.3 MW_e in full condensing mode. The facility is designed for the export of heat, though the exact capacity is not known at this stage. However, based on knowledge of similar facilities (in terms of capacity and fuel specification) and the outline design proposed, it should be technically possible to export up to approximately 10 MW_{th} from the Facility. The maximum heat capacity will be subject to the requirements of the heat consumers and confirmed during detailed design stage.

Based on the heat network identified within this Heat Plan, the average heat load is expected to be 9.39 MW_{th}, resulting in an electrical export of approximately 15.3 MW_e. However, at the time of writing this report, there are no formal agreements in place for the export of heat from the Facility. The power exported may fluctuate as fuel quality fluctuates, and if heat is exported from the Facility to local heat users in the future.

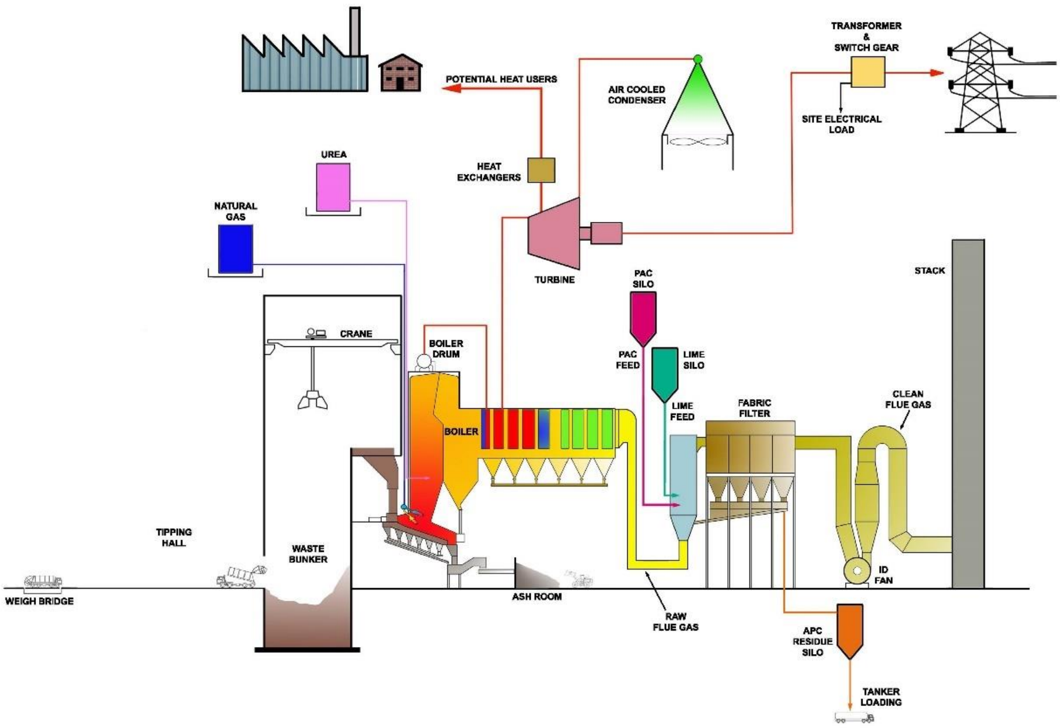
The nominal capacity of the Facility will be approximately 22.8 tonnes per hour of pre-processed Refuse Derived Fuel (RDF), with a nominal calorific value of 10.5 MJ/kg. The plant will have an estimated availability of around 8,000 hours. Therefore, the plant will have a nominal capacity of approximately 182,400 tonnes per annum. It should be noted that the planning permission includes a condition which states that the maximum capacity of the Facility is 180,000 tonnes per annum.

The facility will allow for variations in the net calorific value of the fuels being combusted from 8 MJ/kg to 14 MJ/kg.

4.1.1 Combustion process

Figure 2 is an indicative schematic of the combustion process that will be used in the Facility.

Figure 2: Indicative Facility process schematic



4.1.2 Energy recovery

The heat released by the combustion of the incoming waste will be recovered by means of a water tube boiler, which is integral to the furnace and will produce (in combination with superheaters) high pressure superheated steam at 51 bar(a) and 400°C. The steam from the boiler will then feed a high-efficiency steam turbine which will generate electricity. The turbine will have a series of extractions at different pressures that will be used for preheating air and water in the steam cycle.

The remainder of the steam left after the turbine will be condensed back to water to generate the pressure drop to drive the turbine. A fraction of the steam will condense at the exhaust of the turbine in the form of wet steam, however the majority will be condensed and cooled using an air-cooled condenser. The condensed steam will be returned as feed water in a closed-circuit pipework system to the boiler.

Depending on the requirements of the heat users, either high pressure steam or hot water could be supplied. High pressure steam could be extracted from the turbine and piped directly to the heat users. Alternatively, low pressure steam exiting the turbine could pass through an onsite heat exchanger to heat up water for use in a heat network. The volume of steam extracted would vary depending on the heat load requirements of the heat users. It should be noted that at the time of writing this report, there are no formal agreements in place for the export of heat from the Facility.

4.2 Grid connection

To export electricity from the Oldhall Energy from Waste facility, it is necessary to provide a connection to the local electricity distribution network. Scottish Power Energy Networks (SPEN) is the local distribution network operator in the area.

4.3 Details of heat supply system

Heat is typically supplied from the energy recovery process in the form of steam and / or hot water, depending on the grade of heat required by the end consumers.

The most commonly considered options for recovering heat for a hot water based system are discussed below.

1. **Heat recovery from the air-cooled condenser**

   Wet steam emerges from the steam turbine typically at around 40°C. This energy can be recovered in the form of low-grade hot water from the condenser depending on the type of cooling implemented.

   An ACC will be installed at the Facility. Steam is condensed in a large air-cooled system which rejects the heat in the steam into the air flow, which is rejected to atmosphere. An ACC generates a similar temperature condensate to mechanical draught or hybrid cooling towers. The condensate then returns back to the boiler. Cooling this condensate further by extracting heat for use in a heat network requires additional steam to be extracted from the turbine to heat the condensate prior to being returned to the boiler. This additional steam extraction reduces the power generation from the plant and therefore reduce the plant power efficiency.

2. **Heat extraction from the steam turbine**

   Steam extracted from the steam turbine can be supplied directly to user, used to generate consumer-side steam or used to generate hot water for district heating schemes. District heating schemes typically operate with a flow temperature of 90 to 120°C and return water temperature of 50 to 80°C. Steam is preferably extracted from the turbine at low pressure to maximise the power generated from the steam. However, the pressure of the steam bleed is dependent on the heating requirements of the heat consumer.

   If the consumer requires hot water, extraction steam is passed through a condensing heat exchanger(s), with condensate recovered back into the feedwater system. Hot water is pumped to heat consumers for consumption before being returned to the primary heat exchangers where it is reheated.

   If the consumer requires steam, extraction steam can be directly supplied to the consumer and returned to the supplier as condensate, or a primary heat exchanger can be used to keep the and consumer-side steam loop separate from the supplier-side steam loop. In some cases, steam is used in addition to steam generated by the consumer, and in these cases the condensate may not necessarily be returned to the supplier.

   This source of heat offers the most flexible design for a heat network. The steam bleeds can be sized to provide additional steam above the Facility’s parasitic steam loads. However, the size of the heat load needs to be clearly defined to allow the steam bleeds and associated pipework to be adequately sized. Increasing the capacity of the bleeds once the turbine has been installed can be difficult.

3. **Heat extraction from the flue gas**

   The temperature of cool flue gas from the flue gas treatment plant is typically around 140°C and contains water in vapour form. This can be cooled further using a flue gas condenser to recover the latent heat from the moisture. This heat can be used to produce hot water for district heating in the range 90 to 120°C. This method of heat extraction does not significantly impact the power generation from the plant.

Condensing the flue gas can be achieved in a wet scrubber. However, the scrubber temperature is typically no more than 80°C, which restricts the hot water temperature available for the consumer. Additionally, condensing water vapour from the flue gas reduces the flue gas volume and hence increases the concentration of non-condensable pollutants within it. The lower volume of cooler gas containing higher concentration of some pollutants would likely require a different stack height to effect adequate dispersion. The additional cooling of the flue gas results in the frequent production of a visible plume from the chimney and although this is only water vapour it can be misinterpreted as pollution. The water condensed from the flue gas needs to be treated and then discharged under a controlled consent.

Not all of these options can be used when heat in the form of steam is to be supplied. The best solution to supply heat for the steam network under consideration is by extracting steam from the turbine and supplying it to a steam-to-steam heat exchanger at the consumer site. This will ensure that the condensate returned to the Facility is not contaminated. The heat exchanger could be located at the Facility or at the point of supply at the consumer.

5 Description of the waste to be treated

5.1 Proposed fuel and calorific value

The following table shows the waste type used by the Facility to recover energy.

Table 1: Nominal design fuel profile

	Throughput[(1)] [tonnes/year]	GCV [MJ/kg]	NCV [MJ/kg]
Waste input	182,400	11.55	10.50
Note 1: Assumed availability of 8,000 hours per annum.			

5.2 Energy production

The following table summarises design energy consumption and export for the Facility.

Table 2: Facility design energy consumption and export

Parameter	Unit	Value
Operational hours	hours	8,000
Availability	hours/hours	86.5%
Annual throughput (nominal design capacity)	tonnes/year	182,400
Average GCV	MJ/kg	11.55
Gross thermal input - fuel	MWh/year GJ MW_{th}	585,200 2,106,720 73.15
Gross electrical generation (fully condensing)	MWh/year (GJ) MW	154,400 555,840 19.3
Parasitic load (including electrical and support fuel)	MWh/year GJ MW	16,304 58,694 2.0
Heat export capacity[1] from the Facility	MWh/year GJ MW_{th}	80,000 288,000 10.0
Z factor	MW/MW	4.75
Net electrical export (CHP mode at design case export of 9.39 MW_{th})	MWh/year GJ MW	122,400 440,640 15.3
[1]Calculated in accordance with system boundaries specified in Annex 3 of SEPA's TTWG 2014.		

6 Heat demand investigation

6.1 Wider heat export opportunities

6.1.1 The National Comprehensive Assessment

'National Comprehensive Assessment of the Potential for Combined Heat and Power and District Heating and Cooling in the UK'[4] (the NCA), dated 16 December 2015, was published by Ricardo AEA Ltd on behalf of the Department of Energy and Climate Change (now part of the Department for Business, Energy and Industrial Strategy). The report was produced to fulfil the requirement (under Directive 2012/27/EU on energy efficiency) on all EU Member States to undertake a National Comprehensive Assessment (NCA) to establish the technical and socially cost-effective potential for high-efficiency cogeneration. The report also sets out information pertaining to heat policy development in the UK. Due to the low resolution of the data, the results of the NCA can be considered as an overview only.

Table 3 details the heat consumption in 2012 and estimated consumption in 2025 by sector for Scotland as extracted from the NCA. Heat consumption is greatest in the industrial and residential sectors. The estimated heat consumption in 2025 is lower than in 2012, most notably in the residential and commercial sectors. The energy projections take account of climate change policies where funding has been agreed and where decisions on policy design are sufficiently advanced to allow robust estimates of policy impacts to be made, including measures such as building regulations.

Table 3: Heat consumption for Scotland

Sector	2012 consumption (TWh/annum)	2025 consumption (TWh/annum)
Industry (including agriculture)	22	21
Commercial services	5	3
Public sector	3	2
Residential	35	31
Total	**65**	**57**

Source: National Comprehensive Assessment of the Potential for Combined Heat and Power and District Heating and Cooling in the UK, Ricardo AEA, December 2015

Current and projected space cooling consumption data detailed in Table 4. Given the paucity of available data on energy consumption for cooling, these figures are estimates based on consumption indicators, building types and floor areas; consequently, they should be considered as indicative.

[4] National Comprehensive Assessment of the Potential for Combined Heat and Power and District Heating and Cooling in the UK, Ricardo AEA, December 2015

Table 4: Cooling consumption in Scotland

Sector	2012 consumption (TWh/annum)	2025 consumption (TWh/annum)
Industry (including agriculture)	1	1
Commercial services	1	0
Public sector	0	0
Total	2	2

Source: National Comprehensive Assessment of the Potential for Combined Heat and Power and District Heating and Cooling in the UK, Ricardo AEA, December 2015

It is assumed that the apparent discrepancy in the figures is due to rounding errors. It is not possible to verify this as access to the underlying data is not available.

6.1.2 UK CHP Development Map

The Department for Business, Energy and Industrial Strategy (BEIS) UK CHP Development Map[5] geographically represents heat demand across various sectors in England, Scotland, Wales and Northern Ireland. A search of heat users within 15 km of the Facility was carried out, as shown in Table 5. This is represented as coloured contour areas in Figure 3, with each colour band representing a range of heat demand density values.

The data returned considers the entire regional area into which the search area extends. If a search radius extends marginally into a particular region, the data for the entire region will be included in the results table so there is a possibility that the heat demand can be overestimated.

With the exception of public buildings, the heat map is produced entirely without access to the meter readings or energy bills of individual premises. Therefore, results should be taken as estimates only.

Table 5: Heat demand within 15 km of the Facility

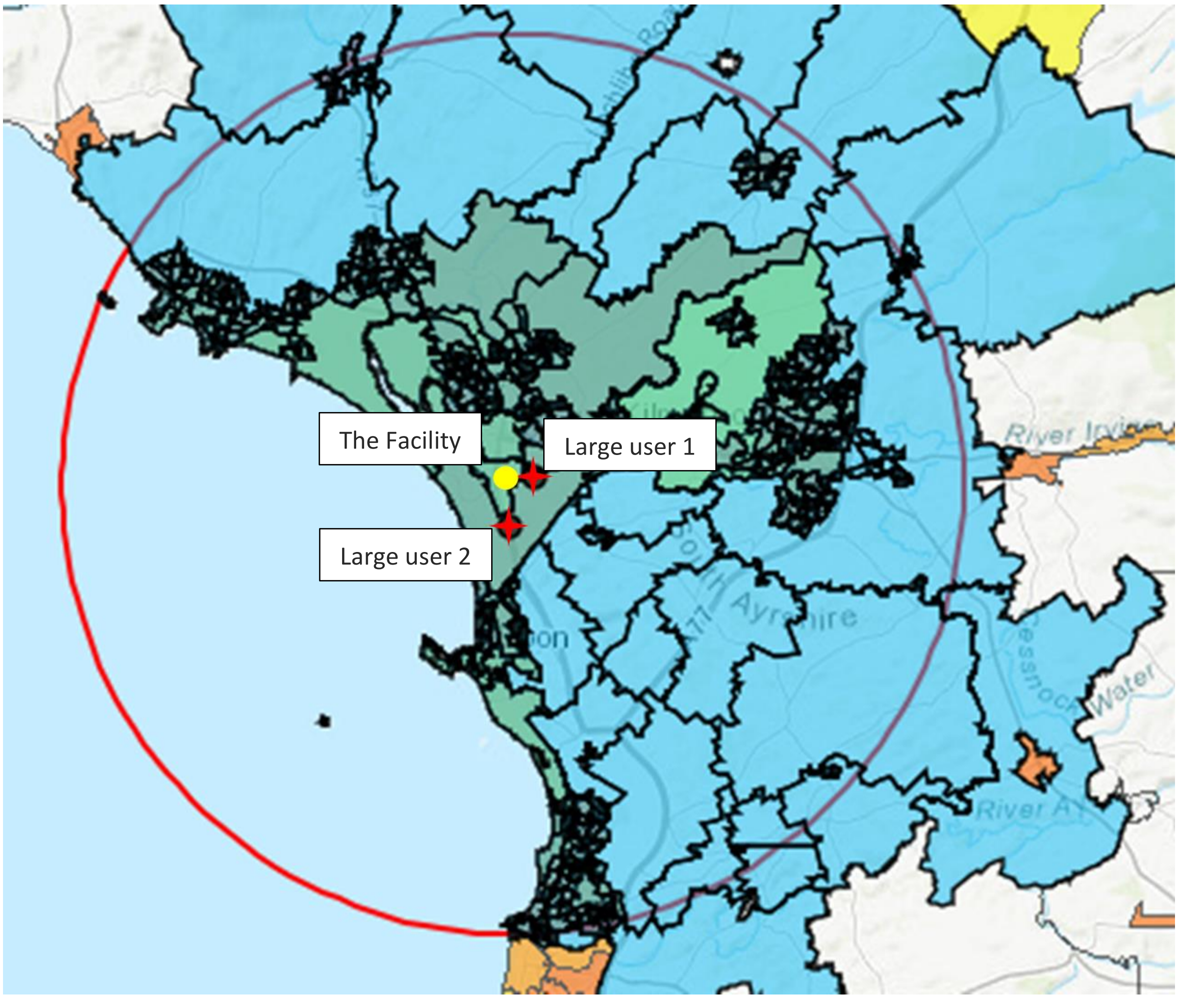
Sector	Heat demand	
	MWh/a	% share
Communications and Transport	24	0%
Commercial Offices	34,196	1.44%
Domestic	1,347,527	56.57%
Education	17,807	0.75%
Government Buildings	3,153	0.13%
Hotels	4,602	0.19%
Large Industrial	105,475	4.43%
Health	2,392	0.10%
Other	3,923	0.16%
Small Industrial	6,829	0.29%
Prisons	0	0%

[5] http://chptools.decc.gov.uk/developmentmap/

Sector	Heat demand	
	MWh/a	% share
Retail	60,274	2.53%
Sport and Leisure	12,587	0.53%
Warehouses	831	0.03%
District Heating	782,507	32.85%
Total heat load in area	**2,382,127**	**100%**

Source: UK CHP Development Map

Figure 3: Local heat demand density



Source: UK CHP Development Map

The heat demand in the area surrounding the Facility is predominantly from the domestic sector, district heat and the large industrial sectors. In most cases, existing domestic buildings are unsuitable for inclusion in a heat network as a result of the prohibitive costs of replacing existing heating infrastructure and connecting multiple smaller heat consumers to a network. In order to secure the most economically viable heat network, Fichtner has attempted to identify consumers that will provide maximum return and carbon saving for the minimum cost. Therefore, the approach to this study has focused on industrial and commercial consumers and new developments within the search radius.

Sections 6.1.3 and 6.1.4 identify potential heat users that would provide maximum return and carbon saving.

6.1.3 Large heat consumers

Two large heat consumers (point heat demands greater than 5 MW_{th}) were identified within 15 km of the Proposed Development using the BEIS UK CHP Development Map[6] tool, as detailed in Table 6 and Figure 3.

Table 6: Large heat consumers

Site	Heat demand [MWh/annum]	Straight Distance from the Facility [km]	Postcode
GlaxoSmithKline	78,886	0.77	KA11 5AP
Caledonian Paper Mill	449,224	1.43	KA11 5AT

Source: BEIS UK CHP Development Map

From a review of satellite imagery, the Caledonian Paper Mill site already has an extensive local pipe network installed. This network is most likely supplied by an onsite CHP engine. Additionally, the paper mill's heat demand is many times larger than the Facility heat export capacity. It has therefore been discounted at this stage.

The GlaxoSmithKline (GSK) site is close to the Facility and requires a single road crossing at the nearby roundabout to connect. The heat demand is in the form of process steam, which adds to the technical challenges of supplying heat; however, the distance between heat user and Facility is small enough that it is technically feasible to connect this large heat consumer to a potential heat network.

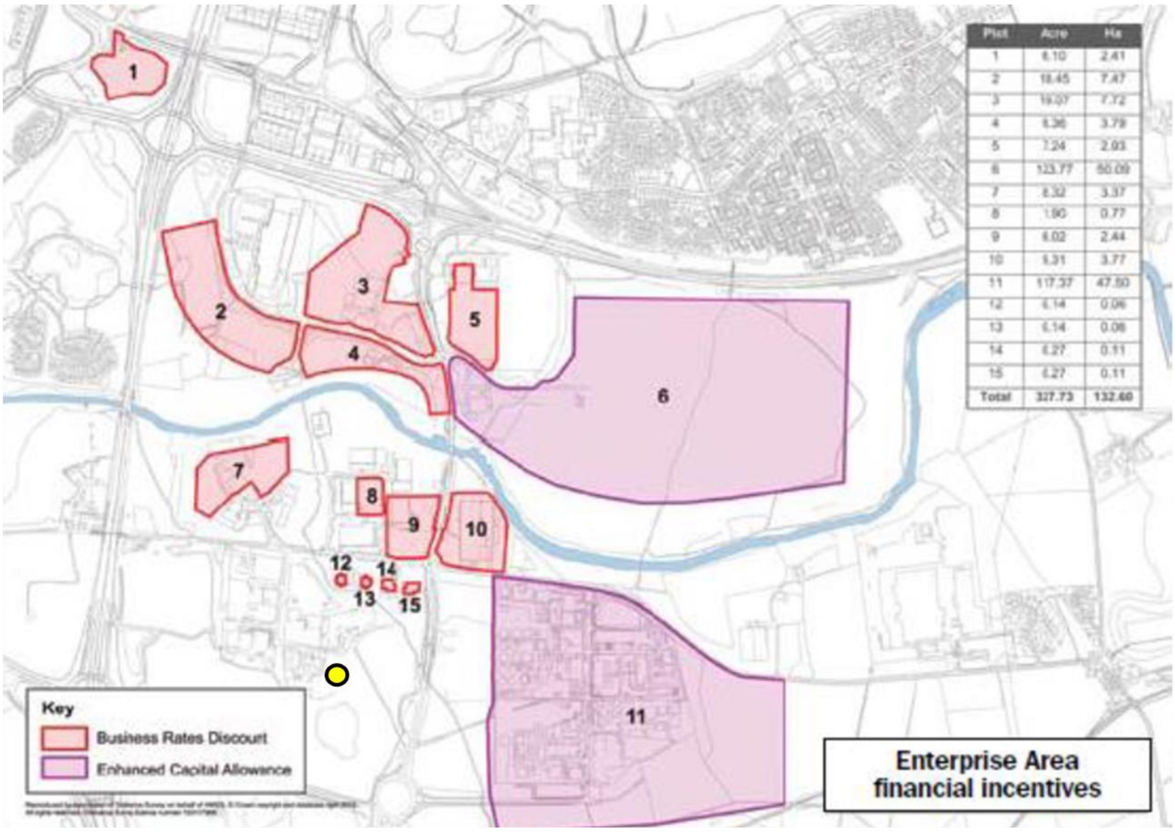
A review of satellite imagery of the area shows an extensive local pipe network installed on site. However, Doveryard has been in advanced discussions with GSK to gauge their interest in the proposed arrangement. GSK has expressed interest in exploring the option of a heat network connection, which would reduce both their site carbon emissions and fuel use. From these talks it has also emerged that the available annual heat demand could be somewhat higher than the Development Map suggests, at 81,421 MWh/a. This figure has been used in subsequent sections of this report.

6.1.4 The Irvine Enterprise Area

The Facility will be located within the Irvine Enterprise Area (i3), an enterprise zone comprising a number of plots to the north and east of the Facility site (see Figure 4). Plot 11 is occupied by the GSK large heat user identified above. With the exception of the GSK site, the anticipated demands are not process heat. Therefore, it is assumed that heat could be supplied to these developments through a hot water heat network.

[6] http://chptools.decc.gov.uk/developmentmap/

Figure 4: Irvine Enterprise Area – approximate layout. The approximate Facility location is shown in yellow



Assuming all sites are developed as planned the anticipated annual heat demand will be approximately 11,232 MWh per annum.

Not all plots have been fully developed, and so the currently-available hot water heat load is likely to be smaller than anticipated. The sites are also spread out, with the furthest corner (plot 1) lying approximately 1.7 km from the Facility and requiring a pipe length of approximately 3 km to connect. Additionally, the total estimated hot water demand is significantly smaller than the known GSK steam demand.

6.2 Estimated overall heat load

From review of the available heat loads surrounding the Facility, a steam network transporting heat to the neighbouring GSK site seems the most viable option. As discussed in Section 6.1.3 above, this therefore gives an approximate total annual heat consumption of 81,421 MWh/a.

This heat demand is to be in the form of 10 bar(g) steam.

7 Heat network technical solution

7.1 Heat network profile

The proposed heat network comprises a steam connection to a single heat user (the GSK site) and therefore heat demand profiles and demand variation depend exclusively on this single demand.

At the time of writing, discussions with GSK on exporting steam are at a high level. As such, heat demand profiles and historic heat demand data were unavailable. This makes it difficult to predict typical daily heat network profiles and demand variation.

Due to the above data being unavailable, it was assumed that the GSK annual heat demand is required at a constant rate throughout the year. This leads to the estimated total annual heat export (and average network) values projected in Table 7.

Table 7: Proposed heat network demand

Annual Heat Load [MWh/a]		Average heat demand [MWth]	
At the point of use	Including pipe losses (at the Facility boundary)	At the point of use	Including pipe losses (at the Facility boundary)
81,421	82,242	9.29	9.39

7.2 Heat network design

As a steam supply network, heat distribution between the Facility and GSK will likely use supported, overground pipework. Steam pipework can be routed underground, but steam piping components such as valves, flanges, expansion joints, would need to be accessible from suitably sized manholes for maintenance purposed. It is possible to house underground steam piping systems in concrete tunnels or large ducts, but the cost of this can be prohibitively expensive. Steam pipes can easily be routed overground but pipe supports are required for the length of the pipe route. Insulated steel pipes would be used to supply pressurised steam to the customer, and to return condensate. Pipe technology is well proven and can provide a heat distribution system with a 30 year plus design life.

Modern heat-insulated piping technology enables steam to be transferred relatively large distances without significant losses.

Heat delivery arriving at a heat consumer's premises usually terminates using a secondary heat exchanger. The heat exchanger is typically arranged to supply heat to a tertiary heating circuit upstream of any boiler plant. The steam in the tertiary circuit can be boosted to the temperature required to satisfy the heating needs of the consumer.

Steam is fed continuously to the consumer's heat exchanger, with condensate pumped continuously back to the Facility. Pumps are operated with 100% standby capacity to maintain heat in the event of a pump fault. Pumps are likely to utilise variable speed drives to minimise energy usage.

The following conservative design criteria relate to a typical steam network utilising conventional heat extraction (as detailed in Section 4.3) and have been used to size the heat transmission pipe diameters. Where possible, the flow temperature will be reduced to minimise heat losses and this will be subject to the requirements of the heat consumers. Flow and return temperatures presented in Table 8 have been selected on the basis of the likely requirements of GSK.

Table 8: Heating – approximate modelled design criteria

Parameter	Value	Unit
Consumer side steam requirements		
Consumer-side steam temperature	184	°C
Consumer-side steam pressure	11	bar(a)
Consumer-side steam flowrate	15.91	tph
Steam export conditions		
Steam temperature at turbine	200	°C
Steam pressure at turbine	14	bar(a)
Steam flowrate at turbine	15.91	tph
Steam pipeline insulation	Rockwool	-
Steam pipeline insulation thickness	80	mm
Condensate return pipeline		
Water return temperature from heat exchanger	160	°C
Water return pressure from heat exchanger	11	bar(a)
Soil temperature	10	°C
Depth of soil covering return pipe	600	mm

Source: Fichtner

Using the above design criteria and allowing for the estimated heat demand for the preferred network, the primary steam transmission pipe size has been calculated as DN200 between turbine extraction and the customer's heat exchanger. This is an indicative figure and will be subject to heat demand verification and subsequent network design.

7.3 Additional heat sources

To maximise the benefits associated with developing a CHP scheme, a review of potential heat sources in the area surrounding the Facility has been undertaken, which could increase the capacity of the heat network and associated benefits. However, there is no additional heat sources identified in the area surrounding the Facility.

7.4 Back-up heat sources

The Facility has been designed to achieve an availability of 91.32 % (i.e. 8,000 operational hours per year). During periods of routine maintenance or unplanned outages the Facility will not be operating, however the heat consumers will still require heat. There is therefore a need, somewhere within the heat distribution system, to provide a back-up source of heat to meet the needs of the heat consumers.

GSK has existing gas boilers that it currently uses to provide process heat. These boilers could be used to supply back-up heat during outages at the Facility. If GSK's back up boilers were used, the cost of a back-up source of heat would not need to be considered when assessing the capital (or operational) costs of the heat network.

If GSK's gas boilers cannot be used, a standby plant would likely comprise oil- or gas-fired boilers with a separate dedicated chimney stack. Back-up boilers are typically designed to ensure that the peak heat export capacity can be met but also provide sufficient turndown to supply smaller loads with reasonable efficiency.

The economic assessment in Section 8.3 assumes that GSK's existing gas-fired boilers can be used as back-up plant.

7.5 Considerations for pipe route

At the present time, no definitive fixed route has been established for the connections from the Facility to the various potential users since no specific agreements have been made. However, an indicative pipe route is presented in Appendix A.

Planning permission, easements and Highways Licenses would need to be obtained for access, construction, and maintenance of the pipeline infrastructure. There is a significant financial implication for obtaining easements, and these would only be progressed once a PPC has been granted for the Facility and heat supply agreements put in place. Traffic management requirements would need to be agreed prior to being able to obtain the necessary Highways Licenses granting permission to install the pipework. The projected timetable for the development of the heat mains is detailed in Section 7.6.

Discussion with the various potential heat users will be entered into which, if successful, would lead into the production of heat supply agreement and designs for the pipework. A full economic analysis will be undertaken, considering the costs associated with pipe installation and lost electricity revenue in order to determine a suitable heat price per unit. However, without a PPC being granted for the Facility, any firm commitment to a supply of heat is difficult to achieve.

7.6 Implementation timescale

The table below gives an indicative timetable for the programme for the construction of the Facility and heat network. The start of the construction of the heat system is dependent on the viability of the system and the location of the heat users. For example, planning and gaining consent for installation of the pipework off the site would take a significant amount of time due to the potential impact on local traffic management. Until a heat supply agreement with GSK has been signed to take heat, pipeline installation will not commence. The installation programme will then need to consider access and working arrangements within the GSK site and any coordination with maintenance to the existing steam supply system. On this basis a conservative programme has been assumed.

Table 9: Implementation programme

Description	Schedule
Obtain Permitting for the Facility	Day 1
Completion of Negotiation for Heat Supply Contracts	6 months
Start of Construction of plant	9 months
Submit planning application for heat mains	18 months
Start of commissioning of the Facility	30 months
Take Over of the Facility	36 months
Completion of Construction on Heat System	52 months
Testing & Commissioning of Heat Network	53 months

Description	Schedule
Start-up of the Heat Supply	54 months

8 Heat network Economic Assessment

8.1 Fiscal Support

The following fiscal incentives are available to energy generation projects and impact the feasibility of delivering a district heating network.

8.1.1 Capacity Market for electricity supplied by the Facility

Under the Capacity Market, subsidies are paid to electricity generators (and large electricity consumers who can offer demand-side response) to ensure long-term energy security for the UK. Capacity Agreements are awarded in a competitive auction and new plants (such as the Facility) are eligible for contracts lasting up to 15 years. Based on the eligibility criteria of the mechanism, the Facility will be eligible for Capacity Market support. Since support is based on electrical generation capacity (which would reduce when operating in CHP mode), these payments will act to disincentivise heat export and have therefore not been included in the economic assessment.

8.1.2 Renewable Heat Incentive

The Renewable Heat Incentive (RHI) was created by the Government to promote the deployment of heat generated from renewable sources. However, no funding announcements have been published for the RHI post March 2022. Therefore, it is unlikely the Facility will receive incentives under the RHI. In addition, to be eligible, the plant in question must not receive any other support or subsidy from public funds including any support received under the Capacity Market. Therefore, if the Facility qualifies for support under the Capacity Market mechanism, it will not be eligible for the RHI.

8.1.3 Contracts for Difference

Contracts for Difference (CfD) has replaced the Renewables Obligation (RO) as the mechanism by which the Government supports low carbon power generation. CfD de-risks investing in low carbon generation projects by guaranteeing a fixed price (the Strike Price) for electricity over a 15-year period. In the second CfD allocation round (executed on 11 September 2017) no funding was allocated for Energy from Waste plants, with or without CHP, on the basis that these are now considered established technologies. The third allocation[7] round was executed in September 2019 with contracts awarded to eligible less established technologies only[8].

The Government has confirmed that it plans to hold the next allocation round in 2021. The Government has also announced that it intends to hold further auctions every two years on a rolling basis. Under the current regulations, CfD delivery years subject to auction must end on 31st March 2026. BEIS has released a consultation[9] on changes ahead of the fourth allocation round for CfD. This consultation proposes that the CfD scheme be extended to cover delivery years until 31st March 2030 and confirms that allocation round 4 will include auctions for both established (Pot 1) and less established (Pot 2) technologies, with energy from waste with CHP included in Pot 1. The

[7] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/832924/Contracts_for_Difference_CfD_Allocation_Round_3_Results.pdf

[8] https://www.gov.uk/government/collections/contracts-for-difference-cfd-third-allocation-round

[9] https://www.gov.uk/government/consultations/contracts-for-difference-cfd-proposed-amendments-to-the-scheme-2020

justification is that the strike price at auction for Pot 1 will likely be below or near the wholesale price for electricity, meaning these projects would effectively be zero subsidy. In this case, the CfD might not provide financial support, but it would provide long term security on the price to be achieved, which can be useful in securing financing. On this basis, the Facility would not receive support under the CfD mechanism but could secure long term security on the electricity price.

8.1.4 Scottish subsidy scheme

We have listed the available renewable subsidy schemes in Scotland. However, the most of them is available for the district heating export schemes, but not for the steam export schemes.

8.1.4.1 District Heat Loan Scheme Scotland

The Scottish Government's district heating loan fund[10] is designed to help address the financial and technical barriers to district heating projects as commercial borrowing can be extremely expensive and difficult to obtain.

Loans up to £500K are available as low interest unsecured loans, with repayment terms of either 10 or 15 years. Loan terms for larger projects (over £500K) will be considered on a case by case basis. A typical interest rate of 3.5 per cent applies for low risk projects (dependent upon credit status). The scheme is open to local authorities, registered social landlords, small and medium sized enterprises and energy services companies [ESCOs] with less than 250 employees.

Since 2011, more than £15M has been lent to 50 different projects across Scotland. These projects have generated benefits such as providing affordable warmth to householders, creating local employment, reducing costs for businesses and reducing greenhouse gas emissions.

8.1.4.2 Energy Investment Fund

The Energy Investment Fund ('EIF')[11] is a Scottish Government Fund managed and delivered by the Scottish Investment Bank. It builds on the success of the Renewable Energy Investment Fund, providing commercial investment for renewable and low carbon energy solutions.

EIF will provide flexible investment and debt funding for energy projects in Scotland that will facilitate, catalyse and accelerate Scotland's transition to a low carbon economy.

EIF is a gap funder and will only invest where there is a demonstrable funding gap in a project's funding package.

A total of £20 million has been allocated to EIF for distribution by 31 March 2020.

Community groups and projects in the process of assembling a funding package should contact the EIF team early in the process to register interest.

Projects must have a demonstrable funding gap, be located in Scotland and have the potential to provide economic benefits to Scotland.

Consideration will be given to both the short and long-term economic impact of projects, and will include a focus on both the fit with the Scottish Government's Energy Strategy and the impact.

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[10] https://districtheatingscotland.com/funding/

[11] https://www.scottish-enterprise.com/support-for-businesses/funding-and-grants/accessing-finance-and-attracting-investment/energy-investment-fund

Projects must be able to evidence the expected carbon emission reduction associated with the project and use no more than 20% fossil fuels (including gas) within the primary fuel source for generation projects.

The fund will not fund R&D, feasibility or pre-development costs.

8.1.4.3 Low Carbon Infrastructure Transition Programme

Scottish Government launched the Low Carbon Infrastructure Transition Programme (LCITP)[12] in March 2015, in partnership with Scottish Enterprise, Highlands and Islands Enterprise, Scottish Futures Trust and sector specialists.

It is a Strategic Intervention supported by the European Structural and Investment Funds, and European match funding for the LCITP is guaranteed up until Autumn 2023. It is overseen by the Low Carbon Infrastructure Transition Programme Board.

The LCITP aims to support Scotland's transition to a low-carbon economy. They provide a range of support, from expert advice to financial support to assist the development and delivery of private, public and community low-carbon projects across the country. Its main focus is assisting projects to develop investment-grade business cases that will help secure public and private capital finance to demonstrate innovative low-carbon technologies in Scotland.

The LCITP is designed to create the conditions to attract commercial investment in innovative low-carbon infrastructure projects, which could be replicated elsewhere in Scotland to maximise our potential in the low-carbon sector. It also aims to contribute towards reducing Scotland's greenhouse gas emissions. The following is the current funding scheme:

Social Housing Net Zero Heat Fund[13]:

The LCITP Social Housing Net Zero Heat funding invitation will target a total investment of £20 million to support social housing landlords across Scotland to deploy low carbon heat and to contribute towards our heat decarbonisation and fuel poverty objectives, improving Scotland’s overall energy efficiency.

This fair and open funding invitation has been designed to accelerate the delivery of energy efficient, low carbon heat provision to social housing projects across the country and to support projects that can effectively contribute towards the achievement net zero emissions in Scotland by 2045.

LCITP wishes to consider applications for capital support from projects led by Registered Social Landlords, Local Authorities and ESCO’s that can contribute towards the realisation of the Scottish Government’s vision to provide warm, high quality, affordable, low carbon homes and establishing a housing sector as part of a successful low carbon economy across Scotland.

Green Recovery: Low Carbon Energy Project Capital Funding invitation

This LCITP funding invitation will target a minimum of £50 million of support for projects that demonstrate innovative low carbon heat solutions for buildings, as well as proposals for integrated energy systems that support the ambitions for Scotland to achieve net zero emissions by 2045 and further catalyse economic recovery from the challenges imposed by the COVID-19 Pandemic.

[12] ttps://www.gov.scot/policies/renewable-and-low-carbon-energy/low-carbon-infrastructure-transition-programme/

[13] https://www.gov.scot/publications/social-housing-net-zero-heat-fund-overview/

This funding invitation has been designed to stimulate and accelerate the delivery of renewable low carbon energy opportunities across Scotland, including the provision of support to projects in urban, rural, island and remote parts of Scotland and areas that are off gas grid. Applications will be considered from private, public and community-led projects, although it is acknowledge that most projects are likely to be supported by consortia of partners.

Projects must be of large scale and must be based in Scotland. As well as delivering emissions reduction, successful projects will also demonstrate economic and social benefit for Scotland and be replicable. LCITP wishes to consider support for projects at capital readiness that can demonstrate a funding gap. For capital ready projects, support may be offered in the form of financial assistance for up to 50% of the total eligible capital costs of a project up to a maximum of £5 million per project, where capital costs cover financial costs associated with the build and installation of an exemplar project.

The closing date for receipt of your Expression of Interest Form is on 13 November 2020.

Expressions of Interest are sought from projects in the below themes:

1. Theme 1 – Low Carbon Heat

   This funding invitation will seek to support the development of projects that aim to deploy low carbon heat projects in Scotland to help meet climate change targets. Projects from both urban, island, rural, off-grid areas providing heat to homes and non-domestic premises, such as businesses and the public sector are welcome to apply.

2. Theme 2 – Integrated Energy Systems

   This invitation will also aim to support the development of projects that can deliver innovative technologies and systems solutions to support Scotland's vision of having a modern, integrated energy system that delivers reliable, low carbon energy at affordable prices to consumers in all parts of Scotland by 2050, as per the Scottish Energy Strategy. This invitation aims to support projects that can deliver integrated low carbon or renewable electricity, heating or storage solutions.

Applications are welcome from low carbon energy projects that will be delivered in Scotland, with a project location, proof of technology concept and an end user for output identified and secured at time of submitting an application.

The project proposal submitted should demonstrate an ability to meet the following criteria:

Mandatory criteria that must be demonstrated by projects

1. ability to demonstrate a contribution to delivery of ambitions to decarbonise Scotland's energy system, including the potential to deliver a significant reduction of greenhouse gas emissions (MtCO2e) and energy consumption;
2. ability to provide confirmation of other sources of funding/finance that make a minimum of 50% contribution towards the capital costs;
3. potential of the project to have a positive and significant social and economic impact on Scotland and to contribute to green recovery;
4. ability to demonstrate additionality of and requirement for LCITP support;
5. potential to demonstrate innovation of technology and/or business case;
6. potential to demonstrate replicability and rollout of project;
7. ability for project to commission by 30 April 2023.

Capital support is to provide funding where projects can demonstrate that they have a project has a completed investment case demonstrating readiness for capital support and a clear funding gap.

Eligible capital costs are:

- financial costs incurred for the purchase of physical assets;
- costs of project build, installation and construction;
- costs of project commissioning;
- non-reclaimable VAT for eligible capital costs;

It is important to note that funding contribution intervention levels will be reviewed in relation to previous public support offered to the applicant or project type to support the Programmes intention to support the low carbon transition to a commercial position.

The Facility would not receive support under this scheme as the heat export scheme would unlikely be commissioned by 30 April 2023.

8.2 Technical feasibility

Step 3 of the CBA methodology requires identification of existing and proposed heat loads which are technically feasible to supply. The draft Article 14 guidance states that the following factors should be accounted for when determining the technical feasibility of a scheme, pertaining to a type 14.5(a) installation.

1. **The compatibility of the heat source(s) and load(s) in terms of temperature and load profiles**

   The CHP scheme has been developed on the basis of delivering steam at the requested demand conditions (refer to Section 7.2). It is reasonable to assume that the Facility would deliver the steam at demand conditions for the identified potential heat consumer. Consumer requirements (in terms of steam temperature and load profiles) will need to be verified in any subsequent design process prior to the implementation of a heat network. Therefore, the heat source and heat load are compatible.

2. **Whether thermal stores or other techniques can be used to match heat source(s) and load(s) which will otherwise have incompatible load profiles**

   Conventional thermal stores or back-up boilers (as detailed in Section 7.4) will likely be included in the CHP scheme to ensure continuity of supply. The specific arrangement will be selected when there is greater certainty with regards heat loads. The option of retaining existing steam raising boiler will be considered.

3. **Whether there is enough demand for heat to allow high-efficiency cogeneration**

   High-efficiency cogeneration is cogeneration which achieves at least 10% savings in primary energy usage compared to the separate generation of heat and power. Primary energy saving (PES) is calculated in the following section.

8.2.1 Primary energy savings

To be considered high-efficiency cogeneration, the scheme must achieve at least 10% savings in primary energy usage compared to the separate generation of heat and power. PES have been calculated in accordance with European Commission Delegated Regulation (EU) 2015/2402 of 12 October 2015 Annex II part (b), using the following assumptions.

1. Annual nominal throughput capacity of 182,400 tonnes per annum based on an NCV of 10.5 MJ/kg.
2. Nominal gross electrical output (expected capacity in fully condensing mode) of 19.3 MW_e.
3. Parasitic load is 2.0 MW_e
4. Z ratio of 4.75, calculated in line with CHPQA Guidance Note 28.

5. Efficiency reference values for the separate production of heat and electricity have been taken as 80% and 25% respectively as defined in Commission Delegated Regulation (EU) 2015/2402 of 12 October 2015[14].

When operating in fully condensing mode (i.e. without heat export) the Facility will achieve a PES of 13.9 %. This is in excess of the technical feasibility threshold defined in the draft Article 14 guidance. The inclusion of heat export at the design case level anticipated for the proposed heat network increases PES to 17.93 %. On this basis, the Facility will qualify as a high-efficiency cogeneration operation when operating in fully condensing mode or CHP mode.

8.3 Results of CBA

A CBA has been carried out on the selected heat load, in accordance with section 3 of the draft Article 14 guidance. The CBA uses an Excel template, '*Environment Agency Article 14 CBA Template.xlsx*' provided by the EA, with inputs updated to correspond with the specifics of this Heat Plan.

The CBA model considers:

1. the revenue streams (heat sales);
2. the costs streams for the heat supply infrastructure (construction and operational); and
3. the lost electricity sales revenue, over the lifetime of the scheme (electricity sales and fiscal benefits).

The following assumptions have been made:

1. The heat export scheme will commence operation in 2023.
2. The heat export infrastructure required to export heat from the Facility to the consumers identified is estimated to have a capital cost of approximately £3.2 million, split over a two-year construction programme.
3. The heat exchanger cost is included within the cost.
4. Back-up boilers will be provided by GSK to meet peak heat demand when the Facility is offline.
5. Operational costs have been estimated based on types of projects.
6. Heat sales revenue will be £22/MWh, index linked for inflation.
7. Electricity sales revenue will be £45/MWh, index linked for inflation.

The results of the CBA indicate that both the nominal project internal rate of return and net present value (before financing and tax) over 30 years are 18.4 % and £0.28million, respectively. Therefore, it is considered that the proposed heat network yields an economically viable scheme in its current configuration. However, no discussions have yet taken place with GSK over the heat price and the figure used is an estimate. Model inputs and key outputs are presented in Appendix C.

[14] http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32015R2402

9 Achievement of energy efficiency threshold

9.1 Heat and power export

The Z ratio, which is the ratio of reduction in power export for a given increase in heat export, can be used to calculate the effect of variations in heat export on the electrical output of the Facility. A value of 4.75 was obtained following CHPQA Guidance Note 28[15], assuming steam extraction at a pressure of 14 bar(a), which is considered sufficient to meet the requirements of the proposed network. Fichtner has modelled heat and power export across a range of load cases and the results are presented in the following table.

Table 10: Heat and Power Export

Load Case	Annual Heat Export at Turbine (MW)	Net Power Exported (MW)	Z Ratio
1. No heat export	0.0	17.3	N/A
2. Heat load required for indicative overall efficiency of 35%,	9.30	15.3	4.75
3. Average network heat load	9.39	15.3	4.75
4. Maximum heat export capacity	10.00	15.2	4.75

An annual average of at least 9.3 MW_{th} must be exported in order to achieve indicative overall efficiency of 35%, as demonstrated by load case 2. The results indicate that for the heat consumers identified in section 6, load case 3 corresponding to an average heat export of 9.39MW_{th} will result in a net power export of 15.3 MW_e.

9.2 Energy recovery efficiency targets

TTWG:

The TTWG states that the Heat and Power Plan must show how, within a period of seven years from cessation of commissioning, further energy can be recovered over and above the initial operational energy recovery. Specifically, the Heat and Power Plan should provide details of how the applicant proposes to achieve the relevant the QI value or Indicative Efficiency specified in Annex 1 of the TTWG's and should give an indication of anticipated progress for each year up to the end of the heat plan period.

TTWG states that the QI value is to be estimated and calculated in accordance with the relevant Combined Heat and Power Quality Assurance (CHPQA) method for the relevant type of thermal treatment facility and fuel type. The calculation must demonstrate that as a minimum the QI or efficiency values meet the energy recovery targets provided in Annex 1 of the TTWG.

Annex 1 of the TTWG requires facilities processing over 70,000 tpa of fuel to meet or exceed the following criteria:

[15] http://www.chpqa.com/guidance_notes/GUIDANCE_NOTE_28.pdf

- QI value ≥ 93; or
- indicative overall efficiency ≥ 35%, in order to demonstrate best practice for thermal treatment of waste facilities.

CHPQA:

CHPQA is an energy efficiency best practice programme initiative by the UK Government. CHPQA aims to monitor, assess and improve the quality of CHP in the UK. In order to prove that a plant is a 'Good Quality' CHP plant, a QI of at least 105 must be achieved at the design, specification, tendering and approval stages. Under normal operating conditions (i.e. when the scheme is operational) the QI threshold drops to 100. The QI for CHP schemes is a function of their heat efficiency and power efficiency according to the following formula.

$QI = X\eta_{power} + Y\eta_{heat}$

where: η_{power} = power efficiency; and

η_{heat} = heat efficiency.

The power efficiency within the formula is calculated using the gross electrical output, and is based on the gross calorific value (GCV) of the input fuel. The heat efficiency is also based on the GCV of the input fuel. The coefficients X and Y are defined by CHPQA based on the total gross electrical capacity of the scheme and the fuel / technology type used.

A number of certificates are required to obtain the financial benefits associated with a CHP scheme. The certification process is overseen by the CHPQA scheme administrator who acts on behalf of the Department for Business, Energy & Industrial Strategy (BEIS). The administrator verifies and validates CHP scheme information submitted by an applicant.

There are two separate CHPQA methods for CHPQA schemes: CHPQA Standard and Guidance Note 44.

1. CHPQA Standard method is used for the CHP schemes to claim;
   a. CHPQA Certificate which is used to claim the Energy Efficiency and Exemption certificates;
   b. CHP Certificate of Energy Efficiency which is used to claim enhanced capital allowances; and
   c. Secretary of State (SoS) CHP exemption certificate which is used to claim climate chance levy (CCL) exemption and exemption from business rates for CHP plant and machinery.
2. Guidance Note 44 QI formulae is used by the CHP schemes to claim the Contract for Difference (CfD) subsidy.

The CHPQA GN44 certificate is an additional CHPQA certificate based on separate QI formulae to those used to access CfD available to Good Quality CHP.

In the June 2018 response to the December 2017 consultation, the Government stated its plans to amend CHPQA GN 44, which is what defines 'good quality' in relation to CfDs and the Renewables Obligation (RO). The changes are to ensure that facilities are not able to achieve 'good quality' while only exporting a low level of useful heat.

Currently, CHP schemes which qualify for a CfD subsidy need to meet the following set of criteria currently set out under 'Fuel Categories and QI Formulae' in Issue 6 of GN44:

- A primary energy saving of 10% for all CHP schemes;
- A heat efficiency of 10% Gross Calorific Value (GCV) for all CHP schemes; and
- An overall efficiency of at least 35% GCV for CHP schemes equal to and over $25MW_e$.

Following the consultation, the Government has decided to apply the following efficiency requirements for GN 44 (Issue 7):

- a primary energy savings of 10% (GCV value);
- a heat efficiency of 10% (GCV value); and
- an overall efficiency of 70% (NCV value).

GN 44 (Issue 7) will only affect future schemes which qualify for CfD under the third and subsequent allocation rounds and will not affect projects which secured CfDs in round 1 or round 2.

The working examples in Annex 5 of the TTWG use QI values from GN 44. This is confusing as GN 44 is not relevant to the CHP schemes which are not applying for CfD subsidy. We believe that the CHPQA Standard method should be applied to the CHP schemes which does not claim CfD subsidy as it is the appropriate "*CHPQA method for the relevant type of thermal treatment facility and fuel type*".

Many large Energy from Waste (EfW) and solid biomass-fuelled CHP plants over 25MW_e were not designed with a sufficient heat offtake relative to power capacity which would be required to meet such high overall efficiency of 70% and, as a result, rarely meet this criterion, so would not fully qualify for RO or CfD purposes regardless of the level of Good Quality CHP output they attain. For this reason, GN 44 Quality Index formulae in previous issues to Issue 7 were derived using criteria that did not include a 70% (NCV) overall efficiency requirement.

Therefore, the government intends to retain this set of criteria for any new CHP schemes which do not claim CfD.

However, we have used GN 44 (issue 7) Quality Index formulae for the ERC to take more conservative approach. The following X and Y coefficients apply to the Facility:

X value = 230; and

Y value = 120.

It is noted that there are a number of differences between the CHPQA method and SEPA requirements with regards to efficiency calculations and system boundaries. We have calculated the QI and efficiency values in accordance with the TTWG for various load cases and the results are presented in in Table 11 below.

Table 11: QI and efficiency calculations

Load case	Gross power efficiency (%), GCV	Heat efficiency (%), GCV	Overall efficiency (%), GCV	CHPQA QI
1. No heat export	25.5%	0.0%	25.5%	58.7
2. Heat load required for indicative overall efficiency of 35%,	22.9%	12.1%	35.0%	67.2
3. Average network heat load	22.9%	12.3%	35.1%	67.3
4. Maximum heat export capacity	22.7%	13.1%	35.8%	67.9

Annex 1 of TTWG stipulates that for facilities processing over 70,000 tpa of fuel, the plant must meet or exceed:

- QI value ≥ 93; or
- indicative overall efficiency ≥ 35%, in order to demonstrate best practice for thermal treatment of waste facilities.

The results indicate that the Facility will exceed indicative overall efficiency threshold of 35% for the average heat load export case (load case 3), based on heat consumers identified in section 6.

For reference, a heat export of 9.30 MW_{th} is required to achieve overall efficiency of 35 %, as demonstrated by load case 2. Based on information provided in the development plans, we estimate that the heat demand capacity identified in the area surrounding the plant will exceed this threshold and that it is technically possible for the Facility to export at least this amount of heat, subject to the subsequent design process.

9.3 BAT 20 of Draft WI BREF - Gross Electrical Efficiency

The Industrial Emissions Directive (IED), which was adopted on 7th January 2013, is the key European Directive which covers almost all regulation of industrial processes in the EU. Within the IED, the requirements of the relevant sector BREF become binding as BAT Conclusions. The 'Final Draft' WI BREF[16] (herein referred to as the Draft WI BREF) was published in December 2018. This includes, as section 5, the draft BAT Conclusions.

BAT 20 Conclusions of the Draft WI BREF includes Energy efficiency levels associated with the best available techniques (BAT-AEELs) range of 25-35 for new incineration plants.

In accordance with the gross electrical efficiency calculation methods of BAT 20 Conclusions, the gross electrical efficiency for the Facility has been calculated in Table 12 below.

Table 11 in Section 9.2 of this Heat and Power Plan is directly comparable to the SEPA Thermal Treatment of Waste Guidelines (TTWG) 2014.

The methodology for calculating efficiency is different between the TTWG and the Draft WI BATC.

For the purposes of the TTWG's, power efficiency is calculated using the gross electrical output based on the gross calorific value (GCV) of the input fuel. The calculation method used in Table 11 in Section 9.2 of this Heat and Power Plan is based on the method described in Annex 3 of the TTWG.

However, for the purposes of the Draft WI BATC, gross electrical efficiency is calculated using the gross electrical output based on the net calorific value of the input fuel and shown in Table 12.

Table 12: BAT 20- Gross electrical efficiency

Load case	Annual Heat Export at Turbine (MW)	Gross electrical efficiency (%), NCV	BAT-AEEL (%) Gross electrical efficiency (NCV) New plant
1. No heat export	0.0	29.0%	25-35
2. Heat load required for indicative overall efficiency of 35%,	9.30	26.1%	25-35

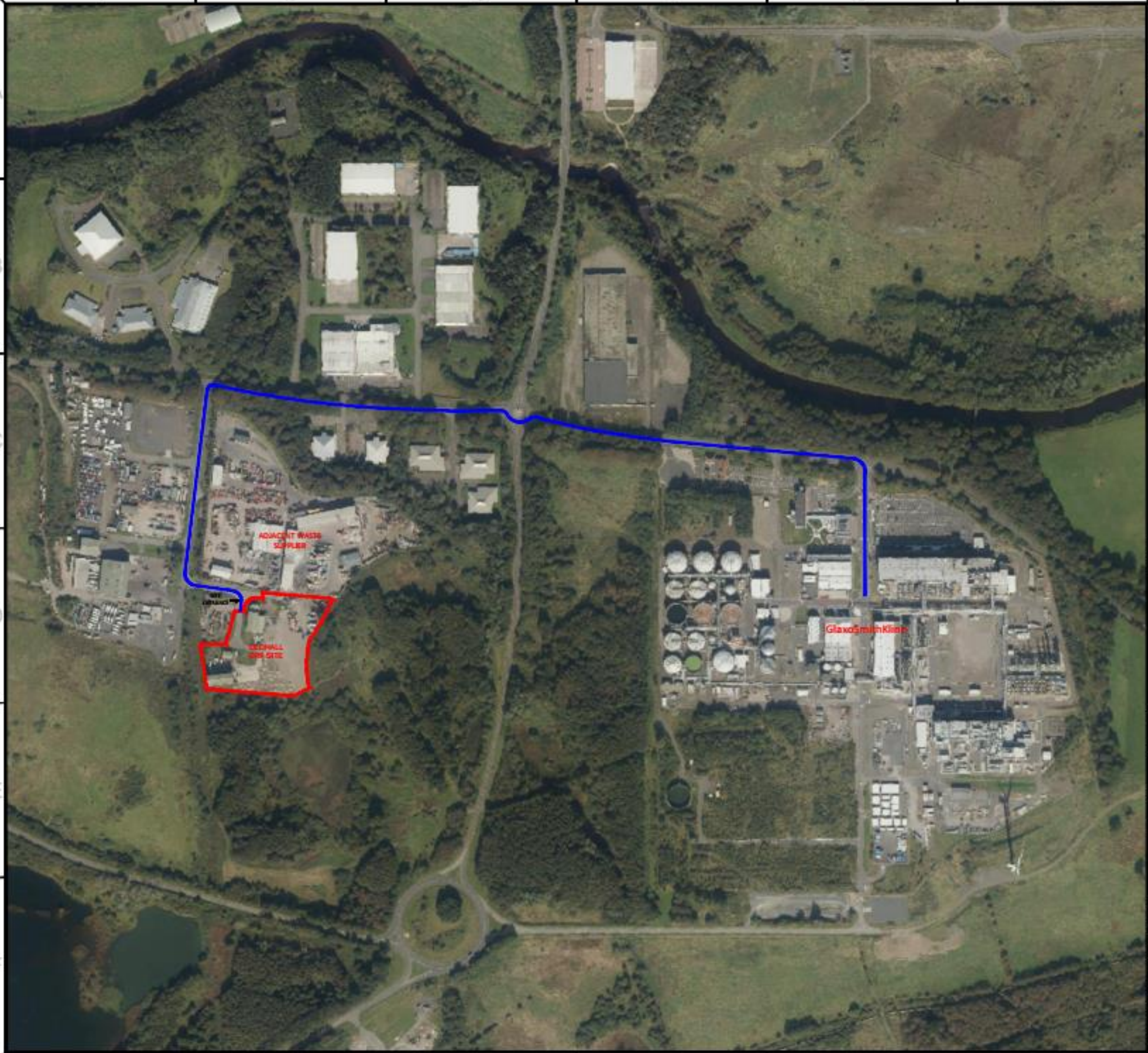
[16] https://eippcb.jrc.ec.europa.eu/reference/BREF/WI/WI_BREF_FD_Black_Watermark.pdf

Load case	Annual Heat Export at Turbine (MW)	Gross electrical efficiency (%), NCV	BAT-AEEL (%) Gross electrical efficiency (NCV) New plant
3. Average network heat load	9.39	26.0%	25-35
4. Maximum heat export capacity	10.00	25.9%	25-35

As can be seen from Table 12 above, the gross electrical efficiency of the Facility for each load case at is in accordance with the BAT-AEEL efficiency ranges of BAT 20.

Appendices

A Pipe route and heat users



ALL INFORMATION ON THIS DRAWING IS INDICATIVE ONLY, AND MAY BE SUBJECT TO FURTHER DESIGN DEVELOPMENT.

DO NOT SCALE

KEY

- OLDHALL ERF FACILITY SITE BOUNDARY
- HEAT USER GlaxoSmithKline PIPE ROUTE

REV.	DETAILS OF REVISION	DRAWN	CHKD	APR	DATE
R0.0	PRELIMINARY	AO	DTW	VBT	22.10.20

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CLIENT: DOVERYARD LTD

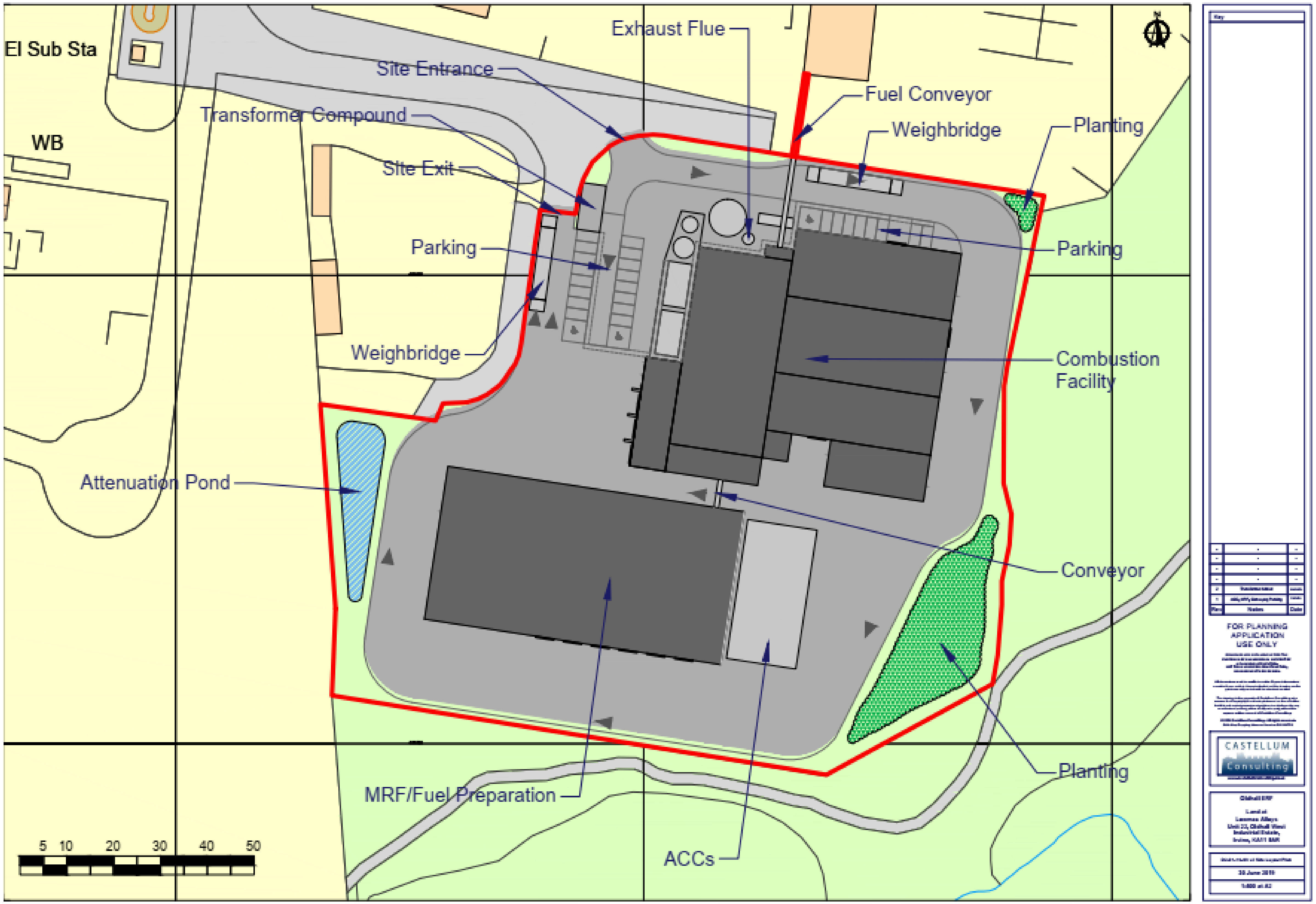
SITE: OLDHALL ENERGY RECOVERY FACILITY

PROJECT: PPC APPLICATION

TITLE: HEAT PLAN

DRAWING STATUS:	PRELIMINARY	
DRAWN BY:	AO	DATE: 22.10.20
CHECKED BY:	DTW	DATE: 22.10.20
APPROVED BY:	VT	DATE: 22.10.20
FILENAME:	S2913-8000-0008AO1 HEAT PLAN R0.0	
OFFICE OF ISSUE:	STOCKPORT	
SHEET SIZE:	A3	SCALE: 1:5000
DRAWING No.:	S2913-8000-0008 Sheet 1 of 1	REVISION: R0.0

B Site Location and Layout Drawings


El Sub Sta
WB
Exhaust Flue
Site Entrance
Transformer Compound
Site Exit
Fuel Conveyor
Weighbridge
Planting
Parking
Parking
Weighbridge
Combustion Facility
Attenuation Pond
Conveyor
Planting
MRF/Fuel Preparation
ACCs
5 10 20 30 40 50
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C CBA Inputs and Key Outputs

INPUTS

Version Jan 2015

Scenario Choice (dropdown box)

Scenario Choice (dropdown box)	1	Power generator (Heat Source) same fuel amount

Key

2	Participant to define
2	Regulatory prescribed
2	Calculated
2	Prescribed - but possibility to change if make a case

Technical solution features

Heat carrying medium (hot water, steam or other) (dropdown box)	Steam
Total length of supply pipework (kms)	1.584
Peak heat demand from Heat User(s) (MWth)	9.39
Annual quantity of heat supplied from the Heat Source(s) to Heat User(s) (MWh)	*Lines 49 & 79*

DCF Model Parameters

Discount rate (pre-tax pre-financing) (%) - 17% suggested rate	17%
Project lifespan (yrs)	30
Exceptional shorter lifespan (yrs)	0

Cost and revenue streams

Construction costs and build up of operating costs and revenues during construction phase

		% operating costs and revenues during construction phase	Heat Supply Infrastructure - used in Scenarios 1, 2, 3 and 5	Heat Station - used in Scenarios 1, 2 and 3	Standby boilers (only if needed for Scenarios 1, 2 and 3)	Industrial CHP - used in Scenario 4 *
Project asset lifespan (yrs)			30	30	30	
Exceptional reason for shorter lifespan of Heat Supply Infrastructure, Standby Boiler and/ or Heat Station (yrs)						
Construction length before system operational and at steady state (yrs)	3					
Number of years to build			3	3	3	0
		% (ONLY IF APPLICABLE)	£m	£m	£m	£m
Year 1 costs (£m) and build up of operating costs and revenues (%)		0%	1.6	0	0	
Year 2 costs (£m) and build up of operating costs and revenues (%)		0%	1.6	0	0	
Year 3 costs (£m) and build up of operating costs and revenues (%)		0%	0	0	0	
Year 4 costs (£m) and build up of operating costs and revenues (%)						
Year 5 costs (£m) and build up of operating costs and revenues (%)						

Non-power related operations

OPEX for full steady state Heat Supply Infrastructure on price basis of first year of operations (partial or steady state) (£m)	0.3
OPEX for full steady state Heat Station on price basis of first year of operations (partial or steady state) (£m)	0.1
OPEX for full steady state Standby Boilers on price basis of first year of operations (partial or steady state) (£m)	0.0
OPEX for full steady state Industrial CHP on price basis of first year of operations (partial or steady state) (£m) *	
Additional equivalent OPEX to pay for a major Industrial CHP overall spread over the life of the asset (£m) on price basis of first year of operations (partial or steady state) (£m) *	
Other 1 - Participant to define (£m)	
Other 2 - Participant to define (£m)	

Total non-power related operations	**0.4**
Annual inflation for all non-power related OPEX from first year of operations (full or partial) (%)	2.0%

Unit Energy Prices, Energy Balance, Fuel Related Operational costs and Revenue Stream

	Scenario used	1 Power generator (Heat Source) same fuel amount	2 Power generator (Heat Source) same electrical output	3 Industrial installation (Heat Source) - use waste heat	4 Industrial installation (Heat Source) - CHP set to thermal input	5 District heating (Heat User)
Heat sale price (£/ MWh) at first year of operations (partial or full)	25.51	25.51				
Annual quantity of heat supplied from the Heat Source(s) to Heat User(s) at steady state (MWh)	82,242	82,242				
Equivalent heat sales if first year of operations is steady state (£ m)	2.1					
Heat sale price inflation from first year of operations (full or partial) (% per year)	2.0%	2.0%				
Percentage of heat supplied by Standby Boiler (if relevant)	0%	0%				
'Lost' electricity sale price (£/ MWh) at first year of operations	60.30	60.30				
Z-ratio (commonly in the range 3.5 - 8.5)	4.75	4.75				
Power generation lost at steady state (MWh)	17,314	17,314				
Equivalent 'lost' revenue from power generation if first year of operations is steady state (£ m)	1.04					
Electricity sale price inflation from first year of operations (full or partial) (% per year)	2.0%	2.0%				
Industrial CHP electricity sale price (£/ MWh) at first year of operations (full or partial)	0.00					
Industrial CHP electrical generation in steady state (MWh)	0					
Equivalent revenue from power generation if first year of operations is steady state (£ m)	0.00					
Industrial CHP electricity price inflation from first year of operations (full or partial) (% per year)	0.0%					
Fuel price for larger power generator/ CHP at first year of operations (full or partial) (£ / MWh)	0.00					
Z-ratio (commonly in the range 3.5 - 8.5)	0					
Power efficiency in cogeneration mode (%)	0					
Additional fuel required per year for larger power generator / CHP in steady state (MWh)	0		#DIV/0!			
Equivalent additional fuel costs if first year of operations is steady state (£ m)	0.00					
Fuel price inflation from first year of operations (full or partial) (% per year)	0.0%					
Fuel price for Standby Boiler at first year of operations (£ / MWh)	26.67	26.67				
Boiler efficiency of Standby Boiler (%)	80%	80%	80%	80%		
Additional fuel required per year for Standby Boiler in steady state (MWh)	-	-	-	-		
Equivalent additional fuel costs if first year of operations is steady state (£m)	-					
Fuel price inflation for Standby Boiler from first year of operations (full or partial) (% per year)	2.00%	2.0%				
Heat purchase price (£/ MWh) at first year of operations (partial or full)	0.00					
Annual quantity of heat supplied from the Heat Source(s) to Heat User(s) at steady state (MWh)	0					
Equivalent cost of heat purchased if first year of operations is steady state (£ m)	0.0					

Heat purchase price inflation from first year of operations (full or partial) (% per year)	0.0%	
Fuel price (£ / MWh) at first year of operations (partial or full)	0.00	
Boiler efficiency of district heating plant	0%	80%
Fuel avoided per year in steady state (MWh)	0	-
Equivalent fuel savings if first year of operations is steady state (£m)	0.0	
Fuel price inflation from first year of operations (full or partial) (% per year)	0.0%	4.0%
Fiscal benefits (£m) in first year of operations assuming it is at steady state **	0.00	0.00
Fiscal benefits inflation rate from first year of opeations (full or partial) (%) **	0.0%	

* In the case of Industrial CHP a separate model template is available for typical indicative CAPEX, non-power related OPEX, additional equivalent OPEX to pay for a major overall, MWh of electricity generated in the steady state and the additional fuel required.

** Operator only needs to enter a value for fiscal benefits (£m) and the annual fiscal benefit inflation rate (%) if the NPV without fiscal benefits is negative at the specified discount rate

OUTPUTS

Nominal Project IRR (before financing and tax) over 33 years	18.4%
Nominal NPV (before financing and tax) (£m) over 33 years	0.28

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