FICHTNER

Consulting Engineers Limited

Portland Energy Recovery Facility

Powerfuel Portland Limited

CHP-Ready Assessment

ENGINEERING + CONSULTING

Document approval

	Name	Signature	Position	Date
Prepared by:	Vildan Taylor	V. Taylor	Associate Senior Consultant	29/09/2020
Checked by:	James Sturman		Lead Consultant	29/09/2020

Document revision record

Revision no	Date	Details of revisions	Prepared by	Checked by
00	29/09/2020	First draft to the Client	VBT	JRS

1 Introduction

1.1 Background

Powerfuel Portland Limited (herein referred to as Powerfuel) is proposing to construct and operate the Portland Energy Recovery Facility (the Facility) at a site within Portland Dock on the Isle of Purbeck, Dorset.

The Facility will comprise an Energy Recovery Facility and associated infrastructure, which will be fuelled by incoming municipal (and some commercial & industrial) non-hazardous waste.

1.2 Objective

The principle objectives of this study are as follows.

1. Conduct an economic assessment in line with the Environment Agency (EA) guidance feeding into the cost-benefit assessment (CBA) for combustion installations as required under Article 14 of the Energy Efficiency Directive.
2. Produce a CHP-Ready Assessment in accordance with the EA's guidance titled '*CHP Ready Guidance for Combustion and Energy from Waste Power Plants*' (herein referred to as the CHP-ready Guidance[1]), including a clear statement on best available techniques (BAT), combined heat and power (CHP) envelope and the CHP-Ready Assessment form.

This report should be read in parallel with the Heat Plan, presented in Appendix F of the EP application, developed to identify potential heat users and their heat demands to support the planning application for the Facility.

[1] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/296450/LIT_7978_e06fa0.pdf

2 Conclusions

2.1 Economic Assessment

An assessment of the costs and revenues associated with the construction and operation of the proposed district heating network has been undertaken. This has been entered into the EA's CBA template. The CBA takes account of heat supply system capital and operating costs, heat sales revenue and lost electricity revenue as a result of diverting energy to the heat network.

The results of the CBA indicate that the estimated £ 9.4 million capital investment will not be offset by heat sales revenue. The nominal project internal rate of return (before financing and tax) over 30 years is projected as 11.7 %, with a net present value of -£2.44 million.

Given the current Renewable Heat Incentive (RHI) scheme is due to end in March 2022, it is unlikely that the Facility will qualify for support under the scheme. The economic feasibility of the scheme will be reassessed in the future when there is a better understanding of heat demands considering any subsidies that support the export of heat.

As construction of a district heating network is currently not economically feasible, the Facility will be built to be CHP-ready. As such, the Facility will meet the requirements of BAT tests outlined in the CHP-ready Guidance.

2.2 CHP-Ready Assessment

A CHP-Ready Assessment has been carried out and the completed CHP Ready Assessment form is provided in Appendix C. As the economic case for the proposed heat network is not viable, constructing the Facility as CHP Ready is considered to represent BAT.

As a 'CHP-ready facility', the Facility will be designed to be ready, with minimum modification, to supply heat in the future. Given the uncertainty of future heat loads, the initial electrical efficiency of a CHP-ready facility (before any opportunities for the supply of heat are realised) should be no less than that of the equivalent non-CHP-ready facility. The Facility will include steam capacity designed into the turbine bleeds to facilitate heat export in the future, and safeguarded space within or close to the turbine hall to house CHP equipment.

To satisfy the third BAT test on an ongoing basis, Powerful is committed to carrying out periodic reviews of opportunities for the supply of heat to realise CHP.

3 Legislative Requirements

3.1 CHP-Ready Guidance

The EA published the CHP ready Guidance in February 2013. The guidance applies to the following facilities, which will be regulated under the Environmental Permitting (England and Wales) Regulations 2016:

- new combustion power plants (referred to as power plants) with a gross rated thermal input of 50 MW or more; and
- new EfW plants with a throughput of more than 3 tonnes per hour of non-hazardous waste or 10 tonnes per day of hazardous waste.

The Facility will be regulated as a waste incineration facility with a throughput of more than 3 tonnes per hour. Therefore, the requirements of the CHP-ready Guidance will apply.

The EA requires developers to demonstrate BAT for a number of criteria, including energy efficiency. One of the principal ways of improving energy efficiency is through the use of CHP, for which three BAT tests exist. The first involves considering and identifying opportunities for the immediate use of heat off-site. Where this is not technically or economically possible, the second test involves ensuring that the plant is built to be CHP-ready. The third test involves carrying out periodic reviews to determine whether the situation has changed and if there are opportunities for heat use off site.

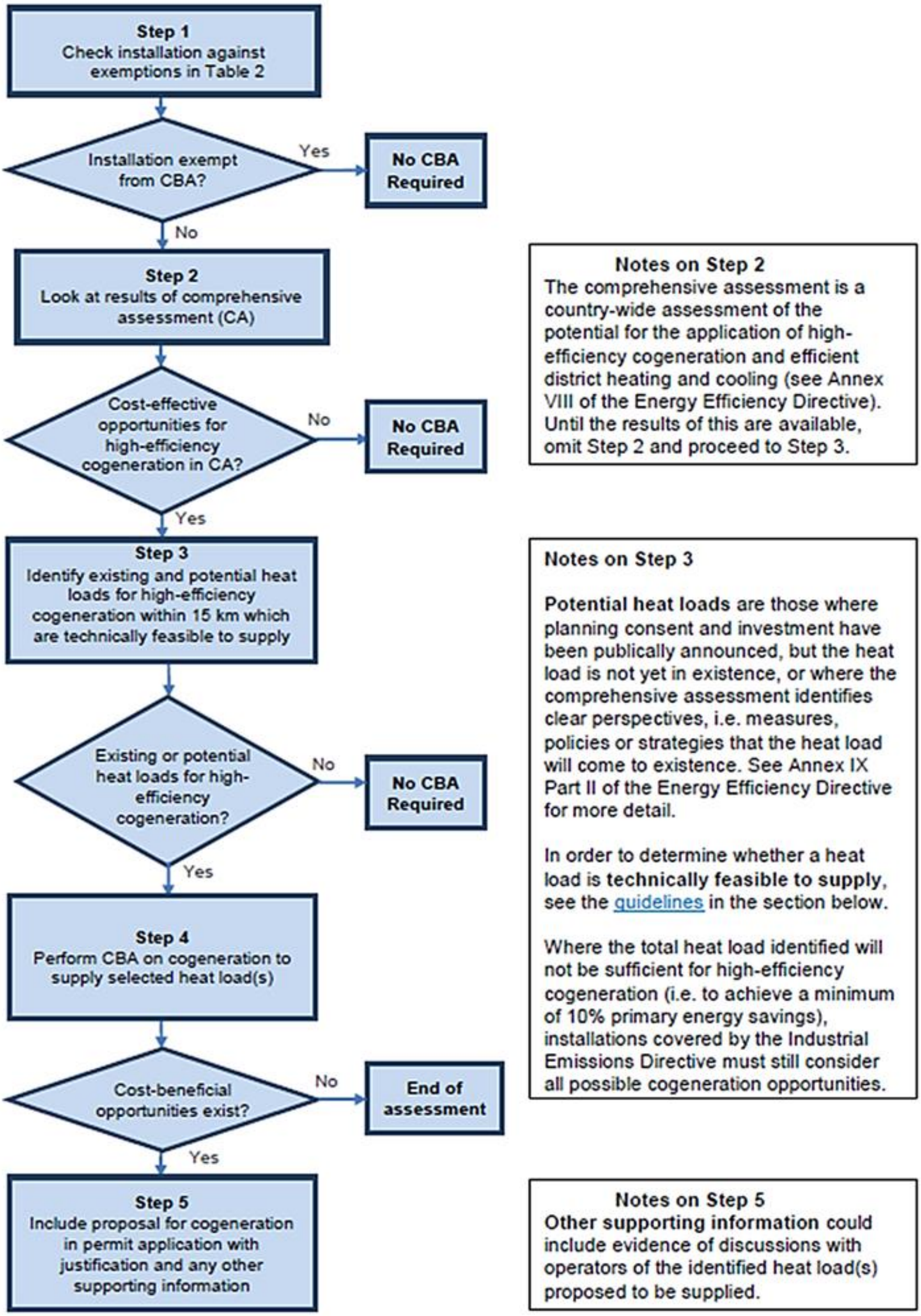
3.2 Energy Efficiency Directive

From 21 March 2015, operators of certain types of combustion installations are required to carry out a CBA of opportunities for CHP when applying for an EP. This is a requirement under Article 14 of the Energy Efficiency Directive and applies to a number of combustion installation types. As a new electricity generation installation with a total aggregated net thermal input of more than 20 MWth, 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*'[2]. Figure 1 describes the process that must be followed for type 14.5(a) and 14.5(b) installations.

[2] 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 Heat Network Economic Assessment

4.1 Fiscal Support

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

4.1.1 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 considered within the economic assessment.

4.1.2 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, the Facility will not receive incentives under the RHI.

4.1.3 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[3] round was executed in September 2019 with contracts awarded to eligible less established technologies only[4].

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. Department for Business, Energy and Industrial Strategy (BEIS) has released a consultation[5] 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 justification is that the strike price at auction for Pot 1 will likely be below or near the wholesale price for electricity, meaning these

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

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

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

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.

4.1.4 Heat Network Investment Project funding

The Heat Network Investment Project (HNIP) aims to deliver carbon savings and create a self-sustaining heat network market through the provision of subsidies, in the form of grants and loans, for heat network projects. Up to £320 million has been made available to fund the HNIP between 2019 and 2022. Following a pilot scheme, which ran from October 2016 to March 2017, the BEIS has confirmed that funding will be available for both public and private sector applicants, and that there will be no constraints on scheme size. In the 2020 Budget, in March 2020, the Government confirmed that £96 million will be made available for the final year of the HNIP, which ends in March 2022.

The HNIP may be a source of funding that would improve the economic viability of the heat network. The level of funding that the Facility could achieve under this program would depend on the final size of the network and commercial arrangements.

Relatively modest grant funding, to assist local authorities in heat network project development, is also available through the Heat Networks Delivery Unit (HNDU), although this could not be received by the Facility directly and would not serve to support the delivery of the project.

4.1.5 Green Heat Networks Scheme

After HNIP ends in March 2022, the Government has committed to investing a further £270 million in a new Green Heat Networks Scheme (GHNS), enabling new and existing heat networks to be low carbon and connect to waste heat that would otherwise be released into the atmosphere.

Following discussions with BEIS, the UK District Energy Association (ukDEA) has confirmed the following regarding the GHNS and difference to HNIP:

1. GHNS is to enable new and existing networks to be low carbon and connect to waste heat. It is not for the construction of heat networks in themselves as the HNIP fund is. To be clear this new GHNS fund is very much about driving the transition towards a low carbon source of heat for planned and existing networks and not specifically about delivering large scale heat networks as HNIP is.
2. GHNS is a capital grant fund and not a split loan and grant as HNIP is.
3. The GHNS fund will be available from 2022 to 2025.
4. The exact mechanics of how it will work are to be decided but it is expected that there will be a consultation in Q4 2020.
5. It is expected that the same state aid rules will apply to this new fund; therefore, it would be unlikely to fund greater than 50 % of the capital costs of the heat source.

GHNS is aimed at waste heat as a heat source and would not apply to steam extractions from turbine. Therefore, the Facility will not be eligible for the GHNS on the basis that heat exported from the facility will be from steam extractions.

4.2 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 heat at typical district heating conditions (refer to the Heat Plan presented in Appendix F of the EP application). It is reasonable to assume that identified potential heat consumers would be able to utilise hot water at the design conditions. Consumer requirements (in terms of hot water 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 considered to be 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 (refer to the Heat Plan presented in Appendix F of the EP application) 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.

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.

4.2.1 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. The PES has 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 11 MJ/kg.
2. Nominal gross electrical output (expected capacity in fully condensing mode) of 18.1 MW_e.
3. Parasitic load of 2.9 MW_e.
4. Z ratio of 7.2.
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[6].

When operating in fully condensing mode (i.e. without heat export) the Facility will achieve a PES of 3.65 %. The inclusion of the average annual heat export of 2.6 MW_{th} at the design case level anticipated for the proposed heat network increases PES to 5.99 %. Where the total heat load identified will not be sufficient for high-efficiency cogeneration (i.e. to achieve a minimum of 10% primary energy savings), installations covered by the Industrial Emissions Directive must still consider all possible cogeneration opportunities.

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

4.3 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 cost streams for the heat supply infrastructure (construction and operational, including back-up plant); and
3. the lost electricity sales revenue, over the lifetime of the scheme (electricity sales).

The following assumptions have been made:

1. The DH scheme will commence operation in 2026.
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 £6.55 million, split over a three-year construction programme.
3. The heat station will cost approximately £1.2 million, split over a three-year construction programme.
4. Back-up boilers will be provided to meet the peak heat demand, at a cost of approximately £1.67 million.
5. Operational costs have been estimated based on similar sized projects.
6. Heat sales revenue will be £40 / MWh, current price and index linked for inflation in CBA.
7. Electricity sales revenue will be £52[7] / MWh, current price and index linked for inflation in CBA.
8. Standby boiler fuel costs will be £23 [8]/ MWh, current price and index linked for inflation in CBA.
9. Standby boiler(s) will supply 6.38 % of annual heat exported.

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 11.7 % and -£2.44 million respectively. Unattractive returns are a result of large network pipe lengths resulting in higher capital expenditure, combined with a relatively low identified heat demand. Therefore, it is considered that the proposed heat network does not yield an economically viable scheme in its current configuration. Model inputs and key outputs are presented in Appendix B.

[7] Please refer to BEIS Updated Energy Projections for electricity and gas prices:
Annex-M https://www.gov.uk/government/publications/updated-energy-and-emissions-projections-2018

[8] Please refer to BEIS Updated Energy Projections for electricity and gas prices:
Annex-M https://www.gov.uk/government/publications/updated-energy-and-emissions-projections-2018

5 CHP-Ready BAT Assessment

5.1 CHP-Ready BAT Assessment

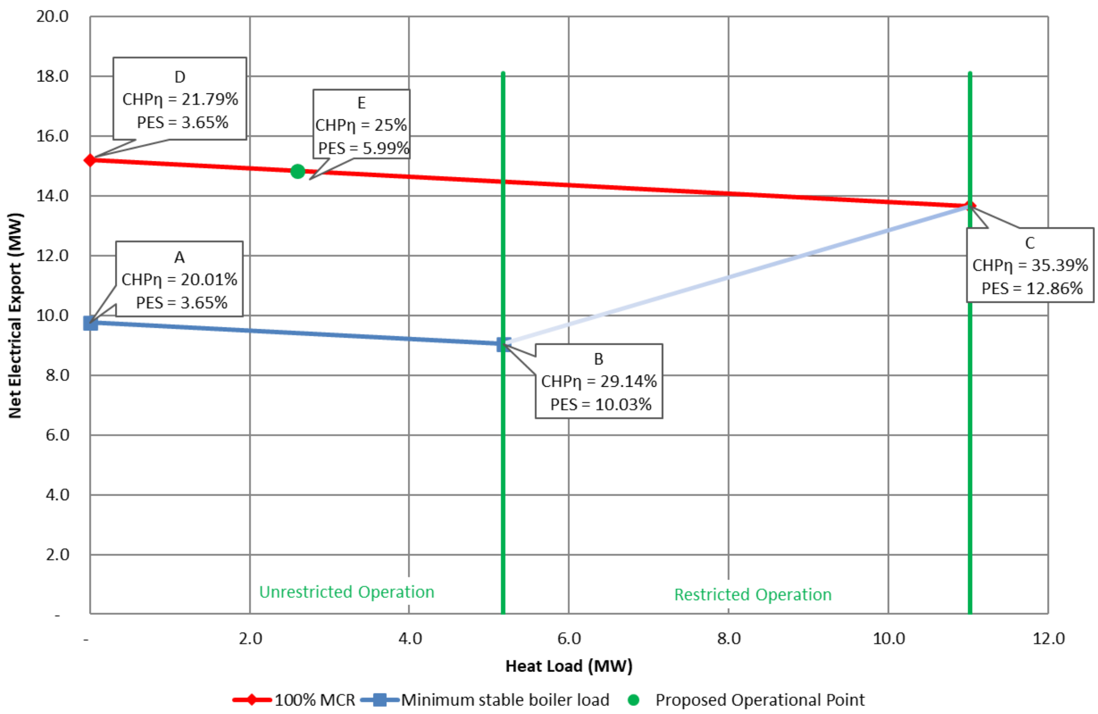
A CHP-Ready Assessment which considers the requirements of the CHP-ready Guidance has been completed, and is provided in Appendix C.

The 'CHP envelope' as outlined under requirement 2 of the CHP-ready Guidance, which identifies the potential operational range of a new plant where it could be technically feasible to operate electrical power generation with heat generation, is provided in Figure 2.

The points defining the CHP envelope are as follows.

- A: minimum stable load (with no heat extraction).
- B: minimum stable load (with maximum heat extraction).
- Line A to B: minimum electrical power output for any given heat load (corresponds to the minimum stable plant load).
- C: 100 % load (with maximum heat extraction).
- D: 100 % load (with no heat extraction).
- Line D to C: maximum electrical power output for any given heat load (corresponds to 100 % plant load).
- E: proposed operational point of the Facility, based on the proposed heat network.
- Unrestricted operation: if a selected heat load is located in this region, the Facility will have the ability to operate at any load between minimum stable plant load and 100 % plant load whilst maintaining the selected heat load.
- Restricted operation: if a selected heat load is located in this region, the Facility will not have the ability to operate over its full operational range without a reduction in heat load.

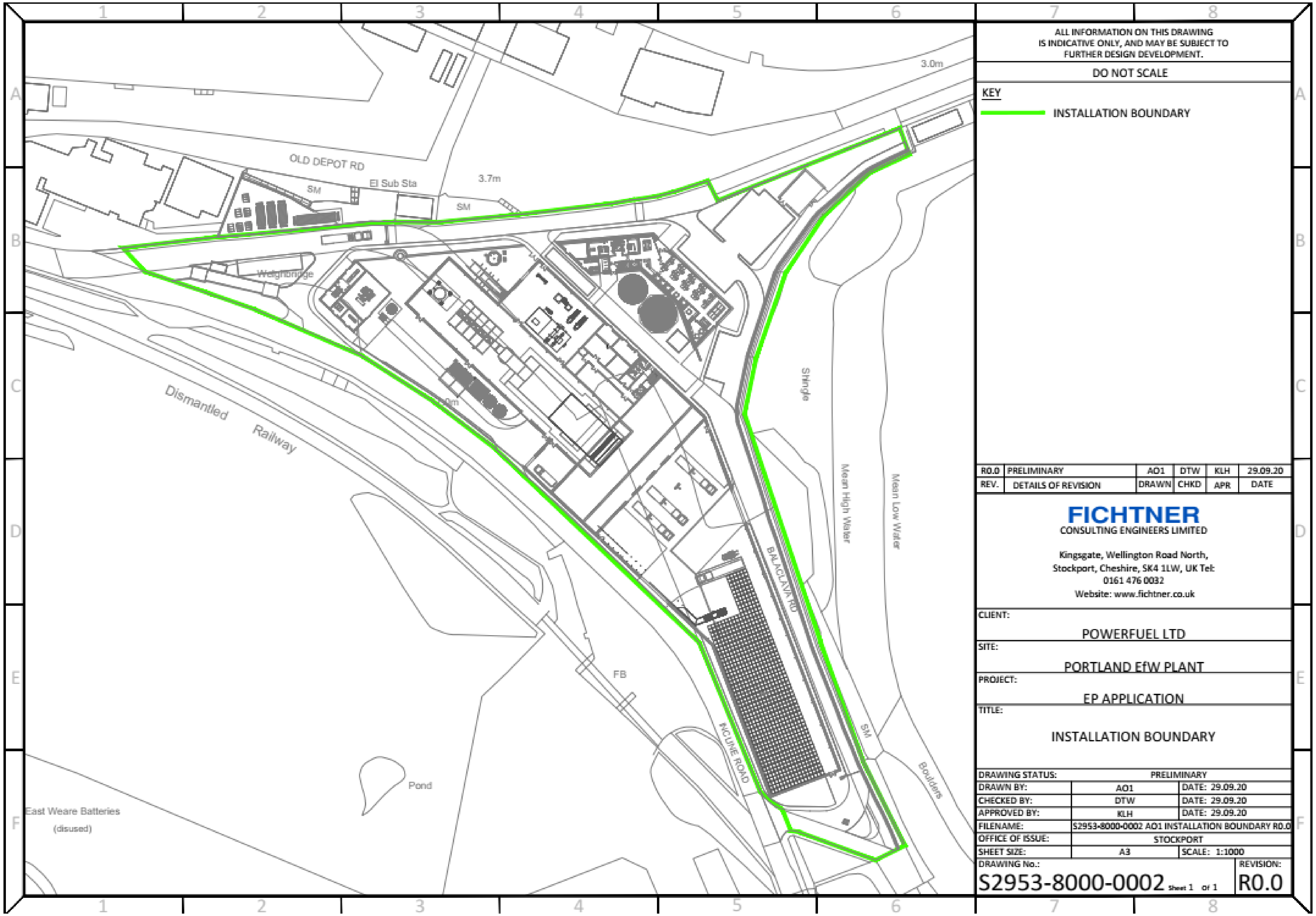
Figure 2: Graphical representation of CHP envelope for proposed heat network



The proposed operational point (point E) represents the annual average heat demand exported to the proposed heat network, as discussed in the Heat Plan presented in Appendix F of the EP application . It considers the heat losses and pressure drop in the pipe network; therefore, it corresponds to the annual average heat demand predicted at the installation boundary. The operational range for the Facility will ultimately be subject to the required hot water flow temperature and final steam turbine selection, which are subject to detailed design.

Appendices

A Site Layout


OLD DEPOT RD
El Sub Sta
3.7m
3.0m
SM
Weighbridge
Dismantled
Railway
Shingle
Mean High Water
Mean Low Water
BALACLAVA RD
INCLINE ROAD
FB
Pond
Boulders
East Weare Batteries
(disused)
ALL INFORMATION ON THIS DRAWING IS INDICATIVE ONLY, AND MAY BE SUBJECT TO FURTHER DESIGN DEVELOPMENT.
DO NOT SCALE
KEY
INSTALLATION BOUNDARY
R0.0 PRELIMINARY AO1 DTW KLH 29.09.20
REV. DETAILS OF REVISION DRAWN CHKD APR DATE
FICHTNER
CONSULTING ENGINEERS LIMITED
Kingsgate, Wellington Road North, Stockport, Cheshire, SK4 1LW, UK Tel: 0161 476 0032
Website: www.fichtner.co.uk
CLIENT: POWERFUEL LTD
SITE: PORTLAND EfW PLANT
PROJECT: EP APPLICATION
TITLE: INSTALLATION BOUNDARY
DRAWING STATUS: PRELIMINARY
DRAWN BY: AO1 DATE: 29.09.20
CHECKED BY: DTW DATE: 29.09.20
APPROVED BY: KLH DATE: 29.09.20
FILENAME: S2953-8000-0002 AO1 INSTALLATION BOUNDARY R0.0
OFFICE OF ISSUE: STOCKPORT
SHEET SIZE: A3 SCALE: 1:1000
DRAWING No.: S2953-8000-0002 Sheet 1 of 1
REVISION: R0.0

B CBA Inputs and Key Outputs

INPUTS — Version Jan 2015

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)	Hot water
Total length of supply pipework (kms)	4.959
Peak heat demand from Heat User(s) (MWth)	11.02
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%	2.182268384	0.401194299	0.556917765	
Year 2 costs (£m) and build up of operating costs and revenues (%)	0%	2.182268384	0.401194299	0.556917765	
Year 3 costs (£m) and build up of operating costs and revenues (%)	0%	2.182268384	0.401194299	0.556917765	
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)	0.0
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)	0.1
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	**0.2**
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)	75.20	75.20				
Annual quantity of heat supplied from the Heat Source(s) to Heat User(s) at steady state (MWh)	20,046	20,046				
Equivalent heat sales if first year of operations is steady state (£ m)	1.5					
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)	6%	6%				
'Lost' electricity sale price (£/ MWh) at first year of operations	60.30	60.30				
Z-ratio (commonly in the range 3.5 - 8.5)	7.20	7.20				
Power generation lost at steady state (MWh)	2,607	2,607				
Equivalent 'lost' revenue from power generation if first year of operations is steady state (£ m)	0.16					
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)	1,599	1,599	-	-		
Equivalent additional fuel costs if first year of operations is steady state (£m)	0.04					
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	11.7%
Nominal NPV (before financing and tax) (£m) over 33 years	-2.44

C CHP-R Assessment Form

#	Description	Units	Notes / Instructions
Requirement 1: Plant, Plant location and Potential heat loads			
1.1	Plant name		Portland Energy Recovery Facility
1.2	Plant description		The main activities associated with the Facility will be the combustion of incoming waste to raise steam and the generation of electricity in a steam turbine/generator. The Facility includes a single waste incineration line, waste reception hall, main thermal treatment process, turbine hall, on-site facilities for the treatment or storage of residues and waste water, flue gas treatment, stack, boilers, 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 has been designed to export power to the National Grid. The Facility will generate approximately 18.1 MWe of electricity in full condensing mode. The Facility will have a parasitic load of 2.9 MWe. Therefore, the maximum export capacity of the Facility is 15.2 MWe. In addition to generating power, the Facility has been designed to be capable of exporting up to 11 MW_{th} heat to local heat users, which is suitable for the identified district heating network. The maximum heat capacity will be subject to the requirements of the heat consumers and confirmed during detailed design stage. 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 is 22.8 tonnes per hour of fuel with an NCV of 11 MJ/kg. The expected operational availability is 8000 hours per annum (91.3 %), which is regarded as typical for an EfW plant

#	Description	Units	Notes / Instructions
			in the UK. Therefore, the nominal capacity for the installation is 182,640 tonnes per annum.
1.3	Plant location (Postcode / Grid Ref)		The site is located on the north eastern coast of the Isle of Portland, approximately 600 m east of the village of Fortuneswell. The site lies within the port and is not publicly accessible. Vehicular access is from the west, through the main Portland harbour complex, via Castletown, Castel Road, Lerret Road and A354. The Facility will be located at an approximate National Grid Reference of SY 69607 74248, with the nearest postcode listed as DT5 1PH.
1.4	Factors influencing selection of plant location		This is given in Environmental Statement: Non-Technical Summary- Alternatives NTS.30, NTS.31, NTS.32, NTS.33, NTS.34, NTS.35.
1.5	Operation of plant		
a)	Proposed operational plant load	%	100
b)	Thermal input at proposed operational plant load	MW	69.76
c)	Net electrical output at proposed operational plant load	MW	15.20
d)	Net electrical efficiency at proposed operational plant load	%	21.79%
e)	Maximum plant load	%	100
f)	Thermal input at maximum plant load	MW	69.76
g)	Net electrical output at maximum plant load	MW	15.20
h)	Net electrical efficiency at maximum plant load	%	21.79%
i)	minimum stable plant load	%	70%
j)	Thermal input at minimum stable plant load	MW	48.83
k)	Net electrical output at minimum stable plant load	MW	9.05
l)	Net electrical efficiency at minimum stable plant load	%	18.53%
1.6	Identified potential heat loads		
			Details of the identified heat loads identified in the Heat Plan, refer to refer to Appendix F of the EP application. Following consumer screening and accounting for network heat losses and consumer diversity,

#	Description	Units	Notes / Instructions
			potential consumers were identified with an average heat load of 2.6 $MW_{th.}$ and a peak load of 11 MW_{th} for the proposed heat network. The estimated heat use of the identified network is 20,046 MWh/year.
1.7	Selected heat load(s)		
a)	Category (e.g. industrial / district heating)		District heating
b)	Maximum heat load extraction required	MW	The average and diversified peak heat demand of the proposed heat network has been calculated to be 2.6 MW_{th} and 11 MW_{th} respectively.
1.8	Export and return requirements of heat load		
a)	Description of heat load extraction		Network to supply hot water at typical district heating temperatures (approximately 80 °C) via turbine steam extractions at approximately 2 bar(a).
b)	Description of heat load profile		The heat load profile is variable due to mixed use developments (primarily industrial and commercial). A detailed heat load profile is presented in the Heat Plan, refer to Appendix F of the EP application. The consumer heat load and profile is subject to verification.
c)	Export pressure	bar a	16
d)	Export temperature	°C	80
e)	Export flow	t/h	89.424 (nominal case)
f)	Return pressure	bar a	3
g)	Return temperature	°C	55
h)	Return flow	t/h	89.424 (nominal case)
Requirement 2: Identification of CHP Envelope			
2.0	Comparative efficiency of a standalone boiler for supplying the heat load	% LHV	80 % - updated in accordance with CHPQA Stakeholder Engagement Document, April 2016, Table 1.
2.1	Heat extraction at 100% plant load		
a)	Maximum heat load extraction at 100% plant load	MW	11.02
b)	Maximum heat extraction export flow at 100% plant load	t/h	Assuming steam extraction at 2 bar(a), export flow rate would be: 3.95 t/hr

#	Description	Units	Notes / Instructions
c)	CHP mode net electrical output at 100% plant load	MW	13.67
d)	CHP mode net electrical efficiency at 100% plant load	%	19.60%
e)	CHP mode net CHP efficiency at 100% plant load	%	35.39%
f)	Reduction in primary energy usage for CHP mode at 100% plant load	%	12.86%
2.2	Heat extraction at minimum stable plant load		
a)	Maximum heat load extraction at minimum stable plant load	MW	5.18
b)	Maximum heat extraction export flow at minimum stable plant load	t/h	Assuming steam extraction at 2 bar(a), export flow rate would be: 1.855 t/hr
c)	CHP mode net electrical output at minimum stable plant load	MW	9.05
d)	CHP mode net electrical efficiency at minimum stable plant load	%	18.53%
e)	CHP mode net CHP efficiency at minimum stable plant load	%	29.14%
f)	Reduction in primary energy usage for CHP mode at minimum stable plant load	%	10.03%
2.3	Can the plant supply the selected identified potential heat load (i.e.is the identified potential heat load within the 'CHP envelope')?		Yes, but not deemed 'Good Quality' CHP as identified in the Heat Plan, refer to Appendix F of the EP application.
Requirement 3: Operation of the Plant with the Selected Identified Heat Load			
3.1	Proposed operation of plant with CHP		
a)	CHP mode net electrical output at proposed operational plant load	MW	14.84
b)	CHP mode net electrical efficiency at proposed operational plant load	%	21.27%
c)	CHP mode net CHP efficiency at proposed operational plant load	%	25.00%
d)	Reduction in net electrical output for CHP mode at proposed operational plant load	MW	0.36

#	Description	Units	Notes / Instructions
e)	Reduction in net electrical efficiency for CHP mode at proposed operational plant load	%	0.52%
f)	Reduction in primary energy usage for CHP mode at proposed operational plant load	%	5.99%
g)	Z ratio		7.20
Requirement 4: Technical provisions and space requirements			
4.1	Description of likely suitable extraction points		Steam for the district heating system could be supplied via a controlled steam flow extraction from low pressure turbine bleed at approximately 2 bar(a). Full details are detailed in the Heat Plan, refer to Appendix F of the EP application.
4.2	Description of potential options which could be incorporated in the plant, should a CHP opportunity be realised outside the 'CHP envelope'		The CHP opportunity lies within the CHP envelope.
4.3	Description of how the future costs and burdens associated with supplying the identified heat load / potential CHP opportunity have been minimised through the implementation of an appropriate CHP-R design		If the scheme were to be implemented, space will be allocated for the CHP equipment within the buildings envelope to avoid the cost of building a dedicated heat station at a later date. The turbine design will be selected to maximise electrical efficiency while allowing for the option of heat export to be implemented in the future. This is in line with the EA CHP-Ready Guidance which states that the initial electrical efficiency of a CHP-R plant (before any opportunities for the supply of heat are realised) should be no less than that of the equivalent non-CHP-R plant.
4.4	Provision of site layout of the plant, indicating available space which could be made available for CHP-R		Detailed design of the Facility has not been undertaken at this stage. However, space has been made available within the buildings envelope to house all required equipment for heat export infrastructure. Please see the site layout in Appendix A. The heat network will (likely) include steam extraction piping, control and shutoff valves, heat exchangers, district heating supply and return lines, district heating circulation pumps, condensate return piping (to the condensate tank), control and instrumentation / electrical connections, an expansion tank for pressurisation of the district heating pipe network and heat metering.

#	Description	Units	Notes / Instructions
			If necessary, a back-up boiler will be located at a suitable location within the installation boundary for ease of connection to the primary hot water circuit.
Requirement 5: Integration of CHP and carbon capture			
5.1	Is the plant required to be CCR?		No
5.2	Export and return requirements identified for carbon capture		
	100% plant load		
a)	Heat load extraction for carbon capture at 100% plant load	MW	N/A
b)	Description of heat export (e.g. steam / hot water)		N/A
c)	Export pressure	bar a	N/A
d)	Export temperature	°C	N/A
e)	Export flow	t/h	N/A
f)	Return pressure	bar a	N/A
g)	Return temperature	°C	N/A
h)	Return flow	t/h	N/A
i)	Likely suitable extraction points		N/A
	Minimum stable plant load		
j)	Heat load extraction for carbon capture at minimum stable plant load	MW	N/A
k)	Description of heat export (e.g. steam / hot water)		N/A
l)	Export pressure	bar a	N/A
m)	Export temperature	°C	N/A
n)	Export flow	t/h	N/A
o)	Return pressure	bar a	N/A
p)	Return temperature	°C	N/A
q)	Return flow	t/h	N/A
r)	Likely suitable extraction points		N/A
5.3	Operation of plant with carbon capture (without CHP)		
a)	Maximum plant load with carbon capture	%	N/A

#	Description	Units	Notes / Instructions
b)	Carbon capture mode thermal input at maximum plant load	MW	N/A
c)	Carbon capture mode net electrical output at maximum plant load	MW	N/A
d)	Carbon capture mode net electrical efficiency at maximum plant load	%	N/A
e)	Minimum stable plant load with CCS	%	N/A
f)	Carbon capture mode CCS thermal input at minimum stable plant load	MW	N/A
g)	Carbon capture mode net electrical output at minimum stable plant load	MW	N/A
h)	Carbon capture mode net electrical efficiency at minimum stable plant load	%	N/A
5.4	Heat extraction for CHP at 100% plant load with carbon capture		
a)	Maximum heat load extraction at 100% plant load with carbon capture [H]	MW	N/A
b)	Maximum heat extraction export flow at 100% plant load with carbon capture	t/h	N/A
c)	Carbon capture and CHP mode net electrical output at 100% plant load	MW	N/A
d)	Carbon capture and CHP mode net electrical efficiency at 100% plant load	%	N/A
e)	Carbon capture and CHP mode net CHP efficiency at 100% plant load	%	N/A
f)	Reduction in primary energy usage for carbon capture and CHP mode at 100% plant load	%	N/A
5.5	Heat extraction at minimum stable plant load with carbon capture		
a)	Maximum heat load extraction at minimum stable plant load with carbon capture	MW	N/A
b)	Maximum heat extraction export flow at minimum stable plant load with carbon capture	t/h	N/A

#	Description	Units	Notes / Instructions
c)	Carbon capture and CHP mode net electrical output at minimum stable plant load	MW	N/A
d)	Carbon capture and CHP mode net electrical efficiency at minimum stable plant load	%	N/A
e)	Carbon capture and CHP mode net CHP efficiency at minimum stable plant load	%	N/A
f)	reduction in primary energy usage for carbon capture and CHP mode at minimum stable plant load	%	N/A
5.6	Can the plant with carbon capture supply the selected identified potential heat load (i.e. is the identified potential heat load within the 'CHP and carbon capture envelope')?		N/A
5.7	Description of potential options which could be incorporated in the plant for useful integration of any realised CHP system and carbon capture system		N/A
Requirement 6: Economics of CHP-R			
6.1	Economic assessment of CHP-R		In order to assess the economic feasibility of the CHP scheme (as required under Article 14 of the Energy Efficiency Directive) a cost benefit assessment has been carried out in accordance with the draft Article 14 guidance. The results of the CBA indicate an internal rate of return of 11.7 % and a net present value of -£2.44 million. The proposed heat network will not yield an economically viable scheme in its current configuration. The economic feasibility of the scheme will be reassessed in the future when there is a better understanding of heat demands and considering any subsidies that support the export of heat.
BAT assessment			
	Is the new plant a CHP plant at the outset (i.e. are there economically viable CHP opportunities at the outset)?		No

#	Description	Units	Notes / Instructions
	If not, is the new plant a CHP-R plant at the outset?		Yes
	Once the new plant is CHP-R, is it BAT?		Yes

ENGINEERING + CONSULTING

FICHTNER

Consulting Engineers Limited

Kingsgate (Floor 3), Wellington Road North,
Stockport, Cheshire, SK4 1LW,
United Kingdom

t: +44 (0)161 476 0032
f: +44 (0)161 474 0618

www.fichtner.co.uk