Joint
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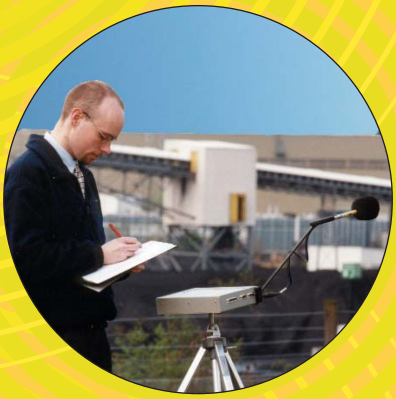
Programme

JEP

Water Use in Biomass and Combined Cycle Gas Turbine Power Plant with Carbon Capture and Storage



by
G Pickens &
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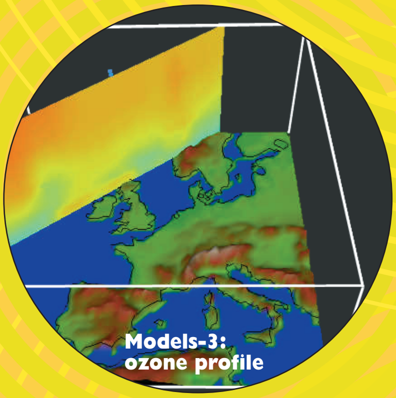


JOINT ENVIRONMENTAL PROGRAMME

The Joint Environmental Programme (JEP) supports a programme of research into the environmental impacts of electricity generation funded by seven of the leading producers in the UK. The objective of the JEP work programme is to understand and increase knowledge of the environmental science and impacts associated with the production of electricity from coal, gas, gasoil and biomass fired power plant.

The main drivers for the programme come from the national and international legislative and regulatory initiatives which now address the full range of emissions-related impacts. The JEP takes a forward look at trends in legislative and regulatory thinking, identifies any gaps and major uncertainties in the scientific knowledge raised by such new proposals together with the modelling, data and other research requirements that arise. This ensures that the representative companies are well placed to make a constructive contribution to national and European debate from initial concepts right through to the practicalities of implementation. Close liaison is maintained, through regular meetings, with UK Regulatory bodies to ensure the correct focus for the programme and JEP members are representatives on a number of European advisory bodies.

The major areas of current activity cover:

Air Quality – the impact of power plant emissions on air quality both locally and more widely across the UK in relation to other sources

- Pollution and Health – the relationships between atmospheric emissions from power plant and human health effects
- Pollution and the Natural Environment – effects of pollutant deposition on ecosystems
- Understanding Emissions – quantifying emission levels and assessing their significance

Compliance Monitoring – development of protocols to support application of consistent best practice in the monitoring and reporting of emissions across JEP power plants

Aquatic Environment – impact of water usage by power plants and long term outlook based on published energy scenarios.

The work is undertaken either by in-house experts within the member companies or when appropriate through contracts with leading environmental consultancies and universities. To facilitate informed debate on key environmental issues related to electricity production, the results from the JEP research studies are shared externally with relevant stakeholders through external publications. There have also been more detailed monograph reviews (listed overleaf) which summarise many years of work on a specific topic.

JEP Companies: RWE Generation UK, Drax Power Ltd, Scottish & Southern Energy, EDF Energy, VPI Power Ltd, EPUKi and Uniper UK

Some Recent Reports and Publications from the JEP

External Reports

ESI-IED compliance protocol for utility boilers and gas turbines

Pollution Inventory 2020 Electricity Supply Industry methodology

BAT Assessment for Existing Gas & Liquid Fuel Fired OCGTs, CCGTs & Dual-fuel GTs with a Thermal Input Rating of 50 MWth or Greater Operating <500 Hours Per Year
Air quality impacts associated with black start operation

Positioning thermal power plant in water resource management planning

Projections of Water Use in Electricity and Hydrogen Production to 2050, under the 2020 Future Energy and CCC Scenarios including BEIS 2020 lowest system cost analysis - with a focus on the East of England

Best practice for use of sponge ball cleaning systems in power station cooling water circuits

EU ETS CO_2 monitoring at coal-fired power plants approaching closure

Characterisation of power plant fuels for compliance with LCP BREF conclusion BAT 9

Monograph Reviews

Ashes to Assets? Studies of the usefulness and environmental management of ash from coal fired power stations.

The Acid Tests? Studies of the ecological effects of atmospheric pollutants

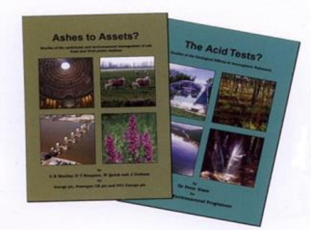
Crumbling Heritage? Studies of the effect of ‘acid rain’ on historic buildings

Flying Chemistry Studies of the long range atmospheric transport of pollutants

Generating Emissions? Studies of the local impact of gaseous power station emissions

Using Water Well? Studies of Power Stations and the aquatic environment

Borne on the Wind? Understanding the dispersion of power station emissions



Copies of these monographs and more details on the current JEP programme can be obtained from the JEP secretary by sending your request in an Email to jepsec@jep.website

JEP Companies: RWE Generation UK, Drax Power Ltd, Scottish & Southern Energy, EDF Energy, VPI Power Ltd, EPUKi and Uniper UK

Technology Centre UTG/21/PMP/119/R

Issued: March 2022

JEP20WT07: Water Use In Biomass And Combined Cycle Gas Turbine Power Plant With Carbon Capture And Storage

By

G Pickens and R M C Brandwood

Executive Summary

This study was undertaken by Uniper Technologies for the Joint Environmental Programme (JEP) in order to provide a updated review on the gross water usage and water consumption of gas-fired power plants fitted with carbon capture utilisation and storage (CCUS) technology as well as bio-energy with carbon capture and storage (BECCS) plants. This was achieved by collating data from CCUS project reports in the public domain, namely: Kårstø, Peterhead, Poza Rica, ROAD, Kingsnorth, Longannet, Petra Nova, White Rose and Shand. Since no BECCS project data was currently available in the public domain, it was assumed that coal-fired plants with CCUS could be substituted for BECCS due to their process and fuel similarities.

From the available data, two key properties were calculated: cooling water abstracted per unit of power generated and cooling water abstracted per unit of CO_2 captured. This proved to be challenging, since key data such as net power generation was often not quantified due to confidentiality or under-developed report data. Therefore in the cases where this was not specified assumptions had to be made regarding efficiency for both gas-fired and coal-fired plants. The projects were divided into four subsets of plant types: gas-fired CCUS plant with once through cooling, gas-fired CCUS plant with cooling cells, coal-fired (biomass) plant with once through cooling and coal-fired (biomass) plant with cooling cells. A range of values with a central value representative of the dataset was then determined to enable comparisons with previous studies.

One of the main findings was that process water consumption for the projects studied was often limited to start-up periods, since the water produced was often of high quality and could be reintegrated for various uses such as cooling water make-up. Additionally, when comparing the cooling water abstracted per unit of power generated figures to previous studies, it was inferred that these numbers were highly plant specific, and while showing some similarities to previous studies not enough data was available in the public domain to accurately predict water usage of future CCUS plants.

It was also observed that there can be significant variation in water use between the different capture processes, when their application is considered on a nominally similar base power plant. This tends to suggest a wide range of water usage data could be expected to be included in permit applications as developments come forward.

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ABBREVIATIONS / NOMENCLATURE

ASU	Air separation unit
BECCS	Bio-energy with carbon capture and storage
CAPEX	Capital expenditure
CCGT	Combined-cycle gas turbine
CCS	Carbon capture and storage
CCUS	Carbon capture utilisation and storage
DCC	Direct contact cooling
EA	Environmental Agency
FEED	Front End Engineering Design
FGD	Flue gas desulphurisation
GGH	Gas-gas heater
GPU	Gas processing unit
GT	Gas turbine
HRSG	Heat recovery steam generator
HSS	Heat stable salts
JEP	Joint Environmental Programme
MEA	Ethanolamine
ROAD	Rotterdam Opslag en Afvang Demonstratieproject
WRE	Water Resources East

1 INTRODUCTION

This study was carried out in order to provide an updated estimate of water usage figures from those used in the JEP report “Scenarios for the projection to 2050 of water use by power producers- with a focus on WRE” [1]. The water usage figures of interest are those of power plants with carbon capture utilisation and storage (CCUS) and bioenergy with carbon capture and storage (BECCS). This update was achieved by collating data from publicly available CCUS front-end engineering design (FEED) and pre-feasibility reports, focussing on combined-cycle gas turbine (CCGT) plants with CCUS and using coal-fired plants with CCUS as a proxy for BECCS given the process similarities between coal and biomass firing.

1.1 Context of This Study

The UK is committed to a legally binding target of reducing emissions by 100% compared to the 1990 emissions baseline by 2050, which will require significant decarbonisation of the power sector. Carbon capture utilisation and storage (CCUS) has a potentially significant role; according to the 2020 Future Energy Scenarios by the National Grid [2], CCUS is required for all net zero scenarios. Despite this, there are currently no operational carbon capture plants in the UK, largely due to the efficiency penalties and increased water consumption carbon capture processes incur. The UK government has set the target for a CCUS facility to be operational from the mid-2020s [3], with the aim to deploy CCUS in industrial clusters in the 2030s subject to cost reductions.

Interest is also growing in BECCS. The negative emissions from BECCS are essential for reaching net zero [2], generating up to 62 MtCO_2e of negative emissions by 2050. This is pivotal in offsetting emissions from industries that are difficult to decarbonise, and in providing baseload generation up to and beyond 2025 as coal power is phased out.

As the UK sets out to achieve net zero by 2050, simultaneously water stress is set to increase in many areas due to population growth and climate change. This poses an additional challenge to the deployment of CCUS, since CCUS typically increases water abstraction at existing sites. Therefore it is important to predict future water use by CCUS in order to assess the implication it will have on future water abstraction and consumption as well as its viability.

2 CARBON-CAPTURE PROCESS

With the exception of the White Rose Project (oxyfuel technology), all of the projects studied for this report employed an amine based post-combustion carbon capture process. The basic premise of this process is to transfer CO_2 from the flue gas into a liquid solvent in a counter-current absorption column. The CO_2 laden solvent is then transferred to a regeneration or stripping column, where the process is reversed by applying heat via steam to release the captured CO_2. Depending on the selected transportation and storage option, captured CO_2 is dehydrated and compressed to a required pipeline pressure for transport to a storage site or liquefaction facility. Further conditioning may also be required, depending on the requirement of the final transport and storage scheme.

2.1 Process Description

The main components of a amine based post-combustion capture plant are described in more detail in the following paragraphs:

- Flue gas pre-treatment section

- Absorption section
- Stripping section
- Solvent reclaiming section
- Cooling system
- Compression system

A simplified process flow scheme for a post combustion capture facility is shown in Figure 1.

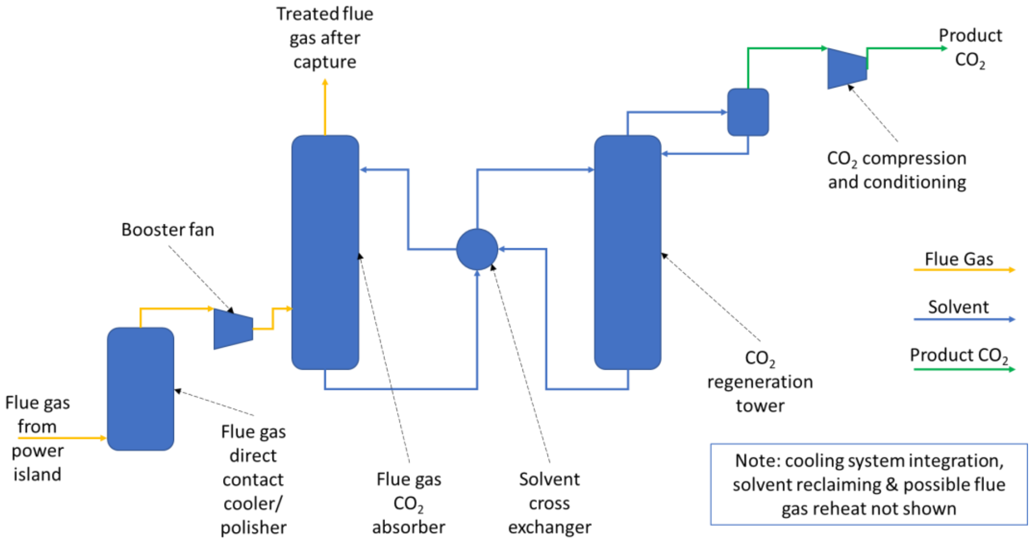

Figure 1: Post Combustion Carbon Capture Scheme

2.1.1 Flue Gas Pre-treatment

Hot flue gas exiting a heat recovery steam generator (HRSG) has to be cooled down significantly before undergoing CO_2 capture in the amine absorber. This is because the absorption reaction is exothermic, and therefore the equilibrium favours lower temperatures (Le Chatelier's Principle).

This cooling could typically take place in one or two stages. In the two step scheme, the first would be cooling in a regenerative gas-gas heater (GGH) which transfers heat from the raw flue gas to treated gas exiting the absorber. This is perhaps most of relevance where final plume dispersion requires a higher exit temperature of the flue gas. Further cooling of the flue gas below its dew point occurs in the second step, a direct contact cooler (DCC), by quenching the gas stream with recirculating, cooled process water produced by condensing out the combustion water (with make-up for starting operation). Circulating water leaves at the bottom of the DCC column and is returned to the top of the DCC via a DCC water cooler under flow control. Excess water is continuously bled from the quench loop to maintain the water balance in the system. This water is of high quality, and can potentially be re-used elsewhere in the process or in the power plant.

In the case of a capture plant treating flue gas from a coal-fired unit, the DCC unit may also serve the additional purpose of removing sulphur oxides (if present) to ppm level by scrubbing the gas with caustic soda or soda ash solution in the upper section of the column (trim FGD); this may be in addition to a "deep" flue gas desulphurisation (FGD) unit upstream that removes the majority of the sulphur oxides. Since natural gas typically contains very low levels of sulphur compounds, SO_2 content in gas turbine flue gas is normally very low, obviating the need for a desulphurisation stage. For fuels with some, negligible, sulphur content, then there will be a cost benefit assessment to be made to assess the optimum scheme for desulphurisation, and whether this is in one, or two, steps.

To overcome the pressure drop introduced into the gas path by the gas-gas heater (GGH), DCC and absorber units, a booster fan may be installed downstream of the GGH and DCC to avoid imposing back-pressure on the HRSG and gas turbine (for CCGTs) or boiler induced draft fan (for BECCS units).

2.1.2 CO_2 Absorption

Flue gas enters the bottom of the absorber and flows upwards through the structured packing sections, where it is contacted with lean amine solvent in a counter-current fashion. As the resulting chemical reaction is exothermic, an absorber intercooler may be installed in the lower section of the intercooler in order to remove the heat of reaction and maintain the solvent temperature within design limits. This enables higher CO_2 loading in the solvent, and also reduces the solvent recirculation rate and therefore the energy requirement of the process.

Treated gas from the absorption column enters a wash section at the top of the absorber where residual solvent vapour is captured by a counter-current water stream. Wash-water is circulated by a wash water pump and cooled in the wash water cooler. Its flow rate is controlled to maintain the required wetting rate of the wash section packing.

Demineralised water may be added to the top of the absorber column to remove solvent vapours and entrained liquid droplets from the exiting gas. Excess wash water is filtered through a wash water filter and combined with the lean solvent entering the top of the column. The flow rate of the excess water is controlled to maintain the water balance in the wash circuit.

Treated flue gas exiting the absorber is virtually at its dew point, and might be reheated in the GGH before it is vented to atmosphere.

2.1.3 Solvent Regeneration

The CO_2 rich solution exits the bottom of the absorber column and is pumped to a stripper column via a cross-stream heat exchanger, where it is pre-heated by a lean solvent stream exiting the reboiler. The hot solvent enters the stripper column below the wash section and flows downwards through the structured packing, where it is contacted with process steam which drives the CO_2 out of the solution. The now lean solvent collects in the sump and is sent to a reboiler to be heated to its boiling point by the de-superheated steam.

The recovered CO_2 enters the wash section of the column, where vaporised and entrained solvent can be recovered by contact with a reflux stream from the overhead accumulator and returned back to the main section of the stripper. The product stream containing only CO_2 and water vapour is cooled and water condensed out in the overhead condenser. The two-phase mixture is then separated in the accumulator and a fraction of process water is returned to the wash section of the stripper as a reflux. The CO_2 product is sent to the compression and dehydration unit under pressure control.

2.1.4 Solvent Reclaiming

The amine solvent often reacts with flue gas constituents in the absorber and undergoes a slow degradation under the high temperatures in the stripper to form heat stable salts (HSS) that cannot be regenerated in the reboiler. This necessitates a solvent reclaimer, where the removal of HSS is carried out by reaction with diluted sodium hydroxide or sodium carbonate solution. The reclaimer is typically operated intermittently and over prolonged periods of time. Due to the increased power consumption during reclaimer operation, Front-end Engineering Design (FEED) reports for CCUS often contain design scenarios for the reclaimer being both in and out of operation in their water and energy balances. A liquid bleed from the reclaimer system containing highly concentrated HSS and degradation products is emitted from the system, which due to its intermittent and low mass can be incinerated or processed by a specialised waste disposal company.

2.1.5 CO_2 Compression

CO_2 from the stripper is routed to the compression and drying section, where the CO_2 is compressed in multiple stages with interstage coolers and knockout vessels to remove condensed water. Following compression, the CO_2 may be subject to further dehydration using molecular sieves, or other drying schemes, before entering an export pipeline.

It is worth noting that this is a general description for an amine carbon capture plant, and that process designs in the FEED reports studied varied from project to project. For example, for the proposed CO_2 capture plant at Kårstø Power Station in Norway, instead of a DCC to pre-cool and saturate the flue gas an evaporative fogging system consisting of two stages of water spraying was selected.

A significant outlier from the projects studied is the White Rose Project, which is the only non-retrofit project considered as well as the only project utilising oxyfuel technology. This technology proposed uses a supercritical boiler that burns coal and/or biomass in pure oxygen produced in an air separation unit (ASU). This results in a flue gas with a high CO_2 concentration, which is separated from the rest of the flue gas by a gas processing unit (GPU) before being compressed and exported.

3 WATER USERS AND CONSUMERS

3.1 Cooling

There were broadly three types of cooling system encompassed in this study:

- Once through cooling water
- Wet cooling tower(s)
- Hybrid cooling (dry and wet cooling)

3.1.1 Once through Cooling Water

A once through cooling water system either uses water directly abstracted from a source (e.g. a river, lake, sea or estuary) or exit water from steam turbine condensers in the host power plant. Once the water has passed through heat exchangers and condensers in the carbon capture plant it is discharged at a higher temperature to the source, sufficiently far from the cooling water intake to prevent appreciable recirculation. Once through cooling systems using exit water from steam turbine condensers are known as “direct integrated” systems, which are relatively easy to retrofit and require no extra space. However, such a system results in increased abstraction rates and higher discharge temperatures, which may lead to challenges in terms of permitted abstraction rates and maximum discharge temperatures.

In comparison, once through cooling systems which abstract water from a source directly to the CCUS plant are known as “direct independent” systems. The advantages of such a system are greater operational flexibility, lower discharge temperatures and no extra space requirements. The lower water outlet temperatures also mean that process and compressor coolers can operate at lower temperatures, resulting in equipment size and cost savings as well as greater capture efficiencies. Nevertheless, this also results in increased abstraction rates, potentially requiring new abstraction and fall-out points so may also risk the exceedance of permit limits. Despite this, direct independent once through seawater is usually preferred to direct integrated because of the aforementioned higher operational flexibility and lower discharge temperatures.

3.1.2 Wet Cooling Towers

Wet cooling towers operate on the principle of evaporative cooling. Hot water enters the cooling tower and is distributed into a fine spray by pressurised nozzles before flowing downwards through the “fill”, or packing, which slows the water flow down and increases the surface area for water-air contact. The water is contacted with ambient air drawn up through the tower in a counterflow design, and a portion of the water evaporates. The energy required to evaporate the water is removed from the remaining mass of water, hence lowering its temperature. The cooled water is then recirculated and removes heat from the capture plant before being returned to the cooling tower at a higher temperature. When water is evaporated it leaves its dissolved salts behind, which accumulate over time in the recirculating cooling water. This is controlled with a blowdown stream when a designated number of cycles of concentrations is reached.

Mechanical or forced draft wet cooling towers use power-driven fan motors to force or draw air through the towers, while natural draft devices use convective action to draw air through the tower.

A closed-loop cooling system with wet cooling towers has the advantage that they have a minimum impact on existing and future site abstraction rates, as well as being independent of the host plant cooling load. However, such a system incurs high CAPEX and has large space requirements.

3.1.3 Hybrid Cooling

A hybrid cooling system utilises both dry and wet cooling. Dry cooling uses ambient air to remove excess heat from hot water by convection; this typically occurs through a surface that separates the working fluid from ambient air, such as a tube to air heat exchanger. Dry cooling systems may cause operation and maintenance issues due to the temperature sensitive nature of some carbon capture processes, and so hybrid cooling systems are often used when sufficient levels of water to support a 100% wet cooled system are not available.

3.2 Process Water

Carbon capture processes may both produce and consume process water intermittently during operation. Since incoming flue gas must be cooled in the DCC below its dew point, the combustion water is condensed out and the excess process water must be bled from the DCC cooling circuit. Process water may also be produced when water is condensed out in the CO_2 compression, and its associated drying section, and when water is purged from a FGD unit (if applicable). Process water may also be consumed in the water wash section of the absorber column in order to prevent the amine concentration building up.

3.3 Integration of Water Use

Due to the low level of contaminants in the wastewater produced by carbon capture plants, namely dissolved CO_2, oxygen and SO_2, water may be re-used as makeup water or demineralised water for various uses within the capture plant after treatment on-site. For example, the Shand FEED scenario was developed with a “zero liquid discharge” philosophy to minimise water use, and this is fully integrated into its design. Therefore, process water consumption may be limited in many cases to make-up quantities during start-up to establish the water balance.

4 WATER USE ASSESSMENT

4.1 Sources of Data

The data for this report was collated from selected front-end engineering design (FEED) and pre-feasibility studies for carbon capture projects in the public domain, namely: Kårstø, Peterhead, Poza Rica, ROAD, Petra Nova, Shand, Kingsnorth, Longannet and White Rose. The data of interest was the water demand information, the power generation both pre and post-retrofit, as well as the abated and unabated CO_2 flows and the cooling duties.

4.2 Challenges

With only the Petra Nova project (USA) reaching an operational stage out of all the projects studied, the quality and extent of the reports available varies widely. In some cases data was omitted due to confidentiality, or as a result of design not being finalised at the time the report was written. Additionally, the basis of the study was not always clearly documented. One key challenge was manipulating the data into outputs on a per megawatt hour net basis, which was problematic because the available sources did not always document the power generation from the parent (unabated) unit, or the share of the flue gas of that unit (and hence the equivalent megawatt abated). In some cases the energy consumption of the capture plant is not met from the power cycle at all, instead being delivered by auxiliary boilers and/or a dedicated combined heat and power plant. This was further complicated as, given the energy consumption of the carbon capture process was itself not always fully quantified, the efficiency impact and net generation could not always be directly assessed.

4.3 Approach to Deriving Values

Where data was not presented in the required form, the equivalent abated power generation was calculated using a number of approaches. In all cases, the assumption was used that the power island does provide the energy required by the capture island so all electrical energy or thermal energy consumed in capturing CO_2 has a direct impact on the power cycle efficiency and therefore on the electrical power output that can be exported for a given thermal power input.

For the CCGT studies where the gas turbine type was known or could be determined, an assumption was made of the net generation for that class of machine, as well as the corresponding thermal input. This gave an unabated net electrical efficiency. Where the energy demand was understood the electrical energy drawn by the capture plant was deducted from the net output, and the steam consumption of the capture plant was converted to an equivalent reduction in electrical output as if that steam was withdrawn from the steam turbine. The efficiency used to relate this thermal energy consumed to a reduction in electrical output is one third of the overall CCGT electrical efficiency. This represents that, typically, one third of the power output from a CCGT is drawn from the steam cycle and two thirds from the gas turbine (which in this instance does not see its electrical output reduced). In reality, this is likely to be an underestimate as some work will have been performed by the steam prior to withdrawal so a linear reduction in output with steam withdrawal may not be entirely accurate. This approach could be refined with thermodynamic modelling, but only where a greater amount of plant data is known. This is more time consuming than this study allows and, in any case, the data inputs that would be required to complete that exercise are not available.

For the coal plant studies, a different approach was used. As the different projects had unique bases of design, judgment was applied to bring the data back to a common basis consistent with that of a power plant island providing energy, with a penalty resulting to its output and efficiency, for consumption by an integrated capture island. The actual water data was used and an effective net power generation calculated by taking the net power before capture (or for slipstreams the pro rata power contribution), and deducting the work's power requirement of the capture plant. The efficiency penalty arising from the steam consumed was calculated based on a calculated thermal input lost to the steam turbine cycle and the assumption that electricity would have been generated with the same efficiency as the Kingsnorth CCS FEED scenario. Therefore a further deduction from the abated plant net output was made accounting for this lost generation. It should be noted that this is a simplification, and in many cases the plant in question would not have benefited from the high efficiencies of the proposed Kingsnorth plant. For one case included, there was insufficient data to calculate the thermal energy consumed in the capture plant (it being redacted in the public domain report) therefore an assumed efficiency penalty similar to the difference between abated and unabated scenarios at Kingsnorth was applied. Again, this approach could be refined by thermodynamic modelling of each case. However, this would entail collecting a greater amount of plant data than is presented in any of the FEED studies, and is beyond the resources available to this project.

5 RESULTS

The water use data was collated from nine separate CCUS projects. The calculated outputs are presented in Table 1.

Table 1: Calculated water use data

Project	Fuel	Cooling circuit type	Scenario	Cooling water abstracted per unit of CO_2 captured (te H_2O/te CO_2)	Cooling water abstracted per unit of power generated (te/MWh)
Kårstø [4]	Natural gas	Once through seawater	Normal (reclaimer off)	128.8	45.6
			Normal (reclaimer off)	125.6	44.2
			Summer (reclaimer off)	139.0	44.7
			Winter (reclaimer off)	132.9	48.5
			Turndown (reclaimer off)*	154.8	58.0
Peterhead [5]	Natural gas	Once through seawater	Maximum load	147.5	53.0
Poza Rica [6]	Natural gas	Wet cooling	Generic 30% MEA case	2.6	1.1
ROAD [7]	Coal	Once through seawater	Maximum load	72.2	63.7
Kingsnorth [8]	Coal	Once through seawater	Maximum load	81.8	76.7
Longannet [9]	Coal	Once through seawater	Maximum load	113.4	151.6
Petra Nova [10]	Coal	Wet cooling	Maximum load	2.5	2.7
White Rose [11]	Coal	Wet cooling	Oxy-firing, maximum load	4.5	2.8
Shand [12]	Coal	Hybrid cooling	Reclaimer off	2.0	2.1

*note: no credit is given here for the potential to reduce the cooling water flow at part load operation.

These projects can be narrowed down into the following categories related to their fuel type and cooling circuits: natural gas with once through cooling (Kårstø and Peterhead), natural gas with cooling cells (Poza Rica), coal (representing biomass) with once through cooling (ROAD, Longannet and Kingsnorth) and coal (representing biomass) with cooling cells (Shand, Petra Nova and White Rose). These categories were taken into account in order to provide a range of values for the cooling water abstracted per unit of power generated, with a central value to represent an estimate of a typical value for the type of plant based on the data collected for this study. This data is presented in table 2.

Table 2: Typical values for varying CCUS plant types

Plant type	Range of cooling water abstracted per unit of power generated (t/MWh)	Central value (t/MWh)
Natural gas- once through cooling	44.2-58	50
Natural gas- cooling cells	n/a	1.1
Coal (biomass)- once through cooling	63-151.6	77
Coal (biomass)- cooling cells	2.1-2.8	2.7

As visible in tables 1 and 2, the two natural gas with once through cooled CCUS plants (Kårstø and Peterhead) yield broadly similar rates of abstraction per power generated and CO_2 capture per cooling water abstracted. However, this differs significantly from previous studies; Gasparino and Edwards (2020) [1] determined a central value of 88 m^3/MWh for gross water usage from a water model, while in 2012 the Environmenta Agency (EA) [13] reported an estimate of 87.4 te/MWh. It is worth noting that the net abated power generation was not specified in the Kårstø FEED study as it was in the Peterhead one, so this was calculated using the assumptions stated in section 4.3 which may have resulted in an underestimate of the te/MWh figures for the Kårstø scenarios.

There was limited data available for a natural gas CCS plant utilising cooling cells, with only the proposed pilot CCS plant at Poza Rica considered in this study. The central value of 1.1 te/MWh attained corroborates with previous studies; the EA [13] estimated a cooling water abstraction of 1.14 te/MWh and Gasparino and Edwards [1] a gross usage of 1.63 m^3/MWh. The Poza Rica project was unique among the projects evaluated, as it was the only pilot plant study considered. The pre-feasibility report focussed on a generic 30% MEA-based post-combustion capture design which served as a benchmark for comparing the performance of six post-combustion capture technology providers that participated in the study (Alstom, BASF, Fluor, HTC, MHI and Shell CanSolv). This is examined in more detail in section 7.

There was a large spread of data for the water abstraction per MWh for coal CCUS projects with once through cooling, ranging from 63.0-151.6 te/MWh. While the ROAD and Kingsnorth projects had similar figures (63.7 te/MWh and 76.7 te/MWh respectively), Longannet was an outlier with 151.6 te/MWh. The abated net power generation for the Longannet project was not provided, and so the calculations described in section 4.3 assuming the same efficiency of the Kingsnorth FEED CCS scenario were carried out. This required a significant amount of processing, and as a result the central value of 77 te/MWh is weighted more towards the ROAD and Kingsnorth projects. Gasparino and Edwards [1] inferred a central gross water usage value of 140 m^3/MWh for both coal and biomass, while the EA [13] estimated cooling water abstraction to be 165.1 te/MWh for a supercritical coal plant with CCS. These values from previous studies are similar to the derived Longannet values, although vary significantly from the ROAD and Kingsnorth projects. This seems to suggest that the rate of cooling water abstraction per power generated is highly plant specific, and that in the absence of a significant number of CCUS FEED studies in the public domain or operational CCUS plants it is difficult to demarcate a reliable range of water usage in which CCUS plants of a certain type will operate. Moreover, while it was assumed that coal-fired plants using CCUS would be a good proxy for BECCS, this is with the caveat that biomass-fired power plants typically operate at lower efficiencies than new build coal-fired counterparts. It is likely therefore that BECCS would require a higher rate cooling water abstraction in order to achieve the same power output as an equivalent coal-fired plant; nevertheless, there are currently no publicly available BECCS FEED studies available which necessitated this assumption, a comparison with a UK BECCS development is considered in section 6.

From the data provided for coal CCS plants with cooling cells, a range of 2.1-2.8 te/MWh with a central value of 2.7 t/MWh was attained. The central value was weighted towards the upper end of the range because the project with the 2.1 te/MWh water abstraction value utilised a complex heating and hybrid cooling arrangement (Shand project), so is not representative of a typical plant using cooling cells as a cooling system only. It is also worth noting that a CCS plant using oxyfuel technology (White Rose Project) was included in this category, which will have implications on power generation and water abstraction compared to a generic amine-based post-combustion CCUS plant, so again this may not be fully representative of a typical plant in this category. Gasparino and Edwards [1] inferred a central gross usage value of 5.2 m^3/MWh while the EA estimated a value of 2.2 t/MWh. Whereas the latter estimation is similar to the range of values gathered from the project data, the former estimation differs significantly. This again implies that water usage figures are highly plant specific, and so estimates may have to encompass a broad range.

6 UK BECCS PROJECT

As discussed elsewhere in this report, there are very few active carbon capture projects from power generation anywhere in the world, not least those capturing carbon from power plant firing biomass. One of the earliest, and largest, conversions of a coal fired plant to biomass has been undertaken by Drax Power, and this Operator is now active in the field of BECCS development and deployment. Some data has been provided on water use in BECCS, based on the pilot plant trials conducted at the Drax location.

6.1 Cooling Water

The volume of cooling water used in meeting the cooling duty of the carbon capture plant will be a function of the cooling approach selected, ambient conditions, and other process specific parameters. The BECCS scheme at Drax is intended to utilise closed circuit, natural draft cooling towers, with a make-up stream of river water. Thermal rejection from the plant is split roughly equally between the capture and power islands of the plant, with the capture plant requiring slightly greater heat rejection than the power island. Assuming that the water demand is split by the share of thermal rejection then the figures in Table 3 are estimated:

Table 3: BECCS Cooling Water Usage

	Total	Capture Island	
Abstracted	29.68	16.38	te/MWh
Released	14.06	7.76	te/MWh
Consumed	15.62	8.62	te/MWh

These figures do differ somewhat from other reference projects using cooling towers, but this is considered to be a function of the bespoke nature of the cooling systems employed, and their integration with the parent unit, rather than any fundamental process difference arising from this data deriving from a BECCS project.

6.2 Waste Water

The post combustion carbon capture process, when applied to BECCS units produces wastewater from the same process steps as when applied to a more conventionally considered coal fired unit. This means that, depending on the final water integration scheme chosen, wastewater could be produced from the Direct Contact Cooler (DCC), polishing FGD (if required), CO_2 compression and absorber wash section, The bulk being from the DCC. For the Drax scheme the volume of waste water would be in the range of 0.21-0.64 te/MWh.

Whilst data on this parameter is variable in the collected dataset, this value is certainly not inconsistent with the values from other projects.

6.3 Process Water

Carbon capture plants consume little, if any, high quality water, with much of the demand being met by internal treatment of water for re-use. Drax have estimated that their process water consumption would be approximately 5 tph, equating to 0.01 te/MWh of electricity generated. It is interesting to note that this process water consumption is in the range of 20-60 times smaller than the predicted wastewater production from the process, indicating that the process water balance of the capture plant is overwhelmingly in favour of water production from the capture process, rather than consumption by it.

No specific conclusion is drawn on high quality process water consumption in this report.

6.4 Overall

The water usage by a BECCS unit is indicated in Figure 2 below, based on data provided from the Drax development. Overall, it is not considered that there is any reason to assume that the water balance for the post combustion capture facility of a biomass fired unit is substantially different to that of a coal fired unit, with variations being substantially due to the selection of cooling approach and the philosophy around water balance integration.

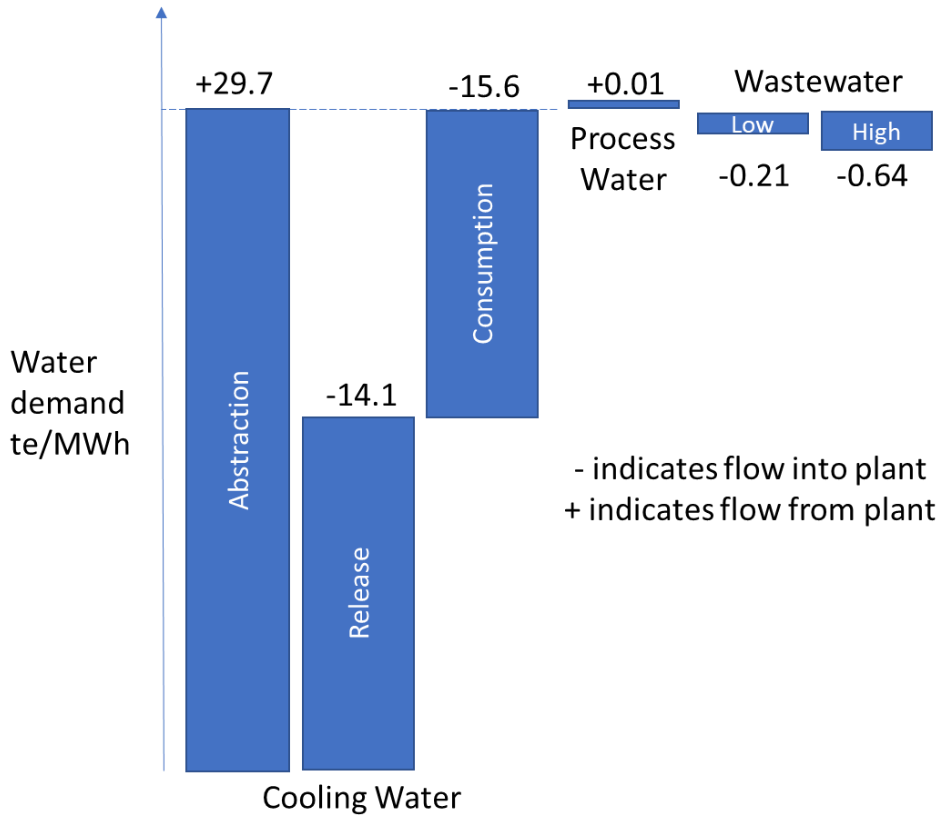

Figure 2: BECCS Water Flow

7 VARIATION IN WATER USE BETWEEN CAPTURE PROCESSES

The amount of water required for post combustion capture is a function of the process itself, as well as the integration of that process into the power plant. The Poza Rica pre-feasibility study completed by Nexant [6] compares the relative water requirements for a range of different capture process suppliers. This gives an indication of the total water requirement for the scheme, a c250MWe (net, unabated) CCGT facility. The listed vendors, were those active in the market at the time of that study, some of these have now changed ownership, or are not now active in the market with the process considered.

This is shown in Figure 3.

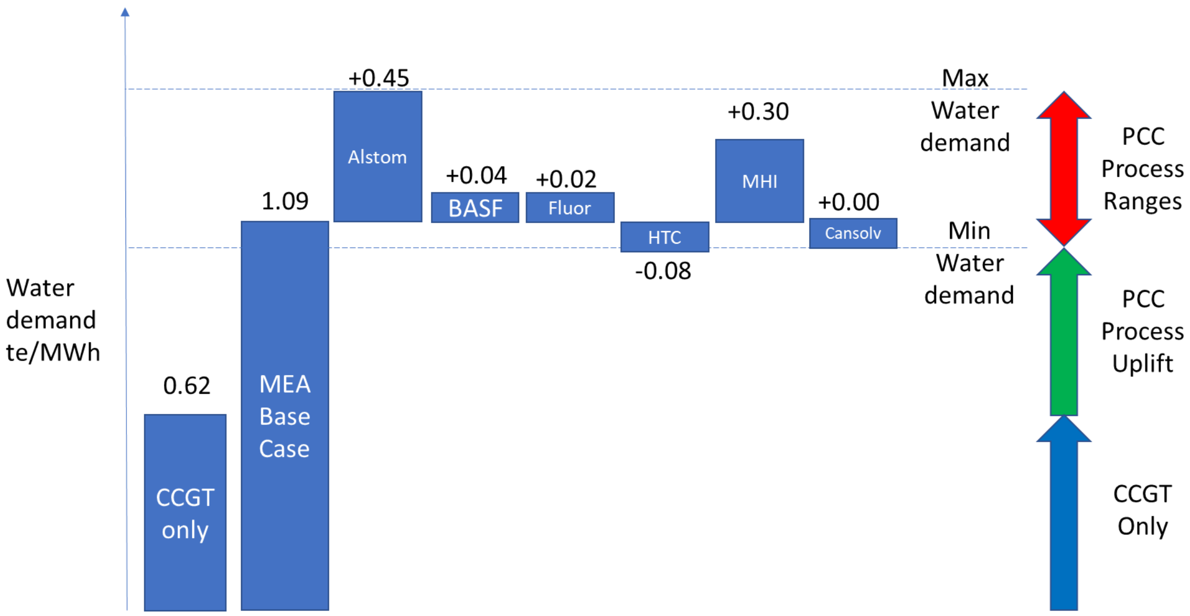

Figure 3: Total Water Requirement for CCGT+PCC [6]

The data here suggests that the increased water requirement for the PCC process is anywhere between a factor of 1.6 and 2.5 times that of the power island only for this CCGT case. Again, this scale of variation, for this single location, supports the variations seen between the different processes, applied at different locations, in the other reference data used in this study. It is clear that there can be significant variation in water use between the different capture processes, when applied in a nominally similar circumstance. This tends to suggest a wide range of water usage data could be expected to be required for inclusion in permit applications as developments using PCC on either CCGT or biomass fired power plant come forward.

8 CONCLUSIONS

Following the review of the publicly available FEED studies, and cross comparison with the data from a UK BECCS development project, a number of conclusions can be drawn. These are;

- Process water consumption for most of the projects studied was either very low or negligible since process water produced by the carbon capture process was often of high quality and suitable for various uses on-site such as cooling water make-up.

- The rate of cooling water abstraction per unit of power generated (t/MWh) was highly dependent on the type of cooling system utilised; once through cooling systems resulted in far higher abstraction rates than evaporative cooling systems.

- While there were some similarities between the water usage numbers (on a per MWh of electricity generated basis) for CCUS plants of the same type, the numbers were highly plant specific.

- For natural gas CCUS plants with once through cooling, an additional cooling water abstraction rate in the range of 44.2-58 te/MWh with a central value of 50 te/MWh was determined. This was lower than previous estimates in other studies.

- For natural gas CCUS plants with cooling cells, only one example was studied which had a cooling water abstraction rate of 1.1 t/MWh, which was similar to estimates in previous studies.

- For coal-fired CCUS plants with once through cooling, an additional cooling water abstraction rate in the range of 63-151.6 t/MWh with a central value of 70 t/MWh was determined; this central value lower than previous estimates, although the outlier from the three projects studied roughly corroborates these estimates.

- For coal-fired CCUS plants with cooling cells, a cooling water abstraction rate in the range of 2.1-2.8 t/MWh with a central value of 2.7 t/MWh was determined. This figure was similar to one estimate, although disparate from another. This category included a plant with a hybrid cooling arrangement as well as a plant utilising oxyfuel technology, so were not considered fully representative as a typical example of a coal-fired CCUS plant with cooling cells.

- The water usage per MWh of electricity generated from coal-fired CCUS plants in this study were assumed to be representative of the water usage numbers of a BECCS, which in reality may be an underestimate due to the lower efficiency of a BECCS unit in comparison to a coal-fired unit. Nevertheless, taking that to one side, there is not felt to be any specific technical difference between PCC when applied to coal or biomass units, so in the absence of better data there can be some read across.

- There can be significant variation in water use between the different capture processes, when applied in a nominally similar environment. This tends to suggest a wide range of water usage data could be expected to be included in permit applications as developments come forward.

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