# 5. Technology Overview

## 5.1 North West Cluster Technologies for Scope 1

Figure 5 Industrial cluster technologies demonstrates the breadth of technologies used to generate thermal energy at each industrial site, based on data collected via EU ETS and NAEI.

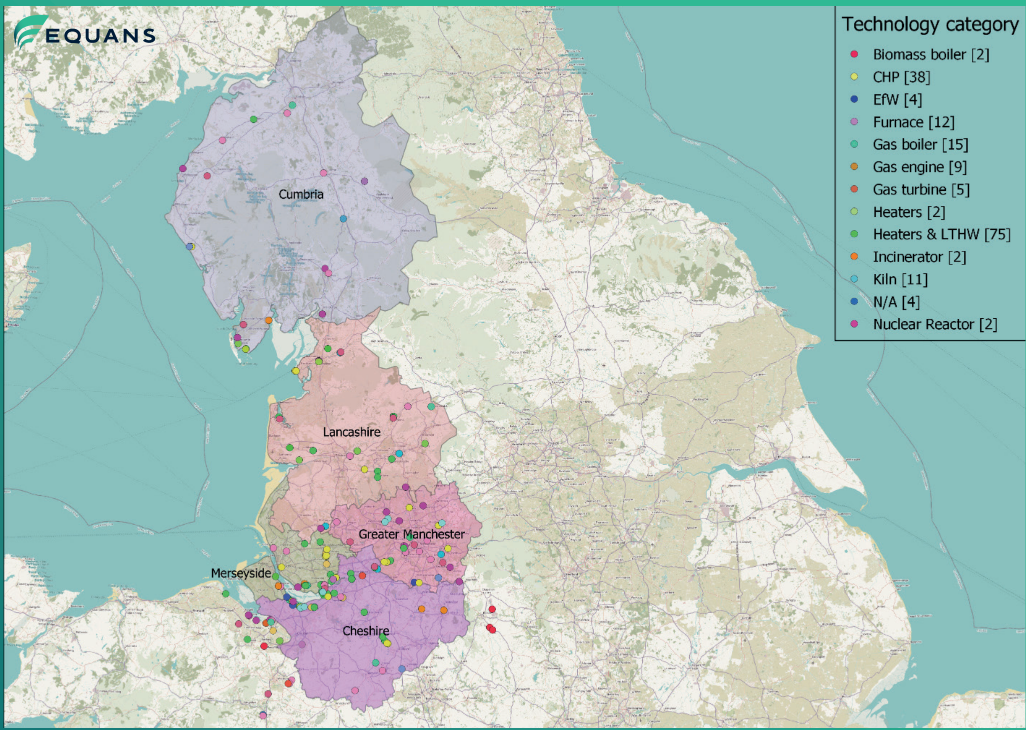


*Figure 5 Industrial cluster technologies*

Industrial heaters and Low Temperature Hot Water (LTHW) are the most common technologies, identified at 75 out of 181 North West England and North East Wales sites, which is representative of the heat demand in industrial processes and space heating requirements. This is followed by CHP, gas boiler, furnace, and kiln, respectively. Highly concentrated regions of these technologies within the North West England and North East Wales indicate opportunities where energy and carbon saving measures could be deployed.

Figure 6 Emission types and technologies used in the North West England and North East Wales illustrates the link between the emission sources on the left and the energy generation technologies on site on the right, weighted using Scope 1 emissions. The category "Manufacturing Process" represents the actual emissions produced as a result of production processes. For example, when producing cement, the Clinker (cement raw material) goes through a chemical process that produces carbon emissions.

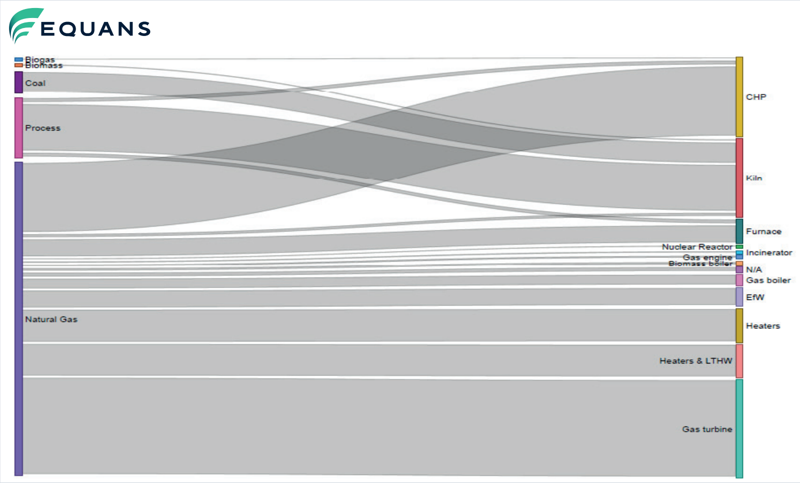


*Figure 6 Emission types and technologies used in the North West England and North East Wales*

Whilst the North West England and North East Wales has a high concentration of Heaters and LTHW in the region, the associated emissions are much lower when compared to technologies such as gas turbines, which are employed at only five industrial sites. Hence the comparison of Figure 5 Industrial cluster technologies with Figure 6 Emission types and technologies used in the North West demonstrates the number of sites utilising a technology is not representative of the volume of Scope 1 emissions. One of the important factors of consideration includes the scale of operations in relation to the technology and processes in place at the site. For instance, a CHP will tend to be deployed at larger sites with the highest overall consumption. According to the data, biogas is used only within a CHP plant whereas biomass and coal are used exclusively within a kiln. The majority of emissions from the Manufacturing Process are from kilns, with a small amount from CHP plants and furnaces.

Figure 7 Breakdown of emissions based on technology utilised in the North West illustrates the concentration of Scope 1 emissions in relation to energy generation technologies used. Gas turbine has the highest share of Scope 1 emissions (28%) with only five sites which are power producers. These are followed by CHP plants with 20% utilisation at thirty eight industrial sites. This technology can be found throughout a variety of sectors including paper and pulp, food and drink, and chemicals. This is largely due to the ability of CHP technology to produce both electricity and heat on site. Kilns produce 20% of Scope 1 emissions within the cement and ceramics sectors exclusively. Despite the high utilisation of Heaters and LTHW at seventy five sites, Scope 1 emissions for this technology only total 9%.

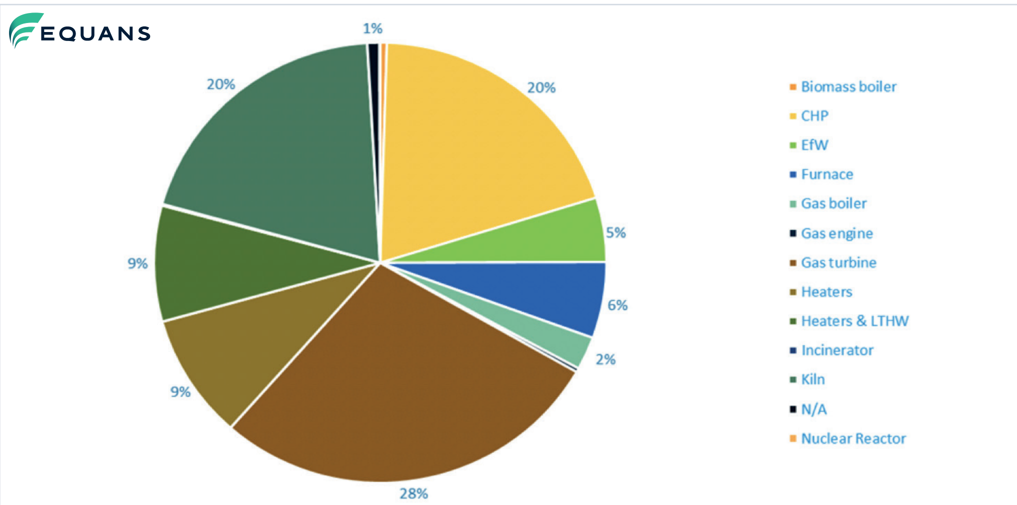


*Figure 7 Breakdown of emissions based on technology utilised in the North West England and North East Wales*

## 5.2 Common Energy Efficiency Opportunities

In its simplest form, energy efficiency is the measure of how much energy is required to perform an action. Strategies that enable organisations to use less energy are one of the easiest, lowest-investment, and often simplest approaches to lowering carbon emissions. However, these are sometimes overlooked for larger transformations that come with corresponding risks. In our experience, reduction through energy efficiency is the first step in addressing the net zero challenge.

The higher the energy efficiency the lower the amount of energy needed to perform the same action. The goal of energy efficiency is to use the least amount of energy without diminishing the performance of the work required. The following section will introduce common energy efficiency measures that can be utilised in an industrial setting across all the sectors. Sector specific opportunities can be found in Section 6.

Energy efficiency opportunities enable an organisation to utilise existing processes and equipment, optimising a systems' performance through new technology implementation or through energy recovery. The following subsections detail areas where this is commonplace within an industrial site, such as improvements within a compressed air or hydraulic pumping system. Typically, the capital expenditure for such improvements is small when compared to implementing a solar array or heat pump installation.

Therefore, to assist an industrial site in reducing carbon emissions and operating costs it can be beneficial to explore these opportunities.

Each of the following areas are commonly used within all industrial sectors, and the respective data is taken from Net Zero Carbon Roadmaps, ESOS reports, and other analysis conducted on industrial sites. This has allowed for a review of specific systems and process areas that can present a carbon and cost reduction through efficiency optimisation.

The following is a short introduction on typical energy saving opportunities across these technologies, which can be found in multiple sectors but are the most common to industrial sites. This is explored in more detail in the each of the respective subsections. The technologies explored in this section include:

- Compressed Air
- Lighting
- Motors and drives
- Heating
- Refrigeration
- Heating, ventilation, and air conditioning (HVAC)
- Smart Metering and Targeting System

Table 8 and Table 9 show the average percentage savings achievable by implementation of the most common energy efficiency opportunities within an industrial site, for each of the analysed sectors. Further manufacturing process related savings within each sector are explored individually in section 6.

| **Technology** | **Automotive** | **Cement** | **Chemical** | **Iron and Steel** | **Food and Drink** | **Glass** | **Pharma** | **Paper and Pulp** | **Average Electricity Savings (%)** |
|---|---|---|---|---|---|---|---|---|---|
| Compressed Air | 2.4% | 5% | 4.0% | 5.0% | 3.9% | – | 5.1% | 4% | **4.2%** |
| Heat Recovery | 0.0% | 10% | -0.1% | 0.0% | 0.4% | – | – | – | **2.1%** |
| Heating Systems | 3.0% | – | 0.0% | 0.0% | 1.0% | – | – | – | **1.0%** |
| HVAC | 3.5% | 4% | 5.0% | – | 5.0% | – | 4.5% | – | **4.3%** |
| Lighting | 2.5% | 1% | 3.0% | 2.0% | 1.9% | 1.0% | 5.9% | 3% | **2.7%** |
| Motors and Drives | 3.0% | 4% | 1.0% | 3.5% | 2.0% | 3.0% | 4.0% | 5% | **3.2%** |
| Pumping Systems | 2.9% | 1% | 1.7% | 2.7% | 1.0% | 2.0% | – | – | **1.9%** |
| Refrigeration | 1.9% | – | 3.5% | 2.9% | 5.7% | 2.0% | 10.3% | – | **4.9%** |
| SMT | 3.0% | 3% | 3.0% | 3.0% | 3.0% | 1.0% | 2.8% | 3% | **3.0%** |

*Table 8 Electricity savings per Sector*

| **Technology** | **Automotive** | **Cement** | **Chemical** | **Iron** | **Food** | **Pharma** | **Glass** | **Paper** | **Average Gas Savings (%)** |
|---|---|---|---|---|---|---|---|---|---|
| Compressed Air | 5.0% | 0% | 0.0% | 1.2% | 0.8% | 2.0% | | 1% | **1.5%** |
| Heat Recovery | 10.0% | 10% | 7.5% | 7.5% | 5.0% | | 5.8% | | **8.0%** |
| Heating Systems | 7.0% | 10% | 4.0% | 2.5% | 2.5% | | 11.6% | | **5.2%** |
| HVAC | 0.0% | 2% | 0.0% | | 2.5% | 1.0% | | | **1.1%** |
| SMT | 3.0% | 1% | 3.0% | 3.0% | 5.0% | 3.0% | 1.2% | 3% | **3.0%** |

*Table 9 Natural Gas savings per Sector*

### 5.2.1 Compressed Air

Compressed air is used in almost all manufacturing processes as a source of motive power for actuators, tools, etc. However, it is one of the most expensive and inefficient utilities in manufacturing plants. In fact, over the lifespan of a typical compressor, energy typically used costs several times more than the purchase price of the compressor. For this reason, maximising energy efficiency in compressors is crucial to achieve savings. Compressed air is an inefficient form of energy, with only 8-10% of input energy converted into useful energy output, the remainder being dissipated as heat.

There are two common applications of compressed air, namely instrument air and process air. Instrument air is used for actuation (pneumatics) such as a robotic arm for packaging machines, while process air is used in the process itself, such as the delivery of raw material from silos to production machinery.

Opportunities for compressed air improvements in a typical manufacturing facility are outlined below.

#### Leak Reduction

Leaks in the compressed air system can be a further source of wasted energy; a typical compressed air system loses 20-40% of the compressors output through leaks. Therefore, frequent checks are required on generation and distribution networks to avoid loss of compressed air from the system The table below demonstrates the typical impact of compressed air losses at varying hole and system pressure sizes.

Leaks can occur in any part of the system, however, the most common problem areas are pipe joints, fittings, valves, and filters. Leaks can be difficult to detect if the system is at a high level or if the leaks are within a noisy environment. The most common equipment used in a leak detection survey is the ultrasonic equipment which converts the air leak ultrasound to an audible frequency that normally can be heard through a set of headphones. A single survey and fix is not enough to maintain an efficient system; a leak prevention program will take a holistic approach to the facility's operations, and include:

- Identification
- Tagging
- Tracking
- Repair (budget)
- Verification
- Employee engagement

If this is implemented effectively the wasted compressed air would realistically reduce from 20-40% to 5-15%.

| Air Pressure (barg) | Leakage (l/s) through various sized holes (mm) | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 0.5 | 1 | 2 | 3 | 4 | 10 | 12.5 | 4.2% |
| 2.5 | 0.14 | 0.58 | 2.3 | 5.5 | 14.6 | 58.6 | 91.4 | 2.1% |
| 5.0 | 0.25 | 0.97 | 3.9 | 8.8 | 24.4 | 97.5 | 152.0 | 1.0% |
| 7.0 | 0.33 | 1.31 | 5.9 | 11.6 | 32.5 | 129.0 | 202.0 | 3.0% |

*Table 10 Estimated Air Leakage rate for different range of pressures*

### Compressors Speed Control

Compressors can be fitted with their own individual control system to control the site demand. The traditional way of controlling a compressor is by running the motor at full speed and then stopping it when the air has been compressed to the correct pressure. It is then stored in a reservoir at a slightly higher pressure than is needed, to allow a hysteresis in the pressure.

Modulation control schemes proportionally adjust the inlet valve from open to closed, altering the compressor discharge according to demand. Whilst this yields a consistent discharge pressure over a wide range of demand, power consumption is significantly higher than with load/unload mode schemes, resulting in approximately 70% of full-load power consumption when the compressor is at a zero-load condition.

A VSD controlled air compressor uses an alternative current (AC) drive to control the speed of the unit, which in turn saves energy compared to a fixed speed equivalent. VSDs reduce the energy output of a compressor, by controlling the speed of the motor, ensuring it runs no faster than necessary for the required compressed air demand.

Compressor manufacturers often sell compressors for worst case scenarios that are essentially too large for the applications. These oversized compressors can easily be identified by the unload running hours when compared to load running hours. Compressors with high run hours and low load hours are ideal for a VSD installation.

### Pressure Optimisation

Pressure optimisation is achieved through reviewing and resetting compressed air pressure to match the demand and activation of setback mode when not in peak demand. Historically, sites will maintain their compressed air pressure regardless of whether it is required or not. As a site evolves over time and equipment changes, the compressed air distribution may not be re-assessed. The higher the pressure to be generated in the compressor, the more expensive it is to provide that air, thus, generating less pressure requires less energy input from the compressor, consequently saving energy. If the pressure can be reduced without detriment to the system or the equipment it serves, the energy savings are immediate at no cost. Even small reductions in pressure setpoints can result in significant energy cost reductions; for every 0.5 barg reduction in the compressor set-point pressure, 3% of energy required by the compressor is saved.

It is important to notice that higher pressures increase compressed-air leakage and consumption at open air lines. If an end of use application requires a different pressure than the output of the compressed air plant, it is more efficient to run a local dedicated system as a booster or a small compressor close to the relevant process than it is to run the whole system at the highest pressure.

Consideration should be given to:

i. Ensuring low pressure requirements where possible when specifying new equipment.

ii. Installing air pressure boosters to specific users.

iii. Installing dedicated air compressors to specific users.

iv. Pressure drop between compressor house and end-user should not be more than 10% .

The use of VSDs and a good control system are both likely to enable more effective optimisation of compressed air delivery due to being able to offer tighter controls of the pressure.

### Reduction In The Compressed Air Inlet Temperature

In many industrial sites the compressor will take its inlet air from within the compressor house, which is often a warm environment due to the heat released from the compressors themselves. The warmer the inlet air the more energy required to compress it. Thus, efficiency of the compressor can be greatly improved by providing cooler air at its intake. This can be as simple as ducting air from outside the compressor house or another location on-site.

Another important consideration is where the waste heat from your compressor is discharged to, whether it is discharged into the compressor house or into the atmosphere. Best practice would ensure that waste heat does not find its way back into heating the inlet air to the compressor. The table below illustrates energy savings arising from reducing the air inlet temperature to a compressor.

| Air Intake Temperature Reduction | 3°C | | 6°C | | 10°C | | 20°C | |
|---|---|---|---|---|---|---|---|---|
| 4 | 80 | 9 | 160 | 18 | 264 | 29 | 528 | 58 |
| 7.5 | 150 | 17 | 300 | 33 | 495 | 54 | 990 | 107 |
| 11 | 220 | 24 | 440 | 48 | 725 | 79 | 1,450 | 157 |
| 15 | 300 | 33 | 600 | 65 | 990 | 107 | 1,980 | 214 |
| 22 | 440 | 48 | 880 | 96 | 1,450 | 157 | 2,900 | 314 |
| 30 | 600 | 65 | 1,200 | 130 | 1,980 | 214 | 3,960 | 428 |
| 37 | 740 | 80 | 1,480 | 160 | 2,440 | 264 | 4,880 | 528 |
| 55 | 1,100 | 119 | 2,200 | 238 | 3,625 | 392 | 7,250 | 783 |
| 75 | 1,500 | 162 | 3,000 | 324 | 4,950 | 535 | 9,900 | 1,070 |
| 110 | 2,200 | 238 | 4,400 | 476 | 7,260 | 785 | 14,520 | 1,569 |
| 160 | 3,200 | 346 | 6,400 | 692 | 10,550 | 1,140 | 21,100 | 2,279 |

*Table 11 Energy Savings from reducing air inlet temperature*

## Compressor Control Systems

A compressor control system should allow the user to select how each compressor will operate in relation to the others given its range of operational options. The compressor control solutions are built around integrated high-speed Programmable Logic Controller (PLC) and local Human Machine Interface (HMI) systems to monitor, log and oversee the connected compressor systems. The compressor controllers have extensive communications capabilities to allow the connection of remote third-party systems. The compressor control system may be connected to host systems to permit data to be made available throughout the plant.

Control systems are often overlooked within compressed air systems. As a site grows or evolves the air compressors are replaced or new air compressors are added to the system to meet the demand. Often the compressor will run on a 'duty and standby' system with the larger compressors meeting most of the demand and smaller compressors coming online as required.

A combination of one or multiple fixed load compressors producing the compressed air base load and a VSD compressor modulating the extra demand peaks is the most cost-effective solution for almost every compressed air system.

A compressor management control system ensures that the most efficient compressors are employed in the most efficient combination to suit a given demand for compressed air.

This is done by installing multiple independent control pressure transmitters in the air distribution system to monitor the demand and communicate to a sequence controller. The controller harnesses the most efficient combination of compressors and optimises the fixed and variable speed air compressors to orchestrate the most efficient control strategy available.

## Heat Recovery

This is achieved by reusing the heat from the air compressors for space heating or process heating. The recovered heat can be supplied to heat exchangers to offset heating energy at different locations. A properly designed heat recovery unit can recover over 80% of this heat for heating air or water. Although compressors can be purchased with a heat recovery kit, a retrofitted unit would also be a good investment. The best payback is achieved when the compressed air and heat recovery systems can be designed as integral parts of the plant. For example, if the heat is used for space heating, it is beneficial to incorporate the design within the existing heating system.

Typical applications for air heating include:

- Space heating (e.g., warehouse or factory areas)
- Pre-heating boiler combustion air.

Typical applications for water heating include:

- Pre-heating boiler feed water
- Pre-heating process water (e.g., bottle washing)
- Water heating in laundries.

The potential savings from heat recovery should be evaluated carefully as they are highly dependent on the load cycle of the compressor being able to generate sufficient heat at the right times.

Furthermore, each compressor is designed with an optimum running temperature range; any heat recovery system should not over-cool the compressor which would impose an unnecessary burden on its performance. A typical air compressor heat recovery system is demonstrated below.

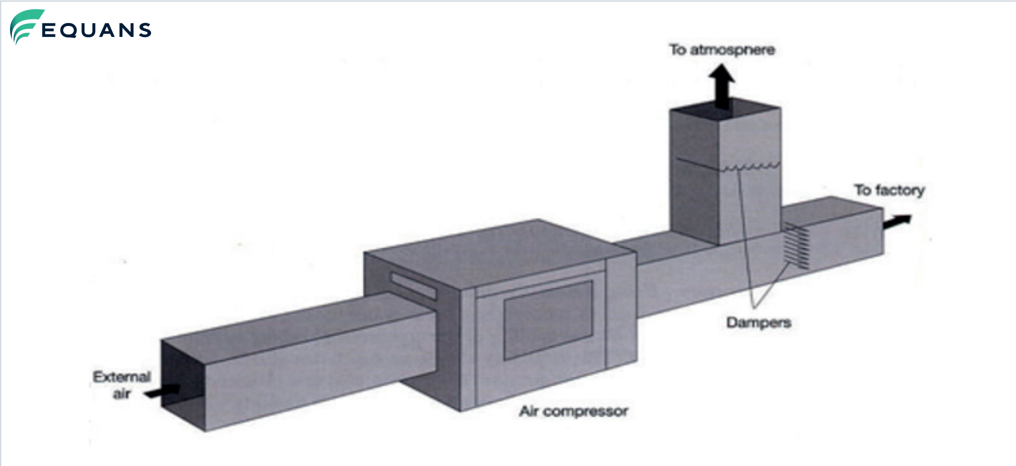


*Figure 8 Typical compressed air heat recovery system*

Table 12 below shows examples of recoverable heat from a range of screw compressors.

| Capacity (l/s) | Nominal Motor Rating (kW) | Cooling Air Flow (l/s) | Available Heat (kW) |
|---|---|---|---|
| 40 | 15 | 450 | 12 |
| 60 | 22 | 810 | 21 |
| 159 | 55 | 1,600 | 54 |
| 314 | 110 | 3,700 | 107 |
| 450 | 160 | 5,600 | 157 |
| 585 | 200 | 8,900 | 197 |
| 725 | 250 | 8,900 | 246 |

*Table 12 Recoverable Heat from a range of screw compressors*

### 5.2.2 Lighting

Lighting improvements are the most common energy efficiency opportunity and can be implemented with quick payback periods. Examples of opportunities for energy reduction are listed below:

• **LED upgrades:** LEDs are semiconductors; as electrons pass through this type of semiconductor, it turns into light. Compared to incandescent and compact fluorescent lamp (CFL) bulbs, LED lights are more efficient at turning energy into light.

• Improved **lighting controls** can result in significant savings. This can be through daylight detectors, occupancy sensors, LUX level control or $CO_2$ sensors. Where smart controls are put in place these should be set up so that lights are controlled in logical groups. For example, lights in an area can be banked so that outer roofs can be switched off when there is sufficient daylight through windows, or halls can be set up so different levels of lighting can be switched on to suit the activity being undertaken.

• **Maximising use of daylight.** Daylight should become the primary light source in buildings for health, productivity, and sustainability reasons. Architects should be designing buildings to maximise the use of daylight, which is measured in lumens, and illumination in lux. Lux levels reveal how many lumens you need to light a given area. A lux (symbol: lx) is equal to an illumination level of one lumen per square metre. In non-SI units, one footcandle is equal to approximately 10 lux. The below table provides a summary of the lux level for different applications (27).

| Lux Level (28) | Area of Activity |
|---|---|
| 20-30 | Car parks, roadways |
| <100 | Corridors, stores, and warehouses, changing rooms and rest areas, bedrooms and bars |
| 150 | Stairs, escalators, loading bays |
| 200 | Washrooms, foyers, lounges, archives, dining rooms, assembly halls and plant rooms |
| 500 | General lighting e.g., offices, laboratories, retail stores and supermarkets, counter areas, meeting rooms, general manufacturing, kitchens, and lecture halls |
| 750 | Detailed lighting e.g., manufacturing and assembly (detail), paint spraying and inspection |
| 1,000 | Precision lighting e.g., precision manufacturing, quality control, examination rooms |
| 1,500 | Fine precision lighting e.g., jewellery, watch making, electronics and fine working. |

*Table 13 Recommended lighting levels for different areas*

### 5.2.3 Motors And Drives

Most moving applications and modern-day devices are powered by electric motors. These range in size from large industrial pumps to small office ventilation fans. In industry they are expected to consume 70% of all electrical consumption. Opportunities for improvements in efficiency through motors and drives are listed below:

• Many assets are fitted with electrical motors such as boiler burners, blowers, chilled water/ cooling tower recirculation pumps, air handling units (AHU) and ventilation fans, etc. They run most of the time to maintain the requirements for the end-user. These motors can be replaced with high efficiency motors or fitted with VSDs and feedback signal for better control.

• VSDs and variable frequency drives (VFDs) (also called adjustable speed drives (ASDs)) vary the speed of a fixed speed motor. In HVAC systems, they are used primarily to control fans in variable air volume systems. Instead of devices such as inlet vanes, pumps and discharge dampers, VSDs provide effective speed control of AC motors by manipulating voltage and frequency. Controlling the speed of a motor provides users with improved process control, reduced wear on machines, increased power and energy savings.

• Belt drives can incur considerable efficiency losses. The efficiency depends on the calculation of the belt gear, the type of belt, and the complete gear adjustment. Normally an expected efficiency of a belt drive is 90% at medium power (3–15 kW), but it can easily slip to 60–70% if the gear adjustment is incorrect. Belt driven systems are more common in extraction and ventilation systems, however, they can be found in various manufacturing dedicated processes. The newly designed systems must avoid belt-driven applications and should always use direct drives where transmission efficiency is 100%.

### 5.2.4 Heating

Heating is used widely in every sector within the North West England and North East Wales, either for space or process heating.

Heating systems vary for different applications and heat loads. The most common heating systems that can be found within a manufacturing facility are listed below:

- Hot water Boiler
- Steam Boiler
- Radiant heaters
- Cabinet heaters
- Direct burners for process or AHUs

Opportunities for heating improvements in a typical manufacturing facility are listed below, the list is separated into two categories; general energy efficiency opportunities and boiler specific opportunities.

#### 5.2.4.1 General Energy Efficiency

**Equipment Efficiency**

Over time efficiency of combustion or heating equipment will degrade. This is mainly atributed to fouling/scaling and poor air fuel ration control. Although a good maintenance strategy will mitigate some of the degradation it cannot stop the inevitable. When paired with new efficient technology, it can be more cost effective to replace the heat provider (see heat pumps and CHP for low carbon alternatives).

**Maintenance**

A good maintenance programme not only increases shelf-life and decreases risk of faults/breakdown, it also maintains efficiency. Cleaning fouling off fans and/or heat exchangers is an example of how a good maintenance routine can maintain a heating system to run as efficiently as possible.

**Controls**

This refers to controls on the heating generator, whether that is boiler controls or controls on a direct heating system, such as a cabinet or radiant heater (see HVAC for more on point of use control). Timers, heating zones and lock-outs to stop simultaneous heating and cooling are the top efficiency opportunities.

**Set-Point Review**

Reducing heating temperature where possible will result in energy savings as the thermal load produced by the heating system will be reduced.

**Install Thermostatic Radiator Valves (TRV) to Heating Radiators**

Smart TRVs are devices that are designed to provide an individual, room-by-room heating control, by working in conjunction with the thermostat kit and creating a so-called zoned heating system, which can be easily managed through an app on smartphones, tablets, or computers.

#### 5.2.4.2 Boiler Specific Energy Efficiency Technology Economiser

Flue gas (or exhaust gas) is generated through the combustion process. A proportion of this gas contains useful heat which is wasted if the gas is released into the atmosphere via a stack. An economiser can recover some of this waste heat and use it to pre-heat the feed water, resulting in a lower energy input to achieve the same output.

**Blowdown**

Blowdown is required for steam boilers to control total dissolved solid (TDS) and the build-up of sludge solids.

There is potential to recover water and heat through the blowdown process. The quality of water dictates the the amount of blowdown required to maintain the required boiler water TDS. Automating this process with TDS sensors has the potential to save energy. Furthermore recovering heat from the flash vessel can limit further wasted heat.

This can be achieved by installing TDS sensors and automating the process, so the blowdown will only occur when necessary.Once the blowdowns are limited this way, further heat waste can be minimised via the use of a flash vessel for heat recovery.

As the water in the boiler is at saturation temperature when it is released into atmospheric pressure, it will flash off as steam. This steam can be recovered and put back into the system, either to heat the feed tank or to be used for other heating applications.Further opportunities for heat recovery may also be available from the sensible heat in the remaining blowdown stream.

**Combustion Controls**

Each combustion process needs to respect a ratio between fuel and air. The theoretical amount of air needed to completely burn the fuel during a combustion process is known as stoichiometric air.

However, due to practical reasons, it is not possible to achieve 100% fuel combustion with only stoichiometric air, therefore, some percentage of excess air is provided to assure that all the fuel is burned and is not transported to the stack. Heat loss through the stack depends on the mass flow and temperature of the gas leaving the boiler. Reducing the gas temperature by reducing the surrounding air temperature can improve system efficiency. The boiler efficiency will depend on the excess air so improving the excess air rate will improve boiler efficiency.

Table 14 shows indicative combustion efficiencies for different excess air rates in gas fired equipment.

| Combustion Efficiency (%) | | | | | | |
|---|---|---|---|---|---|---|
| Excess (%) | | Net Stack Temperature (°C) | | | | |
| **Air** | **Oxygen** | **93.3** | **149** | **204** | **260** | **316** |
| 9.5 | 2 | 85.4 | 83.1 | 80.8 | 78.4 | 76 |
| 15 | 3 | 85.2 | 82.8 | 80.4 | 77.9 | 75.4 |
| 28.1 | 5 | 84.7 | 82.1 | 79.5 | 76.7 | 74 |
| 44.9 | 7 | 84.1 | 81.2 | 78.2 | 75.2 | 72.1 |
| 81.6 | 10 | 82.8 | 79.3 | 75.6 | 71.9 | 68.2 |

*Table 14 Combustion efficiency per excess air rate in a gas fired equipment*

As per the table above, a combustion system with a 9.5% excess air and 2% of oxygen will have an efficiency of 85.4%. As a rule of thumb, the boiler efficiency can be increased by 1% for 15% reduction in excess.

### Pre- Heat The Combustion Air

In a common boiler, where the combustion air is taken from the boiler house, temperatures can vary from 10°C to 30°C, depending on the size of the system, boiler house insulation, etc. The combustion air needs to be heated up to the combustion temperature, which is normally achieved in the burner by burning fuel. Pre-heating the combustion air using heat rejected from the stack will result in fuel savings.

## 5.2.5 Refrigeration

Refrigeration is widely used in different types of industry for process cooling, cold storage, and comfort cooling. The most common refrigeration systems that can be found within manufacturing facilities are listed below:

- Package Chillers
- Refrigeration Compressors
- Adiabatic Coolers
- Absorption Chillers

Opportunities for cooling improvements in a typical manufacturing facility are listed below.

### Replace Old Refrigeration Equipment with High Efficiency Equipment

The efficiency of a refrigeration system is measured by the Coefficient of Performance (COP), which is the cooling load capacity divided by the electrical load consumed by the equipment.

For example, a refrigeration system with a COP of 3, will consume one kW of energy per each 3 kWc produced.

During the operational time of the equipment, depending on the maintenance and external conditions, the COP will decrease resulting in low operation conditions. For example, an old chiller poorly maintained can have a COP of less than two, compared to a new highly efficient refrigeration system (with controls or a free cooling coil) which can have a COP over four.

### Set-Point Review

Increasing the cooling temperature where possible will result in energy savings as the cooled load required from the refrigeration system will be reduced.

### Free Cooling

Free cooling is the opportunity to use external air at low ambient temperatures to cool a space, allowing refrigerant cooling systems such as air conditioning to be turned off during cold periods of the year. A control system can be introduced to determine whether the ambient temperature is sufficiently low enough to use the free cooling, or high enough to use the traditional refrigerant system.

Free cooling can also be used to assist chillers. During periods of low ambient temperature, a valve will allow the cooling water to bypass the chiller and run through an air blast cooler. This may provide the entire cooling demand or be used as a pre-cooler before the chiller, reducing the energy used at the chiller.

### VSD Installation

Installation of VSDs on chillers and distribution pumps to modulate the site cooling load for different times of the day or for different processes will result in significant energy savings.

### Refrigeration Heat Recovery

Heat recovery equipment can be fitted to existing plants or can be integrated into new plant. In both cases, the technology allows waste heat to be re-used for space heating or hot water.

The refrigeration process includes a heat rejection stage to cool the refrigerant for re-use in the cycle. The heat is given up at the condenser, this provides the opportunity for it to be recovered.

### 5.2.6 Heating, Ventilation and Air-Conditioning

HVAC is an important utility for industrial companies as it Is required for both human comfort conditions and certain manufacturing processes. If a poorly designed and controlled HVAC system is in operation a drop in manufacturing output and product loss may be seen. This can be because specific products and materials are being stored at the wrong temperature conditions. For example, with recent technological development of lithium-ion batteries, particularly within the automotive sector, set temperature conditions must be met. This is to reduce the degradation rate of the maximum charge capacity. Additionally, HVAC design and operation is critical for human comfort as deviation to an individual's surrounding temperature conditions will be detrimental to their output.

The equipment used within a HVAC system can also suffer from poor design and operation, as premature wear to components can occur. This could all contribute to a system that will be more expensive to run and maintain. AHUs are the most common equipment used to achieve the distribution of both hot and cool air, with other applications used for air purification. These typically contain a distribution fan and motor, heating and cooling coils, filtration, and sound attenuation. Air will be distributed through the AHU from a source to the sink, which is the area being heated or cooled, achieved via ductwork.

In the most basic explanation, the AHU is simply a heat exchanger, where energy is transferred from the media within the heating or cooling coils to the air being circulated. It is therefore crucial the specification for the coils is correct for the duty required, as over or under sizing of the effective heat transfer area will detriment the efficiency of the system. For heating applications, the most common temperature required is 20°C - 22°C. Therefore, it is more efficient to operate a heating system with low temperature hot water conditions rather than a system maintaining temperature at 90°C and above. Controls for a HVAC system are critical to achieving a fully optimised system configuration.

### 5.2.7 Smart Metering And Targeting System (SMT)

SMT products are specifically designed to measure energy consumption, record, distribute metered energy data, and analyse and report on energy consumption. This enables organisations to identify ways to reduce energy costs, to pinpoint energy wastage, to be notified of instances of exceptionally high energy consumption, and to put in place robust and long-term energy management practices. SMT systems can be started at a high level i.e., measuring main utilities, and then move on to sub-metering by fitting meters on individual end-users. The information/data from a SMT system can be used to create an awareness programme and behaviour change campaigns for staff by analysing the performance against production throughput, looking at energy consumption per floor area or understanding which asset is working the most efficiently.

It is estimated that this technology can help the sectors identify energy savings of 4 - 20% or more, with average cost savings of 10-15% (29).

## 5.3 Low Carbon Technologies

The approach for analysing low carbon technologies shall consist of the review of clustered data of the industrial sites, grouped by their specific sector, then an average figure calculated to gauge a typical thermal energy operating profile for that industry. Electrical data has been used from various industrial sectors to understand how the electrical consumption behaves. This has allowed for a characteristic profile for that sector to be developed, which complements the thermal profile used throughout a normal year of operation.

### 5.3.1 Combined Heat and Power (CHP)

CHP systems produce both electrical and thermal energy from a single fuel input. This is achieved using an internal combustion engine or a gas turbine as the prime mover for the system, driving an alternator. The thermal energy is then recovered from the engine as a by-product of the mechanical work being carried out from combustion.

The most common types of CHP systems use a gas-fired internal combustion engine fuelled by natural gas. The engine assembly is directly coupled to an alternator producing electricity. There are two types of alternators typically used within a CHP application; synchronous, over 100 kW systems, and asynchronous, sub 100 kW systems.

Electrical energy is produced via the alternator coupled to the engine crankshaft. The rotation of the engine rotates the alternator which in turns produces an electromagnetic force (EMF). This EMF is the voltage generated for the site in the form of an alternating current distributed over three phases. This can be generated at 430/440 V (Low Voltage) or 11 kV (Medium Voltage). The requirement of either depends on the size of the CHP output and the site's electrical requirement.

The thermal energy is recovered from a series of separate streams (engine jacket water, oil system, intercooler and the exhaust stream) within the engine assembly and can be combined depending on the application. The operation of the engine produces heat through mechanical work and combustion of fuel. If this heat was not removed from the engine assembly, it would suffer from catastrophic failure.

The arrangement shown in Figure 9 is of a typical thermal energy flow diagram through the engine assembly. This arrangement is shown as an illustrative aid for the internal heat recovery system for a particular configuration. The flow arrangement for this system may differ depending on the application and manufacturer.

Figure 10 shows a CHP system typically used for LTHW application. The system beyond the limits of the engine arrangement is shown in Figure 10 illustrating the interface into the site. The advantage in utilising this type of arrangement is to offset the sites' water demand of temperatures up to approx. 100ºC. However, the most common thermal conditions for this type of arrangement would be providing water at 90ºC returning at 70ºC. The capital expenditure of this type of arrangement is much higher in comparison due to the additional equipment needed to produce steam. However, if a CHP is sized appropriately for a site, then a significant saving can be made against the use of natural gas for the use of conventional hot water boilers.

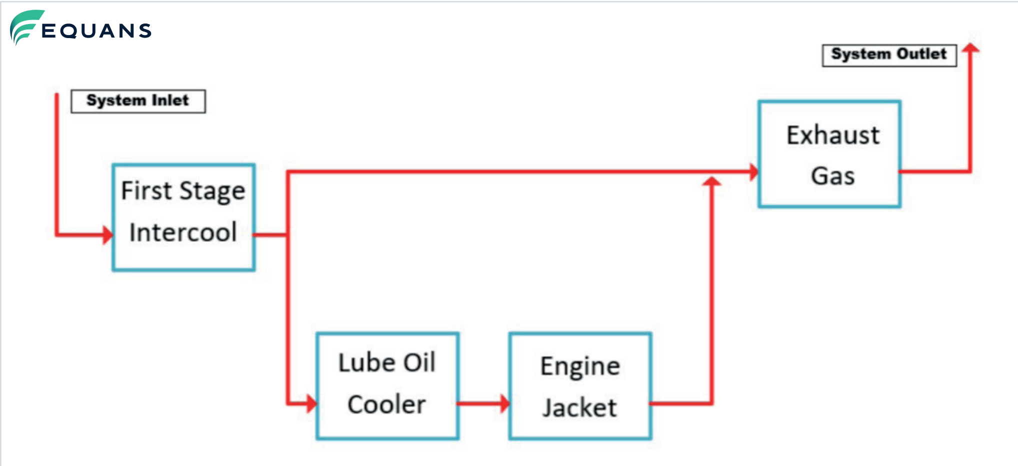


*Figure 9 Typical thermal energy flow*

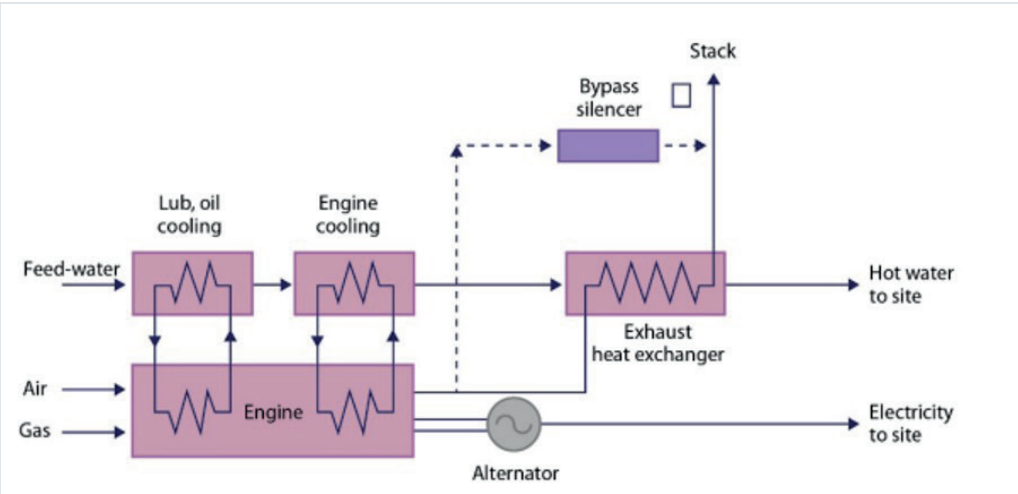


*Figure 10 Low Temperature Hot Water (LTHW) CHP system (30)*

Rather than being combined with the engine hot water circuit the exhaust gas energy can be recovered separately for steam applications. This is shown in Figure 11. The advantage of this application is the versatility of the system; if a site has multiple mechanical processes requiring both steam and hot water, then a CHP can supplement both simultaneously.

Both configurations shown in Figure 10 and Figure 11 are referred to as cogeneration, whereby two separate energy streams are being generated from a single fuel source. In addition to this, trigeneration systems have presented significant benefits for industrial sites that require cooling in tandem with thermal and electrical energy. This requires the CHP system to be used in conjunction with an absorption chiller. The process would then utilise some or all the hot water generated by the engine within the chiller through a condensing and evaporation process. The typical chiller system outlet temperatures would be between 4°C to 10°C, however, this can change subject to system design and manufacturer. A typical arrangement for this type of system is shown in Figure 12.

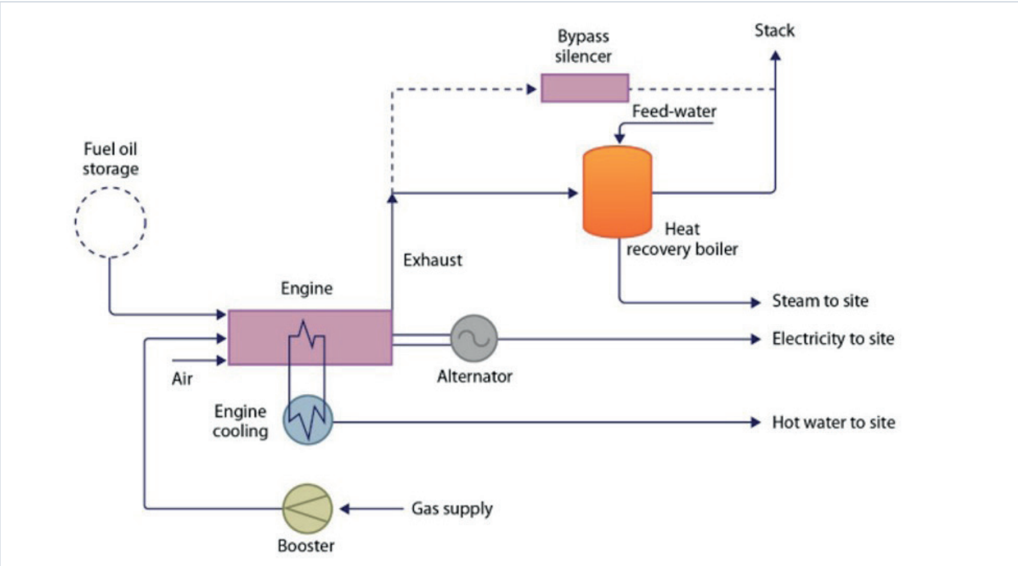


*Figure 11 CHP custom steam and hot water generation (30)*

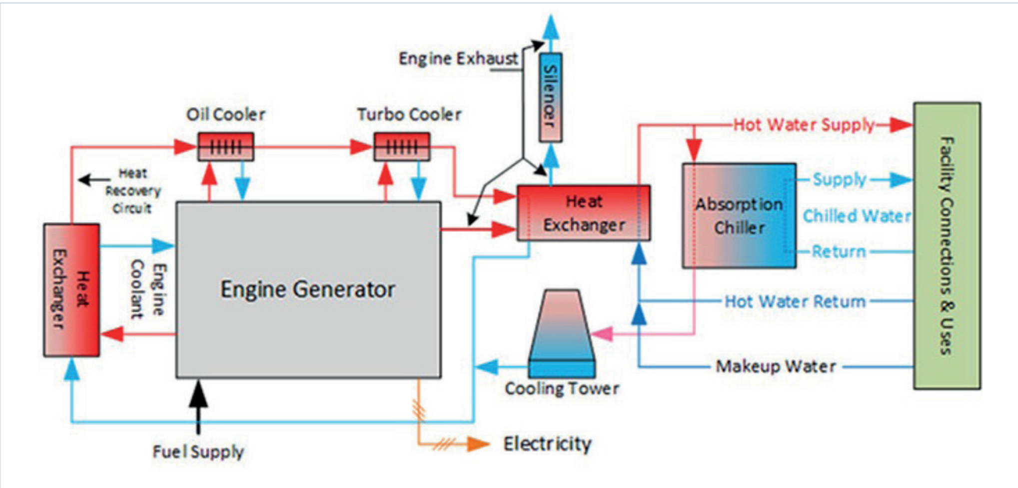


*Figure 12 Trigeneration System (31)*

As previously stated, the advantage of this system is the generation of multiple energy outputs for a site. However, it should be recognised that for this to be a feasible solution for a site, termination points for each respective system need to be in relative proximity to each other. The viability of a CHP installation needs to be explored with a feasibility study.

Due to space constraints within most installations, modern CHP systems are designed to be supplied as a modular assembly, removing the need for additional construction works on a site. This would be within a container of an approximate size of 3m(w) x 3m(h) x 12m(l) including the respective equipment within the supply of the assembly. Systems exceeding 2.5 MW would require a more bespoke container or enclosure design specifically for that installation.

#### 5.3.1.1 CHP Feasibility

CHP systems work best when installed within a system that operates with a consistent base load, avoiding the need to modulate between full and part load conditions and reducing start/stop operation. This will allow for the most optimised and efficient system with the quickest payback and will reduce premature wear to components.

In the event the CHP exceeds the site thermal requirements, it will have the capacity to eject the energy to the atmosphere via a dry air cooler. This is not a desired situation as the efficiency of the system will decline dramatically below the potential savings available. If the site's electrical requirement drops below the CHP output, then certain constraints shall be in place to de-rate the system to suit. This is largely due to recent constraints with network operator issues with 'back feeding' electricity onto the National Grid. Local control systems must ensure the CHP does not exceed the required site electrical output.

Consideration of the future of hydrogen fuel within the horizon of CHP applications would enable CHP technology to count towards a significant carbon reduction for industrial sites. The review that has been undertaken within this report is to understand the technology of CHP being implemented within an existing infrastructure. Further review is needed to demonstrate how the technology can be future proofed with the introduction of low carbon fuels such as hydrogen. Hydrogen fuels are discussed further in Section 5.5 of this report. Existing fuel types such as biogas from anaerobic digestion (AD) plants can be shown to reduce carbon further within power generation applications. The process of biogas production is through the anaerobic decomposition of organic material. Biogas can then be utilised within a CHP plant to produce electricity. This process and the application is explained further in Section 5.4.3 of this report.

#### 5.3.1.2 CHP Methodology

Considerations were made for the selection of the CHP system with existing CHP data sheets acquired by EQUANS, ensuring the most accurate selection for the industry. This allows for an understanding of carbon reduction, quality index (QI) score, which determines the quality of the CHP through the CHP Quality Assurance (CHPQA) standard, and a total saving for the installation and operation of the equipment. The QI score for a CHP installation is defined by the energy output from a system compared with the fuel input. This is calculated against an equal alternative power supply from electrical and thermal sources. The alternative values are published values from government guidelines for CHP installations. With the threshold for good quality CHP being over 100, this has been considered within the analysis as a parameter for the modelling of CHP within the industrial sectors.

Another parameter for modelling a CHP system within an industrial site is the thermal and electrical utilisation rate. A minimum of 90% thermal utilisation is required to ensure the system does not reject too much energy during a yearly operation profile. Electrical utilisation rates need to be as close to 100% as possible to enable the greatest benefits through displacing site power and national grid constraints, as previously mentioned.If this does not occur, then the CHP shall need to de-rate to suit the site requirements which is illustrated below in Figure 13 in a load duration curve. This curve shows the CHP can run for 7,884 hours of the year with a utilisation rate of 99.93%. This type of system is an electrically-lead system.

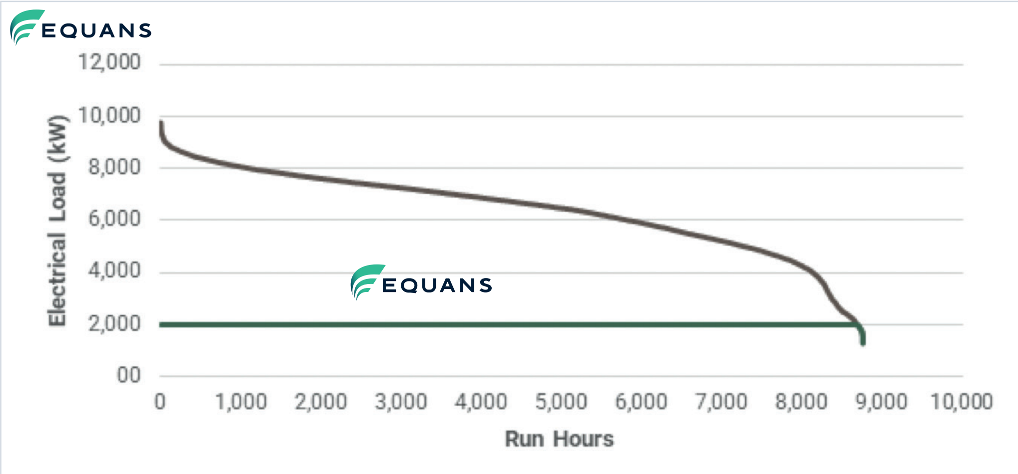


*Figure 13 CHP load duration curve*

The payback for the installation of the system is a key input to the overall report as this is the most attractive motivation behind a CHP installation. For the calculations carried out within this report, the electricity and gas prices used for all costings and savings are shown in Table 15. Table 16 shows the grid carbon figures applied to the model to understand the carbon savings from a CHP installation.

| Fuel | £/kWh |
|---|---|
| Electricity | 0.108 |
| Gas | 0.023 |

*Table 15 Utility Costs*

| Fuel | mg/kWh |
|---|---|
| Electricity $CO_2$ | 255.6 |
| Natural gas $CO_2$ | 183.53 |

*Table 16 Carbon Factors*

#### 5.3.1.3 CHP Review

For this stage of the analysis each sector was reviewed to understand its suitability to support the operation of a CHP system. A specific criterion had been defined for thermal and electrical utilisation and payback so an understanding could be reached as to whether the site would benefit from the installation of a CHP system. This has been applied to a range of industries contributing to approx. 40% of the carbon output for the North West England and North East Wales industrial users. This has allowed for a clear comparison between various industries with differing processes and operating profiles. Due to the type of review undertaken, assumptions have been made regarding the thermal energy usage on site. Modelling has considered only a LTHW system, which does not exceed an operating temperature of 90ºC.

It is appreciated that this does not make a true reflection of circumstance, so a feasibility study would be required at each site to understand the appropriate system to install. This section of the report does not detail the operating intricacies of each industry, a more detailed review of each industry is in section 6.

#### 5.3.1.4 The Future of CHP

The current forecast for the industrial landscape has shown that natural gas combustion equipment is not viable to achieve net zero carbon by 2050. However, the narrative for the report is to appreciate the carbon savings available through hydrogen integration. Therefore, a huge investment is being placed within research and development to produce an alternate solution moving away from natural gas combustion to hydrogen gas. Currently hydrogen gas engines are commercially viable up to 1 MW with a view to expand this to a larger scale output matching the market's existing system offering.

The characteristics of a hydrogen engine differ slightly from a conventional natural gas engine due to the nature of the fuel type. This is expected as hydrogen fuel has a higher calorific value than natural gas when comparing mass, but is much lower on a volumetric basis. Hydrogen in a gas form needs to be pressurised before combustion, this allows for a comparative energy output from the CHP when changing from natural gas to hydrogen gas.

Current legislation restricts CHPs from being classified as low carbon solutions. However,, the installation of the system can still contribute to a significant cost reduction to site from the offset of electrical and thermal energy.

If we assume that there are no changes in the current legislation, natural gas CHP modelling has been applied to understand the operation of the CHP and that when hydrogen is introduced it is possible to reduce carbon further, thus savings could be vast across each industrial sector. The model for the CHP system includes the assumption there is an existing boiler working at 75% efficiency. It is understood that newer boilers can operate up to an approximate efficiency of 86%. Therefore, the benefit of a CHP installation will be different for each site.

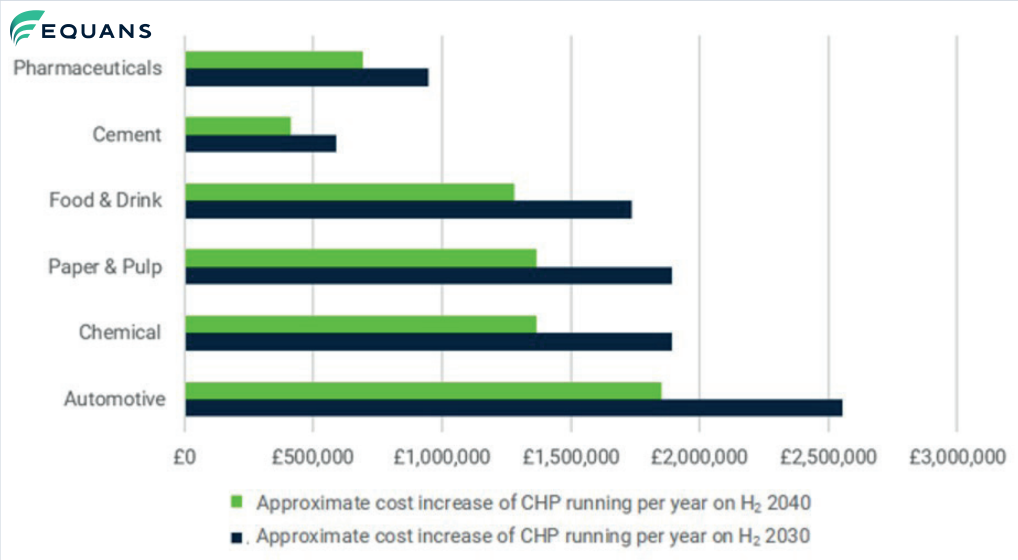


*Figure 14 H2 Cost Increase 2030 and 2040 Comparison*

Figure 14 $H_2$ Cost Increase 2030 and 2040 Comparison illustrates that the initial application of hydrogen gas can cause an increase in cost of over £2,500,000 per year in certain sectors, with a reduction in cost by approx. 28% 10 years later in 2040 (if unsubsidised). However, we recognise that the hydrogen business models consultation is set to benchmark the cost of hydrogen to the counterfactual fuel of natural gas. Therefore, the cost increase delta would be covered by the Contract for Difference (CFD) mechanism, meaning the consumer sees no additional cost.

Figure 15 simply illustrates the importance of the CFD mechanism in ensuring technologies such as CHP are viable. With significant savings presented when considering the offsetting of carbon production from onsite generation. This increase in potential financial savings is from the combination of the utility price gap and carbon reduction savings. Therefore, the integration of CHP technology operating with hydrogen fuel would provide a significant financial benefit when comparing to the existing climate. This scenario is only viable with a CFD mechanism in place, otherwise these savings would be unachievable.

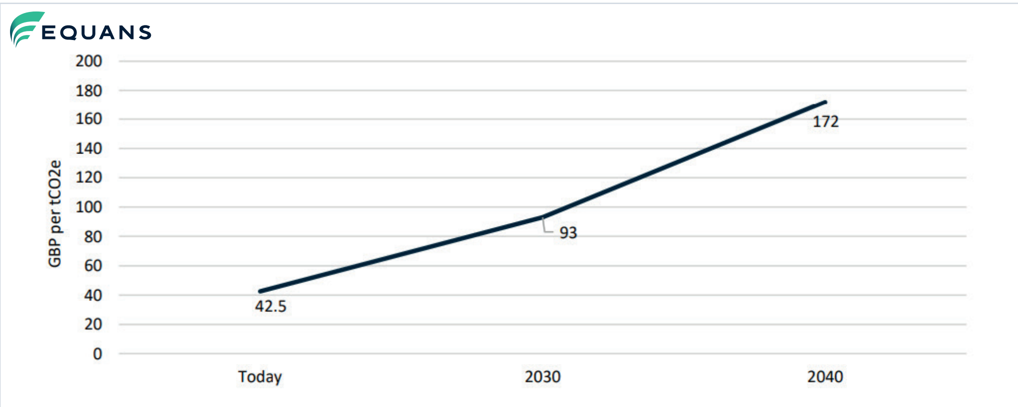


*Figure 15 Carbon Pricing Per Tonne*

The savings presented for each industry throughout Section 6 Decarbonisation Opportunities are for a hydrogen fuelled CHP system. The savings that would be presented per sector are shown in Figure 16 Savings from Hydrogen Fuel Carbon Offset. This comparison is assuming the use of hydrogen fuel, completely eliminating the carbon produced from the equivalent CHP system using natural gas fuel.


*Figure 16 Savings from Hydrogen Fuel Carbon Offset*

The CHP plant does produce a spectrum of benefits within the existing market, and with the introduction of hydrogen fuel further savings would be apparent for industrial users, including reducing costs from fines and taxes imposed through carbon emissions emitted. Section 6 discusses the savings presented to a sector by using hydrogen for combustion plant when considering the same analysis undertaken for a CHP. It identifies the potential benefits to end users of fuel switching in conjunction with the implementation of CHP technology. When the fuel switch occurs from natural gas to hydrogen, an industrial site can change fuels with little impact on their existing infrastructure.

### 5.3.2 Heat Pumps

Heat pump (HP) technology utilises energy from a source (air, ground or water) and transfers it to a sink, process or space heating. This is achieved by the transfer of energy through an intermediate system using a compression and expansion cycle. This cycle requires the input of electrical energy, with the ratio of electrical energy input to useful heat energy output being measured as COP. For the cycle to be effective the COP must be greater than 1 with a typical COP between 2 and 3, with some systems as high as 5 (32). As the COP is the result of the energy output divided by the energy input, a COP of 3 would mean 3 kW of heat energy is produced compared with 1 kW of electrical energy consumed. The intermediate system contains a specific media such as $CO_2$ or Hydrocarbons (HC) which classify as natural refrigerants. Previously environmentally harmful gases such as hydrofluorocarbons (HFCs) were used which have been phased out of use due to their detrimental effect on the environment.

Different energy sources can be utilised in a HP application, such as ground source (GSHP), air source (ASHP) and water source (WSHP). The fundamental characteristics of a HP work the same with different sources of energy.

GSHP require the use of boring into the ground to extrapolate the thermal energy, as is shown in Figure 17, they can also extrapolate heat through buried coils. When reviewing this type of HP application, ground heat conditions must be understood during the feasibility of the system. Ground temperatures can fluctuate respective to ambient temperatures above a ground level of 10m, up until this depth the latency between ambient temperatures and ground temperature increases (34). Below a depth of 10m the temperature remains effectively constant respective to the annual mean air temperature (35).

HPs work best under similar conditions to CHP systems, meaning a consistent flat base load and fixed flow and return temperature is needed for optimum performance. Therefore, a process load connected to a district heating scheme, for example, would favour the use of heat pumps as this can ensure a constant base load throughout a 24-hour period. The use of a pre-heat for other equipment such as boilers is a useful method to reduce the gas consumption for a process or site. This allows a HP to pre-heat the return water from site before entering a boiler, offsetting the requirement for burning more gas to produce the same process system temperatures. An example this type of arrangement is shown below.

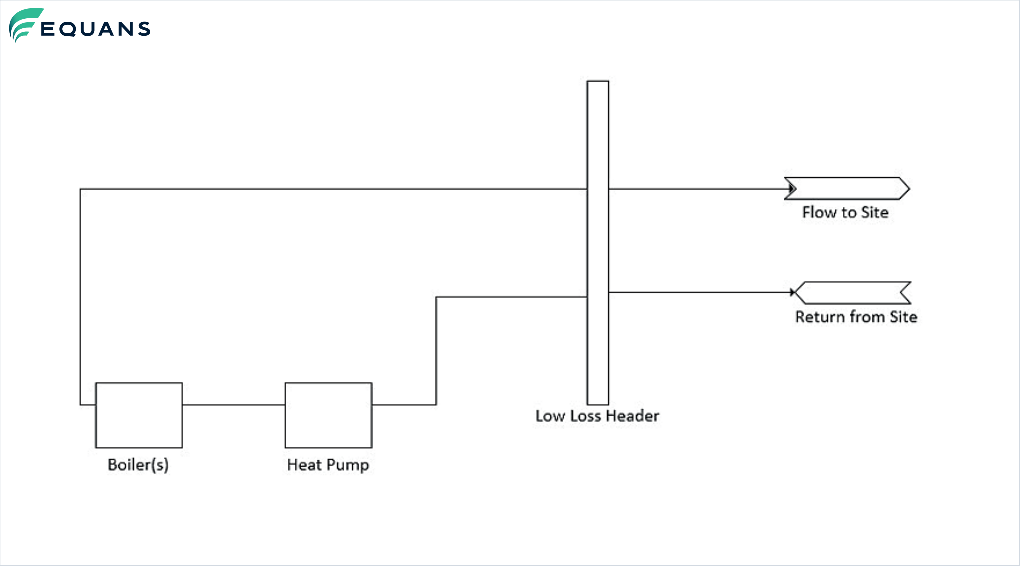


*Figure 17 Heat Pump System Arrangement*

Waste heat recovery can also be utilised, making use of the wasted energy from a process whether it be air or process water as an energy source. This inlet energy stream to the HP will allow for a higher temperature output to a site process. This will again offset the need for combustion plant and increase the efficiency of the process as that energy would then not then be rejected to the atmosphere.

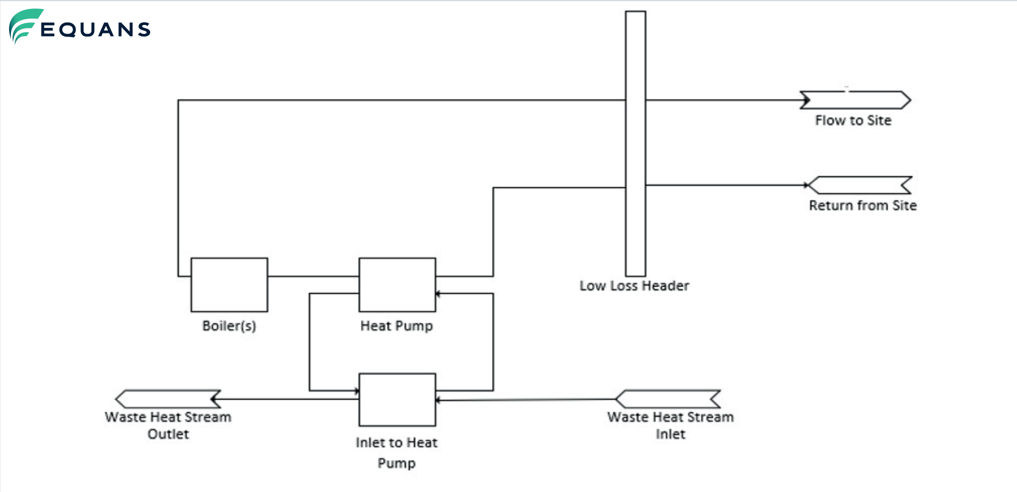


*Figure 18 Heat Pump System Arrangement*

Industrial HP installations need to account for space for both the heat pump unit and the cooler/condenser. Typically, these range from 6m(L) x 2.5m(H) x 1.5m(W) for the HP and 5m(L) x 1.2m(H) x 3.7m(W) for smaller systems around 150 kW output to 10.5m(L) x 2.6m(H) x 1.5m(W) for the HP and 9.5m(L) x 2.75m(H) x 18.5m(W) for the cooler/condenser unit for a 2.7 MW. The HP unit increases accordingly due to the increase in output however, the cooler for the system increases dramatically. This needs to be included when evaluating the scope of a HP installation.

#### 5.3.2.1 Heat Pump Methodology

Heat pumps are affected by the external energy sources, which are adversely affected by the environment and weather conditions. Therefore, the initial requirement for ASHP design is to understand the weather conditions for the local area. This was achieved by choosing an area close to the North West England and North East Wales which had accurate weather data for a 12-month period. This could then be used in a calculation process to ascertain the SCOP, calculated with the method set out in BS EN 14825:2018, which covers air conditioners, heat pumps and liquid chilling packages. Once this was understood, the maximum and minimum required energy input for that industry would be applied and using the data sheet information for different heat pump models, a SCOP could be calculated. Based on this information an indicative operation for the HP throughout the year could be derived. This would allow for an understanding of operating hours, electricity requirements, gas offset and additional heat input required in the event of the heat pump not satisfying site load.

From this, the payback and potential financial savings could be obtained, however, it is common for HPs that as the output temperature increases the COP for the HP decreases. This is due to the compression and expansion cycle of the HP; the greater the difference in temperature from the source to the sink the more work is required from the compressor (36). Therefore, a decision would need to be made during the feasibility and concept design stage of a project on how a HP would work within an existing system.

For the sake of the analysis carried out by EQUANS, a comparison for both higher and lower temperature HPs have been shown in Section 6 for each industry. These are working to a flow and return of 85°C/60°C for high temperature and 60°C/35°C for low temperature. The units selected shall match as close as possible to offer the best comparison, as the high temperature and low temperature HPs operate with slightly differing output duties. This offers the comparison between system flow and return temperatures, efficiency, and potential savings both for financial and emissions output.

A benchmark figure for gas and electricity prices were used across all sectors as shown in Table 17 and Table 18. These prices have been used to align with Work Package 5 of this report, however, standing charges and CCL taxes have been added to represent a more realistic financial outcome. Table 18 shows the grid carbon figures applied to the model to understand the carbon savings from a HP installation.

| Fuel | £/kWh |
|---|---|
| Electricity | 0.108 |
| Gas | 0.023 |

*Table 17 Utility Costs*

| Fuel | mg/kWh |
|---|---|
| Electricity $CO_2$ | 255.6 |
| Natural gas $CO_2$ | 183.53 |

*Table 18 Carbon Factors*

#### 5.3.2.2 Heat Pump Considerations

The review of HP technology within industries adopts the same approach as a CHP system regarding a consistent heating load profile. Therefore, it is critical when sizing a HP that it can satisfy the base load requirements for the site process and / or heating loads. HPs will also increase the electrical consumption for that site which is considered when calculating the potential savings.

Due to the existing gas and electricity prices for industrial users, the installation of a HP in some circumstances can in fact be detrimental to any financial savings. This difference in price can be referred to as the 'spark spread'. To allow for an offset against the spark spread energy prices, certain government incentives can be sought when applying to the installation of HP technology. Currently non-domestic Renewable Heat Incentive (RHI) supports the installation of certain low carbon technologies, with a grant awarded for the installation of the technology and generation of heat. However, a new scheme is expected in April 2022.

The installation for a large-scale HP for an industrial user must consider the carbon savings available when removing the requirement for combustion plant. This ensures the installation of a HP is more attractive against conventional cheaper combustion plant, as it is a critical step towards a carbon neutral industry.

With the available ESOS data, ASHPs have been modelled against the thermal profiles for each of the industrial sectors. ASHPs were chosen as they are simplest to model and understand given the data available for this report. ASHPs are also the easiest to install within an industrial application due to the smaller space requirements when compared with GSHPs and can be installed within a land locked location when compared with WSHP. Further GIS mapping would be required to understand the thermal energy available within both ground and water sources for a specific site.

The following sections detail the findings from the modelling of each sector with the application of the most suitable HP model. The graphs included within each section detail the sector demand for heat and the base operation of the HP selected. This is plotted against the outside ambient temperature conditions to calculate the SCOP for the HP. In addition to this is the requirement for additional back up heat supplied by a boiler which should be implemented to satisfy the peak loads only. During modelling of the HP for a sector, the gas reduction, thermal output, carbon savings, and operational performance towards 100% full load running have been priority. This ensures a fair benchmark when comparing between high and low temperature models and between the various industrial sectors.

### 5.3.2.3 The Future of Heat Pumps

A further review of HPs within the industrial sector against predicted hydrogen prices shows a significant reduction in cost when utilising HPs within a site process. Industries that typically use large amounts of gas such as the Automotive industry can benefit from the use of a HP to reduce the gas usage on site.

Figure 19 Heat Pump Savings with Hydrogen Usage Offset 2030 and Figure 20 Heat Pump Savings with Hydrogen Usage Offset 2040 show that with no supplement of hydrogen prices there can be a comparative saving found. However, due to incentives placed by the government to reduce the cost of hydrogen to natural gas prices through CFD, HPs shall still present a poor return on investment.

Figure 21 illustrates the possible savings for HP technology when applying a carbon offset due to the reduction in carbon from site processes. This is comparative against the use of conventional hydrocarbon fuels and electrification.

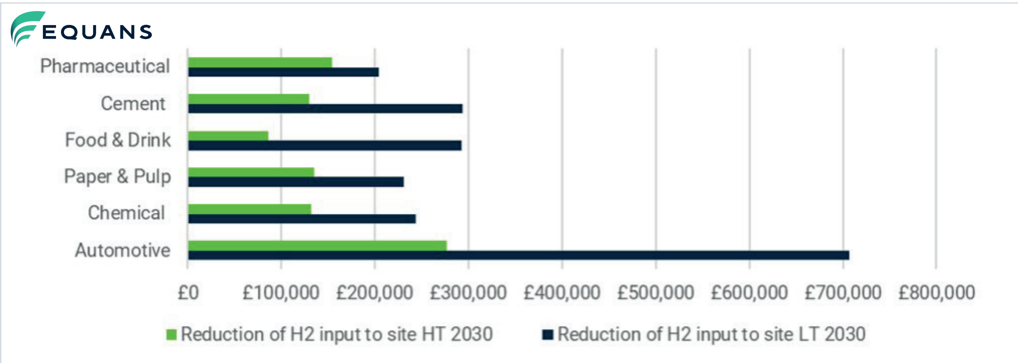


*Figure 19 Heat Pump Savings with Hydrogen Usage Offset 2030*

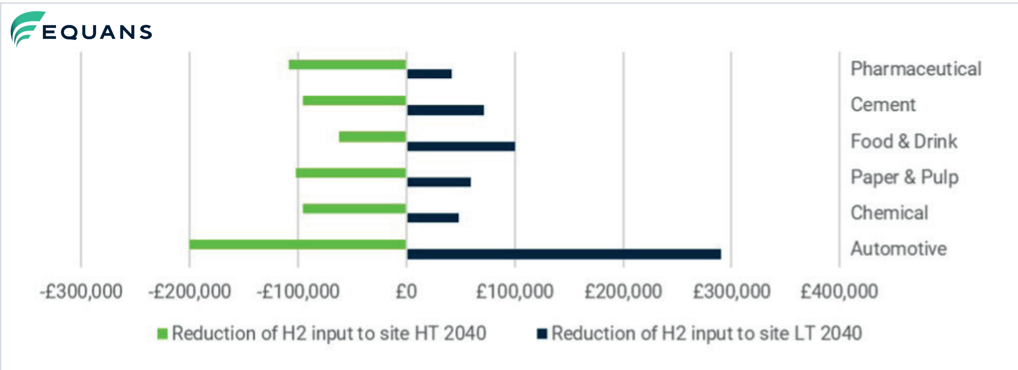


*Figure 20 Heat Pump Savings with Hydrogen Usage Offset 2040*

A clear comparison between 2030 and 2040 hydrogen prices against electricity prices shows that both the high and low temperature HPs provide a benefit financially in energy savings during 2030. However, due to the drop in hydrogen production price and the increase in electricity purchased from the district network operator (DNO), high temperature HPs do not present the same saving in 2040. Therefore, with changes to pricing throughout that decade high temperature HPs will become less profitable. This analysis is based solely on utility pricing and does not consider any incentives or schemes offered by the government, giving the reader an understanding of the market if there were no CFD mechanism in place. Low temperature HPs do, however, offer a financial benefit due to the larger system performance with greater COPs bridging the gap between hydrogen and electricity costs.

The figure below shows the savings possible through carbon offset from a reduction in emissions. Due to the nature of the system only low temperature HPs have been shown, providing an insight into the financial savings possible through HP implementation with carbon offset.

The review offers insight into how HP technology can retain its value within industrial processes. This analysis only considers existing technology; with continuous development HP systems could achieve higher efficiencies and secure their foothold within the industry. Further to this, HP technology has been proven to be beneficial to users that are able to electrify their thermal processes. A detailed review would be required to understand the costs for connection onto the network and appreciate the savings through the implementation of HP technology.

### 5.3.3 Fuel Cells

A fuel cell is a device that converts chemical energy (in this case hydrogen and oxygen) into electricity with by-products of heat and water. A typical fuel cell consists of three main components, a positive and negative electrode separated by an electrolyte. The positive electrode is called a cathode and the negative electrode is called an anode. Hydrogen passes through the anode while oxygen passes through the cathode. At the anode the hydrogen molecules are separated into protons and electrons. The protons can pass through the membrane while the electrons cannot, and the electrons are forced through a circuit which generates an electric current and heat. The hydrogen protons and electrons combine with oxygen to create water ($H_2O$). See Figure 22 Fuel Cell Diagram below for reference.

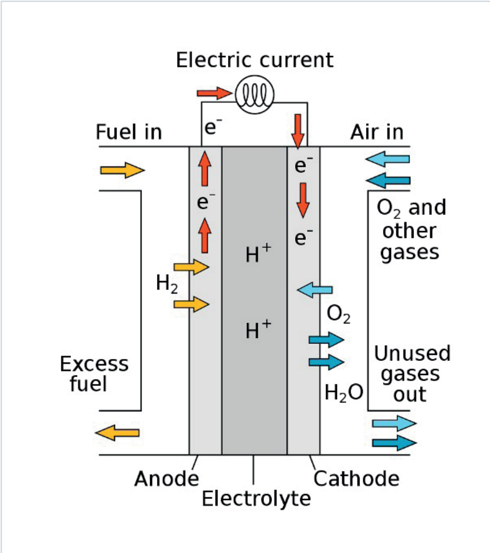


*Figure 22 Fuel Cell Diagram (37)*

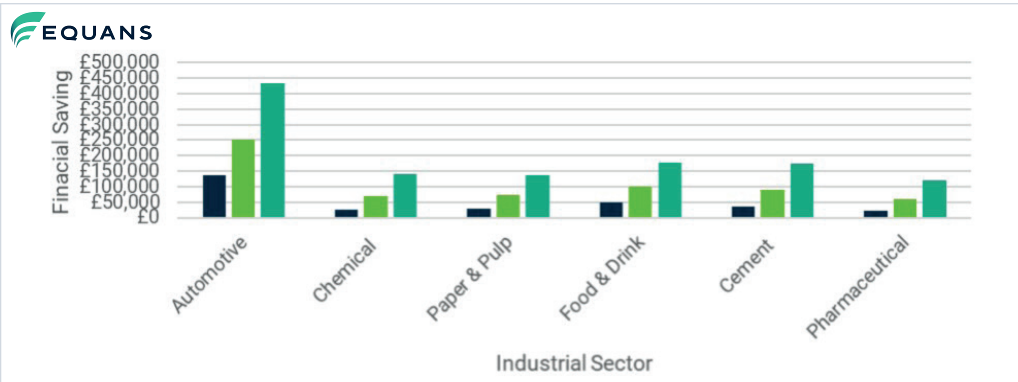


*Figure 21 Heat Pump Saving Through Carbon Offsetting*

The two main applications for hydrogen fuel cells are backup power and transport. Backup power is used when the primary source of power is disrupted, and transport is used to move people or goods by the means of a vehicle. Backup power and transportation have both traditionally used the combustion engine to satisfy demand. Typically, the backup power has been provided by diesel generators and transportation has used combustion engines fuelled by diesel or petrol. Batteries (usually lithium-ion or lead-acid batthers) have been used as a lower carbon alternative for both backup power and transportation.

Below, Table 19 shows a summary of the advantages and disadvantages of hydrogen fuel cells as a low carbon alternative compared to combustion engines and batteries.

#### 5.3.3.1 Combustion Engines

Fossil fuelled vehicles and diesel fuelled backup power has been the norm for many years, providing stability and reliability, but ultimately eroding reserves of fossil fuels and generating significant carbon emissions. This traditional method has the flexibility to cope with high power demands, which is essential for large generators and larger vehicles such as large goods vehicles (LGV) and heavy goods vehicles (HGV). Applications for generators include, but are not limited to, industrial sites, hospitals, and data centres. The fuelling time is relatively short and if the system is maintained, the degradation is minimal. However, the use of fossil fuels means that they have high pollutants levels particularly $CO_2$ and NOx.

#### 5.3.3.2 Batteries

Batteries are a well-known and well-established lower carbon alternative[i] to generators and traditional combustion engines.

The advantage of using batteries is that the technology is mature and integrated in everyday life. Additionally, the infrastructure largely already exists, for charging in both applications, transport and backup power, the 'well-to-tanks' is simple. Electricity is generated and transported through the national grid to charge the batteries. The main disadvantages are the time it takes to charge the batteries, the degradation of power, limited charging cycles and storage capacity. The time it takes to charge a battery back for backup power or a vehicle's battery is substantially longer than fuelling using fossil fuels or hydrogen. The power charge degrades over time, therefore, if the battery remains dormant over time it will need recharging, which causes issues with reliability. A batteries charge capacity degrades over time and has a finite number of cycles; in time, a battery system will require a costly replacement.

#### 5.3.3.3 Fuel Cells

As a direct comparison to the two technologies above the hydrogen fuel cell has advantages and disadvantages. The main advantage of a fuel cell is that due to the lack of moving parts it is completely reliable; if hydrogen is supplied, the cell will generate electricity. Another advantage is the process of fuel cells generating electricity is very quiet compared to combustion engines. A fuel cell also requires considerably less space than a battery system. The fuel cell combines the lower carbon nature of a battery with the speed and reliability of fuelling a combustion engine. The main disadvantage of the hydrogen fuel cell is access to the fuel; the infrastructure and market is not as advanced as needed for hydrogen to be a cost-effective alternative to batteries and combustion engines. Additionally, the fuel cells themselves can be expensive due to the use of precious metal as a catalyst.

| | Zero Carbon | Fuelling Time | Well-to-Tank Process | Infrastructure | Running Costs |
|---|---|---|---|---|---|
| Combustion Engine | ✗ | ✓ | ✗ | ✓ | ✗ |
| Batteries | ✓ | ✗ | ✓ | ✓ | ✓ |
| Fuel Cell | ✓ | ✓ | ✗ | ✗ | ✗ |

*Table 19 Representation of advantages and disadvantages of each technology*

[i] Please note for the purpose of this document it is assumed that the batteries are charged using renewable electricity

#### 5.3.3.4 Future Roadmap

In Figure 23 Fuel Cells Roadmap, is a pictorial representation of the fuel cell road map for Europe.

The information presented is from *'HYDROGEN ROADMAP EUROPE: A SUSTAINABLE PATHWAY FOR THE EUROPEAN ENERGY TRANSITION'* (38). The sections highlighted in blue are aspirational and those highlighted in green are industrial expectations. For example, the aspirational hydrogen fuel cell for aviation is 2035 but the industrial expectation is 2045.

#### 5.3.3.5 Cost of Fuel Cell CHP

Due to the variations in material and maturing manufacturing process prices, the cost of fuel cell technology fluctuates widely. To give a sense of the scale of cost for a fuel cell CHP, the following table 20 has been generated from Battelle analysis on behalf of the US Department of Energy (39). Table 20 highlights the influence of how large-scale production can influence the cost of the fuel Cells.

### 5.3.4 Electrification

Fuel switching, in the context of this report, is replacing a fossil fuel with a low carbon alternative. Fuel switching is an important step towards Net Zero 2050 as highlighted in the government released literature (1) (40) (41) (42). The three low carbon alternatives highlighted in the government literature in reference to fuel switching are electrification, hydrogen, and biofuels. The two mainstream low carbon alternatives are electrification and hydrogen. For more on hydrogen see Section 5.5.

As stated above, electrification is one of the main steps towards Net Zero 2050. Electrification is the process of moving away from fossil fuel-based energy sources such as natural gas and replacing that with low-carbon sources of electricity, such as electricity generated via a wind turbine. One example of a market where electrification is prevalent is in transportation.

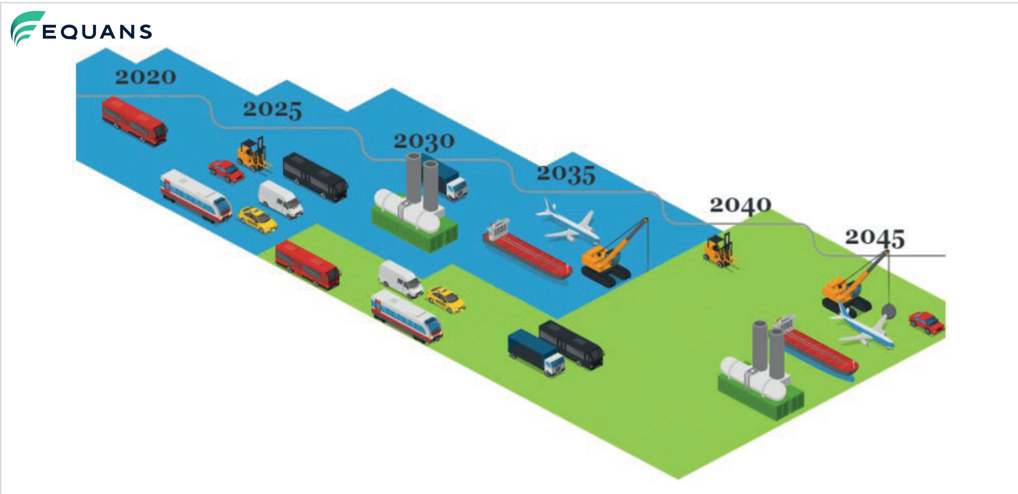


*Figure 23 Fuel Cells Roadmap*

| Type of Fuel Cell | System Size kW | 100 Units/ Yr | 1,000 Units/ Yr | 10,000 Units/ Yr | 50,000 Units/ Yr |
|---|---|---|---|---|---|
| Solid oxide fuel cell | 100 | £162,124 | £128,647 | £112,604 | £103,667 |
| | | £1,621 | £1,286 | £1,126 | £1,037 |
| | 250 | £318,724 | £262,915 | £230,451 | £211,339 |
| | | £1,275 | £1,052 | £922 | £845 |
| Proton-exchange membrane | 100 | £258,173 | £215,915 | £191,413 | £177,285 |
| | | £2,582 | £2,159 | £1,914 | £1,773 |
| | 250 | £460,168 | £384,676 | £338,680 | £311,039 |
| | | £1,840 | £1,539 | £1,355 | £1,244 |

*Table 20 Cost of fuel cell CHP from Battelle 2017 analysis of the fuel cell market*

The decarbonisation of heat is a major challenge for the UK. For this report the focus is industrial heat, including space and process heating. The Sixth Carbon Budget from the climate change committee (42) highlights the necessity for electrification, especially in the industrial sector, and indicates the pathway for the manufacturing and construction sector.

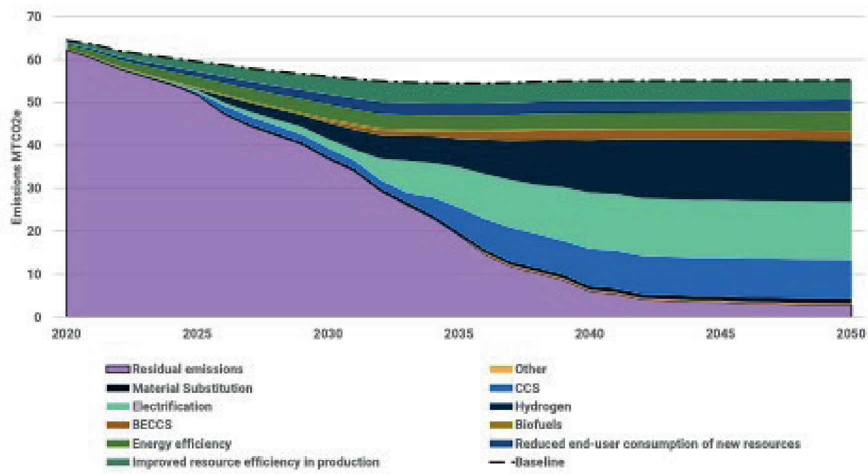


*Figure 24 CCC 6th budget net zero pathway for manufacturing and construction sector (43)*

In the industrial decarbonisation strategy (1), which the government released in March of 2021, it indicates that electrification of industry could reduce emissions by between 5 $MtCO_2e$ and 12.3[ii] $MtCO_2e$ per annum by 2050. Based on current technology[iii], electrification may not be suitable for industrial processes that require higher temperatures, for example, processes that can be found in industries such as cement, ceramics, steel production or chemical. For these processes, it is currently more cost effective to investigate alternatives such as hydrogen or CHPs. However, as stated in section 5.3.4.2, as technology develops and electricity prices fall, electrification for industrial processes would become a more attractive proposition.

#### 5.3.4.1 Potential Barriers

Most of the heat that electrification would be replacing is produced by natural gas. The current main barrier to electrification is the cost disparity between gas and electricity. Another barrier to electrification is that the infrastructure may not be able to support the increased electrical demand. The government is working with Ofgem, National Grid and DNOs to plan and deliver a robust, future proof electrical network.

#### 5.3.4.2 Future of Electrification

In the 10-point plan published by the government (41) investment in research and development (R&D) for a net zero future is a priority. A significant component of the future of net zero will be innovation which includes electrification.

Taking the food and drink sector as an example, electrification can play a big part in their route to decarbonisation.

Pasteurisation is an energy intensive process, electrifying this process through non- thermal or cold pasteurising can reduce carbon and can occur in several forms including ultra violet (UV) pulsed light or ultrasound. Non-thermal or cold pasteurising can occur in several forms including ultra violet (UV) pulsed light or ultrasound. These have applications in dairy, fruit juices and brewing. In addition to the environmental benefits, there are other benefits and barriers electrification can bring, a selection of which is illustrated in table 21 below.

| Benefits | Barriers |
|---|---|
| Taste of product unaffected | Requires a change of process |
| Extends shelf life | High CAPEX charge |
| No heat required | Price of electricity |

*Table 21 Electrification of pasteurisation benefits and barriers*

ii Please note that these figures include the use of HPs
iii This references to technology that is commercially readily available

Another future technology which is currently undergoing trials is the Grid Scale High Temperature Energy Store (GSHTES). GSHTES is electrification of heat and heat storage. The basic concept is that the GSHTES is using renewable energy to heat steel elements to store the energy and provide heat on demand for processes up to ~550ºC. This technology is currently being trialled within the UK. Additional to the environmental benefits the technology has other benefits and barriers, a selection of which is illustrated in table 22 below.

| Benefits | Barriers |
|---|---|
| Easy to retrofit | Large footprint |
| Easily scalable | Likely to require planning permission |
| Can be used to balance the grid | Price of electricity |
| OPEX minimal | Continuity of subsidies |

*Table 22 GSHTES benefits and barriers*

## 5.4 Renewable Energy Generation

This section deals with on-site energy generation and utilisation technologies. Deployment of these technologies are considered for specific industrial sites as behind the meter assets, as well as for the areas available within the industrial clusters as in front of the meter assets. Fourteen industrial clusters in the North West England and North East Wales were analysed to assess the overall potential for renewable energy generation. These clusters were defined in the North West Industrial Energy Zone Prospectuses by Buro Happold in 2020 as part of Net Zero North West Cluster Plan Phase 1 (44). In this way, utility scale generation opportunities, within the boundaries of industrial clusters, were included in the analysis. A holistic approach was taken to capture the dynamic energy potential of industrial sites with the rest of the region including domestic and commercial energy demand.

An important constraint for the deployment of renewable energy generation will be the available capacity in the electricity grid network. Electricity North West, who supply a large portion of the North West, has unveiled their ambitions to lead the North West to net zero carbon (44). It is stated that the growth of renewable generation and storage across the region is encouraged by the DNO. They are investing in the network to ensure that the potential of decarbonisation of the grid is met by 2038. Similarly, Scottish Power Energy Networks, which supplies the rest of the North West around Merseyside and Cheshire, has announced their plans to invest £3.2 billion between 2023 and 2028 to aid critical upgrades to connect an additional 5 GW of renewable generation (45).

### 5.4.1 Wind

Wind energy utilises aerodynamic forces of the wind acting on blades of a wind turbine to convert wind energy into rotary motion, kinetic energy. This energy is later used to drive a generator, housed within the hub of the turbine, to generate electricity. Generally, numerous wind turbines are deployed within a wind farm. Wind energy is a prominent renewable energy generation technology in the UK, both on and offshore. Futher deployment of wind energy has the potential to help achieve a net zero grid. Wind energy can be coupled with other technologies to increase flexibility. Adding flexibility to intermittent energy sources like wind energy can help reduce curtailment – turning down of wind turbines when wind energy generation is higher than the electrical demand in the grid – and increase penetration. Examples of such technologies are battery storage or hydrogen production. Cost of wind energy has been reducing over the years and it is at a competitive state with combined cycle gas turbine (CCGT) plants, without any subsidies (46).

Onshore wind farm development is ongoing in the North West. A total of 15.3 MW of capacity for two wind farms located in Lancashire have been granted planning permission and they are awaiting construction. A further 35.8 MW of capacity over two wind farms is also awaiting approval on their planning application in Lancashire and Cumbria according to the quarterly renewable energy planning database published by BEIS (47).

Wind speed is one of the most important parameters in determining the wind energy generation potential of a site. The average wind speed varies from one year to the next. Figure 25 shows the wind speed variability in the North West of England. Wind speed measurements on site are cross-examined with historical data from a meteorological station. This ensures that extremities of a particular year can be averaged to provide a more realistic generation potential over the lifetime of the windfarm.

Wind speed is affected by the friction against the surface of the earth which is determined by roughness length. The higher the roughness length, the larger the decrease in wind speed magnitude. For example, water surface poses negligible influence on wind speed unlike large cities with tall buildings. Therefore, locations with minimal built-up environment and obstacles are preferable, especially considering the prevailing wind direction.

**Environmental Considerations**

Noise is a very important constraint, particularly in the more populated parts of the country. In general, the perceived noise from a wind farm will depend on the noise power output from each turbine and its distance from dwellings, the frequency (pitch) of the noise, the ground absorption and blockage or reflection by obstacles. For wind farm design purposes, a common requirement is that the noise from the turbines should not exceed given threshold values at the dwellings. Guidelines indicate ETSU-R-97 as a recommended method to be used in the UK (49).

Shadow flicker is the flashing effect when moving turbine blades pass between the sun and the observer, which is perceived as an annoyance. The effect is more likely to be an issue if the turbines are built relatively close to dwellings. The occurrence depends very sensitively on the latitude of the location and the time of year. Guidelines for the assessment of shadow flicker typically require the maximum potential to be calculated assuming standard conditions.

Visibility can also be a vital part of a wind farm design. Therefore, accurate assessment of the extent of visibility of wind farms from sensitive areas is important. Inter-visibility between radar facilities and proposed turbines should be assessed in the planning stage of a wind farm development project. This is to ensure minimal disruption to important services such as civilian aviation, military radar, or weather radar systems. Optimisation of penetration can locate areas where turbines will be below radar sweep or provide information as a basis for discussion when turbines intersect the radar.

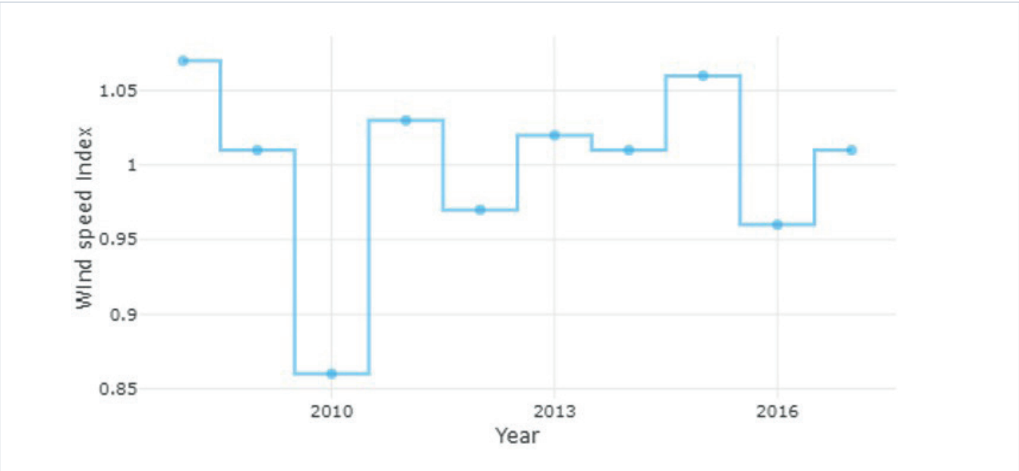


*Figure 25 Annual wind speed variability in North West (48)*

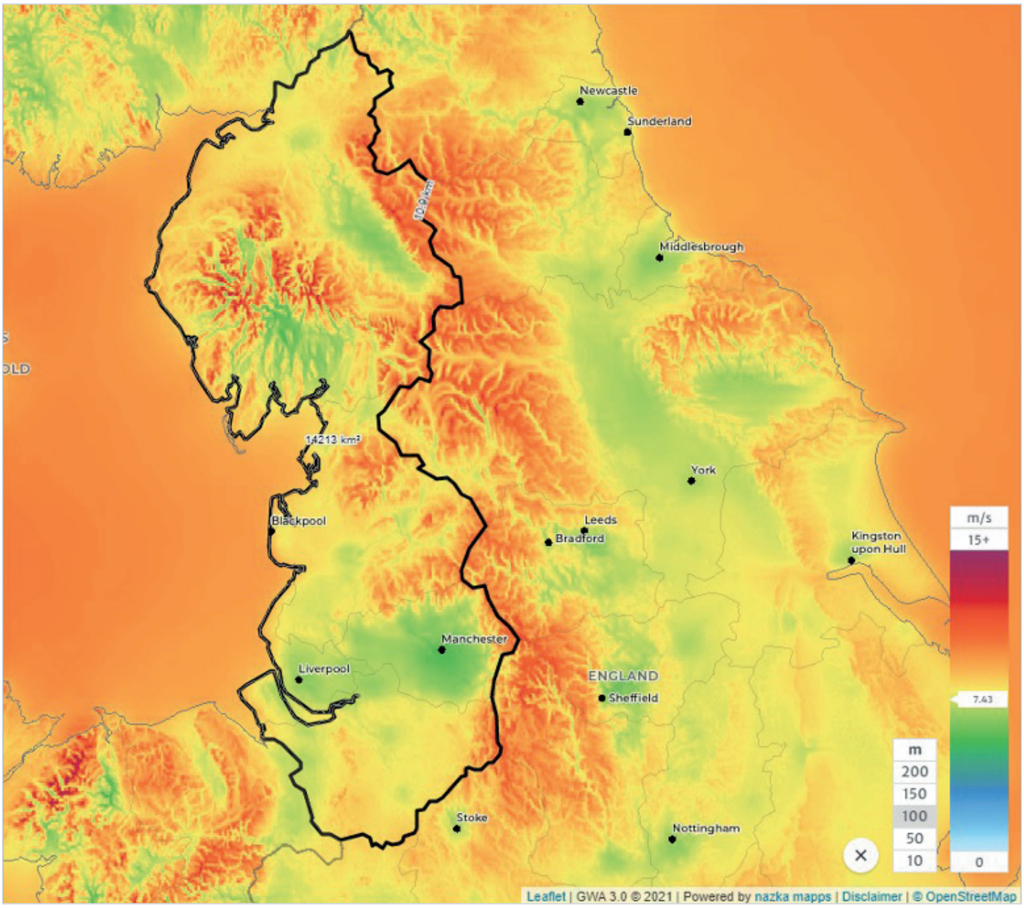


*Figure 26 Mean wind speed map of North West of England (48)*

Figure 26 illustrates the mean wind speed for the North West of England at 100m height in Global Wind Atlas. This area covers roughly 1,413 km$^2$ of land. For this study, only onshore wind energy generation is considered. According to this tool, the mean wind speed at 100m within this area is 10.56 m/s. Figure 27 shows the distribution of the mean wind power density in North West of England in W/m$^2$. This is calculated based on the mean wind speed at 100m. The mean power density for the 10% windiest areas in the region are estimated to be 1,34 9W/m$^2$.

The windiest areas in the North West are within Lake District National Park and Forest of Bowland which are due to the topography of the area. However, these areas do not contain industrial sites and would not be eligible for wind farm development due to environmental constraints. Regions where wind farms can be developed are Red Marsh, ICI Fleetwood, Furness business park and Buccleuch dock as highlighted in North West Industrial Energy Zone Prospectuses (47).

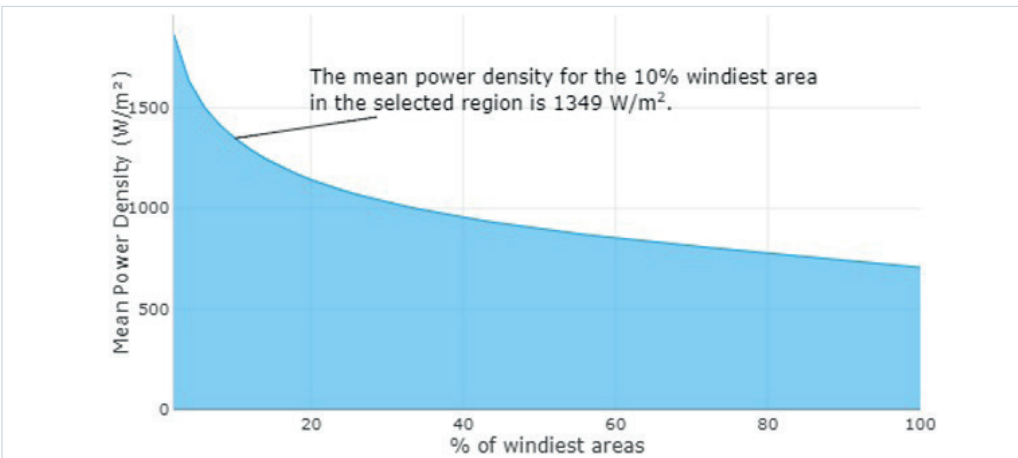


*Figure 27 Mean power density distribution in North West of England (48)*

Based on the available land and local restrictions, twenty four units of 4 MW wind turbines with a total installed capacity of 96 MW could be deployed at Red Marsh, ICI Fleetwood, Furness business park and Buccleuch dock clusters. This scale of installation would have the potential to generate 336 GWh/year of energy assuming 3,500 full load hours. Various costs for the deployment of wind turbines were estimated based on normalised figures (i.e., £/MW or £/MWh) from BEIS electricity generation costs (2020) (50).

The estimated costs are summarised in Table 23. Assuming a lifetime of 25 years the estimated cost of generating 1kWh of energy would be 2.54p. The projected price and carbon factor of electricity from the grid is used from 2020 to 2044.

Table 24 summarises the savings offered by the proposed installation.

| Cost type | Estimated cost (£) |
|---|---|
| Pre-development cost | £11,520,000 |
| Construction cost | £96,000,000 |
| Infrastructure | £3,500,000 |
| Fixed O&M (annual) | £2,256,000 |
| Variable O&M (annual) | £2,016,000 |
| Insurance (annual) | £153,600 |
| Connection and use of system charges (annual) | £393,600 |

*Table 23 Associated capital and operational cost of the proposed wind farm installation*

| Savings Summary | |
|---|---|
| Estimated no. of wind turbines | 24 |
| Estimated installed capacity (MW) | 96 |
| Estimated electrical savings (MWh/year) | 336,000 |
| Estimated $CO_2$ savings (te) | 493,417 |
| Estimated annual financial benefit (£/year) | 36,335,040 |
| Estimated budget capital cost (£) | 231,500,000 |
| Estimated simple payback period (years) | 6.37 |

*Table 24 Estimated savings summary for wind energy generation in North West*

### 5.4.2 Solar Photovoltaics (PV)

Solar PV is a renewable energy technology that converts energy from the sun into electricity. Solar PV systems can be installed on a building rooftop, as a large-scale ground-mount system, floating on a body of water or building integrated system which replaces traditional materials in the envelope of a building.

The increase in solar generation production and deployment globally has reduced the price, especially utility-scale solar PV, to very low levels when compared to fossil-fuel alternatives such as coal and CCGT (46). Solar PV has a significant role to play in decarbonising the electricity grid and lowering the demand on the grid through decentralised production. Battery storage and EV charging stations add flexibility to solar PV maximising financial gains.

Large buildings with substantial roof space are ideal for rooftop installation. Within industrial areas warehouses have significant space availability without shadows during the day. Carports are another example where solar PV panels can be integrated, and electricity generation can be coupled with electric charging stations to contribute towards decarbonisation of transport.

South-facing and flat roofs are ideal locations for solar PV installation. However, east, and west facing roofs can be utilised if shading can be avoided. It is important to consider the structural integrity of the roof to ensure it can bear the weight of the panels intended for installation. Access to the roof and sufficient space for installation should be considered at an early stage.

Coastal regions of England have a slightly higher solar potential compared to in land areas. This can be seen in Figure 28 in terms of specific photovoltaic power output. The average specific photovoltaic power output in the North West is between 862 and 1,008 kWh/kWp whereas global horizontal irradiation (GHI) is between 868 and 989 kWh/m$^2$/year. These figures were estimated based on the area captured by the North West.

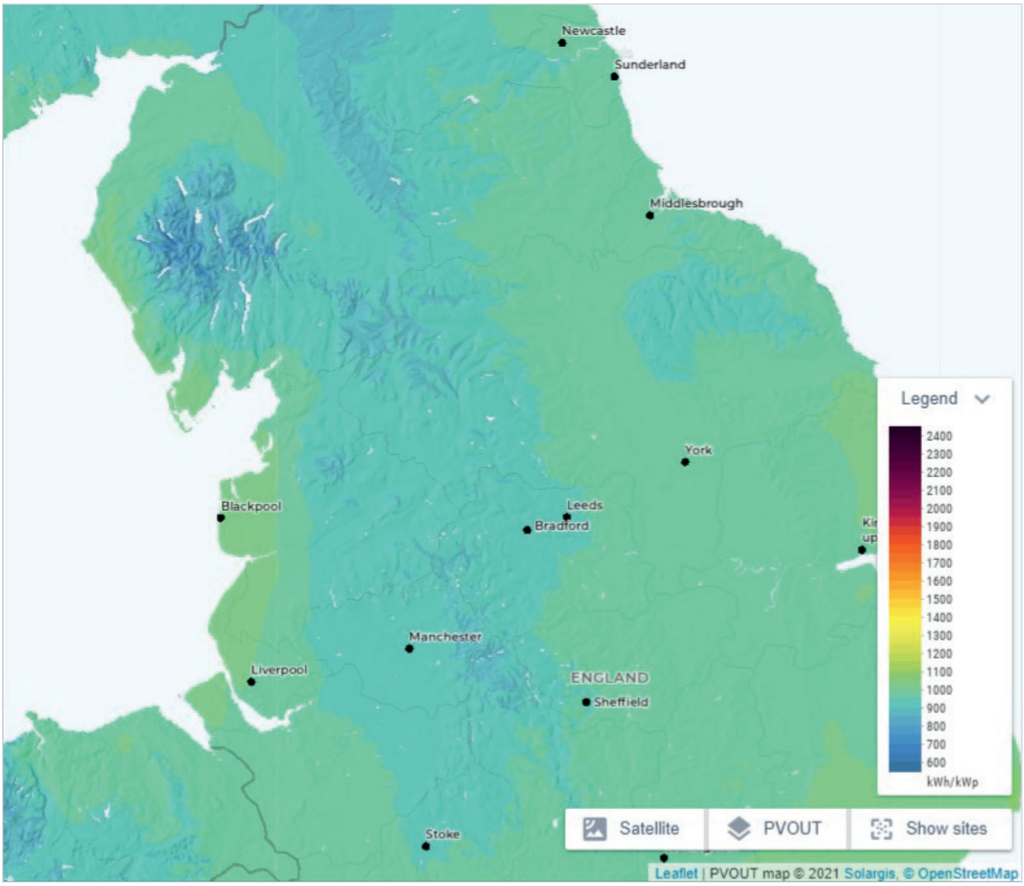


*Figure 28 Specific photovoltaic power output map of North West of England (51)*

Table 25 illustrates the industrial clusters and the types of solar PV systems identified in the North West Industrial Energy Zone Prospectuses. Industrial clusters in various sizes (i.e., small, medium, and large) were chosen to be studied in detail to estimate average energy generation. In each sample cluster, available area - land, roof, and water - were studied to estimate an average installation size. This analysis includes industrial sites outside of the ETS and NAEI data collected because all the industrial sites within sample clusters were considered.

| Industrial Cluster | Ground Mount | Roof Mount | Floating |
|---|---|---|---|
| 1 Sellafield to Siddick | ✓ | ✓ | ✗ |
| 2 Furness Business Park | ✗ | ✓ | ✗ |
| 3 Red Marsh and ICI Fleetwood | ✓ | ✓ | ✗ |
| 4 Leyland Area Business Park | ✓ | ✓ | ✗ |
| 5 Trafford Park Area | ✗ | ✓ | ✗ |
| 6 Knowles Business Park | ✗ | ✓ | ✗ |
| 7 St Helens | ✗ | ✓ | ✗ |
| 8 Manchester Science Park | ✗ | ✓ | ✗ |
| 9 Wirral Waters to Port Sunlight | ✓ | ✓ | ✗ |
| 10 Speke Industrial Area and Business Parks | ✗ | ✓ | ✗ |
| 11 Sealand and Deeside | ✗ | ✓ | ✗ |
| 12 Alderley Park | ✓ | ✓ | ✓ |
| 13 Ellesmere Port | ✓ | ✓ | ✗ |
| 14 Weston Point | ✓ | ✓ | ✗ |

*Table 25 Breakdown of industrial clusters and Solar PV systems applicable*

Ground-mount systems are applicable in industrial areas with various land use such as landfill, contaminated land, or land not in use. As highlighted in the North West Industrial Energy Zone Prospectuses, all the energy zones defined have solar PV deployment opportunities. However, some promising areas that should be mentioned are Fleetwood, Trafford Park, Knowles business park, Manchester science park, Speke industrial area and business parks, Alderley Park and Ellesmere port area.

Six industrial clusters were identified for ground-mount systems and three of these clusters were chosen as a sample to estimate the average generation potential to be 15 GWh/year per industrial cluster, amounting to 90 GWh/year in total. Roof-mount systems are, in principle, applicable to every cluster

In the analysis, four industrial clusters of various sizes were chosen to estimate the available roof space for roof-mount solar PV deployment. Roof space considered in these sample clusters included manufacturing sites, warehouses, and distribution centres. This was later compared to the area of industrial cluster to obtain a ratio between available roof space and size of cluster. As a result, 5% of the cluster roof area is estimated to be suitable. To consider equipment on the roof such as HVAC and skylights, a factor of 0.75 was applied. A further factor of 0.75 was applied to omit roofs that may not be structurally sound to carry roof-mount solar PV system. A conservative figure of 878 kWh/m$^2$/year was assumed as the GHI at North West. Table 26 shows the estimated roof area and energy generation potential for each industrial cluster whereas Table 27 shows the estimated total solar energy generation through various systems.

| Estimated Energy Generation Potential (MWh/year) | |
|---|---|
| Ground-mount | 90,380 |
| Roof-mount | 168,955 |
| Floating | 458 |
| **Total** | **259,793** |

*Table 27 Estimated energy generation potential via solar PV in the North West*

The estimated average cost of generating 1 kWh of energy assuming a lifetime of 35 years for ground-mount and floating systems, and 30 years for roof-mount system would be 3.72p. The projected price and carbon factor of electricity from the grid is used from 2020 to 2054. Table 28 summarises savings offered by the proposed installations.

| Savings Summary | |
|---|---|
| Estimated installed capacity (MW) | 301.4 |
| Estimated electrical savings (MWh/year) | 259,793 |
| Estimated $CO_2$ savings (te) | 393,540 |
| Estimated annual financial benefit (£) | 47,641,214 |
| Estimated budget capital cost (£) | 306,825,880 |
| Estimated simple payback period (years) | 6.4 |

*Table 28 Estimated savings summary for solar energy generation in North West*

| Industrial Cluster | Estimated cluster area (km$^2$) | Estimated roof area (m$^2$) | Estimated energy generation potential (MWh/year) |
|---|---|---|---|
| 1 Sellafield to Siddick | 18 | 900,000 | 21,819 |
| 2 Furness Business Park | 2.6 | 92,640 | 2,246 |
| 3 Red Marsh and ICI Fleetwood | 2 | 124,009 | 3,006 |
| 4 Leyland Area Business Park | 2 | 100,000 | 2,424 |
| 5 Trafford Park Area | 11 | 550,000 | 13,334 |
| 6 Knowles Business Park | 5.6 | 280,000 | 6,788 |
| 7 St Helens | 4 | 200,000 | 4,849 |
| 8 Manchester Science Park | 0.1 | 5,790 | 140 |
| 9 Wirral Waters to Port Sunlight | 9.5 | 475,000 | 11,516 |
| 10 Speke Industrial Area and Business Parks | 5 | 250,000 | 6,061 |
| 11 Sealand and Deeside | 27 | 1,350,000 | 32,729 |
| 12 Alderley Park | 0.2 | 16,555 | 404 |
| 13 Ellesmere Port | 49.5 | 2,475,000 | 60,003 |
| 14 Weston Point | 3 | 150,000 | 3,637 |
| **Total** | **13,945** | **6,969,094** | **168,955** |

*Table 26 Breakdown of industrial clusters, estimated roof area and energy generation potential*

### 5.4.3 Anaerobic Digestion (AD)

AD is a series of processes in which microorganisms break down biodegradable material in the absence of oxygen and is widely used to treat wastewater. The organic pollutants in the wastewater are converted by anaerobic microorganisms to a gas containing methane and carbon dioxide, known as "biogas". The process is classed as a renewable energy source because the methane and carbon dioxide rich biogas is suitable for energy production, helping reduce the use of fossil fuels. Also, the nutrient-rich digestate or excess sludge can be used as fertiliser. Anaerobic digesters can be designed and engineered to operate using several different process configurations depending on the application.

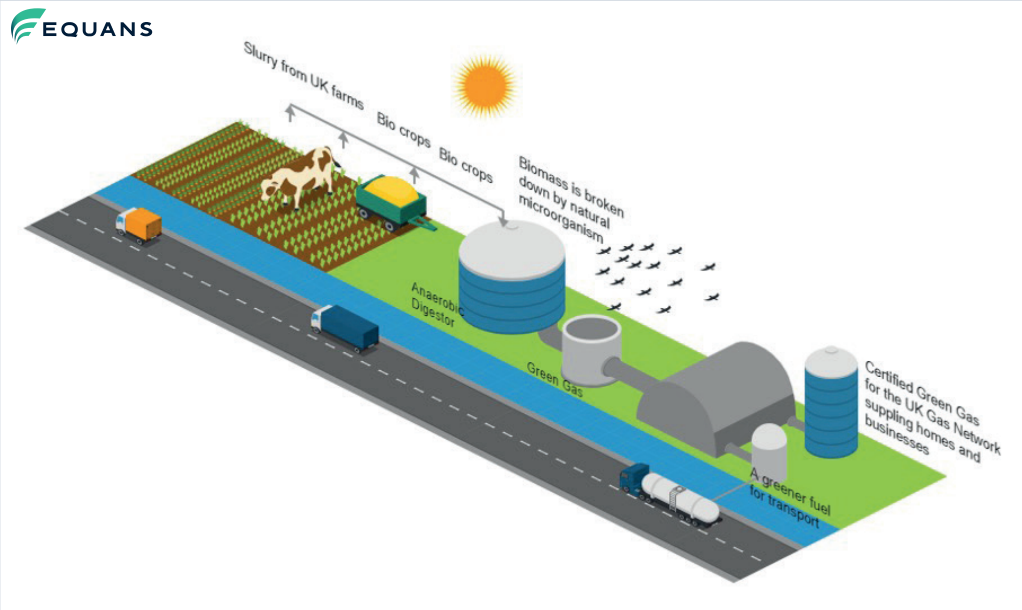


*Figure 29 Biogas production from an anaerobic digestion plant*

There are numerous financial benefits of an AD plant. A digester degrades waste that would otherwise need to be disposed of, often at a cost. For example, industrial wastewater from food manufacturing has organic contaminants that need to be treated. f the waste is fed to sewer, the site needs to pay to discharge it so that it can be treated at the local municipal treatment works. This charge can reach over £1/m3 so a large site could be paying more than £2,000 per day in effluent charges. Reducing the contaminants prior to discharge can reduce effluent bills significantly.

The biogas produced by an AD system can also be used to offset the import of natural gas and can therefore create a direct saving in utility bills associated with creating steam for process and heating. As mentioned in section 5.3.1, biogas can also be used in CHP to generate electricity which creates a direct saving against import electricity. Green Gas Support Scheme (GGSS) will also replace the previously available Renewable Heat Incentive (RHI) for AD plants.

GGSS will provide financial incentives for new AD biomethane plants to increase the proportion of green gas in the gas grid. However, the biogas produced at an AD plant needs to be upgraded to biomethane before it can be injected to the gas grid. The scheme will run for four years with applications opening in autumn 2021. Registered AD plant will receive quarterly payments over a period of 15 years.

AD plants require a constant and good quality supply of feedstock to ensure a smooth, viable and sustainable operation. Feedstock can be obtained through food and drink waste, processing residues, agricultural residues, crops, and sewage sludge streams. The yield of biogas production depends on several factors such as dry matter content, length of time in digester, type of AD plant, digester conditions and purity of feedstock.

The capital cost, operational cost and payback period of a new AD plant depends on multiple factors. These include the type of AD plant, administration of the plant, revenue opportunities, cost savings from waste treatment, management, disposal, and utilisation of the biogas produced, whether it is used on site to meet the heat and electricity demand via a CHP or upgraded to be injected to the gas grid. Therefore, associated costs are normalised through biogas production of the plant. Despite high capital cost, the payback period can be relatively short due to incentives and reduced cost of waste disposal. An AD plant would be expected to have a payback period of 5-6 years or even less and the lifetime of the plant is 20 years.

Industries that would be able to utilise biogas production through AD plants in the North West England and North East Wales include food and drink manufacturers, in particular breweries due to their continual production line and waste by-products that require treatment and disposal. Brewing is a sub-sector of the food and drink sector, however, it is separated here to highlight its potential. Wastewater and sewage treatment facilities also utilise AD plants in their treatment process. Figure 30 shows the breakdown of industrial sites per sector and region in the North West England and North East Wales where AD sites may be a suitable energy generation opportunity.

Deployment of AD plants are relatively common in water treatment and sewage sector. Therefore, it was assumed that there are no further installation opportunities within that sector. On the other hand, around 70% of food and drink and brewing sectors were assumed to deploy AD plants to generate on-site green heat and power. As mentioned before, the capital cost, financial benefits and payback period are heavily influenced by various parameters. EQUANS' experience in AD feasibility studies and ESOS reporting for these sectors were utilised to evaluate the potential opportunity at North West England and North East Wales and this is tabulated below.


*Figure 30 Breakdown of sectors in regions where AD opportunities may be applicable in the North West England and North East Wales*

| | Food & Drink | Brewing | Total |
|---|---|---|---|
| Estimated no. of sites applicable | 15 | 2 | 17 |
| Estimated electrical savings (MWh) | 49,248 | 5,699 | 54,610 |
| Estimated thermal savings (MWh) | 45,298 | 16,859 | 62,157 |
| Estimated $CO_2$ savings (te) | 33,720 | 14,720 | 48,440 |
| Estimated net financial benefit (£) | 11,281,080 | 1,722,110 | 13,003,190 |
| Estimated budget capital cost (£) | 81,750,000 | 7,750,532 | 89,500,532 |
| Estimated payback period (years) | 7.3 | 4.5 | 6.9 |

*Table 29 Estimated energy, carbon, and financial benefits of AD plants in North West England and North East Wales*

### 5.4.4 Waste Heat Reuse

In the UK, 20% of the total energy consumed can be accounted for by industry, which produces 32% of heat related $CO_2$ emissions, with 73% of industrial energy demand being for heating. The Digest of UK Energy Statistics (DUKES) states that almost half of this demand is for low temperature processes while 22% is for high temperature processes, with drying and separation processes (42 TWh/yr) and space heating (36 TWh/yr) making up the remainder (52). Cement, ceramics, steel and iron, glass, chemicals, refineries, paper and pulp, and food and drink are heat intensive sectors that also generate substantial waste heat. It should be noted that considerable amount of waste heat is suitable to be used directly on site, through integration with existing processes or other energy efficiency measures. As with AD plants, the brewing sub-sector has been separated from food and drink sector to highlight the available opportunities.

This section aims to focus on additional energy generation or utilisation opportunities that are not covered and cannot be obtained through energy efficiency improvements. Depending on the sector and the processes in place, waste heat generated between 90-500°C can be used in an Organic Rankine Cycle to generate electricity on-site. Additionally, waste heat from one or more industrial sites can be fed into a network to meet the hot water and space heating demand for commercial and residential buildings that are near the industrial sites. Both examples unlock additional revenue generation potential for the industry as well as advancing the decarbonisation of energy for the wider region.

### 5.4.5 District Heating

Currently, district heating meets 2% of the heating demand of buildings in the UK and the UK government aims to reach 18% by 2050. This ambitious target can only be achieved by unlocking access to waste heat opportunities from industrial process, data centres and geothermal heat. The majority of waste heat from industry is available between 100°C - 200°C excluding metallic, mineral and chemical sectors. Currently, it is estimated that 9 TWh of waste heat within this temperature range is being lost to the atmosphere within the UK (53). District heating utilises this waste heat to provide space heating and hot water for nearby commercial and residential premises. Waste heat from this specific temperature range can be captured and transferred to end users via heat exchangers. Waste heat below 100°C may require an additional generation technology such as heat pumps to increase the required temperature.

According to a study, around 14% of the hot water and heating demand for residential buildings in the UK could be supplied through the reuse of waste heat from buildings and industrial processes (54). The quality and quantity of waste heat, practicality of heat recovery, demand of heat users and distance between the heat source and heat users are important considerations for realising viable schemes. UK examples of waste heat as a heat source in district heating has been limited to energy from waste, mines water and wastewater treatment. However, industrial waste heat opportunities have also been tried and found to be economically viable low-carbon options in Europe.

Figure 31 illustrates the heat demand of buildings which are concentrated in urban areas and excess heat from various sources. Industrial regions such as Ellesmere Port, Runcorn, St. Helens, Trafford Park, Clitheroe, Sellafield and Siddick are located close to heat sinks in the form of towns and cities. These regions should be prioritised to couple waste heat utilisation from industry with decarbonisation of heat for homes and businesses. Figure 32 shows the breakdown of sectors and regions where waste heat from industry can be recuperated as a heat source for district heating.

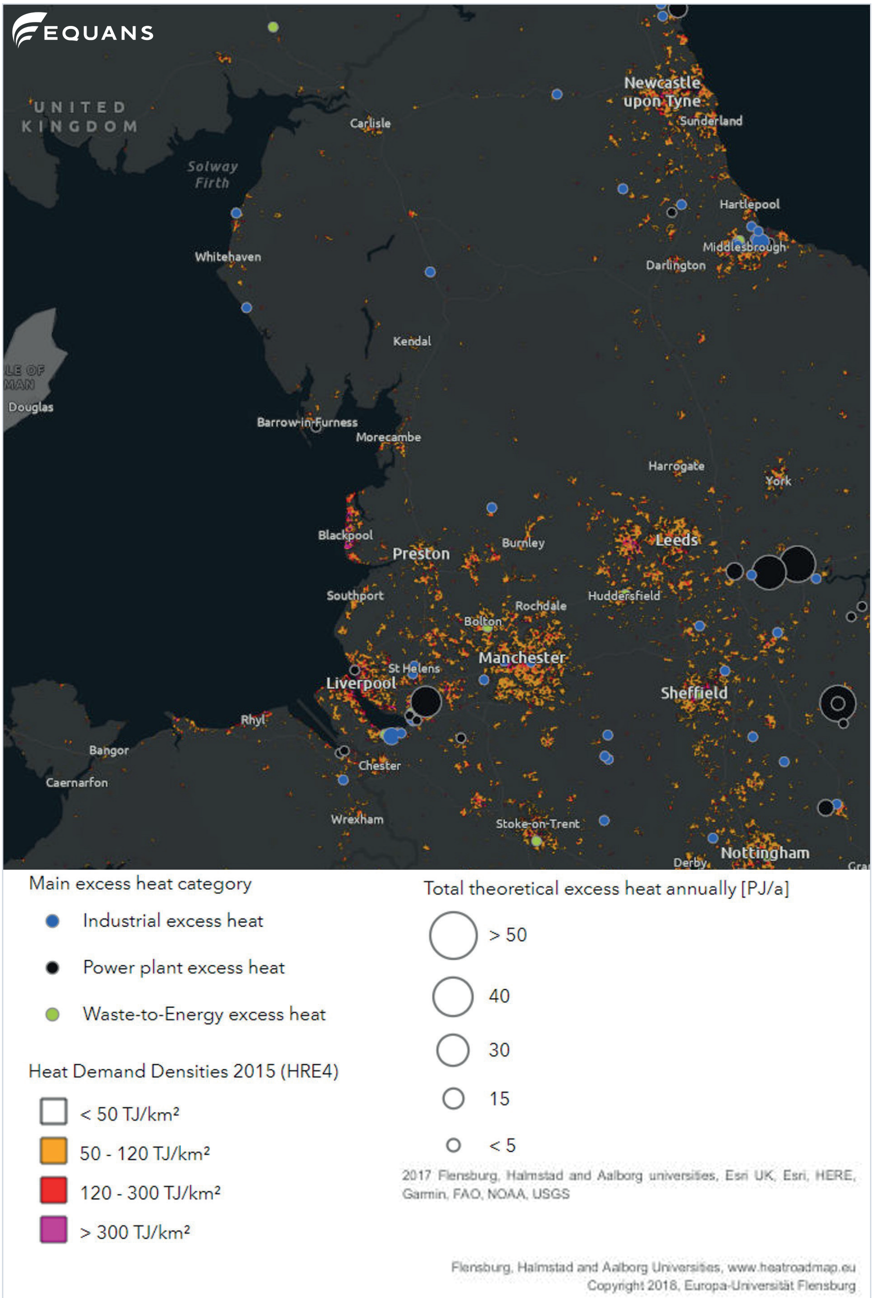


*Figure 31 Heat demand density and excess heat from industrial sector in North West*

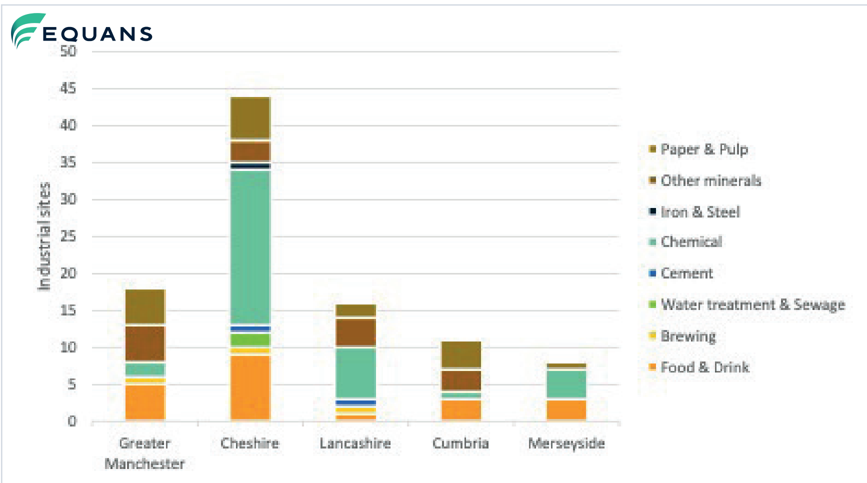


*Figure 32 Breakdown of sectors in regions where district heating opportunities may be applicable in the North West*

Recuperation of waste heat will not result in energy or carbon savings for the industry. However, sale of waste heat could offer a great financial benefit for waste heat producers. Cost of heat produced at a district heat network utilising waste heat has been estimated to be £30/MWh whereas a natural gas fired boiler would be £40/MWh (52). Besides financial benefits for the industry and heat users, waste heat could help decarbonise the building stock in North West England and North East Wales. Local governments and waste heat producing industrial sites can play an important role in coupling supply and demand for waste heat in the region with the help of central government. The proposed Oldham district heat and Alderley Park ambient loop networks are some examples of current district heat networks in the region. Figure 33 illustrates the heat networks in the North West that are operational or in the pipeline for development. The future of hydrogen production is expected to increase the amount of waste heat generation in the region. Whether it is blue or green hydrogen, its production will result in substantial amounts of energy being lost as heat. Hence, hydrogen production projects should consider ways in which associated waste heat can be utilised via district heating at an early stage (55).

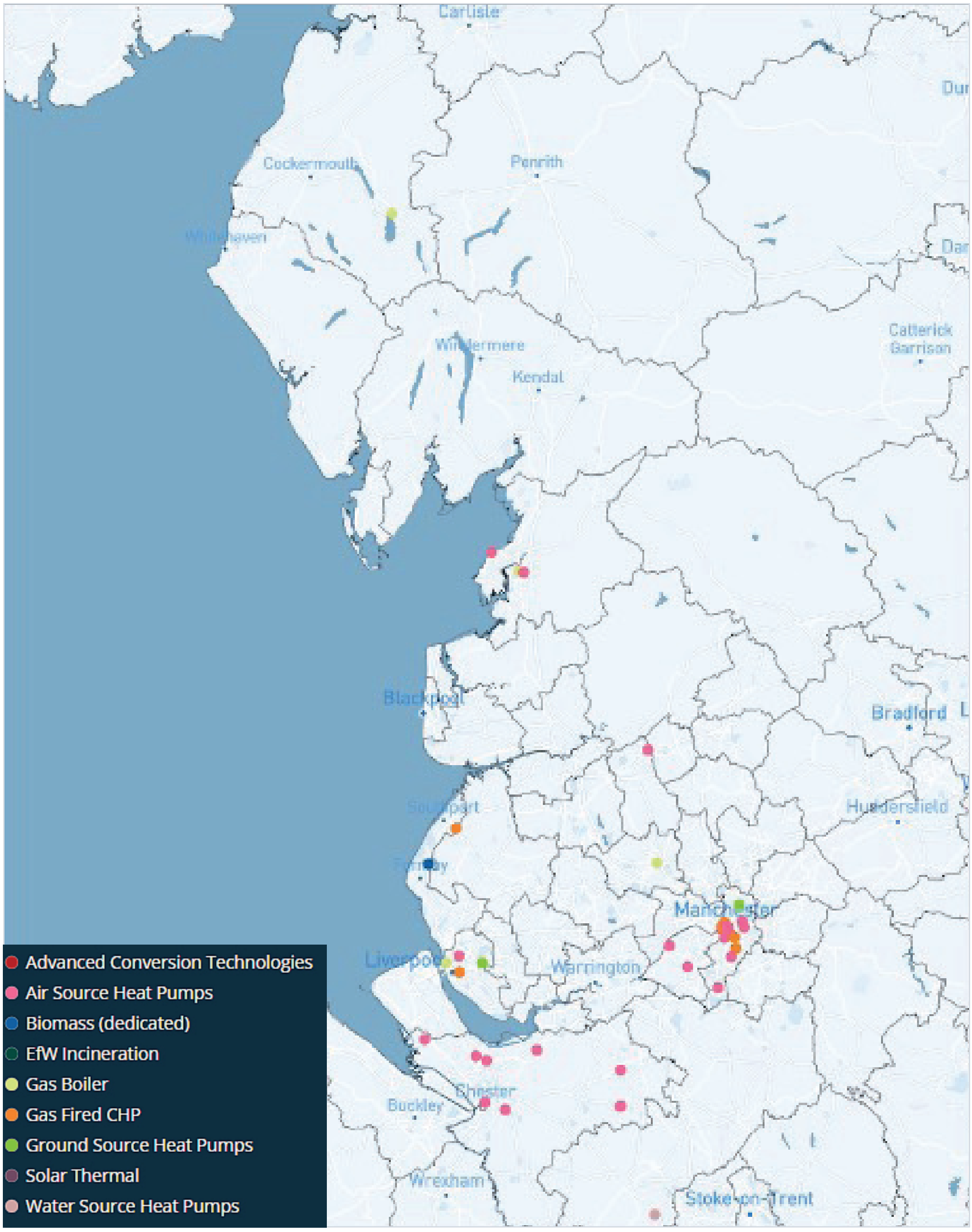


*Figure 33 Heat network planning database in the North West (56)*

### 5.4.6 Rankine Cycle

Rankine cycle is a process where heat is converted into mechanical work, which in turn can be used to generate electricity. A common example for this process is steam Rankine cycle which is used in power stations to convert high temperature steam into electricity. Organic Rankine Cycle (ORC) can do the same with low-grade heat (90-500°C). Hence, ORC is an important energy generation opportunity at industrial sites with waste heat from industrial processes or from internal combustion engines, gas turbines and fuel cells operating on open cycle.

ORC is fuel flexible which means that the site can be fuelled by natural gas, biomass, residual waste, or hydrogen. This flexibility allows the technology to be adapted to the changing fuel type over the lifetime of the plant in decarbonising its energy demand. Figure 34 illustrates the working principle of ORC. The ORC process enables electricity and steam generation on site which can be consumed on site or exported to the grid or nearby users.

There are numerous plug-and-play models readily available as commercially viable solutions within the market. Implementation of ORCs are not complex and can very easily be adopted where a feasibility study is carried out and funding is provided. ORCs are particularly suitable for energy intensive industries such as cement, steel, glass, ceramics and, non-ferrous metals sectors. Figure 35 shows the breakdown of industrial sites per sector and region in the North West where the ORC technology may be suitable for energy generation. Estimated nominal cost of ORC per kW is between £2,000 - 3,000 with a payback of under five years depending on application, operating temperatures, and size of installation (58) (59).

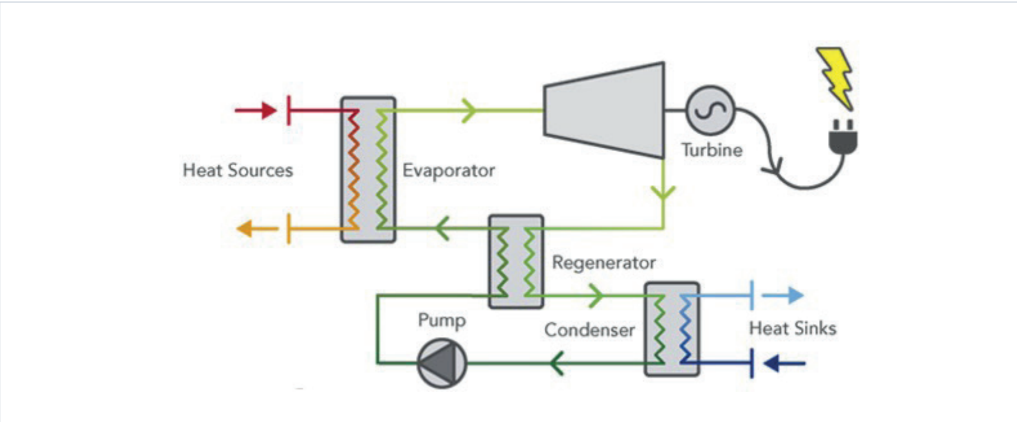


*Figure 34 Working principle of ORC (57)*

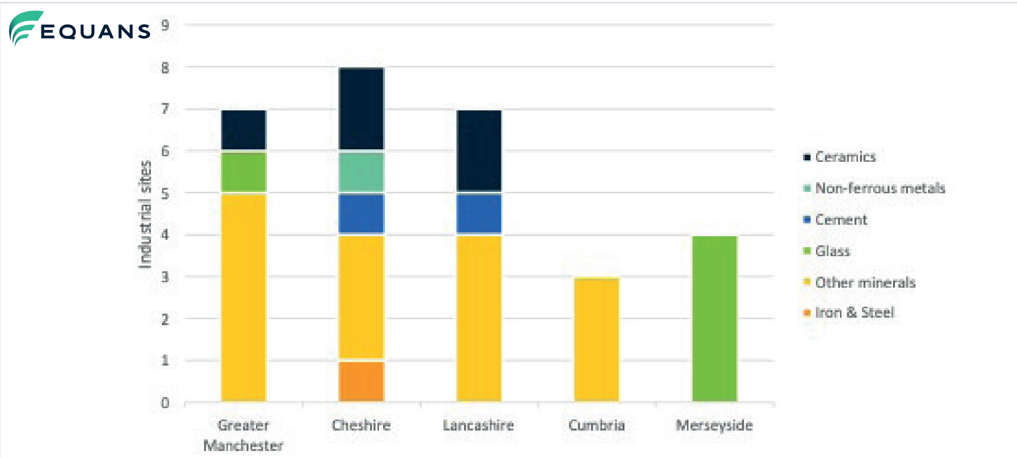


*Figure 35 Breakdown of sectors in regions where ORC opportunities may be applicable in the North West*

## 5.5 Hydrogen

Hydrogen is one of the most abundant elements throughout the universe and is one of the most common elements on Earth. One of the significant benefits of utilising hydrogen as a fuel is that it produces no carbon emissions during the process of combustion as no hydrocarbons are present in the fuel. Hydrogen, unlike fossil fuels, is not available within nature in its usable form (60), processes including steam reforming and electrolysis can be used.

This section discusses the implications for hydrogen use at a local point with further considerations for generation and distribution to industrial consumers upstream of a site. This is covered in detail within *EQUANS' Electrolytic Hydrogen Recommendations* document which shall be referenced to provide a holistic view on the landscape of the new fuel. Industrial site integration is one of the key areas for review of specific sites when hydrogen fuel becomes available.

Most manufacturers are now aligning their technology to a potential change in fuel to meet the demands of industrial users. Manufacturers of equipment such as boilers and gas fired CHP systems (61) have published figures that state a 25-30% blend of hydrogen with existing fuels requires no change to the equipment. This would include boiler burners or gas engine ignition systems. When a site looks to carry out a full fuel change from natural gas to hydrogen, a review of the combustion equipment would be needed. This would include items such as a gas train and burner for boiler equipment with additional auxiliary equipment such as gas boosters.

• Existing gas engines would require a gas train change, modifications to injection systems and currently would require de-rating to 75% output, due to the poor knock resistance of the hydrogen fuel when switching from natural gas. Additional equipment such as turbo by-pass valves may need to be changed depending on the manufacturer.

• Existing boiler equipment can be modified as mentioned with a new burner and ignition systems, however, beyond 20-30% this is not sufficient. New boiler plants installed will have to be specified as hydrogen ready which means current technology will have to be oversized to account for a larger heat transfer area. This is the largest change to existing equipment but means that an existing boiler shell and tube arrangement would not produce the required output.

• Safety equipment such as gas leak detection would need to be upgraded to account for the different type of gas, in addition to this, further risk assessments governed by current gas regulations would need updating for a site. With existing practices for testing piping systems using nitrogen gas, the same system can leak when hydrogen gas is used (62). This is due to hydrogen having a much lower kinetic diameter than methane, therefore it possesses the ability to leak past joints that would hold natural gas.

• The Hynet scheme includes the use of underground storage of hydrogen fuel and has been considered within the modelling for the feasibility for the network infrastructure. However, if there is a need for onsite storage, local systems would need to be purpose built for hydrogen gas. Aside from leakage, hydrogen embrittlement can occur which can lead to high strength metals failing at stresses below yield stress. As such, 316 stainless steel is becoming popular for hydrogen storage applications with higher pressure systems using composite materials.

Hynet is undertaking the review and research of a fully integrated hydrogen network spanning the North West of the UK. This is not conducted as a theoretical report but as a system that can be implemented forming part of the UK's commitment to achieving a 100% carbon emission reduction by 2050. Figure 36 proposed HyNet project illustrates the plan for the hydrogen network being implemented as detailed within WP5 *EQUANS' Electrolytic Hydrogen Recommendations*.

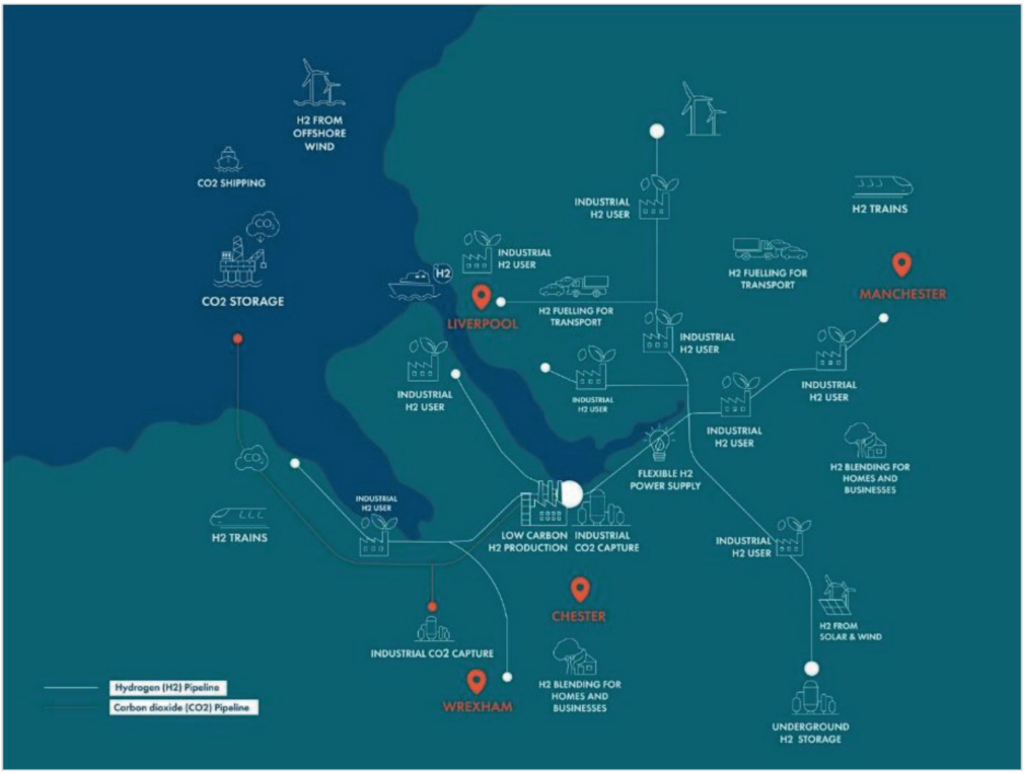


*Figure 36 proposed HyNet project (63)*

The review of the generation and distribution has been undertaken within this document, specifying locations which would be ideal for hydrogen generation based on consumption. Therefore, this report shall not repeat the work carried out in that section but will refer where required.

### 5.5.1 Grey and Blue Hydrogen

Grey and blue hydrogen account for approximately 80-90% of hydrogen generated worldwide. This is produced typically from the process of steam reforming which requires temperatures between 700 -1100ºC. A metal-based catalyst, normally nickel, causes steam to react with methane to yield carbon monoxide (CO) and hydrogen. The endothermic process of steam reforming can be improved to produce more hydrogen by using a process called the 'water-gas shift reaction', in which CO and steam are reacted with a catalyst.

The significant difference between the two processes is that blue hydrogen uses carbon capture to reduce the carbon emissions emitted from the system.

### 5.5.2 Green Hydrogen

The process of green hydrogen production centres around the application of electrolysis which can be classified as an entirely carbon free process. There are a range of different methods of electrolysis systems used with the most common being Proton Exchange Membrane (PEM) which does not require additional electrolytic solution. This is due to the polymer electrolyte membrane being the catalyst for ion transfer.

### 5.5.3 Hydrogen Utilisation

This report details areas of decarbonisation through electrification and lower carbon technologies all considering the application of hydrogen fuel.

The review of hydrogen fuel used with existing technologies and low carbon alternatives has been explored within this report, comparing the use of hydrogen within a CHP and HP system. The analysis conducted within work package 5 specifies the generation of hydrogen throughout various locations in the North West, with the input of electricity from renewables and other low carbon technology such as Small Modular Reactors (SMR) using nuclear technology. This is to allow for sufficient distribution of the fuel to maintain the same amount of combustion plant within the area for industrial processes, and therefore allowing other areas of the industry such as peaking plants to become fully decarbonised when used to support the National Grid. However, the process of converting electricity into hydrogen fuel, then combusting it in a boiler or CHP system for power and heat is not particularly efficient. Due to the existing equipment, within the entire process a site can expect approximately 50-55% overall efficiency. This is considering the initial electrical generation equipment such as wind turbines, the process of electrolysis, transmission losses and pressurisation of the gas for storage and finally combustion within an industrial site.

However, *EQUANS' Electrolytic Hydrogen Recommendations* emphasises the ability to produce hydrogen fuel with a high degree of versatility, unlike oil and natural gas which are governed by location, thus creating a monopoly. The key motivation for the application of hydrogen gas is the ability to become carbon neutral when utilising combustion plant. This would enable existing older methods of heat generation and onsite electrical generation to continue operating within a future market.

Hydrogen fuel provides a feasible application for energy storage beyond battery storage. The significant difference hydrogen storage offers is the ability for it to be produced at a location, transported, and then used in another location. It should be noted that there are restrictions on how much hydrogen can be transported in bulk.This is something battery storage is not able to facilitate which emphases the versatility of the fuel type. Fuel switching allows for a completely carbon neutral solution to existing combustion fuels. It will enable industrial sites to remove the use of conventional combustion methods of producing thermal energy, alleviating the demand of hydrocarbon fuels. It is understood that certain direct firing processes currently do allow for fuel switching, however, ongoing research has proven benefits to moving away from natural gas.

### 5.5.4 Hydrogen Behind The Meter

As well as network connected solutions, behind the meter solutions are also available for hydrogen production. In this case, an electrolyser would be installed behind the meter allowing a consumer, or a group of consumers, to produce the necessary hydrogen on site. In *EQUANS' Electrolytic Hydrogen Recommendations Report*, three behind the meter sites were modelled to understand how different variables would impact the cost of producing hydrogen on site. These variables included the amount of hydrogen needed, the demand profile, the availability of renewables and wider system constraints. As was demonstrated in this report, these factors can significantly impact the cost of hydrogen, demonstrating the requirement to consider them early in the feasibility process. This is further discussed in the Project Blueprints section of that report.

Drawing upon this work, in this report, EQUANS examines an application for a behind the meter solution, discussing some practical implications of the system design. This application involves incorporating renewable electrical production, used for balancing fluctuating grid power, in the form of gas to power systems (64), providing an alternative to energy storage beyond battery technology.

This process requires a renewable electricity source; wind turbines and solar panels have been selected for the review. The system is designed so that a portion of the output of the renewable generation is fed to the site, supplementing the electrical demand with the remaining feeding into an electrolysis plant.

The average modelled data illustrates an average operation of nine hours per/day for wind turbine generation. Therefore, this has been the selected figure to support the model at a constant output of 4,200 kW. From this 4,200 kW, only 720 kW shall feed into the site demand with the rest being used to power the hydrogen production process. Based on the input requirements, the turbine shall provide enough electricity to produce approximately 600kg of hydrogen fuel.

A further parasitic load for the system is the compression of the hydrogen fuel to ensure its suitability for storage. Pressurising the gas minimises the required footprint on site as it is appreciated that space can often be a commodity on industrial sites. This provides a required energy input of 39 kW for the nine hours of hydrogen production due to 0.71 kWh/kg energy input to compress per kg. The required storage is calculated to a total of 100,000 L storing hydrogen at a pressure of 100 barg, storing approximately 25 MWh of hydrogen fuel.

Once the renewable technology no longer produces electricity after the nine hour period, the system assumes switching to a CHP system. The CHP selected is based on existing technology which is commercially available to run on 100% hydrogen fuel (66). This CHP system has an output of 750 kWe and 747 kWth and requires a supply of 54.6 kg/hr of hydrogen, thus allowing for a total of eleven hours of continuous operation.

It is found that with this process, applying existing technology, and the site being able to fully utilise the electrical and thermal energy generated by the CHP system, an overall efficiency of approximately 52.5% can be found. This would require further review and a detailed analysis of the process on a site-by-site basis. Also, with ongoing improvements with the technologies applied, this efficiency will increase providing a lower payback.

Figure 37 shows a diagram of a similar process of an engine gas turbine hydrogen conversion demonstration project

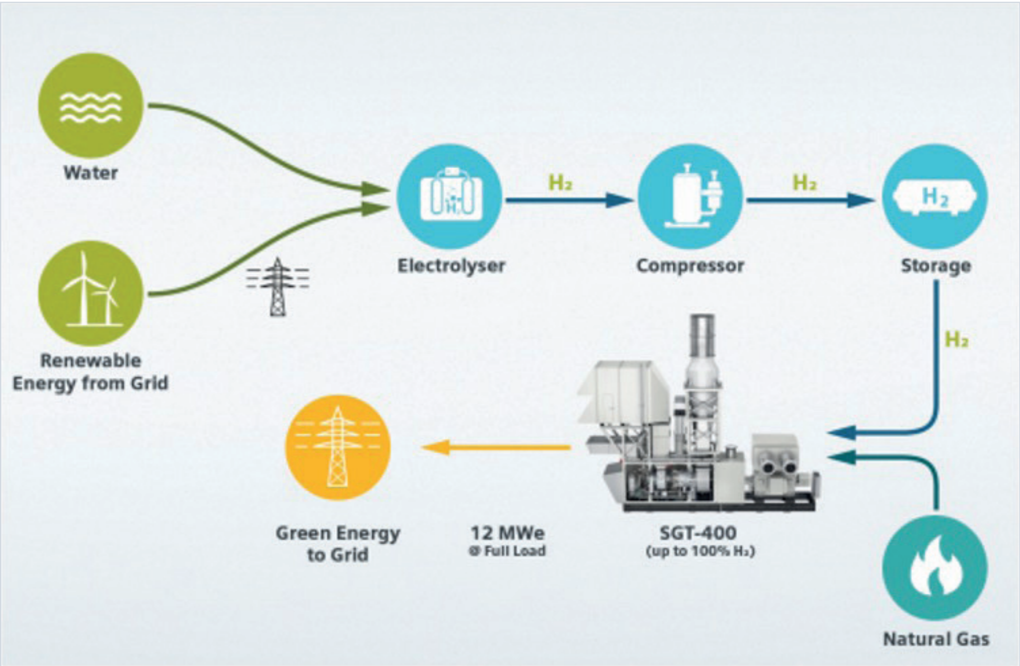


*Figure 37 Hydrogen production with CHP integration (157)*

### 5.5.5 Hydrogen Utilization - Manufacturing Processes

The difficulty presented for the industrial user is being able to move certain processes away from the existing use of natural gas or oil to hydrogen fuel with little to no interruption upon manufacturing and production. Certain industries such as glass and ceramics require natural gas for direct fired processes as part of the manufacturing of the product. The fuel is applied directly into kilns and furnaces with the product responding to the temperature and combustion characteristics. Other industries such as vehicle manufacturing require a large portion of their gas use for space heating. The food and drink sector, which accounts for 14% of the emissions produced in North West England and North East Wales, predominantly uses natural gas for steam, high and/or low temperature hot water production. These are simpler to resolve the issue of decarbonisation through switching fuels. Therefore, sector and government road maps for decarbonisation rely heavily on the implementation of hydrogen used within existing combustion equipment. This would be a *'do nothing'* scenario due to the changes being significantly reliant on external parties and the influence of technological developments.

Section 6 of this report details the current emissions generated for each sector. These roadmaps illustrate what the indicative carbon producers are and ways to mitigate these towards a net zero carbon future. This highlights that a large portion of some industries are using natural gas to produce heat and therefore rely on the integration of hydrogen fuel to achieve the set targets for the industry. Another consideration is the requirement for green electricity to fully support industrial processes embarking on a net zero carbon future. Hydrogen fuel can reduce the carbon emissions, however, further consideration is required to allow for complete decarbonisation in certain industries and processes.

#### 5.5.5.1 Oil Refineries

Hydrogen can be used in several hydrodesulphurisation (HDS) and hydrocracking processes. The first being a catalytic chemical process to remove any sulphur from natural gas or refined petroleum products e.g., petrol, kerosene, and diesel, while the latter takes the heavier products of the refinery industry and cracks large molecules into smaller more desirable ones. The oil refinery industry in the UK produces a significant amount of hydrogen which could be utilised both onsite and transported for use off-site (67). These processes centre around the generation of hydrogen through steam reforming, which is common within oil refineries throughout the refinement process of crude oil. Existing refineries throughout Europe are undertaking research around the integration of green hydrogen within certain processes, removing the need for methane from steam methane reformation (SMR) process to produce hydrogen. This has led to the integration of a 'behind the meter' (like the diagram shown in Figure 37) approach with onsite hydrogen production plants feeding into the existing processes. This would result in a significant drop in natural gas input to the site and therefore, a reduction in carbon emissions.

#### 5.5.5.2 Ammonia Production

The Haber Bosch process, the main method used for ammonia production, combines both hydrogen and nitrogen at a ratio 3:1. Usually hydrogen used in these plants is produced via the SMR method. The ammonia industry accounts for approximately 55% of global hydrogen consumption (68). The manufacturing process for ammonia produces hydrogen through steam reforming to enable the production of ammonia. This process is shown below (Figure 38).

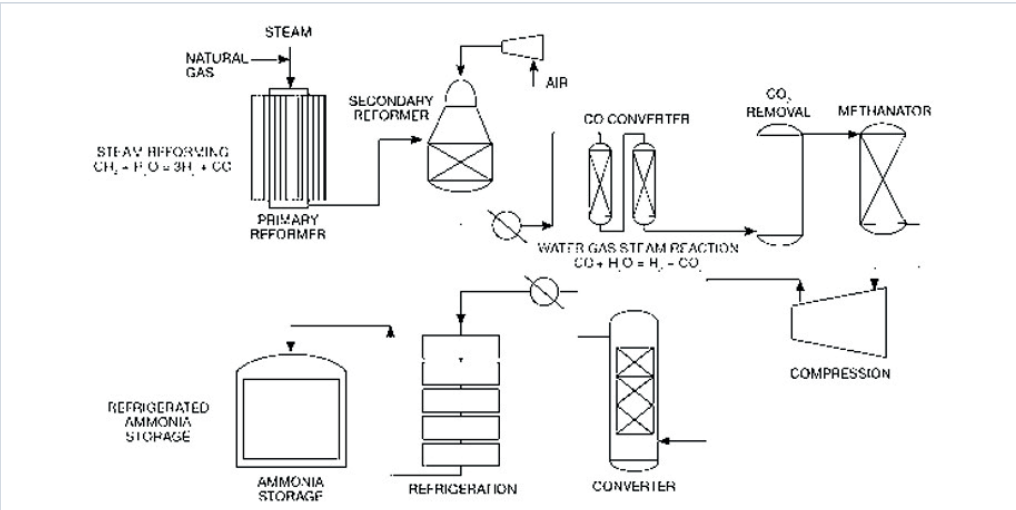


*Figure 38 Ammonia Production Schematic (69)*

As a result of utilising an electrolyser to produce hydrogen rather than through steam reforming, the carbon input can be reduced to zero. Further requirement for the input of renewable energy is needed for the Haber-Bosch process to fully decarbonise the system (70). See figure 39.

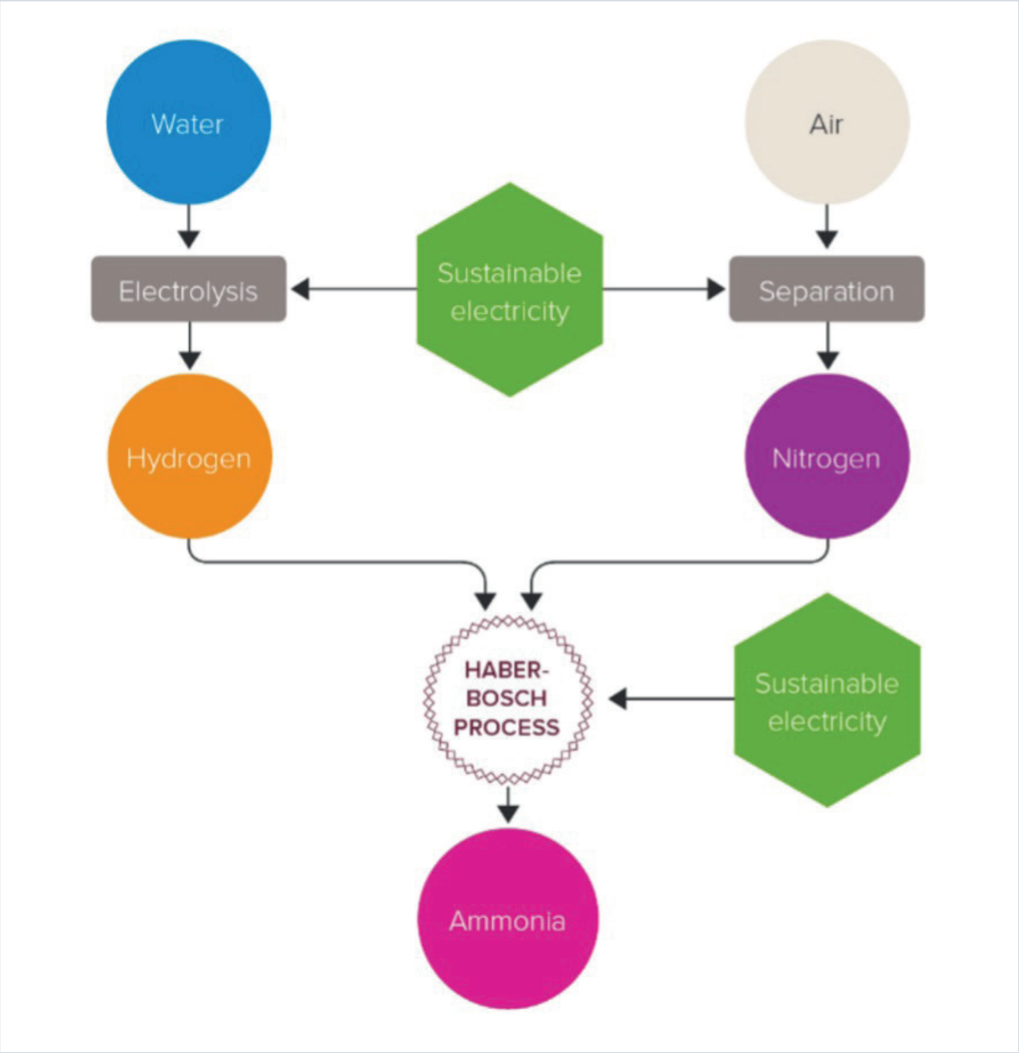


*Figure 39 Green Ammonia Process (152)*

### 5.5.5.3 Glass Industry

As stated previously, the glass industry's carbon emissions are produced from direct fired equipment which are part of the manufacturing process rather than through conventional combustion equipment.

The glass industry has recently undertaken successful trials to operate using hydrogen gas rather than natural gas within the glass manufacturing float process. The glass float process already applies hydrogen to stop molten tin from oxidising whilst the molten glass is undertaking its curing process.

However, the recent testing used hydrogen fuel gas to the heating process which takes place before curing, heating the glass to approximately 1000°C over a heating cycle process (71). The makes the glass turn to a liquid state so it can be then fed onto a molten tin pool where working takes place to form the final thickness of the sheet of glass. Because this process is widely used throughout the industry and is a considerable output to emissions for the glass sector, the fuel change presents significant carbon reduction.

## 5.6 Carbon Capture and Storage (CCS)

CCS will need to form a key pillar on the path to net zero emissions. A net zero energy system requires a profound transformation in how we produce and use energy that can only be achieved with a broad suite of technologies. Alongside electrification, hydrogen and sustainable bioenergy, CCS will need to play a major role. It is the only group of technologies that contributes both to reducing emissions in key sectors directly and to removing $CO_2$ to balance emissions that cannot be avoided – a critical part of net zero. (72)

CCS facilities have been operating for decades in certain industries, but they are still a work in progress in the sectors that need them the most. CCS has primarily been used in areas such as natural gas processing or fertiliser production, where the $CO_2$ can be captured at relatively low cost. But in other areas, including cement and steel, CCS remains at an early stage of development. These are the sectors where CCS technologies are critical for tackling emissions because of a lack of alternatives.

CCS refers to a suite of technologies that involves the capture of $CO_2$ from large point sources, including power generation or industrial facilities that use either fossil fuels or biomass for fuel. The $CO_2$ can also be captured directly from the atmosphere. If not being used on-site, the captured $CO_2$ is compressed and transported by pipeline, ship, rail or truck to be used in a range of applications or injected into deep geological formations (including depleted oil and gas reservoirs or saline formations) which trap the $CO_2$ for permanent storage. The extent to which $CO_2$ emissions are reduced in net terms depends on how much of the $CO_2$ is captured from the point of source and how the $CO_2$ is used. The use of the $CO_2$ for an industrial purpose can provide a potential revenue stream for CCUS (Carbon Capture, Utilisation and Storage) facilities.

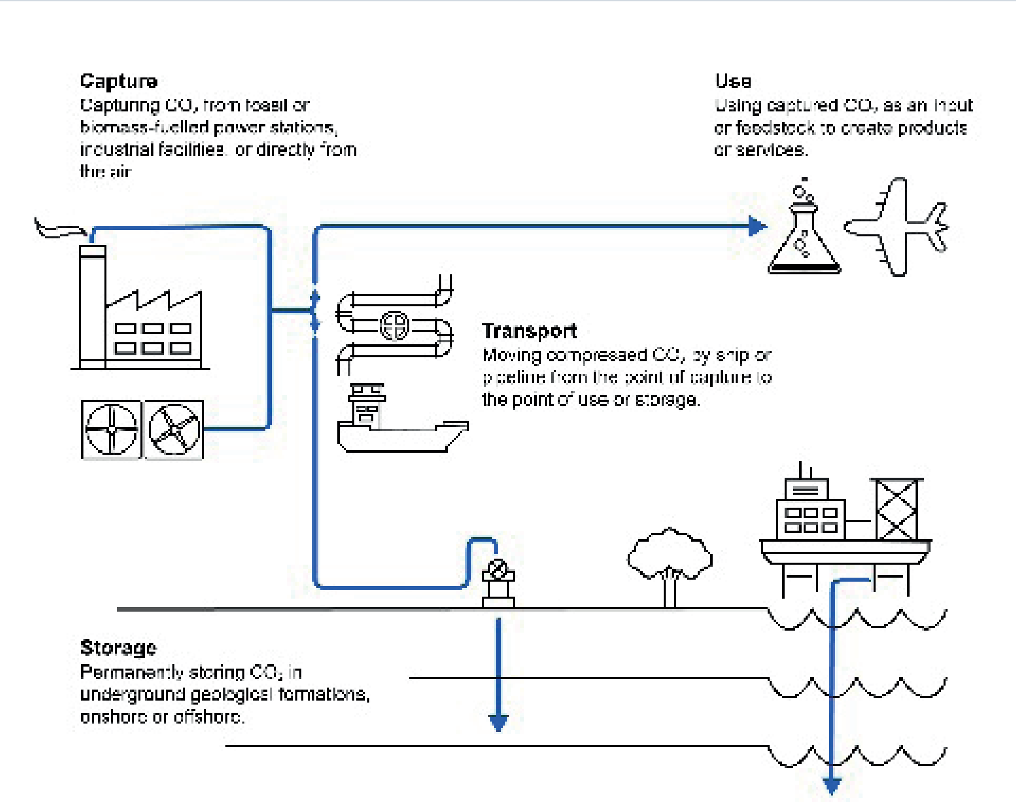


*Figure 40 CCS Schematic (73)*

$CO_2$ can be captured from a range of sources, including the air, and transported by pipeline or ship for use or permanent storage. Different terminology is often adopted when discussing CCS technologies, as detailed below.

• Carbon capture and storage: includes applications where the $CO_2$ is captured and permanently stored

• Carbon capture and utilisation (CCU) or $CO_2$ use: includes where the $CO_2$ is used, for example in the production of fuels and chemicals

• Carbon capture, utilisation and storage: includes CCS, CCU and also where the $CO_2$ is both used and stored, for example in EOR or in building materials where the use results in some or all of the $CO_2$ being permanently stored.

As discussed previously, the HyNet project is exploring low carbon energy generation for the North West cluster, and includes carbon capture and storage as part of the project proposal, demonstrated below in figure 41.

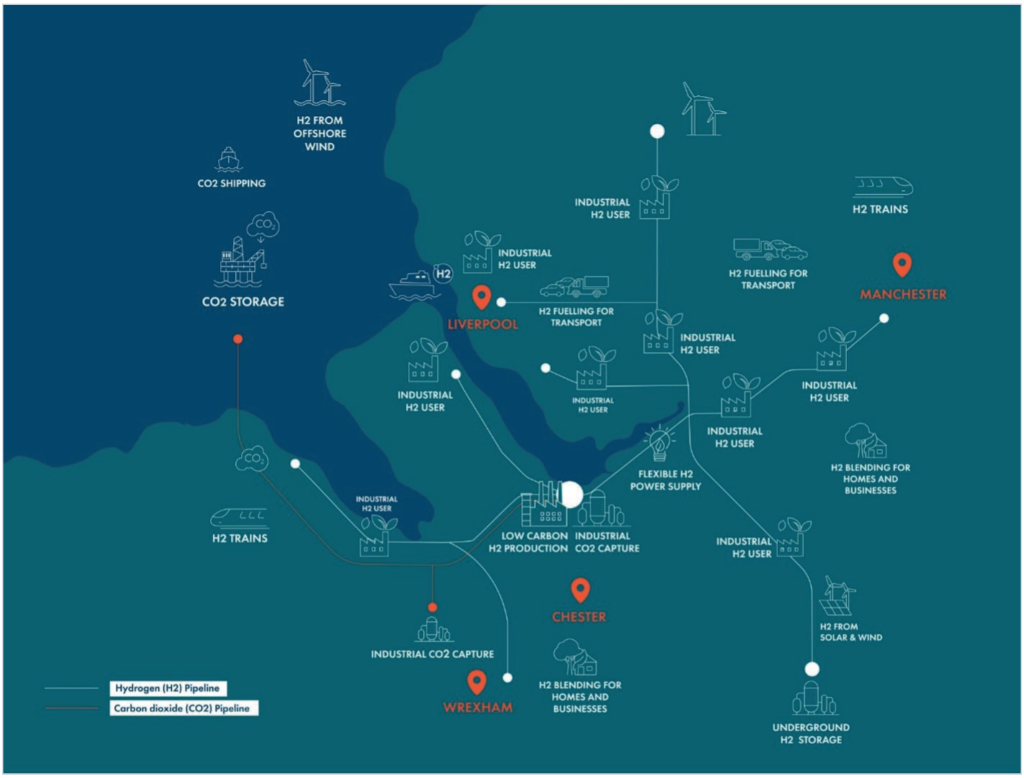


*Figure 41 Proposed HyNet Project including Industrial CO2 Capture and Storage (63)*

Phase 1 of the proposed HyNet project includes development of the infrastructure for capture and storage of $CO_2$ (63). There are also numerous pilot and demonstration scale projects in operation as well as significant CCS RandD activity.

## 5.7 Funding Available

The government recently consulted on two significant support mechanisms to support hydrogen producers, namely the Net Zero Hydrogen Fund which will provide CAPEX support, and the Hydrogen Business Models, which will provide revenue support. These producer-led support schemes are further explained within *EQUANS' Electrolytic Hydrogen Recommendations Report*. However, demand side support will also be important to support consumers with the CAPEX associated with converting plant equipment, such as the Industrial Energy Transformation Fund (IETF).

### 5.7.1 Industrial Energy Transformation Fund (74)

The IETF is a grant which supports high energy consuming industrial sites with aspirations to achieve a low carbon future. The IETF is aimed at industrial processes which will help companies:

• cut energy bills by investing in more efficient technologies, and

• reduce emissions by bringing down the costs and risks associated with investing in decarbonising technologies.

BEIS manage the UK government's £289m grant commitment through the IETF which is split across two phases.

**PHASE 1 (2021 – Q1 and Q2)**

Up to £40m of funding was made available for all companies with SIC codes between 10-33 and data centres for:

• projects deploying technologies that improve the energy efficiency of industrial processes, and
• feasibility and engineering studies into energy efficiency and deep decarbonisation measures for industrial processes.

The grant thresholds were:

| Funding applied for | Minimum threshold per application | Maximum threshold per project |
|---|---|---|
| Energy efficiency deployment projects | £100,000 | £14 million |
| Engineering studies | £50,000 | £14 million |
| Feasibility studies | £30,000 | £7 million |

*Table 30 IETF Phase 1 Grant Threshold*

**PHASE 2 (2021 – Q3 and Q4)**

Up to £60m of funding was made available specifically for companies with; mining and quarrying processes (SIC codes between; 05101-05200, 07100-08990 and 09900); manufacturing processes (SIC codes between 10000-33200); recovery and recycling of materials processes (SIC code 38320); and data centres (SIC code 63110) for:

• studies - feasibility and engineering studies to enable companies to investigate identified energy efficiency and decarbonisation projects prior to making an investment decision,

• energy efficiency - deployment of technologies to reduce industrial energy consumption, and

• deep decarbonisation - deployment of technologies to achieve industrial emissions savings.

The grant application window opened on 27/9/2021and closed on 6/12/2021.

The grant thresholds available were:

| Funding applied for | Minimum threshold per application | Maximum threshold per project |
|---|---|---|
| Energy efficiency deployment projects | £100,000 | £14 million |
| Deep decarbonisation deployment projects | £100,000 | £30 million |
| Engineering studies | £50,000 (total eligible cost) | £14 million |
| Feasibility studies | £30,000 (total eligible cost) | £7 million |

*Table 31 IETF Phase 2 Grant Threshold*

Further details can be found here


EQUA