INDUSTRIAL HEATING 2025

Acknowledgements
The following people contributed work included in this paper: Sarang Gadre, Prudence Hoffman, M. Krishna, Nathan Lozanoski, Anton Mlinar, Ayan Sarkar, Shannon Todd, Gavin Towler, Greg Turner

Honeywell

EXECUTIVE SUMMARY

Industrial heating is a major contributor to global climate change, accounting for roughly a fifth of all anthropogenic greenhouse gas emissions. Manufacturing plants use heat across a wide range of temperatures for a variety of process applications, so there is no simple "one-size-fits-all" solution for mitigating the emissions impact of industrial heat. Greenhouse gas emissions associated with industrial heating consist mainly of the carbon dioxide released during combustion, but also include methane (from fuel system leaks or incomplete combustion) and nitrogen oxides formed as a combustion byproduct.

Mitigation of the greenhouse gas emissions associated with industrial heating is therefore a critical step for companies in the manufacturing sector to achieve GHG emissions targets, particularly for companies in the materials processing industries whose products then feed into all other manufacturing processes and determine the carbon footprint (embodied carbon) of subsequent products throughout the value chain. The optimal path to decarbonization of a manufacturing site will depend on the local availability and cost of alternative fuels such as biogas or hydrogen, low GHG-intensity electricity and access to CO_2 sequestration sites or pipelines. The cost of decarbonization will also be substantially affected by local regulations and permit requirements, government incentives and national and international tax penalties.

As a developer of technology, equipment and automation systems for the energy and process industries, Honeywell offers a range of products and services that can help reduce the carbon intensity of industrial operations, many of which are discussed in this paper. In general we expect that:

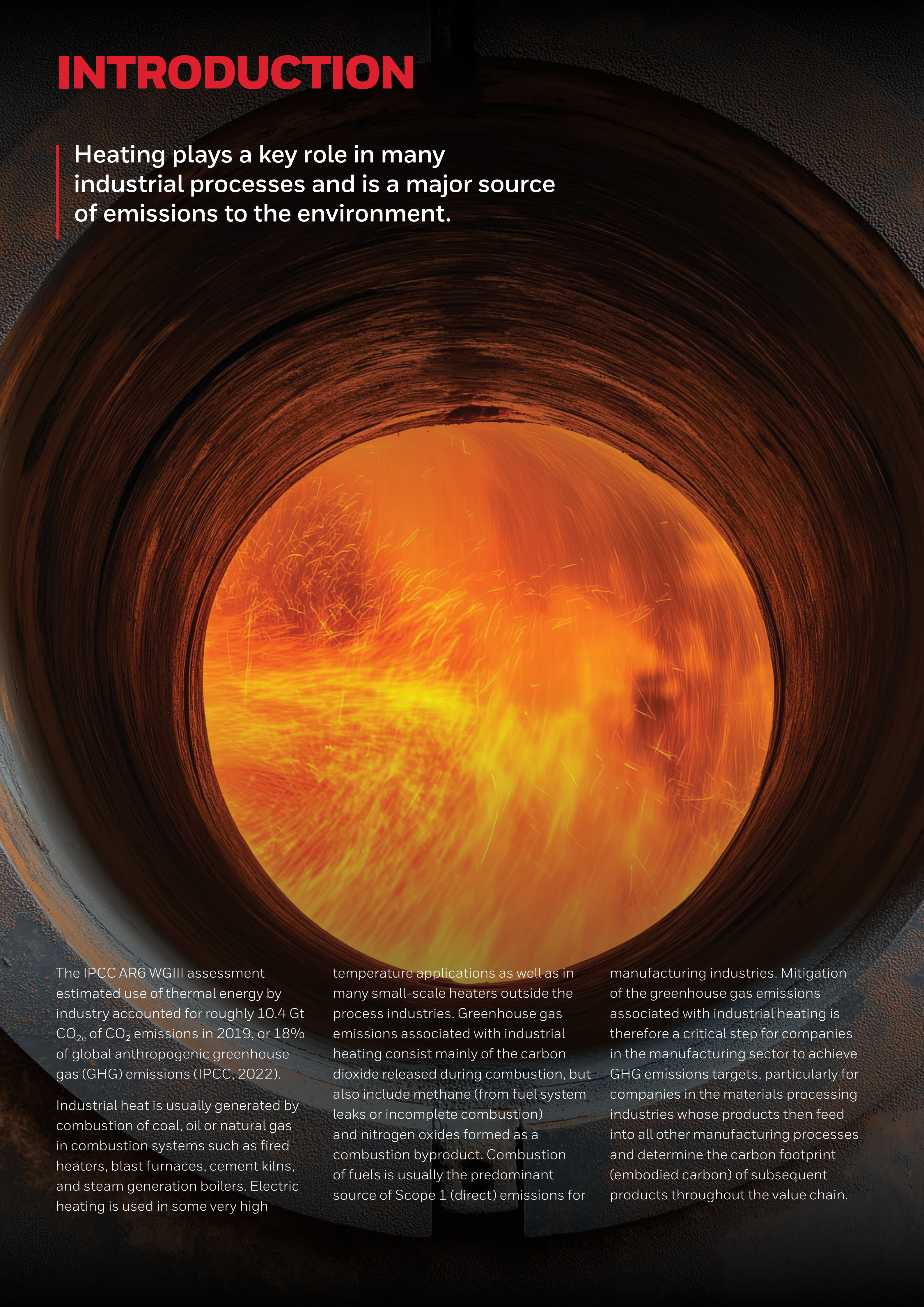
- High temperature heating will be addressed by switching fired heaters to low GHG-intensity fuels (initially from oil and coal to natural gas then later to clean hydrogen or biogas), or by deployment of carbon capture and sequestration on very large point sources. Electric arc heating will be used for some very high temperature processing (e.g. in metalworking) and electrification will also be used for small duty high temperature heat applications where it will be lower cost than fuel switch or CCS.
- Medium temperature heating will continue to rely heavily on steam systems, with the boilers / cogeneration plants achieving emissions abatement by deploying the approaches listed for high-temperature heating. Smaller fired heaters for medium temperature heat will probably switch to electric heating unless part of a large site that is pursuing a fuel-switch strategy. Heat pumps (particularly chemical heat pumps) will also be used to recover low-grade heat for medium temperature applications.
- Low temperature heating will be able to take more advantage of heat pumps and electrification, but will also use steam systems and low-GHG intensity fired heat in some applications that call for specific process temperature profiles (e.g. some types of food processing)
- Energy efficiency should be the first step in all industrial heating decarbonization plans as it generates immediate savings as well as reducing the investment required in abatement technology. Ensuring that automatic process control systems are operating correctly and have appropriately priced energy to include full emissions costs is a key requirement.
- Emissions tracking and monitoring software will be used to drill into the emissions profile of a site and go from the high-level data reported for regulatory purposes to a detailed understanding of the daily and seasonal variation in operations that underlies the site emissions and hence identify the governing loads and prioritize abatement approaches.

Reducing the emissions from industrial heating requires capital investments while also increasing operating costs, and so will not be undertaken unless manufacturers either see an opportunity to sell low GHG-intensity products at a premium price (allowing them to recover the cost) or are legally required to reduce their GHG emissions. Current levels of carbon taxes are not high enough to incentivize widespread decarbonization of industrial heating and relatively few companies practice green procurement and are willing to pay higher prices for low GHG-intensity products, so adoption of these technologies is currently limited to sectors where energy costs are a very low part of total production costs and regions where governments create incentives to accelerate decarbonization. We believe this situation will evolve over the next decade as more countries take steps to meet their obligations under the Paris Agreement and more companies come under regulatory or investor pressure to reduce their GHG emissions.

TABLE OF CONTENTS

INTRODUCTION

> **Heating plays a key role in many industrial processes and is a major source of emissions to the environment.**



The IPCC AR6 WGIII assessment estimated use of thermal energy by industry accounted for roughly 10.4 Gt CO_{2e} of CO_2 emissions in 2019, or 18% of global anthropogenic greenhouse gas (GHG) emissions (IPCC, 2022).

Industrial heat is usually generated by combustion of coal, oil or natural gas in combustion systems such as fired heaters, blast furnaces, cement kilns, and steam generation boilers. Electric heating is used in some very high temperature applications as well as in many small-scale heaters outside the process industries. Greenhouse gas emissions associated with industrial heating consist mainly of the carbon dioxide released during combustion, but also include methane (from fuel system leaks or incomplete combustion) and nitrogen oxides formed as a combustion byproduct. Combustion of fuels is usually the predominant source of Scope 1 (direct) emissions for manufacturing industries. Mitigation of the greenhouse gas emissions associated with industrial heating is therefore a critical step for companies in the manufacturing sector to achieve GHG emissions targets, particularly for companies in the materials processing industries whose products then feed into all other manufacturing processes and determine the carbon footprint (embodied carbon) of subsequent products throughout the value chain.

INDUSTRIAL HEATING APPLICATIONS AND DEMAND BY TEMPERATURE RANGE

Thermal energy has a wide range of industrial uses in materials processing and manufacturing of parts and assembled products.

High-temperature heat (>400°C) is used in materials transformation, melting, metals purification, parts forming and for high-temperature endothermic reactions. High temperature heat is needed in metals processing, casting, oil refining and petrochemicals production, fertilizer, hydrogen, cement, glass and ceramics manufacture. Roughly half (44%) of all high temperature heat is used in the manufacture of iron, steel and other non-ferrous metals, 13% is used for cement, glasses and other ceramic materials and 31% is used in chemicals manufacture (including oil refining, fertilizer, polymers, general chemicals and pharmaceuticals) (IEA, 2023).

Medium-temperature heat (150 - 400°C) is used for reactions, distillation, melting, extrusion, calcining and a range of other process operations typically encountered in the manufacture of chemicals and polymers as well as for a wide range of materials processing operations such as extrusion, casting and injection molding in general manufacturing. Use of medium temperature heat is significant in all industrial sectors.

Low-temperature heat (<150°C) is widely used in the food, beverage and pharmaceutical industries for applications such as boiling, pasteurizing, sterilizing, cleaning, drying, washing, bleaching, steaming, pickling, cooking, etc. as well as in other industrial applications such as paint drying, cleaning, dyeing and solvent removal. Non-energy intensive industries account for 67% of low-temperature heat use (representing 19% of overall industrial heat use) (IEA, 2023). Low temperature heat is also used for heating industrial buildings used for general manufacturing.

The IEA has assessed that roughly 46% of industrial energy is used in high-temperature applications, 25% in medium temperature applications and 29% in low-temperature applications (IEA, 2023). Breakdowns of energy use within each of the major industrial segments are given in Figure 1.1.

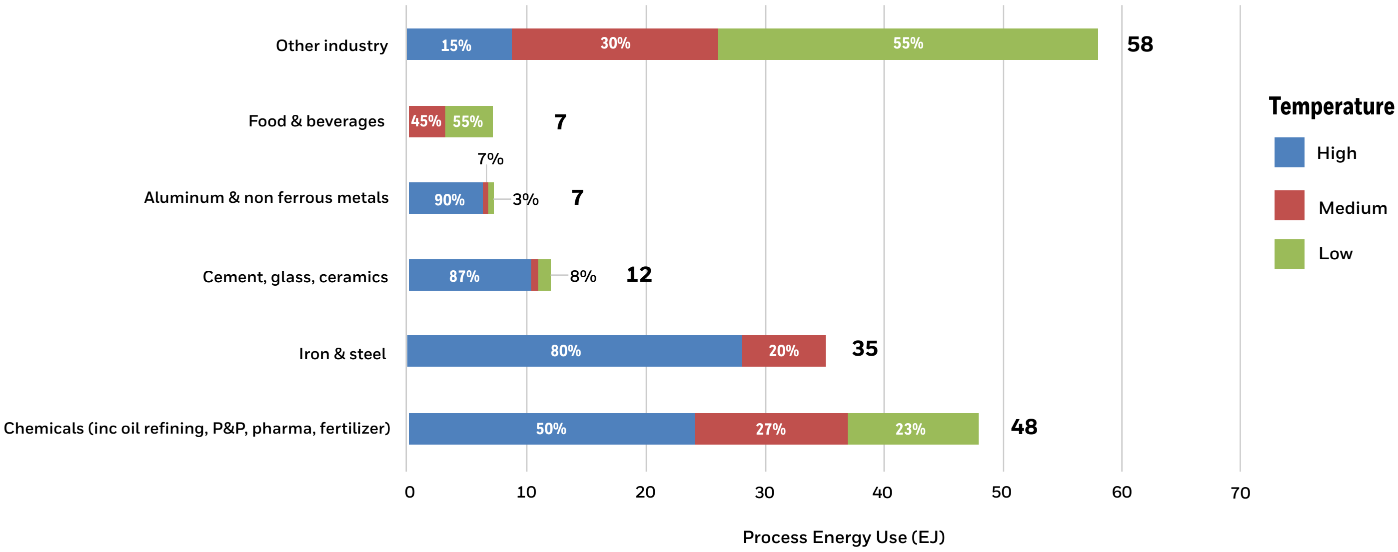


Figure 1.1 Energy use (EJ) by industrial sector (IEA, 2023; IPCC 2022)

OPTIONS FOR LOW-GHG (LOW CARBON INTENSITY) INDUSTRIAL HEATING

The environmental impact of industrial heating can be reduced by improving energy efficiency, switching to fuels that emit less greenhouse gases (lower carbon-intensity or lower GHG-intensity fuels– see Appendix 1 for a glossary of commonly used terminology), capturing carbon dioxide from the stack gases for sequestration or converting to electric heaters powered by low-GHG intensity electricity from hydroelectricity, nuclear power or renewables such as wind and solar. Electrification can also take advantage of heat pumps to raise the temperature of energy and increase options for energy re-use.

Energy efficiency

Improving energy efficiency should always be the first step in any plan to reduce GHG intensity. Energy savings almost always mean cost savings and can be achieved at reasonably attractive paybacks unless fuel costs are low. Even in regions with low fuel prices, energy efficiency projects reduce the size of the problem and the level of investment needed for transitioning from high GHG intensity to lower GHG intensity. Conducting regular energy audits helps identify areas of energy inefficiency and potential savings. Audits provide valuable insights into energy consumption patterns and can highlight opportunities for improvement. A critical step in improving energy efficiency is to ensure that automated process control (APC) systems are functioning correctly and the control optimization algorithms correctly account for the full cost of energy and for emissions costs if emissions taxes are in place.

In addition to improving the energy efficiency of industrial operations, many plants have options for waste heat recovery and re-use, either inside the plant or in nearby plants or communities. Industrial processes usually only consume very small amounts of energy (for endothermic reactions, heat of separation, etc.) and much of the energy that is put into heating process feeds is rejected from the process and can be recovered by cooling of the process products, albeit usually at lower temperatures. Re-use of energy by heat recovery is widely practiced in the materials processing industries. Some plants are even able to use waste heat or recovered heat to generate electric power to meet internal needs or for export.

Energy efficiency and heat recovery have been extensively studied since the 1970s but although there are well-proven methodologies for maximizing energy efficiency, the variation in relative costs of fuel and capital over the past 50 years has meant that very few companies consistently manage energy consumption optimally and many small sites and operations that are less sensitive to energy costs have very poor heat integration. Many sites also do not take full advantage of automation technologies to operate at peak energy efficiency and consequently waste energy and have higher operating costs. Technologies for energy efficiency and energy system optimization are discussed in Section 2.

Fuel switch options

Any plant or equipment that burns liquid or gaseous fuels can be relatively easily modified to different fuels by changing out the fuel supply piping, burners and burner control systems. Equipment that uses solid fuels (coal, wood, waste products) can also be modified to either co-fire or switch completely to gas or liquid fuels with similar changes and may even achieve lower costs with fuel change due to the reduced need for back-end emissions controls. Switching to a fuel that has a higher hydrogen content or that has a higher content of biogenic (i.e. renewable) carbon rather than fossil carbon will lead to a reduction in the GHG intensity of the operation.

The GHG intensity of different fuels is given in the IPCC Emissions Factor Database (IPCC, 2014). For conventional fuels the GHG intensity varies from coal with highest carbon intensity (100 tCO_2/TJ) to oil-based fuels (73 tCO_2/TJ) to natural gas (56 tCO_2/TJ). An oil-fired operation can therefore achieve a 23% reduction in GHG intensity by switching to natural gas.

Many oil refineries and chemical facilities actually burn a mixed fuel gas that is made up of process off-gases and purge gases supplemented with natural gas. These fuel gases can contain substantial amounts of hydrogen. Some plants also combine waste destruction in thermal oxidizers with heat recovery steam generation. In all of these cases, the carbon dioxide concentration in the flue gas (& hence GHG intensity of the operation) can vary with time and may be difficult to calculate unless the fuel gas composition or flue gas composition is monitored in real time.

Estimating the GHG intensity of biofuels is also not straightforward. While the carbon in biofuels has been derived from atmospheric carbon dioxide using solar energy (through plant growth), other energy inputs go into crop fertilization, harvesting, transport and processing of biofuels, causing them to have a non-zero GHG intensity. The GHG intensity of biofuels should be determined through lifecycle analysis (LCA) to ensure that all inputs are properly included. For example, a Honeywell UOP lifecycle analysis of renewable diesel fuel made by hydro de-esterification of fats and fatty acids (HEFA) found that the fuel had a GHG intensity of 11.1 tCO_2/TJ (Kalnes et al., 2011).

While fuel switching is always the lowest capital cost approach to reducing Scope 1 GHG intensity, it can sometimes involve a substantial increase in cost of fuel. The potential for fuel switching at a given location may also be limited by the availability of lower GHG-intensity fuels such as biofuels and hydrogen in that area. Technologies for enabling fuel switching and the cost impact of fuel switching are discussed in more detail in Section 3.2.

Carbon capture, utilization and sequestration (CCUS)

Carbon dioxide can be captured from heater flue gases (also known as stack gases and exhaust gases). Once captured, the carbon dioxide can be injected into oil and gas production facilities for enhanced oil recovery (EOR) or sent to geological sequestration in saline aquifers or abandoned oil and gas wells (carbon capture and sequestration, CCS). In locations that have abundant low-cost renewable electricity carbon dioxide can be electrolyzed to make chemicals or reacted with green hydrogen produced by water electrolysis to make methanol that can then be converted into a wide range of fuels and chemicals (carbon capture and utilization, CCU). Capturing carbon dioxide chemically and reacting it with green hydrogen generated from solar power is chemically and thermodynamically no different than capturing carbon dioxide via photosynthesis and reacting plant biomass to produce chemicals – the end result is that solar energy is captured in the condensed form of hydrocarbon compounds that can then be used as fuels and chemical feedstocks. There are, however, important social and political differences between the two routes, as one has strong linkages to the biofuels and agriculture industries and hence rural jobs and votes, while the other is more likely to be practiced by large industrial companies in remote areas and so usually has less political support.

Technologies for CCUS are described in detail in Section 3.3. The stack gases from industrial heaters are in principle a good place to apply CCS, because stack gases typically contain about 10% carbon dioxide, so it is much cheaper to recover CO_2 from stack gases than from air, which has concentration 425ppm. However, there are several factors that limit the adoption of CCS in practice:

- Many existing plants do not have adequate space near to the fired heaters to install CCS equipment. The cost of running ducting for the flue gases or piping for the CCS solvent over long distances (>200m) is almost always prohibitive.
- Many existing heaters operate on natural draft. Combustion takes place at atmospheric pressure and the hot stack gases are exhausted through a chimney to create draft for the burners. Such heaters rarely have sufficient pressure drop to accommodate gas-liquid contacting stages that are needed for CCS and a forced convection (blower) system must be added to create the necessary pressure drop.
- The capital cost of building CCS equipment becomes relatively expensive at small scales. CCS is therefore unlikely to be economic for small heaters (< 10 MW). There is also an upper limit to the size of a single CCS plant at roughly 500 MW where the cost of building a very large diameter scrubber becomes excessive, and larger plants must be accommodated by using multiple absorbers in parallel.
- CCS requires a nearby sequestration site or access to a CO_2 pipeline system. Progress in certifying sites for sequestration can be very slow if local communities voice concerns about potential impacts.
- There is a perception among some environmentalists and members of the general public that CCS is a form of "end-of-pipe" treatment that polluters use to prolong the life of existing assets, while carbon dioxide removal from the atmosphere (CDR, also known as direct air capture, DAC) is a "clean technology" that cleans up pollution by sucking carbon dioxide out of the air. The fact that both routes accomplish the same thing while DAC is 5-10 times more expensive than CCS and therefore requires large government subsidies that could have much higher impact on GHG reduction if used elsewhere is not necessarily appreciated or valued by many environmental activists. Understandably, companies in the DAC space and their investors actively lobby for preferential government support and this can be very influential in diverting government money towards their investments and away from activities that would have more impact on mitigating global climate change.

Electrification

Electric heating can be deployed across the full range of temperatures needed by industry. At very high temperatures electric arc heating is cheaper than burning fuels (because furnace efficiency is low for very high temperature heating – see Section 2.3). Electric heating is also usually the preferred option for very small scale heating (<100 kW), though electric heaters can be cheaper than steam heating even at low-single digit MW if utility investments such as pipe runs are avoided.

Electrification of heating allows operations to take advantage of low GHG-intensity electric power when it is available and attractively priced. For this reason, industries such as aluminum smelting and polysilicon manufacture that use large amounts of electricity are often located in regions that have access to low cost hydroelectricity. As the cost of solar power continues to decrease it is likely that more industrial plants will take advantage of solar power to meet their heat needs, particularly when solar power and pumped hydropower energy storage (PHES) systems are both available to ensure a 24h power supply.

Technologies for the electrification of industrial heating and barriers to wider adoption of electrification as a strategy for GHG mitigation are discussed in Section 4. One of the main challenges of electrification of industrial heat is that it reduces Scope 1 (direct) emissions at the cost of increasing Scope 2 emissions (indirect emissions from imported heat and power) and thereby does not lead to overall emissions reduction unless the site is assured of access to low GHG-intensity electricity. In addition, electrification of industrial heating can require substantial upgrades to electrical infrastructure and close coordination with the electric utility to be successful.

LIFECYCLE ANALYSIS AND ABATEMENT CURVES

Lifecycle analysis (LCA) is an important tool in understanding the system-wide impacts of technologies and ensuring any steps taken to improve environmental impact do not create additional externalities that reduce the expected environmental benefits. All forms of industrial heating should be compared on a lifecycle basis to ensure the following impacts are captured:

- Direct emissions from combustion of fuels at site (Scope 1 emissions under the GHG protocol).
- Indirect emissions due to combustion of fuels used to produce any imported heat or electric power (Scope 2 emissions).
- Emissions from any upstream fuel processing facility used to generate the fuels that are burned (e.g., biofuels plant, natural gas treating plant, coal gasification plant, etc.) (part of Scope 3 emissions).
- Emissions from any downstream operations associated with remediating site emissions, for example emissions resulting from compression of carbon dioxide in CCS (part of Scope 3 emissions).
- Embodied emissions (aka “embodied carbon”) associated with any new equipment that is required, such as new heaters, new burners, additional piping, gas scrubbing plant, new electrical substations, carbon dioxide compressors, etc. (part of Scope 3 emissions).

Lifecycle analysis allows comparison of the GHG intensity of different options but it is important to note that every activity (including generation of renewable power) has a carbon footprint on an LCA basis. The technologies described in this paper can be used to reduce the GHG intensity of industrial operations and achieve carbon neutrality as defined by the Greenhouse Gas protocol (no burning of fossil fuels, all electricity sourced from renewables or nuclear), but true net-zero GHG emissions operation can only be achieved if sufficient additional carbon dioxide is captured and sequestered to offset all the residual GHG footprint due to renewable power and embodied emissions.

When the GHG reduction impact of different technologies is calculated on an LCA basis the marginal abatement cost (MAC) can be calculated by dividing the lifetime (or annualized) cost of the modification by the avoided lifetime (or annual) emissions to express the cost in $\$/tCO_{2e}$. A large site that has multiple heat-consuming operations will have a range of options to address each of them. Plotting the lowest MAC option for each operation against the amount of GHG mitigated and Pareto ranking the options from lowest to highest MAC generates a marginal abatement cost curve (often shortened to “abatement curve”). The abatement curve can be thought of as a roadmap that identifies the sequence of mitigation activities from best to worst payback. There is an abundance of abatement curves in the literature that have been created for industrial sites, buildings, corporations, cities and even countries.

The use of abatement curves can be misleading when evaluating options for reducing the GHG intensity of industrial heating. While abatement curves provide the right answer for each operation when viewed in isolation, they typically miss site-wide or system-wide solutions that have lower overall cost. For example:

- If CCS is the best option for any operation on a site then the cost of expanding the CCS regeneration plant slightly and fitting additional scrubbers elsewhere dramatically lowers the MAC of CCS for other point sources on the site.
- If fuel switch to hydrogen is an option for any part of a site the cost of bringing in additional incremental hydrogen is much lower than the initial cost (associated with pipelines / hydrogen production / CCS) and so it will likely make sense to convert the entire site to hydrogen rather than deploy other solutions piecemeal.
- If electrification of a large-scale operation is the best option and an increase in site generation capacity or new sub-station to accommodate increased grid electricity consumption is needed, the additional incremental cost of building a larger sub-station or generation plant and electrifying additional operations will be lower than previously estimated.

It is therefore likely that a site will achieve the lowest overall cost by selecting one or at most two GHG mitigation approaches and solving the problem at site scale rather than mitigating each operation separately.

THERMODYNAMICS AND ECONOMICS OF INDUSTRIAL HEATING

This section provides a brief overview of typical conventional industrial heating systems in the materials processing industries and established approaches for improving energy efficiency.

SITE UTILITY SYSTEMS

Most manufacturing facilities in the process industries contain several individual processing plants, all of which are supported by a common network of site services (utilities) that typically includes:

- **Electricity system:** Grid electricity is usually brought in via a substation that steps the voltage down from local high or medium voltage transmission systems. Most sites supply electricity at 480V for heavier equipment as well as 240/220/110V for lighting, control systems and other uses. Most larger sites also have some degree of on-site electric power generation capacity: typically a cogeneration (combined heat and power, CHP) plant consisting of gas turbine engines with heat recovery steam generators to provide site steam. Larger sites also often employ power recovery systems such as backpressure letdown turbines between different steam mains. In some cases the on-site power generation capacity is large enough to run the entire site or to maintain site operation at reduced rates during periods when grid power is lost. In such cases, the site electric grid usually has at least partial microgrid capability allowing island mode operation (and less commonly full microgrid capability including black start). Almost all sites also have some level of emergency power supply from either batteries or stand-by generators to allow for safe shutdown and critical operations during power outages.
- **Fuel gas system:** Most sites contain a large number of small gas-fired heaters that are supplied with fuel from a site-wide network of gas mains. The gas fuel is typically primarily natural gas brought in from the local gas company, but this gas is often supplemented with flammable process purge gases or vent gases. In some cases (e.g. some oil refineries or petrochemical plants) the site production of off gases is greater than the site fuel needs in which case the site is said to be “fuel long” or “long on fuel” and surplus fuel gas may be exported or flared to maintain the fuel gas system pressure. Some sites that are long on fuel also send fuel gas to recovery plants to recover components such as ethane, propane and butanes that have potential byproduct value. Sending purge and vent gases to the fuel system reduces site consumption of natural gas and offsets energy costs. If the purge gases contain hydrogen then using them as fuel can also reduce the average carbon intensity of fuel fired and hence site emissions.
- **Steam system:** Steam is widely used as a process heat source, as it has high heat of condensation, gives high heat transfer coefficients, allows precise control of heating rates and is nontoxic and nonflammable. Sites typically generate steam in high-pressure boilers or combined heat and power (CHP) plants as well in heat-recovery steam generators in individual process units. Steam is distributed around the site in steam mains that are usually at three different pressures: high pressure (typically 30-40 bar); medium pressure (typically 10-20 bar) and low pressure (typically 2-5 bar), allowing steam heating to be used across the full range of temperatures up to 250°C. Condensate from steam heaters is collected and returned to the site boilers as boiler feed water (BFW). Make-up water is added to compensate for boiler blowdown, process use of live steam and any system losses. A typical site steam system is shown in Figure 2.1. Larger sites use backpressure turbines to recover power from steam when letting it down from high pressure (HP) or medium pressure (MP) main to lower pressures. Use of turbines allows for power recovery, offsetting site electricity needs or providing motive power to heavy equipment. Many sites use differential pricing for steam at different pressure levels to encourage use of lower-grade heat and maximize the amount of higher-grade steam available for power recovery through turbines.

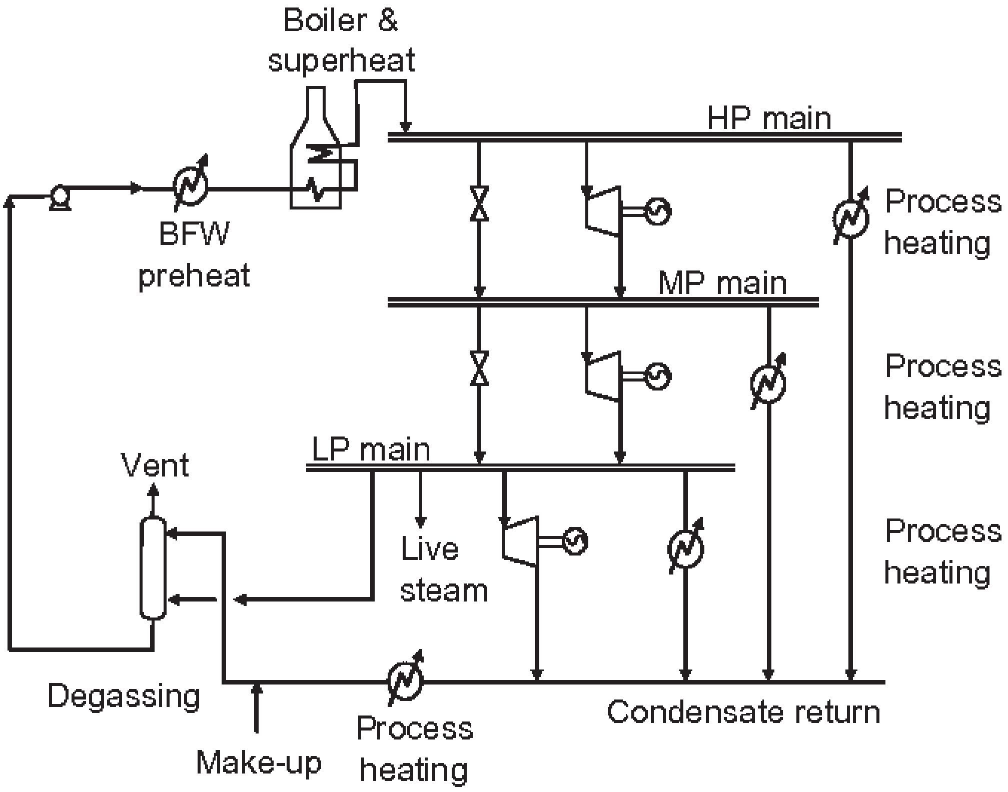


Figure 2.1: Typical site steam system

- **Heating oil system:** Some sites use circuits of hot circulating heating oil or thermal fluids, particularly in situations where steam use would be potentially hazardous or where a large number of small fired heaters can be avoided. Heating oil systems usually have a primary fired heater as heat input and then distribute hot thermal fluid to heat exchangers around the plant.
- **Furnace oil system:** some sites have furnace oil circuits that supply liquid fuel to fired heaters. In these cases, the fired heaters are usually equipped with dual burner systems for both furnace oil and fuel gas. Furnace oil circuits provide consistent and reliable operation of process heaters in situations when the fuel gas network undergoes pressure fluctuations due to transient operating conditions or gas grid instability.
- **Cooling water system:** Plants in colder and temperate climates usually reject waste heat to cooling water. Used cooling water is returned to a cooling tower and chilled by evaporative contact with air, so cooling water systems work best when the ambient temperature is low or the ambient air humidity is low. Regions where water is scarce or ambient temperature and humidity are high will usually use electric-powered air coolers (“fin-fan coolers”) instead of cooling water. Cooling water systems handle very large amounts of energy (necessarily because the site has to energy balance) but at low temperatures where the heat usually cannot be used for any industrial purpose. Several heat recovery approaches are based on reducing heat rejection to cooling water so as to extract more value from waste heat.
- **Off-gas and vent gas system:** Many industrial plants have to process vent gas or off-gas streams from operations such as tank filling, solvent cleaning, drying, vessel purging, vacuum pumps and partial condensers. If these vent gases contain volatile organic compounds (VOCs) or toxic gases they must usually be sent to a thermal oxidizer for VOC control before they can be emitted to the atmosphere. The amount of flammable material in the vent gases is usually insufficient to sustain a flame (i.e., is below the lower flammability limit), so the thermal oxidizer maintains a steady flame by burning natural gas or fuel oil to ensure that all gases fed to it reach a temperature high enough to destroy the VOCs and other toxic compounds while controlling nitrogen oxides (NOx), particulates and other emissions. Thermal oxidizers can represent a significant fraction of the overall heat availability of some sites and larger thermal oxidizers often incorporate heat recovery, either for air-preheat or by use of heat recovery boilers on the flue gas.

WASTE HEAT RECOVERY AND REUSE

All industrial processes necessarily reject waste heat. Hot products from reactors and separation equipment need to be cooled down before they can be sent to storage. Hot parts from casting, welding, soldering, injection molding, brazing or machining all have to be cooled before they can undergo additional work. Even operations that do not require high temperature heating release waste heat from motors and other electrical equipment. In accordance with the first law of thermodynamics, the energy that is put into the process operations must be rejected to preserve overall energy balance (less any actual thermodynamic heat of reaction or mixing), and in accordance with the second law of thermodynamics the heat is rejected at a lower temperature than it was supplied (unless the process incorporates an exothermic chemical reaction such as combustion that converts chemical potential energy to heat).

Industrial plants ultimately reject heat to the atmosphere, either by direct heat transfer to circulating air or indirectly via a cooling fluid such as cooling water or a refrigeration plant. When heat is rejected to ambient air inside buildings it can create additional requirements for ventilation or for air conditioning if the space is air conditioned. Rejection of waste heat to the atmosphere degrades the energy to the ambient temperature, making it unusable for any industrial or other socially-useful purpose.

Most process plants attempt to make use of waste heat by internal process heat exchange or use of waste heat boilers. Heat exchangers allow waste heat from hot process streams that need cooling to be used to heat up cold streams that need heating, thereby reducing the demand for utility heat sources. Waste heat boilers use waste heat from hot streams to generate steam that can then be used elsewhere in the site. In some cases, heat pumps are used to raise the temperature at which waste heat is available so that more of the energy can be used for heat exchange or steam generation.

Industrial waste heat can be used for heating buildings such as offices or homes in nearby communities. This can be as simple as rejecting waste heat to a circulating hot water district heating system or exporting surplus low pressure steam from the industrial site. Such schemes are widely used for heating corporate labs and offices co-located at manufacturing plants (particularly in Europe and China), but very rarely for export of energy unless there is a local community heating provider available to sign an off-take contract with the industrial site and handle the retail side of supply to the consumers.

PINCH ANALYSIS

Pinch analysis is a set of methods used to analyze process heat recovery and the design of heat exchange networks and site utility systems. The method is based on the fundamental insight that heat is put into processes at high temperatures and rejected from processes at lower temperatures. Every process therefore can be divided into a set of operations above a certain “pinch temperature” that on balance consume energy and a set of operations below that temperature that on balance reject waste heat. Any increase in heat supply above the pinch temperature must be cascaded to lower temperatures and results in additional heat rejection below the pinch temperature. Minimum energy consumption is therefore attained by eliminating heat transfer “across the pinch” (from the higher temperature set of streams and operations to the lower temperature set).

A variety of tools and guidelines for finding the pinch temperature and applying the pinch concept to process heat recovery and utility systems design were developed by Linnhoff and coworkers in the 1980s. A good summary of the most relevant methods is given by Smith (2016). Pinch analysis was very successfully deployed across the fuels and chemicals industries in the 1980s and 1990s. More recently, low energy costs relative to capital costs have led to less emphasis on heat recovery and many modern plants were designed with less internal heat exchange, so may have opportunities for additional heat recovery.

The simpler parts of pinch analysis are often taught as part of chemical engineering design courses and most chemical engineers have some familiarity with the subject. Actually carrying out a pinch project on an operating plant is less straightforward, as setting up the problem requires careful analysis to avoid data extraction traps that constrain the design to the status quo. The largest energy savings in pinch studies are almost always achieved by making changes to process operating conditions, so if there is no willingness to change process conditions the results are likely to be unimpressive.

OPERATIONAL CONTROL OF PROCESS ENERGY COSTS AND CARBON COST IMPACT

Once an industrial plant, factory or site is operational, the owner has strong incentives to optimize energy use as a means of controlling operating costs and increasing gross margins. Unfortunately, the incentive to minimize operating costs and conserve capital can also be a barrier to making site improvements or fuel changes that would reduce site carbon dioxide emissions and greenhouse gas impact.

When assessing operational changes to site utility systems, the utility energy should always be priced on a marginal basis, i.e. the cost of the utility energy is the cost of the next marginal unit of energy added or taken away from the site. For fuel gas systems, the marginal cost per GJ (or MMBTU) is usually the cost of natural gas imported to the site (unless the site is fuel-long and actively flaring fuel gas). For steam systems the marginal cost is the cost of increasing supply of high-pressure steam (including the cost of adding boilers if peak demand is currently matched to supply and there is no spare boiler capacity). For electricity the marginal price is the cost of electricity from the local electric utility company (including the capital cost of any additional transformers or switchgear if the site power consumption is expanded beyond the capacity of the existing grid connections). If additional internal heat or power recovery projects could supply the needed fuel, steam or electricity for lower than these marginal prices then they would be considered as alternatives to increased energy imports during any expansion in site production.

The marginal cost of energy can be very different from the actual average cost of energy consumed at a site, depending on the source and composition of the fuel gas consumed. For example if a site consumed 1000 GJ per day of energy (950 MMBTU/d) generated using a fuel gas that was 10% imported natural gas and 90% process off gases, the actual operating cost per day would be the cost of the 100 GJ (95 MMBTU) of imported natural gas, i.e. the site would have an effective cost one tenth of the price of natural gas. Decarbonizing this site by electrification of the heaters would be an extremely expensive proposition, as the full 1000 GJ would have to be replaced at the price of electricity. If natural gas cost 4 $/MMBTU and electricity cost 0.1 $/kWh, the actual daily cost of energy would go from (4 x 95 =) $380 to (1000 x 278 x 0.1 =) $27,800, i.e. a factor 73 increase in operating costs. Any plan for mitigating the emissions of an industrial site therefore has to start by understanding the existing fuel sources and utility system bottlenecks so as to avoid modifications that would have prohibitive impact on production costs.

Some manufacturing plants outsource the supply of fuel, steam and electricity to an “over-the-fence” supplier under energy supply contracts. Outsourcing of utilities makes sense when multiple companies operate on a single site (as in some industrial parks) or when small scale plants can be supplied by a larger neighboring plant, as the receiving plant avoids the need to deploy capital in offsite systems such as boilers, electric substations, etc. Outsourcing of utilities reduces scope 1 emissions but makes a corresponding increase in scope 2 emissions and gives the plant much less direct control over emissions reduction.

Since most sites are already designed and operated to take advantage of the lowest cost energy sources available, modifications that reduce carbon dioxide emissions and product carbon footprint will very rarely lead to a reduction in production costs (with the obvious exception of energy efficiency and heat recovery projects if the site is not initially well optimized). Such projects can only be justified if there is a need to reduce GHG emissions, either to offset tariffs such as the EU carbon border adjustment mechanism (CBAM), avoid local emissions taxes, reduce product carbon footprint to achieve a green premium on price or meet a corporate GHG emissions goal. Alternative methods for reducing GHG emissions can be compared on the basis of marginal abatement cost (MAC) of carbon dioxide: the total annualized cost of the modification including annualized capital cost and changes in operating costs divided by the amount of carbon dioxide (strictly carbon dioxide equivalent including other GHGs) avoided. Marginal abatement costs provide a simple way of ranking alternative site modifications, as well as a means of benchmarking against carbon taxes, import duties and cost of available offsets if these apply in the region where the plant is located.

If a site is located in a region where carbon taxes apply then the tax impact has to be factored into the cost of the fuel used. In this case, the tax impact must include the emissions due to any process waste gases consumed and so the site operator needs to have good measurement systems to understand the composition of the site fuel gas. Burning 1 MMBTU of natural gas releases 52.9 kg of carbon dioxide, whereas 1 MMBTU of propane produces 62.9 kg of CO_2 and 1 MMBTU of hydrogen produces essentially none. (Burning hydrogen produces very small amounts of CO_{2e} due to nitrogen oxides formed during combustion).
If the carbon taxes are significant, the operator has a good incentive to maximize recovery and burning of waste gases that are rich in hydrogen and remove gases such as ethane and propane from the fuel gas system and divert them to other applications such as sale to petrochemicals producers.
In regions where carbon taxes apply it is critical to update automatic process control (APC) algorithms frequently to reflect the current cost of emissions as well as fuel, otherwise there is a risk the plant will operate at sub-optimal conditions. Failure to adequately reflect emissions costs not only leads to higher plant emissions, it also causes higher operating costs and reduces plant profitability.

FURNACES AND FIRED HEATERS

FURNACE DESIGN, FURNACE EFFICIENCY AND FIRED HEATER HEAT RECOVERY

Most high temperature heating in the process industries is carried out in fired heaters or furnaces in which a fuel is burned in a combustion chamber and process fluids are heated by passing through pipes in the combustion chamber. Heat transfer to the tubes occurs by direct radiant heat transfer from the burner flames, indirect radiant heat transfer from the hot walls of the combustion chamber (which are usually lined with refractory material) and direct convective heat transfer from the hot combustion gases inside the combustion chamber. The design of the combustion chamber and layout of the burners optimizes the flow of heat to guarantee even heating of the tubes and ensure there are no hot spots where the heat flux would be too high and could cause mechanical failure of any of the tubes or other equipment in the furnace. The radiant section design geometry, burner selection and air to fuel ratios are also designed to avoid conditions that could lead to formation of controlled air pollutants such as nitrogen oxides (NOx) and hence meet air quality permit requirements. Industrial furnaces range from small cylindrical heaters that may have as few as one burner and a single pipe coil to large cabin furnaces that can contain hundreds of burners and pipes.

The hot flue gases leaving the radiant section of a fired heater still contain a substantial amount of usable high-temperature energy and are usually sent to a convective section of the heater to recover heat for process use, steam generation or furnace air pre-heat. The temperature of the flue gas at the outlet of the radiant section is referred to as the bridgewall temperature and is typically in the range 700 to 900 °C (1300 to 1650 °F). The convective section can in principle recover heat from the flue gas down to near ambient temperature, but in practice flue gas heat recovery is limited by capital cost efficiency, the need to avoid acid gas dew point temperatures (which is typically around 60 to 80 °C when burning natural gas or waste gases, depending on the sulfur level), lack of a use for energy below the process or site pinch temperature and in some situations the desire to avoid forming a visible plume of condensation from the plant (e.g. if the plant is located near to residential areas). The temperature at the outlet of the convective section is referred to as the stack gas temperature.

The furnace efficiency is defined as the ratio of useful heat delivered to total heat released by combustion of the fuel, i.e. radiant section useful heat + convective section useful heat divided by heat content of fuel fired. As a first approximation, furnace efficiency can be estimated from the adiabatic theoretical flame temperature of the fuel and the stack gas temperature:

$$\text{Furnace efficiency} \approx \frac{T_{\text{TFT}} - T_{\text{stack}}}{T_{\text{TFT}} - T_{\text{ambient}}}$$

Where:

T_{TFT} = adiabatic theoretical flame temperature (adiabatic temperature that would be achieved if fuel is completely combusted)

T_{stack} = stack gas temperature

T_{ambient} = ambient temperature

Furnace efficiency is therefore largely determined by the extent of heat recovery in the convective section and the existence of a need for low temperature heat. If the process (or site) has a relatively high pinch temperature then it may be more economic to recover low-grade heat from process streams below the pinch temperature (because liquid-to-liquid heat transfer is more efficient and has lower capital cost than convective section heating at low temperatures) and operate the furnace with a higher stack temperature and lower furnace efficiency.

Furnace flue gases are also sometimes used to preheat the furnace air if the furnace is forced convection type (i.e. has a blower to provide the necessary pressure drop). Air preheat increases furnace efficiency by effectively reducing the amount of fuel that needs to be fired to reach a given flame temperature. Air preheat is relatively capital intensive (gas-to-gas heat transfer coefficients are low) so large temperature approaches are specified and furnaces that only have air preheat in the convective section usually have lower furnace efficiency than those that have heat recovery steam generators or process heat recovery.

CARBON TAX IMPACT ON COST OF FIRED HEAT

Delivering a GJ of heat through a natural gas fired heater with 80% furnace efficiency requires 9.48/0.8 = 11.85 therms of natural gas and produces 0.063 t of CO_{2e} (using the US EPA emissions calculator: Greenhouse Gas Equivalencies Calculator | US EPA). So the impact of a 50 $/t CO_{2e} GHG tax on the cost of fired heat is an additional 3.15 $/GJ (= 3.31 $/MMBTU). While not insignificant, this is substantially smaller than the global variation in natural gas prices that currently drives all the LNG trade and associated investments, and industrial energy consumers already pay more than 20 $/GJ of delivered fired heat in some regions. It is therefore not clear that any carbon tax less than 100 $/t CO_{2e} would drive a broad move away from fired heating for high-temperature energy needs and it is more likely that GHG emissions mitigation technologies will be deployed primarily by companies that are seeking to achieve GHG reduction goals or create low C-intensity products to capture a green premium.

FUEL SWITCH OPTIONS

The simplest way to reduce the GHG emissions of a fired heater is to switch to a fuel that releases less carbon dioxide per GJ of heat. Oil-fired heaters can be switched to natural gas, sites that use a mixed fuel gas can remove the heavier hydrocarbons from the mixed fuel, and sites that have waste hydrogen available can send it to fuel gas instead of flaring or venting.

If a site is long on fuel gas (as is the case with most non-petrochemical producing oil refineries and many renewable fuels plants) the first step should be to upgrade the fuel gas by recovering non-methane hydrocarbons. Natural gas liquids such as ethane, propane and butane have sale value higher than their fuel value (on a $/GJ basis), particularly in regions that consume these molecules as petrochemical feedstocks. Typical refinery fuel gases can contain 10 to 30% of these light hydrocarbons, giving enough yield to justify adding the necessary process equipment. It is important to understand which process streams that feed into the fuel gas system are richest in these light hydrocarbons and also what treatment technology might be needed to meet product specifications. For example the off-gases from catalytic reformers require minimal treatment, those from crude units and hydrocrackers require desulfurization and those from FCC units and coking plants require saturation and removal of a range of gas contaminants that are not present in the other off-gases. A single plant designed to process all the off gases together would face the hardest separation challenges for the lowest concentrations of recoverable components, so it is better to segregate the gases for pretreatment and then send collected gases to a single plant for final separation to meet sales specs. Honeywell UOP has developed a range of technologies for recovering value from light hydrocarbon gases in refineries and natural gas plants, including Recovery Plus, FCC ERU, UOP Ortloff NGL Recovery and UOP Russell modular plants. Since all of these processes are designed to generate a payback, their application to fuel gas upgrading is typically one of the most economically-attractive options for GHG reduction.

Biogas

In locations where renewable natural gas such as biogas from agricultural waste, sewage plants or landfill gas is available, this can be used in place of natural gas with no change in burner operation. Some locations issue renewable energy certificates (or equivalent) that allow a user to purchase the "renewableness" of gas from a project even if the gas is supplied to the natural gas pipeline system and not directly to the consumer. While biogas is attractive as a low carbon-intensity fuel for heaters, its availability is rather limited outside of the EU, China and USA. The IEA estimated the total amount of biogas produced in 2022 as 37 bcme (IEA, 2023). Global natural gas production in 2022 was 4159 bcm, so biogas represented roughly 0.9% of the global supply of fuel gas. Biogas is also usually expensive relative to natural gas because of the cost of cleaning up the gas and compressing it to meet pipeline specifications.

Hydrogen

For sites such as oil refineries and petrochemical plants that already use a hydrogen-rich gas as fuel gas, the simplest path to reducing Scope 1 emissions is to increase the hydrogen content of the fuel gas as long as the hydrogen can be supplied with low carbon intensity. Sites that are located near to hydrogen pipeline infrastructure (e.g. US Gulf Coast, NW Europe) can bring in additional hydrogen "over-the-fence" if the site hydrogen supply is inadequate. Low carbon-intensity hydrogen can be sourced from hydrogen plants fitted with carbon capture technology ("blue hydrogen") or from plants that electrolyze water using renewable electricity ("green hydrogen") or nuclear power ("pink hydrogen").

Although hydrogen has some unique characteristics that require special attention, much of the existing combustion equipment can use hydrogen or blends of hydrogen and natural gas with relatively minor changes. This allows industrial manufacturers using combustion-based heat to continue using the same oven and furnace designs they have used for decades with minimal changes. The differences with hydrogen combustion, such as flame luminosity, flue gas composition and mass flow rate must be evaluated for potential impact to the process and the products being heated.

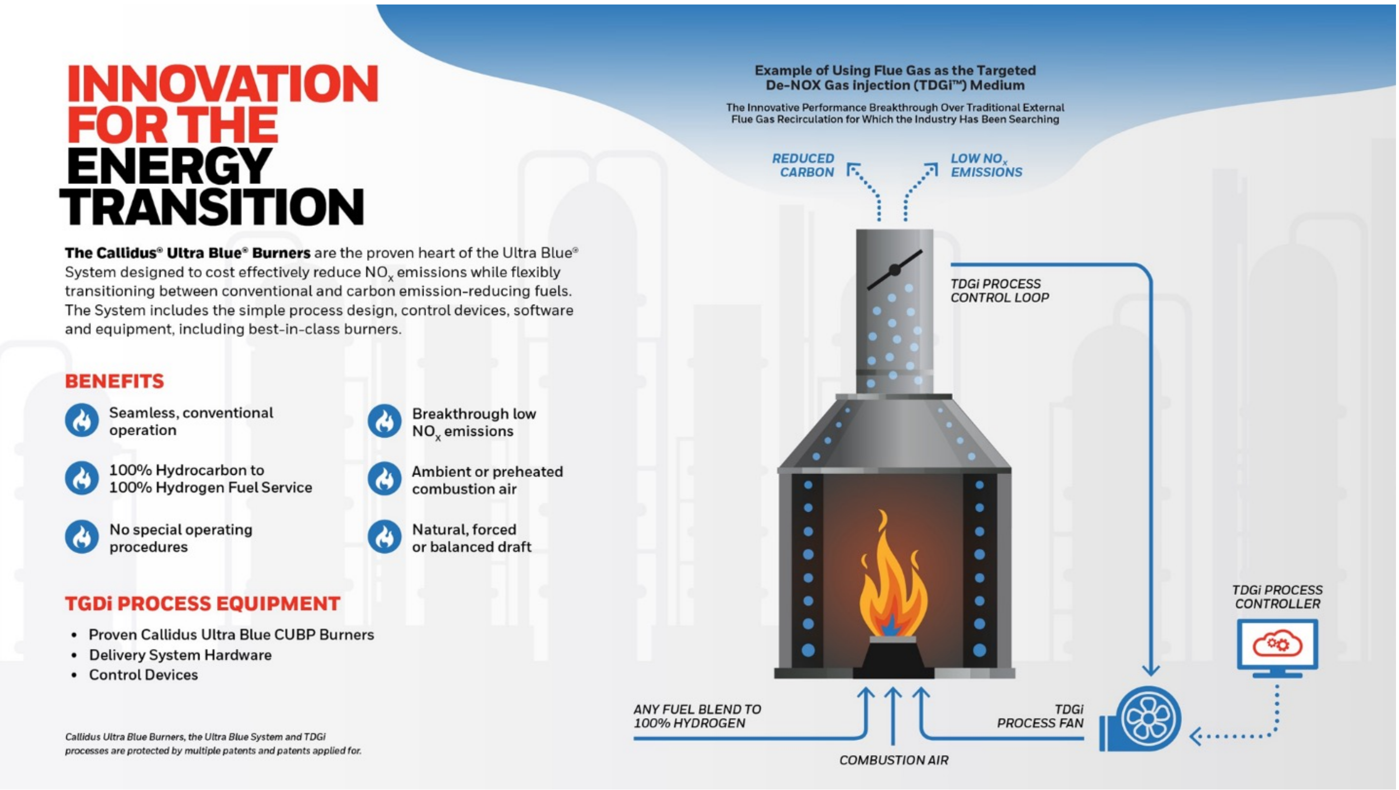
Through its Thermal Solutions and Callidus businesses, Honeywell offers low NOx combustion solutions for hydrogen in industrial process heating. The HTS ECOMAX® LE is a high efficiency self-recuperative burner capable of firing in low NOx flameless mode with 100% hydrogen for metals heat treatment applications. The Honeywell Callidus Ultra Blue® system (shown in Figure 3.1) is for petrochemicals and refining applications and can reduce NOx emissions and thereby help eliminate the need for selective catalytic reduction systems or significantly reduce the size of the unit needed. Honeywell has worked with fuels containing significant percentages of hydrogen, including refinery fuel gas, cracker fuel gas, process-off gases, blast furnace gas, coke oven gas, and hydrogen blended with natural gas.

The main impediments to using hydrogen as fuel are the availability of low-carbon-intensity hydrogen (lack of supply) and the cost relative to conventional fuels such as natural gas. The cost of low-carbon intensity hydrogen is currently considerably higher than natural gas. During 2024, green hydrogen prices in the USA varied from 3.5 to 5 $/kg, corresponding to 26 to 44 $/MMBTU, while natural gas was in the range 1.6 to 3.1 $/MMBTU. Even in the EU, where gas prices are much higher, green hydrogen prices were 4 to 9 €/kg (42 to 75 €/GJ) vs natural gas prices of 8 to 44 €/GJ. The price differentials for blue hydrogen are substantially lower, particularly in the USA when IRA subsidies are factored into the price, but there is currently negligible supply of blue hydrogen in either region. The cost differential for green hydrogen is expected to shrink considerably over time as electrolyzer costs decline and the price of renewable electricity also declines. In the absence of subsidies or incentives though, we expect fuel switch to hydrogen to only occur in industries where fuel costs represent a very small part of the cost of production or where the increased cost can be passed on to customers as part of a "green premium".

Site fuel switch considerations

In sites that have a large number of fired heaters and packaged boilers scattered across the site, fuel switching will usually be the most cost-effective strategy for addressing Scope 1 emissions. When there is a large number of heaters, distributed stack gas carbon capture is very expensive, as is electrification of all the heaters, as many small capital projects are needed.

In this situation it makes more sense to put in a larger hydrogen plant with carbon dioxide capture (blue hydrogen) and use hydrogen to decarbonize the fuel gas system, thereby achieving better economies of scale and avoiding a lot of small project work.



INNOVATION FOR THE ENERGY TRANSITION

The Callidus® Ultra Blue® Burners are the proven heart of the Ultra Blue® System designed to cost effectively reduce NO_x emissions while flexibly transitioning between conventional and carbon emission-reducing fuels. The System includes the simple process design, control devices, software and equipment, including best-in-class burners.

BENEFITS

- Seamless, conventional operation
- 100% Hydrocarbon to 100% Hydrogen Fuel Service
- No special operating procedures
- Breakthrough low NO_x emissions
- Ambient or preheated combustion air
- Natural, forced or balanced draft

TGDi PROCESS EQUIPMENT

- Proven Callidus Ultra Blue CUBP Burners
- Delivery System Hardware
- Control Devices

Callidus Ultra Blue Burners, the Ultra Blue System and TDGi processes are protected by multiple patents and patents applied for.

Example of Using Flue Gas as the Targeted De-NOX Gas injection (TDGi™) Medium

The Innovative Performance Breakthrough Over Traditional External Flue Gas Recirculation for Which the Industry Has Been Searching

Figure 3.1: Honeywell UOP Callidus® Ultra Blue® burner system

CARBON CAPTURE AND SEQUESTRATION (CCS)

Carbon Capture Utilization and Sequestration (CCUS) is mitigation of emissions by capturing CO_2 before it enters the atmosphere; this CO_2 can be either stored in geologic formations to avoid atmospheric release (CCS) or monetized through conversion to higher value products (CCU). CCS is particularly promising for industries that rely on high-temperature heating processes when the emissions are concentrated in very large heaters and when switching to alternative fuels might be challenging, such as steel and cement production, petrochemical manufacture, or burning of fossil fuels in power generation.

Post-combustion carbon capture is achieved by using liquid solvents to scrub carbon dioxide from the stack gas. A range of proprietary solvents can be used in the scrubbing operation and each has different implications for the capital and operating cost of the process. Usually CCS can be implemented with changes to the ducting of the flue gas but without requiring changes to the process itself or to the fuel gas system.

Global status of CCS deployment

The IEA global CCUS projects database (IEA, 2024) shows 54 operational CCUS projects with combined operating capacity of 73.5 Mt/y. An additional 395 projects with combined capacity of 1100 Mt/y have been announced with plans to enter operation by the end of this decade, but it is unlikely that all of these will be funded or completed on schedule. Even if all these projects went ahead, the total capacity would still be tiny compared to global anthropogenic GHG emissions of 58 $GtCO_{2e}$/y, so governments around the world are still incentivizing projects to accelerate deployment of CCUS technology. It is also worth noting that about half of the current operational CCS capacity (33.5 Mt/y) is capturing co-produced CO_2 from acidic natural gas for wellhead reinjection, a common practice for enhancing gas recovery from sour wells, while a quarter (19.1 Mt/y) is recovery from stack gases.

Some examples of policy support for CCS include:

- The American Recovery and Reinvestment Act of 2009 (Public Law 111-5) provided $3.4 billion for CCS, and the Infrastructure Investment and Jobs Act (IIJA, P.L. 117-58), enacted in November 2021, provided $8.2 billion.
- The EU Innovation Fund has funded 26 CCUS projects to date and has a budget of €40 billion through 2030 depending on EU ETS prices (European Commission, 2024).
- Canada has introduced a CCUS investment tax credit established through the Canadian federal government Bill C-59 and passed into law in June 2024, estimated to be worth CA$5.7 billion from 2023 through 2028.
- Brazil's bill 1425/2022 has been passed into law, establishing a legal and regulatory framework for CCS. Brazil is the first South American nation to enact CCS-specific legislation.
- Japan's CCS Long-term Roadmap (Ministry of Economy Trade and Industry Japan, 2023) established a target of achieving between 120 and 240 Mt of CO_2 storage by 2050. Japan has selected the country's first nine CCS projects which will store up to 20 Mt/y of CO_2 by 2030.
- The UK announced £21.7 billion over 25 years for carbon capture projects located in the East Coast and HyNet clusters (Millard and Pickard, 2024). These clusters are expected to collectively sequester over 8.5 Mt/y of CO_2.

While many governments have proposed policies and incentives to encourage CCS projects, the development of the sector is still being hindered by regulatory and policy barriers to project implementation. In particular:

- Difficulty in obtaining permission for new pipeline infrastructure to carry carbon dioxide from capture sites to sequestration sites.
- Difficulty in obtaining permits for drilling new wells at potential sequestration sites.
- Local community opposition to re-purposing of existing underground gas storage assets.

Failure to adequately address local community concerns about safety and local environmental impact of CCS projects could lead to lengthy timelines for pipeline and sequestration project approval and commissioning, making CCS a potentially high-risk strategy for companies that have set aggressive timelines for decarbonization. However, the widespread availability of geologically-suitable sites in most regions together with the ability to feed into existing pipeline systems as network coverage expands ensure that CCS will continue to become easier and lower cost over time.

Honeywell UOP Advanced Solvent Carbon Capture

Advanced Solvent Carbon Capture (ASCC) is Honeywell UOP's latest CO_2 capture offering. Utilizing a proprietary solvent developed by researchers at the University of Texas at Austin, ASCC combines Honeywell UOP's engineering expertise and UT's 20+ years of research in amine-based scrubbing to help reduce CO_2 emissions.

In the ASCC process, a gaseous stream containing CO_2 is mixed with a proprietary amine-based solvent, and the CO_2 is absorbed into the solvent, see Figure 3.2. The CO_2-rich solvent is sent to a stripper where CO_2 is separated from the solvent, and the CO_2 gas stream is then compressed and transported to be utilized or stored geologically. Honeywell UOP's ASCC solutions are specifically designed for post-combustion flue gas applications, enabling greater than 95% CO_2 capture (Honeywell, 2023). The patented solvent enables a system design with a lower-cost capture of CO_2 emissions from power plants, heavy industry, and other heavy emitters.

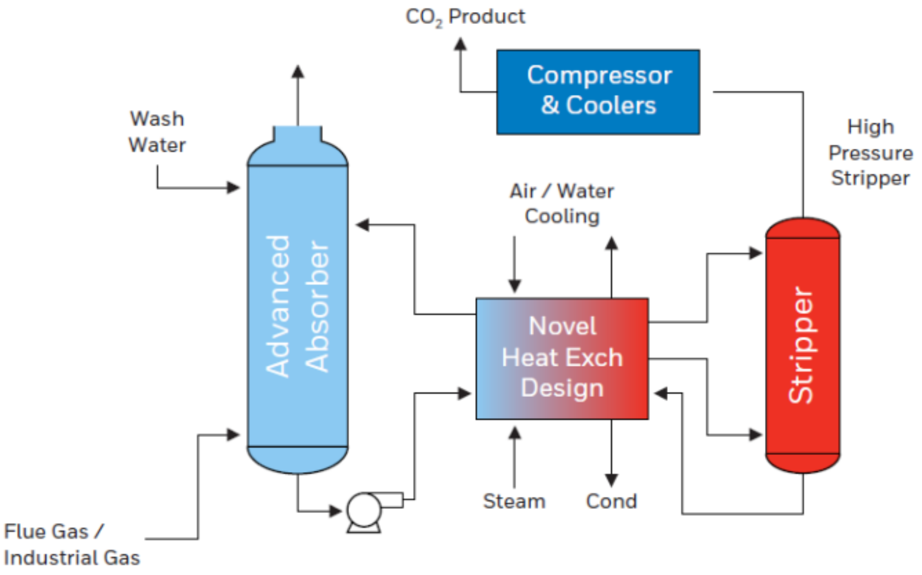


Figure 3.2: Honeywell UOP ASCC Process

The ASCC process is a point source carbon dioxide removal technology which can be retrofitted to existing plant installations as well as designed into new ones, and multiple emissions sources from one facility can be combined and fed to one ASCC unit. This gives the technology significant potential to reduce emissions globally.

Key advantages of the ASCC technology include high mass transfer properties of the solvent, enabling a smaller and more efficient absorber column, high solvent stability which allows the system to operate the CO_2 stripping process at higher pressure and therefore reduces compression requirements, and a high-efficiency heat exchanger system which reduces overall energy consumption. ASCC is being successfully demonstrated at the National Carbon Capture Center in Alabama in the United States, where over 4,000 hours of testing has been done in multiple ongoing projects across a wide range of flue gas compositions.

Carbon capture economics

The cost of carbon capture depends on the capital cost of the system deployed and the operating costs of providing energy to regenerate the solvents. Project economics will vary widely between sites and will be determined by site- and company-specific factors. As with all chemical plants, lowest cost per ton is achieved at largest scale (due to economies of scale), so CCUS is most competitive for plants that have large point sources of stack gas. Additional cost synergies are possible when several large point sources can share a common CO_2 compression and pipeline infrastructure and solvent regeneration system. Small-scale systems will always have higher cost per ton of CO_2 but may still be the lowest-cost option for decarbonization of a facility when compared with fuel switch or electrification.

ELECTRIFICATION

ELECTRIC PROCESS HEATING

Electricity can be used to directly supply the heat required for industrial processes or to generate steam for use elsewhere at site using electric heaters. Electric heaters tend to have very high efficiencies (>>90%) meaning nearly every unit of energy supplied by electricity is converted into a unit of heat delivered to the process. Resistive heating is the most common means to implement direct electrification into a process and several companies, including Watlow, Thermon, Armstrong Chemtec, F.A.T.I., Chromalox, and Heat Exchange and Transfer, Inc (HEAT), supply resistive heating equipment. In addition to resistive heating, some of these companies also offer radiant and impedance electric heater options.

There are a number of advantages to using resistive heating over other electrification technologies:

- The designs are simple and relatively cheap compared to other electrification technologies. They do not require equipment with moving parts. Equipment costs average approximately one million $/MW.
- The equipment is smaller than other electrification technologies making retrofits or revamps easier for customers who are short on plot space.
- Electric heaters have nearly 100% turndown capability. This allows for improved operability over other technologies, including traditional fired heaters which must maintain a certain heat output to satisfy emissions and other burner requirements.
- Resistive heating can reach very high temperatures, well in excess of 550°C, allowing for high process outlet temperatures comparable to those achieved with fired heaters.
- Since all of the heat is supplied by the heater, the only requirement for supplying heat is electrical capacity where the heat is needed.

Resistive heating also has a number of potential drawbacks however:

- Current scale is limited to a maximum of ~3-5 MW per heater. This means that higher capacities require multiple electric heaters hurting their economy of scale potential versus traditional fired heaters.
- The heating elements themselves can be quite hot, often exceeding 550°C. Many process streams are not stable under these conditions resulting in coking on the elements which can burn them out. Once burned out, the entire heating element must be replaced which can be expensive. The maximum temperature can be moderated somewhat by the use of an intermediate working fluid or sheath protecting the element from the process stream.
- The high surface temperature of resistive heaters can be problematic if it causes unwanted product degradation (e.g. charring in polymer processing or food processing).
- Every unit of energy needed for the process must come from the electricity itself. This means that the electricity needs to be cheap relative to fuel to have a positive economic return. Furthermore, to realize a net GHG savings over fossil fuel heating, the electricity must be sourced from renewable or other low-carbon sources.

Often the choice to use electricity directly for heating comes down to the nature of the process stream being heated, scale, fuel versus electricity pricing, and applicability of other electrification technologies such as heat pumps.

Electric heating can also be deployed in hybrid electric / fired heater systems. In a hybrid system, the plant has both electric resistive heaters and fired heaters using conventional fuel such as natural gas. During times of the day when low-cost renewable electricity is available, the process runs primarily using electrical heat and the furnace is maintained in a fully turned down mode (but typically not allowed to cool down). This allows the plant to exploit low intra-day prices for renewable power when electricity demand is low. When electricity demand increases and prices peak (typically early afternoon in regions with high air conditioning loads or during evening hours elsewhere) the site switches to using primarily furnace heat and sheds the electric heating load, thus avoiding any peak usage surcharges and in some cases even getting favorable pricing from the electric utility company for peak load shedding.

Hybrid schemes are capital intensive and require more plot space but can be very attractive as a retrofit to an existing process, as they allow the operator to take advantage of hourly price variations in electricity and avoid the highest daily prices, while giving a substantial reduction in GHG intensity (peak hours are rarely more than 4h per day, so emissions are reduced 84%). Deployment of a hybrid system also gives operators the ability to gain confidence with electric heating equipment while retaining the fired heater as a fallback option if the electrical heating system does not meet reliability expectations.

HEAT PUMPS

A heat pump is a process for upgrading low-temperature heat to higher temperature heat through a reverse Carnot cycle. A general diagram of a heat pump is shown in Figure 4.1.

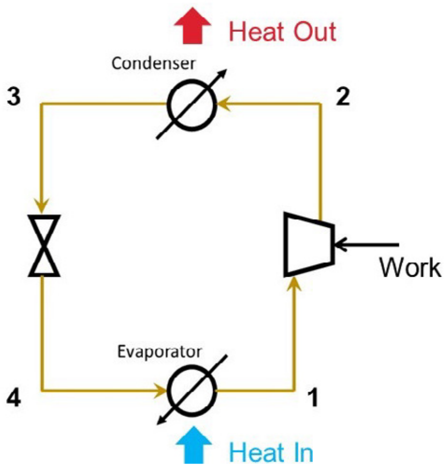


Figure 4.1: Single stage closed loop heat pump cycle

In a heat pump, a working fluid (often referred to as the refrigerant) is used to transfer heat from a low temperature heat source to a higher temperature heat sink while being circulated between the two using a compressor. The steps of the process shown in Figure 4.1 are as follows:

1 → 2: Vaporized refrigerant is compressed to a higher pressure using an external source of work (typically electricity).

2 → 3: The compressed refrigerant is condensed in the condenser, releasing the heat that was picked up in the evaporator plus the work that was put into the system via the compressor. The condenser operates at a higher temperature than the evaporator due to the refrigerant having a higher dew point at higher pressure.

3 → 4: The condensed refrigerant is passed across an expansion valve to lower the pressure. The refrigerant expansion vaporizes some of the refrigerant and decreases the refrigerant temperature.

4 → 1: Heat from the low temperature source is used to vaporize the refrigerant at low pressure in the evaporator and complete the cycle.

The heat supplied to the evaporator can be process waste heat or heat that is available below the process pinch temperature.

The coefficient of performance (CoP) of a heat pump is a measure of the thermodynamic and mechanical efficiency of the system. For a heat pump the coefficient of performance is defined as:

$$\text{CoP} = \frac{\text{Energy delivered}}{\text{Energy used by the compressor}}$$

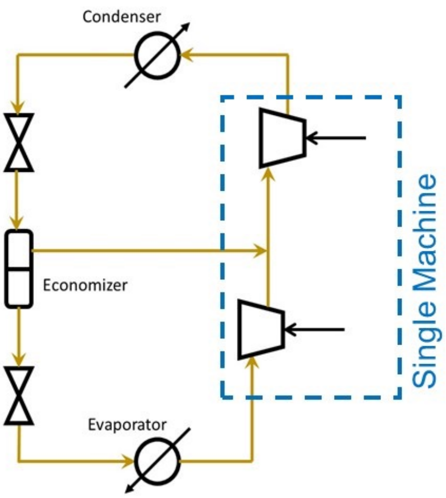
The CoP is a very good measure of the performance of the heat pump in leveraging waste heat, as opposed to just using the electricity to provide heat. The CoP depends on the mechanical efficiency of the device, the thermodynamic properties of the working fluid and the temperature lift that is achieved between the evaporator and condenser temperatures. Higher temperature lift always leads to lower CoP, and it is hard to find refrigerants with thermodynamic properties that give good performance at higher temperatures, so heat pumps are usually limited to recovering waste heat from low to medium temperatures.

More complex heat pump arrangements can increase CoP and temperature lift at the expense of additional capital cost. Figure 4.2(a) shows a split-loop design with two compression stages that can achieve higher CoP at higher temperature lifts. Figure 4.2(b) shows a cascade of two heat pump cycles, allowing even higher temperature lift. In a two-stage cascade design the two stages can use different refrigerants, which can give additional improvement in performance if the temperature range is wide.

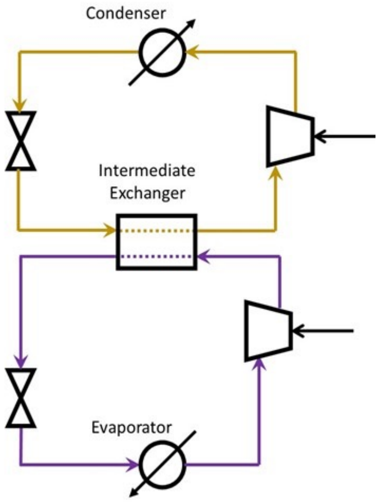
Steam mechanical vapor recompression (MVR) (sometimes referred to as steam mechanical vapor compression) is a heat pump with water and steam as the working fluid. A steam MVR functions the same as the heat pump shown in Figure 4.1. The main mechanical difference between a heat pump and steam MVR system is that the compressor in a steam MVR is more like a blower which results in a significantly lower capital cost for the rotating equipment. This cheaper design is largely due to the relaxed mechanical specifications around the device permitting some loss of water to the surrounding atmosphere which would not be allowed with an organic refrigerant.

With steam as the working fluid, an open-loop heat pump concept can be used when steam is the final product of the cycle. With an open-loop system, a condenser is not needed which reduces the capital expense of the cycle by eliminating equipment but also by reducing the compressor pressure increase by the condenser approach temperature. Steam MVRs can be used as standalone devices or can be coupled with refrigerant-based heat pumps in two-stage cascades to achieve higher lifts.

Chemical heat pumps



(a) Two-stage split loop compression



(b) Two-stage cascade

Figure 4.2: Complex heat pump cycles

Chemical heat pumps operate using a reactive working fluid instead of a vapor-compression cycle. An endothermic reaction is brought to equilibrium at low temperature in a cold reactor (usually with separation of one of the products to drive the equilibrium further) taking up low-grade heat. The reaction is then reversed and run to exothermic equilibrium at a higher temperature in a hot reactor (usually with addition of the separated component), releasing heat at higher temperature. The products from the hot reactor must then be cooled back to the temperature of the cold reactor to complete the cycle, so part of the heat that is generated is lost to cooling, satisfying the 2nd law of thermodynamics.

An example of a chemical heat pump is the Qpinch Heat Transformer (QHT) process developed by Qpinch BV. In the QHT process, heat is absorbed by a phosphate working fluid at low temperature which drives an endothermic phosphate dimerization reaction to occur that releases water. Following the dimerization, the phosphate solution is passed to another exchanger where the reaction is reversed by the addition of water. The splitting of the dimer molecules is exothermic which causes the temperature of the solution to rise and results in the delivery of higher temperature heat.

Cold reactor:

2 Phosphate → Phosphate dimer + water $\Delta H > 0$

Hot reactor:

Phosphate dimer + water → 2 Phosphate $\Delta H > 0$

Chemical heat pumps tend to have a lower coefficient of performance than vapor compression cycles but have the advantage that they do not depend on the vapor-liquid equilibrium properties of a working fluid, so can be used at higher temperatures where good refrigerants are hard to find. They can also be used in two-stage cascade systems such as that shown in Figure 4.2(b).

Heat pump economics

The cost of upgrading energy using a heat pump depends on the capital cost of the system and the cost of electricity. If the CoP is greater than 2.0 the total cost of ownership of using a heat pump will almost always be lower than the cost of resistive heating unless the cost of electricity is very low (less than 0.02 $/kWh).

The operating cost in $/GJ of heat delivered is shown as a function of the heat pump CoP and price of electricity in Figure 4.3, with the cost of resistive heating for comparison. The capital cost of the heat pump system varies depending on machine size, cycle complexity, refrigerant and vendor, but will typically be in the range 2 to 5 $/GJ for industrial-sized systems when expressed on a per unit of energy delivered over a 10 year service life basis. Figure 4.3 can thus be used to estimate the approximate breakeven electricity price needed for a heat pump to be competitive with a fired heater (remembering to allow for the furnace efficiency of the fired heater).

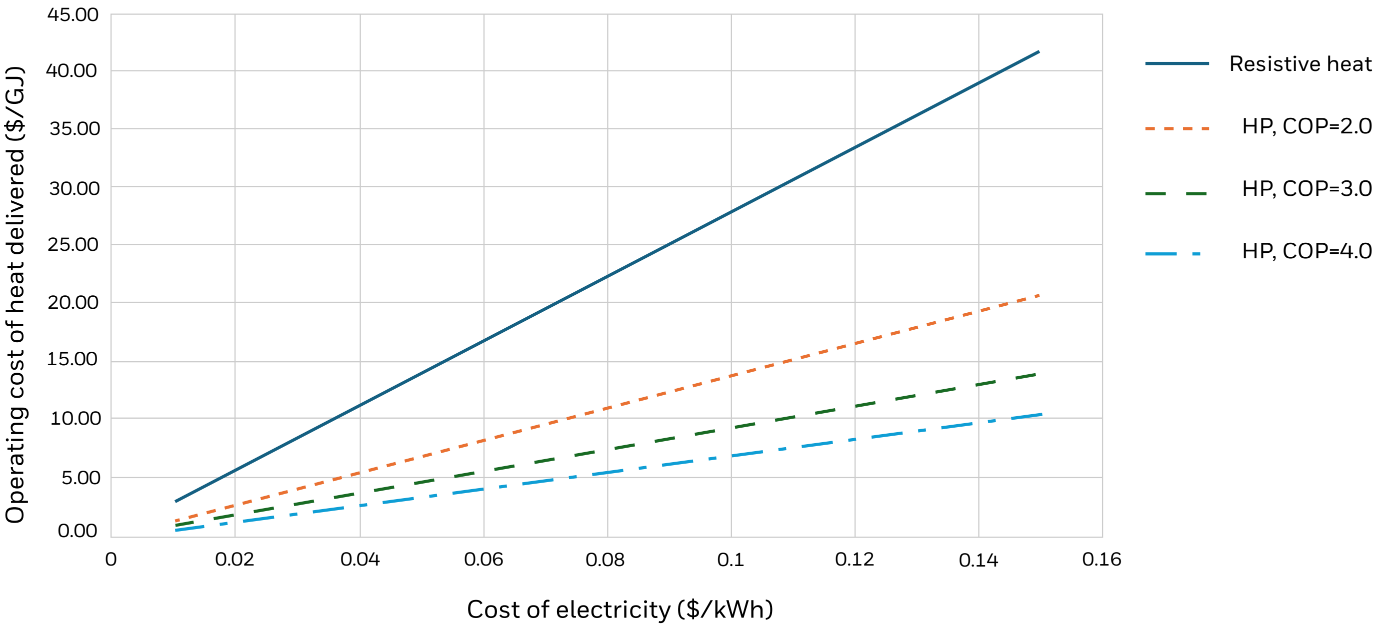


Figure 4.3: Operating cost of energy delivered by heat pumps and resistive heating

(Note: capital cost typically adds 2 to 5 $/GJ to total cost of delivered energy for heat pumps)

A more detailed technoeconomic analysis of different heat pump configurations was recently conducted by Honeywell UOP. The cost per GJ of delivered heat when recovering 20 MW of waste heat from 70 °C to different temperatures with an electricity cost of 0.05 $/kWh is shown in Table 4.1. A service life of 10 years was assumed and no GHG penalty was assessed

DELIVERED TEMP, °C	SINGLE STAGE - R1234ZE	TWO STAGE - R1234ZE / R1233ZD CASCADE	SINGLE STAGE - R1233ZD	TWO STAGE - R1233ZD	SINGLE STG R1233ZD + STEAM MVR CASCADE	TWO STG R1233ZD + STEAM MVR CASCADE
80	3.97	7.10	4.09			
90	4.91	7.72	4.64			
100		8.43	5.32			
110			6.18			
120			7.31	6.22		
130			9.10	6.96	8.41	7.42
140			12.52	7.99	9.06	7.86
150				9.58	9.74	8.50
160					10.95	9.32
170					11.72	10.36
200					14.79	13.24
230					18.42	16.47
250					21.39	18.78

Table 4.1: Total cost of energy delivered for heat pump systems ($/GJ delivered)

Note: recovering 20 MW of heat from 70 °C, 0.05 $/kWh electricity cost, 10y operating life

The results in Figure 4.3 and Table 4.1 show that use of heat pumps to recover process waste heat in the temperature range where waste heat boilers are not feasible (i.e. from about 130 °C to 70 °C) can be cost effective in regions where electricity prices are low or fuel prices are high, as long as the process has a demand for heat at temperatures corresponding to low-pressure or medium-pressure steam (120 °C to 180 °C). Sites that have a high demand for medium pressure steam and a surplus of low-pressure steam should investigate open-loop steam MVR systems as a means of boosting the MP steam supply (which is essentially what the last two columns in Table 4.1 are doing to reach the highest temperature lifts).

COMBINED HEAT AND POWER

Cogeneration

Many industrial sites have the ability to generate part or all of the electricity that they consume. There are several reasons why on-site generation can be attractive:

- Exhaust heat from gas turbine engines can be used (with or without secondary firing) to generate steam, allowing a site combined heat and power (CHP) plant (also referred to as cogeneration plant) to meet site needs for both steam and electricity.
- On-site power generation provides additional operational resilience in regions where electric power grid reliability is low.
- Power that is generated on site is usually lower cost than imported power and can be substantially cheaper in regions that have time-of-use electricity pricing (peak surcharges).
- On-site generation can take advantage of low cost fuel sources such as process off gases or waste liquid streams.

Power generation using a heat engine such as a gas turbine with rejection of waste heat to steam generation or process heating is known as a “topping cycle” and is thermodynamically and economically efficient, because a greater proportion of the waste heat from the gas turbine engine is used than would be the case for stand-alone power generation. Cogeneration with steam co-production is by far the most widely adopted method for site power generation in the process industries. Use of gas turbine exhaust in process fired heaters is also feasible, because gas turbine engines operate at very high excess air (typically around 2.4) and duct burners can be used for secondary firing to maintain temperature control, but this arrangement is much less common.

Electric power can also be generated in “bottoming cycles” such as a Rankine cycle, in which waste heat is used to evaporate a low-boiling working fluid under pressure and the working fluid is then expanded through a turbine and condensed at cooling water temperature or using air coolers. Organic Rankine cycles (ORC) have very low energy costs but high capital costs, and for MW scale systems the cost of electricity produced is typically in the range 0.1 to 0.3 $/kWh, making them less attractive than topping cycles or generation of on-site solar power.

Power recovery

Some sites that operate high pressure processes also have the potential to generate power through expanding process fluids in power recovery turbines such as turboexpanders or energy harvesting control turbines (EHCTs). EHCTs are commercially available for vapor streams and are commonly used in chemical plant natural gas letdown applications. Companies such as Flowserve, Sapphire (Calnetix spin-off), and Cryostar have also been developing options for recovering energy from liquid services, though these are not currently used as widely. In vapor applications, the lower frictional losses in an EHCT as compared to a control valve result in appreciably lower outlet temperatures from the device. According to Cryostar, this lower outlet temperature can be extremely valuable in a refrigeration cycle where lower temperatures otherwise require higher heat rejection at the heat pump condenser. These devices are therefore often used in cryogenic applications.

Cost estimates for EHCTs are typically

3-4 million $/MW of electricity produced for installed equipment, giving costs of electricity produced in the range 0.04 to 0.06 $/kWh. While this can give attractive paybacks in some regions, the amount of energy available for use by EHCTs is usually much lower than the amount of heat available to topping or bottoming cycles.

RENEWABLE POWER INTEGRATION

Some sites are able to take advantage of large rooftops or open land (e.g. brownfield space within an existing site) to deploy arrays of photovoltaic (PV) solar panels and generate renewable electricity. More rarely, some very large and more remote sites (such as refineries and ports) may even have enough space to deploy wind turbines. The power intensity of renewable energy generation is low (typically ~ 10-20 MW/km^2), so in most cases on-site renewable power generation will not be adequate to meet site needs for electricity (affecting Scope 2 emissions), let alone expand to meet additional needs from electrification of industrial heating and impact Scope 1 emissions.

Photovoltaic panels generate DC electricity on an intermittent basis, with very high hourly, daily and seasonal variability in the amount of power supplied. Because of this intermittency, wind and solar power are often referred to as variable renewable energy (VRE) as distinct from more dispatchable forms of renewable energy such as hydropower and biofuel-fired turbines. The capacity factor of VRE is the ratio of the average power produced to the nominal power rating. For newly installed wind turbines in 2020, the average capacity factor was 42.6% (Engel-Cox, 2020). For solar power (class 5 resources) the average capacity factor in 2020 was 26.8% (NREL, 2021; EIA, 2021a). Adding on-site generation therefore entails either adding sufficient power inverter and transformer capacity to handle the highest rates of power delivery and operating at low capital utilization of the power conditioning equipment or else undersizing the power conditioning equipment and curtailing power from the VRE assets on the highest production days thereby under-utilizing the capital deployed in the solar panels.

For larger projects, the solution to this dilemma is to install a battery energy storage system (BESS) along with the VRE project. The BESS can accept direct DC charge from the PV cells, obviating overdesign of the power conditioning system and then provide DC power to the power conditioning system and maintain electricity supply when the level of VRE production falls (e.g. overnight). An optimally integrated solar + BESS system gives both stable power supply and improved capital efficiency on a daily basis, but it is not capital efficient to deploy enough batteries to smooth out seasonal variations in VRE supply. Solar + BESS projects therefore need to carefully evaluate site conditions and may need to contract for renewable power from other locations (or rely on grid power) during seasons when on-site production is too low.

Honeywell Ionic™ modular BESS

Honeywell Ionic™ is a compact, end-to-end modular battery energy storage system (BESS) and energy management tool that can offer improved energy density compared to what's currently available on the market, while helping to deliver a significant reduction of installation costs, see Figure 4.4. Honeywell's scalable modular architecture can help provide an optimized energy outcome, improve uptime, and allow electricity market participation to help our customers increase their use of renewable electricity and meet corporate sustainability goals. Honeywell Ionic is currently available with (LFP type) lithium-ion-based batteries but can be configured to use other battery chemistries.

Honeywell Ionic includes Honeywell's Experion® Energy Control System and a chemistry-agnostic Battery Management System (BMS). Experion helps users to manage and optimize energy use by improving uptime, maximizing arbitrage potential from peak shaving and providing the ability to create a Virtual Power Plant. The BMS provides insight into performance at the cell level, and is configurable with advances in battery chemistry, insulating the end user from future supply-chain risks.

Key features of the Honeywell Ionic BESS include:

- Scalable architecture allowing the ability to right-size the system for both front of the meter and behind the meter use cases.
- Proven lithium-ion-based cell chemistry, with 730kWh modules scalable to any capacity.
- Compliant to energy storage standard UL9540.
- Optional, industry-leading off-gas detection which can enable earlier mitigation actions to prevent thermal runaway and fires.
- Integrated Honeywell controls to support all use cases.
- Turnkey installation from utility engagement, engineering, procurement, construction, commissioning, start-up, operations, and maintenance. EPC scope is evaluated case by case.
- The batteries come pre-installed to reduce the on-site hours.
- The forklift-able design allows for fast installation without the use of expensive cranes.

Figure 4.4: Honeywell Ionic modular BESS

In addition to the Honeywell Ionic lithium-ion based system, Honeywell UOP is developing proprietary technology for iron redox flow batteries (IRFB) and expects to commercialize a 1MW first commercial scale offering in 2025. IRFBs have a lower power density than lithium ion batteries but are made from much lower cost materials. They are therefore not suitable for transport applications but are projected to give lower lifecycle cost of electricity for stationary energy storage.

MICROGRIDS AND VPPS

A microgrid is a local electrical grid that acts as a single controllable entity. Most microgrids have the ability to operate in grid-connected or "island" mode, but some operate only in stand-alone mode with no connection to a broader utility grid (e.g. for geographical island communities, isolated rural areas, military bases and some large industrial sites). Microgrids always operate their own local generation assets, often including a high proportion of variable renewable energy (VRE) from wind or solar power and usually incorporate energy storage (batteries or pumped storage hydropower) to provide backup power, regulate frequency and voltage and mitigate variability in VRE generation. All microgrids require an energy management system to maintain grid stability under varying demand and generation loads. Smaller microgrids may have a simple SCADA system, but larger microgrids often use hierarchical control under the IEEE 2030.7 standard (device level; local area control; SCADA; grid connection layer). Larger microgrids can also incorporate transformers and mid-low voltage transmission systems to transmit power over longer distances (e.g. when serving several communities on an island or villages near an isolated town).

Industrial sites (e.g. refineries) and larger commercial sites (e.g. ports, airports) that have their own generation assets and storage can operate as a microgrid. Mutually beneficial interactions between commercial and industrial sites and their distribution utility grid can be facilitated or optimized by Honeywell offerings or services and offer an opportunity for value sharing. While energy markets cover net import and export of energy between microgrids and the main grid, there are ancillary services that can be provided by microgrids to the utility grid (voltage regulation being the most useful one). Islanding operations can shed load as needed and can assist in grid formation when recovering from an outage (cold load pickup assistance) by soft or partial reconnection or by coordinating reconnection with other nearby microgrids.

Figure 4.5 shows the evolution of the US microgrid sites and growth over time by number of microgrid sites and average microgrid size (BNEF, 2022). The US had fewer than 700 microgrids as of May 2021, for a total of 4,132 megawatts (MW), a very small number compared with the roughly six million non-residential buildings that the Energy Information Administration (EIA) tracks. Almost 300 commercial sites have a microgrid, by far the biggest sector, followed by 80 universities and 70 health-care facilities. The average microgrid size decreased to 1.9MW between 2018 and 2021, down from 7.7MW between 2014 and 2017, as smaller corporate sites turned to microgrids for resiliency. Corporate campuses require much smaller installations, on average 1.5MW, compared to universities (18MW) and military sites (17MW).

BNEF expects more corporations to add on-site energy assets, such as microgrids, as power outages become a growing concern and electric grids become increasingly stressed due to the electrification of transport and increasing deployment of ever-larger data centers to serve the market for AI applications. According to EIA (2021b), the average US customer experienced 456 minutes of non-momentary electric interruptions in 2020, up from 227 in 2013.

A Virtual Power Plant (VPP) allows several microgrid owners to combine their energy generation and storage assets to create virtual resource groups with combined capacity to participate in wholesale electricity markets. Individual asset owners can join an existing VPP with other asset owners or combine their fleet of assets for their own private VPP, enabling asset owners to access additional revenue from resources that may otherwise be too small to participate in electricity markets.

Independent power producers (IPPs, sometimes also referred to as non-utility generators or NUGs) who operate stand-alone power generation assets such as wind farms, solar farms or cogeneration units, operate microgrids in some regions depending on local regulations. In the USA, section 210 of the Public Utility Regulatory Policies Act required utilities to purchase power from qualifying facilities (QFs) < 80MW at the utility's avoided cost, and hence strongly incentivized IPPs to sell direct to the local utility.

The 2020 update of this rule (Federal Energy Regulatory Commission Order 872) relaxed that constraint and incentivized IPPs to negotiate legally enforceable obligations (LEO) to supply power to utilities through a binding long-term contract known as a power purchase agreement (PPA). This gave utilities more control of pricing, but also encouraged IPPs that operated renewable assets to seek preferential pricing by selling fully renewable PPAs direct to consumers (or by separately selling the associated renewable energy certificates (RECs)). IPPs that offer renewable PPAs often incorporate energy storage systems in order to "firm" the power availability. Delays in obtaining network interconnections in many regions are also incentivizing IPPs to develop projects as microgrids to secure earlier revenues.

Net-zero economic zones (NZEZ) are a special case of microgrid, with the additional constraint that the electric power supplied to the consumers cannot come from unmitigated fossil fuel combustion. A NZEZ that draws on grid power must be able to demonstrate that the power is sourced from non-fossil assets (through purchase of RECs or equivalent or via renewable PPAs).

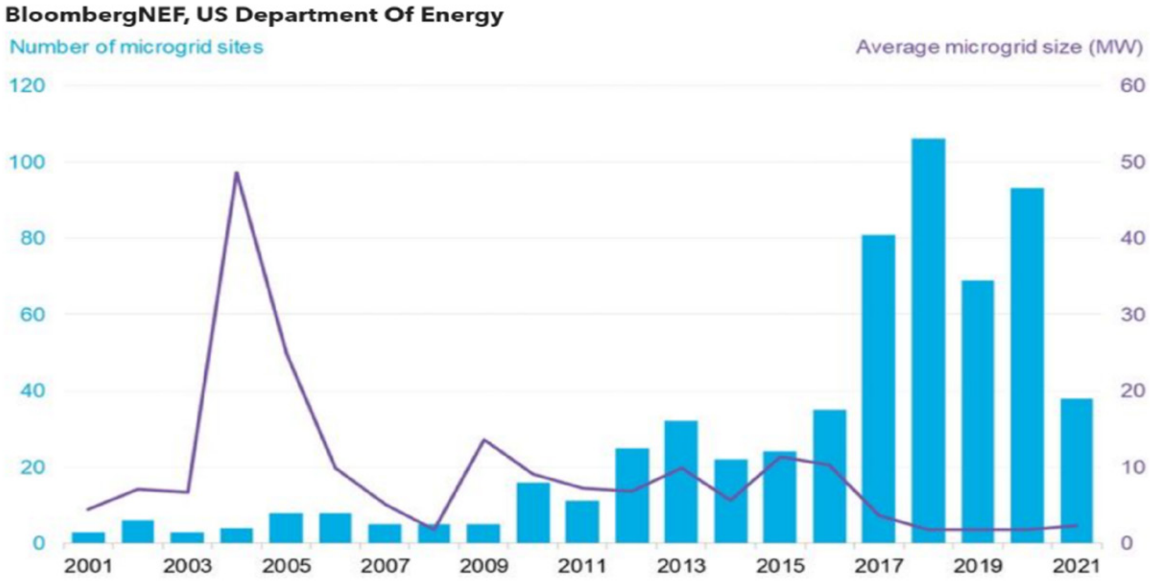


Figure 4.5: New US annual microgrid sites and average microgrid capacity as of May 2021 (BNEF, 2022)

Honeywell microgrid experience

Honeywell has guaranteed $9.5B in energy and operational cost savings via 3,400+ energy optimization projects for customers around the world. Honeywell has significant experience in deploying, managing, and operating behind the meter microgrids on federal and commercial facilities, from projects as small as 500kW to large 65MW microgrid projects. This includes the Federal Drug Agency's headquarters, where Honeywell manages a 65MW microgrid facility. Inclusion of energy storage is becoming more pervasive in microgrid projects to meet customer's decarbonization and resiliency goals. Honeywell Experion process control systems are also used to control generation and cogeneration assets in many oil refineries and chemical plants around the world.

Electrification of industrial sites has the unintended effect of increasing building electricity consumption, increasing the grid loads, and electrical infrastructure needs. Onsite microgrids with energy storage as well as facility demand side management (load shedding/shifting policies) help to manage these additional loads, avoid incurring expensive demand charges, and can help defer investment in electrical infrastructure.

Honeywell has deployed microgrids with energy storage opportunities in warehouses, pharmaceuticals storage and distribution centers, municipalities, military bases, higher education, airports, big box retail, and manufacturing facilities. These customers operate critical infrastructure requiring continuity of operations, need to decrease demand and ToU utility charges to maintain network operating income (NOI), and have key stakeholders demanding progress on environmental sustainability goals. Honeywell has also deployed microgrids at our own manufacturing sites, providing increased site resilience to power disruptions as well as helping to meet our decarbonization goals.

To address these needs, Honeywell's building automation and industrial automation businesses have partnered to integrate our microgrid controls and battery management systems with the building controls that can be used for demand response management.

Case study: Improving energy security at a Honeywell manufacturing plant in Romania
Grid reliability is a major concern for manufacturing operations because any loss of power causes machines to idle, potentially resulting in significant losses in revenue. Honeywell has overcome these issues with the implementation of an industrial microgrid at one of its key sites in Romania.

A core problem at Lugoj Plant was the frequent loss of grid power, which resulted in plant shutdowns. With a 1.7 MW solar PV installation combined with a 1.6 megawatt-hour (MWh) Honeywell BESS and backup generators, the plant now has complete electrical power back-up during grid blackouts, and lower electrical bills

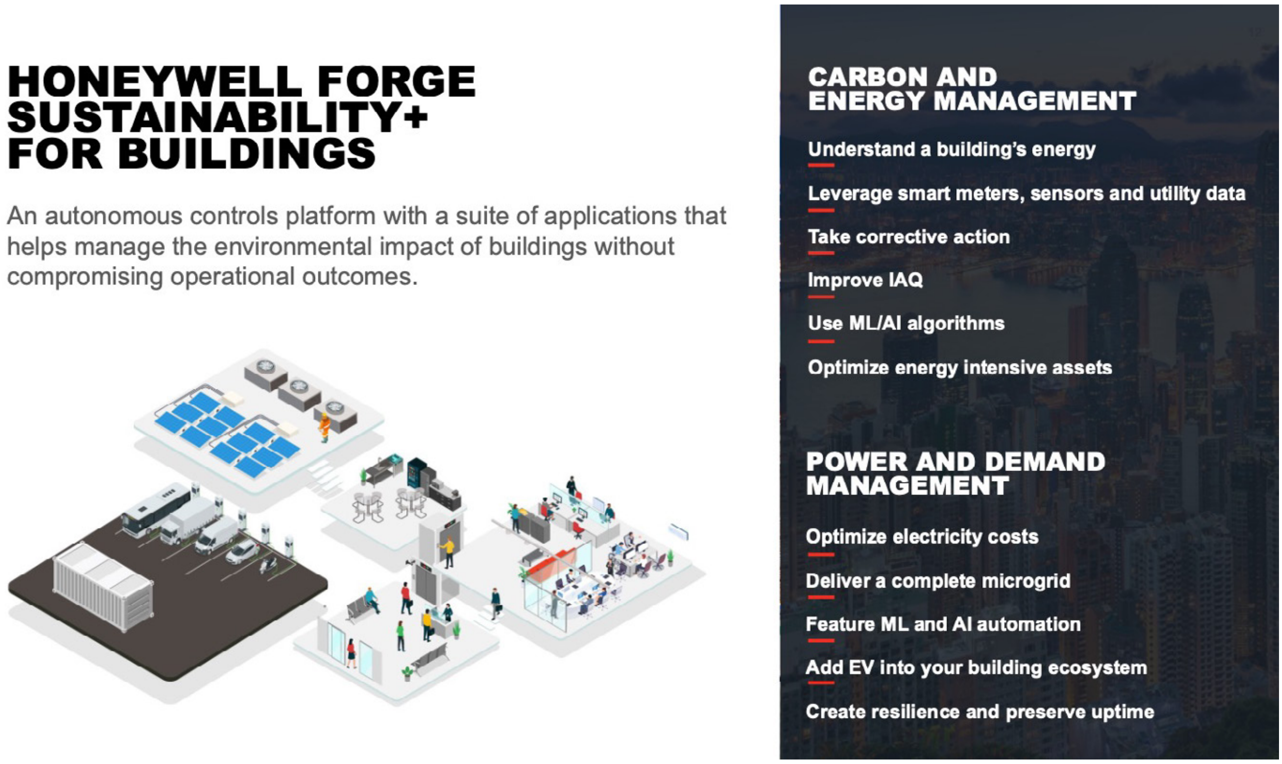
By applying the load shedding and limiting techniques, the facility can now reduce energy use and waste after hours, which is projected to deliver 10% energy savings. Its carbon footprint has also been lowered, achieving all the goals set by the Honeywell team.

Microgrid control systems: Experion® Energy Control System

Experion® Energy Control System optimizes selection of energy sources based on priorities for generator efficiency curves, dynamic grid power pricing, start/stop maintenance costs, weather forecasts, and carbon footprint reduction. Honeywell's microgrid controls are based on the proven ControlEdge™ RTU and PLC controllers, which are powerful, modular, and scalable devices capable of all remote automation and control applications. The microgrid controls provide improved management of field assets through simplified and efficient remote monitoring, diagnostics, and management. The ControlEdge™ RTU and PLC come with an extensive library of control algorithms for renewable energy and can be configured to help provide stable high-availability edge control of assets during communication outages, while storing data in onboard memory for uploading when communications are restored. Cybersecurity is built into the ControlEdge™ RTU and PLC with ISASecure EDSA Level 2 certification ensuring the safety of the system, personnel, and data.

Honeywell Forge Sustainability+ for Buildings

Honeywell Forge Sustainability+ for Buildings is a turnkey end-to-end solution for optimizing on-site supply side resources and building assets from project design and execution to ongoing operation and maintenance for commercial facilities. It enables orchestration and optimization using artificial intelligence and machine learning (AI/ML) algorithms of building demand side and supply side assets based on grid consumption, utility rates, and building demand. Supply side assets includes onsite energy generation (Solar PV and traditional fuel generation) as well battery energy storage. The Power Manager solution helps reduce operational and utility costs, increase site resiliency and uptime, and allow customers to meet some of their sustainability goals, as shown in Figure 4.6



HONEYWELL FORGE SUSTAINABILITY+ FOR BUILDINGS

An autonomous controls platform with a suite of applications that helps manage the environmental impact of buildings without compromising operational outcomes.

CARBON AND ENERGY MANAGEMENT

- Understand a building's energy
- Leverage smart meters, sensors and utility data
- Take corrective action
- Improve IAQ
- Use ML/AI algorithms
- Optimize energy intensive assets

POWER AND DEMAND MANAGEMENT

- Optimize electricity costs
- Deliver a complete microgrid
- Feature ML and AI automation
- Add EV into your building ecosystem
- Create resilience and preserve uptime

Figure 4.6: Honeywell Forge Sustainability+ for Buildings

Key Features of Honeywell Forge Sustainability+ for Buildings include:

- Automated peak shaving, frequency and voltage regulation with Experion controls integration
- Microgrid operational status and key KPIs for solar PV, BESS, fuel generation
- Microgrid controls to help achieve cost optimization, carbon optimization, and microgrid islanding to enable grid load shedding.
- Real time building load demand forecasting with AI/ML algorithms.
- Reducing building demand charges using dynamic load management with load shedding and limiting AI/ML algorithms to reduce demand charges.
- Monthly and real time reporting on energy consumption, utility savings, and carbon emissions.

BARRIERS TO ELECTRIFICATION

Electrification is usually the lowest cost decarbonization approach for small manufacturing sites and for sites that are not able to access low C-intensity fuels or CCUS infrastructure. Electrification can also play an important role in sites that have many widely distributed small heat loads or large demands for low-grade heat that can be partially filled by energy re-use using heat pumps. There are, however, a few factors that must be taken into consideration when selecting electrification as the primary strategy for decarbonization.

- **Availability of low C-intensity electricity**: electrification only makes sense as a decarbonization strategy if the electric power that is consumed is generated at low carbon intensity. Most industrial facilities (and almost all process plants) operate 24/365, but the supply of renewable electricity from wind and solar power often has significant hourly, daily and seasonal variability, making consistent operation on renewable power difficult. Hydroelectric power and nuclear power are more dispatchable, but the supply of power generated from these sources is not increasing rapidly enough to meet the demands of large scale electrification of homes and transport, let alone industrial sites. Some regulatory frameworks (e.g. the current Renewable Energy Certificate system in the USA) allow purchasers of renewable energy to avoid temporal and spatial matching of renewable power to end use, enabling consumers to store renewable power "on paper" to use whenever it is needed, but it is possible that future regulations and green tariffs such as the EU carbon border adjustment mechanism (CBAM) will close this loophole and require time matching of renewable power supply to demand. If sufficient renewable power is not available, electrified sites will continue to run on residual grid power and have correspondingly higher scope 2 emissions. Good energy management software will be needed to create an audit trail of the power consumed so that companies do not risk under- or over-payment of CBAM or similar duties.
- **Electric power pricing:** in addition to concerns over the future pricing of firm (24/365) supply contracts for renewable power, electricity suppliers in many regions are expanding use of demand-based pricing mechanisms to reduce peak electricity consumption. As utilities in more locations also come under carbon caps or targets, their use of even newly built assets like natural gas peaker plants is likely to be curtailed. The increased peak demand from electrification, and the

increasing dynamics of generation source constraints (e.g., days when there is no wind, cloudy, very hot or cold, etc.) will drive much larger Time of Use Cost and Energy Spot Market volatility, especially in fully deregulated power markets like Texas. In the long term, we expect utilities will expand energy storage capacity to allow them to address this variability, but that currently appears to be a lower CapEx priority than expanding generation and transmission systems to meet electrification demand.

These factors will combine to create uncertainty in electric power prices and stronger incentives to deploy microgrids and VPPs that assure sites some ability to go "off-grid" when grid prices become prohibitively high.

- **Expansion of grid supply:** in some sites or regions substantial increases in electricity consumption may require negotiation with the local grid operator to expand the electric power supply or to put in additional substation (i.e., transformer) capacity. Expansion of the grid supply will incur additional costs that the electric utility will seek to pass on to the industrial consumer.
- **Reliability of electric power supply:** in the absence of major (usually weather-related) events, the average US household experiences two hours of power outage per year, but in recent years the increased frequency of weather events has led to an increase in outages to 8 h/year, see Figure 4.7 (EIA, 2021b). In 2020, seven US states experienced total average power outages of more than 20 hours (MS 25, ME 28, IA 29, AL 29, CT 44, OK 48, LA 61; EIA, 2021b), while in 2022 the USA experienced 82 power outages of greater than four hours (EIA, 2022). Utilities are experiencing significant load growth due to electrification of transport and increased demand for data centers due to AI, which erodes their reserve margins on hot days and cold days. The demand for electricity in the USA has been forecast to increase by 15.8% by 2029 (Wilson, et al., 2024). Other regions that have less resilient grid infrastructure experience more frequent outages and it can be expected that outages will become more frequent in all regions as increased electrification increases the load on grid systems and climate events that impact the production of VRE become more severe and more frequent. Loss of power has safety implications for industrial sites as well as commercial implications from lost productivity, lost inventory of work in progress that may be damaged by unplanned shutdowns, increased maintenance costs for equipment and increased labor and overtime costs to restore normal operations.

  These additional costs create a strong financial incentive for industrial site operators to install backup power systems sufficient to cover short duration outages and are one of the principal reasons why many sites are establishing microgrids as a means of increasing power resilience.

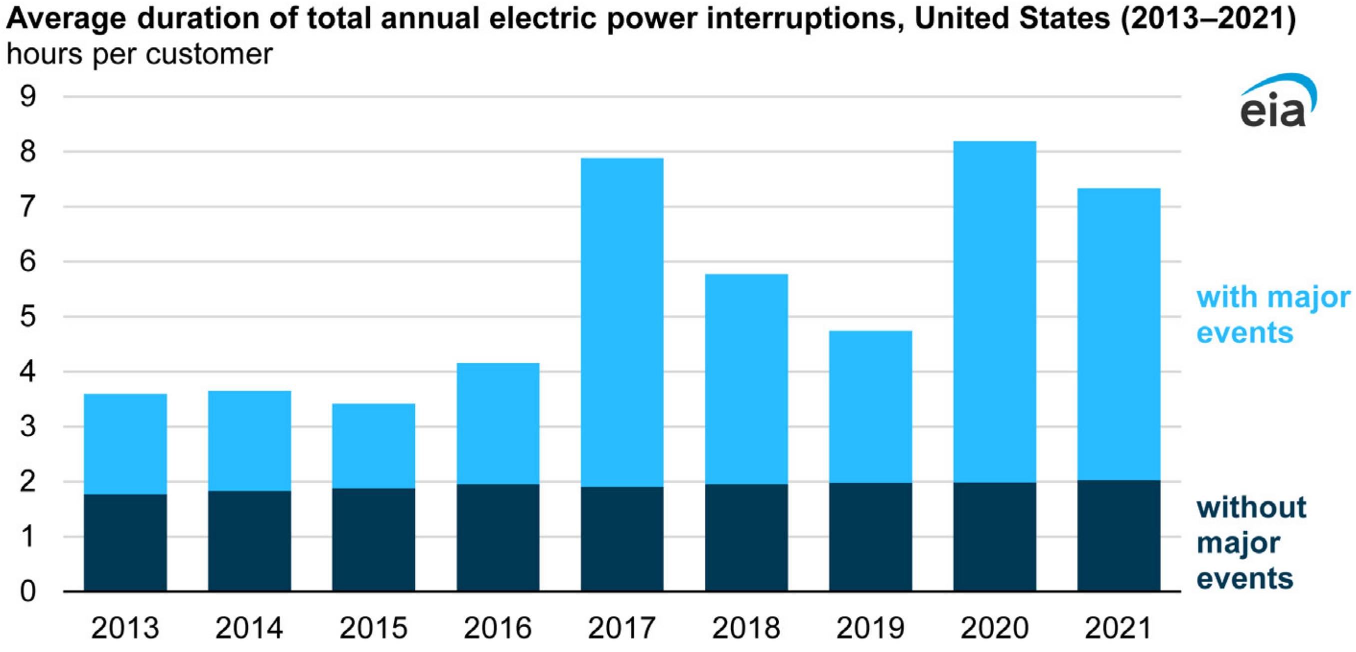


Figure 4.7: Average duration of electric power outages for the USA (EIA, 2021b)

INDUSTRIAL BUILDING HVAC SYSTEMS

> **While fuels and chemicals manufacture is usually carried out in outdoor chemical plants, most factories are contained inside a building.**

High temperature operations inside buildings create additional demands on the building heating, ventilation and air conditioning (HVAC) system that must be addressed through building architecture and design or by operational management through the building control system (BCS) or building energy management system (BEMS). HVAC operation can be a substantial contributor to the scope 1 and 2 emissions of manufacturing facilities, particularly when waste heat is rejected from the manufacturing process via air cooling to the building envelope.

VENTILATION

Ventilation requirements

The most widely recognized international standard for ventilation requirements of commercial buildings is ASHRAE 62.1 (ASHRAE, 2022). This standard specifies minimum ventilation requirements (in terms of air changes per hour) to ensure indoor air quality (IAQ) while allowing for air recycle in mechanically vented systems so as to improve energy efficiency in line with energy standards such as ASHRAE 90.1. Many industrial facilities are designed to operate with higher levels of ventilation or more stringent air quality levels. For example, laboratories are usually designed to comply with NFPA 45 ventilation standards (NFPA 45-2019), while clean rooms for electronics or biotechnology manufacturing are usually designed to meet ISO 14644 specifications (ISO, 2015). Many industrial facilities also operate several spaces designed to different ventilation requirements. For example, a single manufacturing building may contain several clean rooms, a laboratory area, chemicals storage and general manufacturing, shipping and receiving space.

Management of humidity can be an important additional consideration for industrial buildings. Higher and lower levels of humidity are usually avoided. High humidity can cause condensation, mold and damage to equipment and stores, as well as impacting quality control in food processing and drug manufacture, while low humidity can cause static discharges (which are a fire and electrical hazard) as well as dry skin and eye irritation for occupants.

One of the most important approaches in sustainable building operation is to use demand-controlled ventilation (DCV), in which CO_2 (or other indoor air quality) sensors are used to control the air flow. When room occupancy is low, the air flow rate can be decreased. Conversely, rising CO_2 levels indicate higher occupancy or plant activity and mechanical systems will be directed to increase air flow and ventilation rates. Effective sensor selection and location are critical for adoption of DCV, as the building automation system needs reliable data on indoor air quality and humidity to balance the air flows and meet ASHRAE requirements. DCV efficiency is enabled by a sufficient number and configuration of sensors, duct controls, and variable speed air blowers. Lin and Lau (2016) discuss system design and control strategies for DCV and show that it can give savings up to 33% in annual building HVAC energy costs, with corresponding reduction in building operational carbon footprint.

HVAC design software

Developing or upgrading the mechanical and HVAC design of an industrial building relies upon an expanding suite of software tools that help understand structural constraints, material and equipment characteristics, environmental loads, types of use and occupancy as factors in an equation to solve for lowest energy, lowest operating cost and best overall constructability. Design of a new manufacturing facility should carefully consider ventilation and heat management needs so as to expand the viable operating range of the building HVAC system under the dynamic load, weather and energy supply conditions expected. Optimizing these systems across the design performance curve improves asset life, operating cost and sustainability footprint.

Building Information Modeling (BIM) provides the ability to integrate data and information prior to construction, digitally representing the entire building, systems and components. BIM allows for more sophisticated analyses, including energy performance simulations, thermal analyses, and lighting studies that consider the building envelope and mechanical systems together This allows stakeholders to evaluate the energy efficiency of various design options and drives decisions that lead to optimized building performance. For example, a decision to change the type of exterior glass may result in needing less cooling in a space, reducing piping, air handler and chiller sizing.

A model driven design enables the integration of passive design strategies, such as natural ventilation, daylight harvesting, and solar orientation, which can significantly reduce energy consumption without compromising occupant comfort. Furthermore, BIM allows for the evaluation of various energy-efficient technologies, such as high-performance insulation, energy-efficient HVAC systems, and smart lighting solutions. The BIM can be used to generate Integrated Part Load Value (IPLV) Curves to model chiller or heat pump performance across the broad operating range of industrial buildings. These calculations inform the size, sequence and energy budget to best adjust to variable occupancy and spot cooling loads, frequently leading to hybrid cooling designs for low-load conditions.

Computational Fluid Dynamics (CFD) models are increasingly being used during design to optimize ventilation and thermal comfort, considering the building geometry, internal loads, external environmental conditions, and occupancy. Using these models helps define micro-climates within a building, which through integrated sensing and control can then consider both passive and mechanical means to achieve defined spot space conditions at the lowest energy cost. While CFD has been used for many years during design for efficient duct work, air velocity, heat transfer and mechanical noise abatement at peak design conditions, these were largely static boundary condition models. New connected building control systems allow for this type of optimization to be a routine, automated calculation, which adjusts in near real time to the many variables to deliver the most efficient path to providing a safe and comfortable space on demand.

CFD is also key to designing HVAC fire and smoke propagation, helping minimize life and property risk and facilitate evacuation during fire conditions. For complex buildings such as high rise or sub-terrain designs, the models allow damper and fan control sequences to be designed and proven.

When deployed, these sequences rely on real-time data from the fire detection system to implement HVAC pressurization to contain smoke and heat, ensuring clear stairwells and elevator lift shafts for faster evacuation and then changing modes to quickly evacuate the smoke in spaces where no windows can be opened, further limiting damage and business interruption.

A building that has been designed using CFD models can leverage these models as a "digital twin" when the building is placed in service. Real time data from building sensing systems and the building management system can be used to tune and update the CFD model, enabling the model to be used for validation of changes to operating strategy, investigation of the effects of setpoint changes and design of renovation projects or changes in space use and occupancy.

HVAC design for resilience

One of the effects of climate change is that the design of HVAC systems now needs to consider resilience against natural disasters and other climate impacts (UNEP, 2024). Outdoor air ventilation is not always the best operating mode for IAQ or energy efficiency targets. If a city is affected by smoke from forest fires, increasing the building ventilation with outside air can create worse indoor air quality if the air intake system filters are inadequate or become overloaded. The ASHRAE 241 standard allows for the use of "equivalent clean airflow" that has been filtered to remove particulates or airborne pathogens, and this can be applied in situations where high external levels of PM2.5 pollution require tighter control of outside air intake if the building air filtration systems have been adequately sized to allow deployment of upgraded filters when necessary.

ANTAGONISTIC LOAD MANAGEMENT

Parasitic and antagonistic energy loads unnecessarily increase the energy consumption of buildings and create additional cooling requirements for the HVAC system in climates that require cooling.

Parasitic electricity loads include devices that continue to draw electric power when not in use ("energy vampires"), devices that should have been shut down but were not, and devices that are drawing high power for uses that are not intended by the building owner or operator (energy theft). Most of these loads are plug loads that are not visible to the building management system unless connected outlet technology is installed. Common examples of parasitic loads are devices that draw power when switched off or not in active use (TVs, DVRs, cable boxes, routers, printers, copiers), power inverters that draw power at high rate when not in use (battery chargers), and devices that are accidentally left powered (space heaters, coffee makers, water boilers, water coolers, hair dryers and curlers). In a light industrial setting, parasitic loads often include manufacturing equipment left powered or heated overnight. Minor levels of energy theft are often ignored by employers (e.g., charging of personal devices at work) but extreme cases can be a significant power drain.

Antagonistic loads are loads that intrinsically fight the HVAC control system (or BEMS) or that have an adverse impact on surrounding equipment and cause it to operate less efficiently. Common examples include poorly ventilated drying operations that increase humidity loads, refrigerators placed too close to heat sources such as ovens so that they are unable to achieve their rated efficiency, high temperature equipment operating in air-conditioned areas, etc. Antagonistic loads are difficult to assess remotely but can often be inferred by equipment surveys or by benchmarking against rated equipment performance if plug load data is available.

Education and training approaches to parasitic load management can be moderately effective in the short term but are hard to sustain. The best approach is to use smart connected outlets or electrical sub-meters that allow the building management system to monitor circuit and plug loads, analyze usage trends, implement smart scheduling (and demand response strategies) and if necessary isolate circuits or outlets that indicate unexpected power loss or potential safety hazards. Connected outlets have the additional advantage that they can detect overheating from excess power draw and hence help prevent fires started by faulty electrical equipment. Connected outlet data on equipment power draw can also be used to benchmark equipment performance versus specifications such as Energy Star ratings.

Honeywell's solution for connected power monitoring, Connected Power, is shown in Figure 5.1. We have developed connected outlets that detect and transmit data on the outlet power draw and temperature, allowing non-intrusive load monitoring (NILM) so that the building management system can track outlet usage, identify parasitic loads, schedule loads for demand response management and set alarm thresholds to prevent fires, enhance building safety and help eliminate large-scale energy theft.

Honeywell offers a fully integrated building small power management system. Ideal for both new build or retrofit, this market changing innovation enables the building management system (BMS) to automatically monitor and control centrally or at an individual outlet, providing , safer and more cost-effective building management with reduced carbon emissions. Up to 50 hubs can run from a single BMS, giving a maximum system capability of up to 2500 sockets or 5000 individual outlets. The Supervisor displays collective or granular information regarding plug load usage across the estate. The user can then control, monitor and set alerts related to power usage for all plugged in devices. Capabilities of the Honeywell Connected Power system are shown in Figure 5.2.

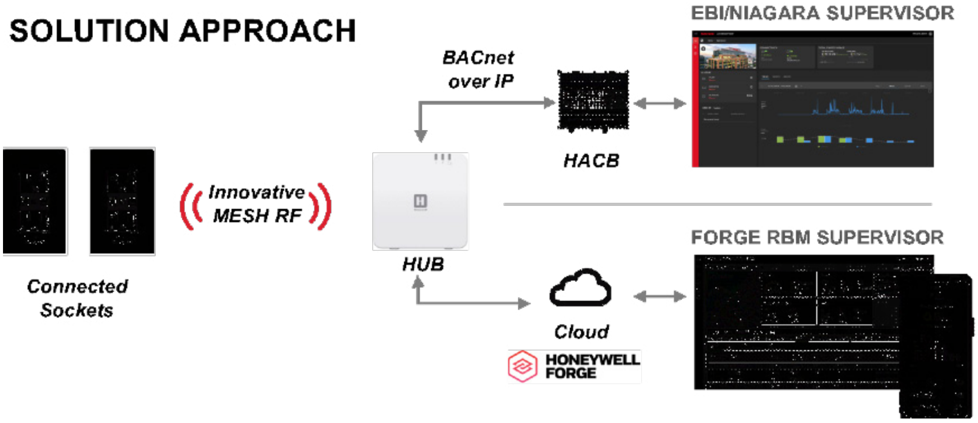
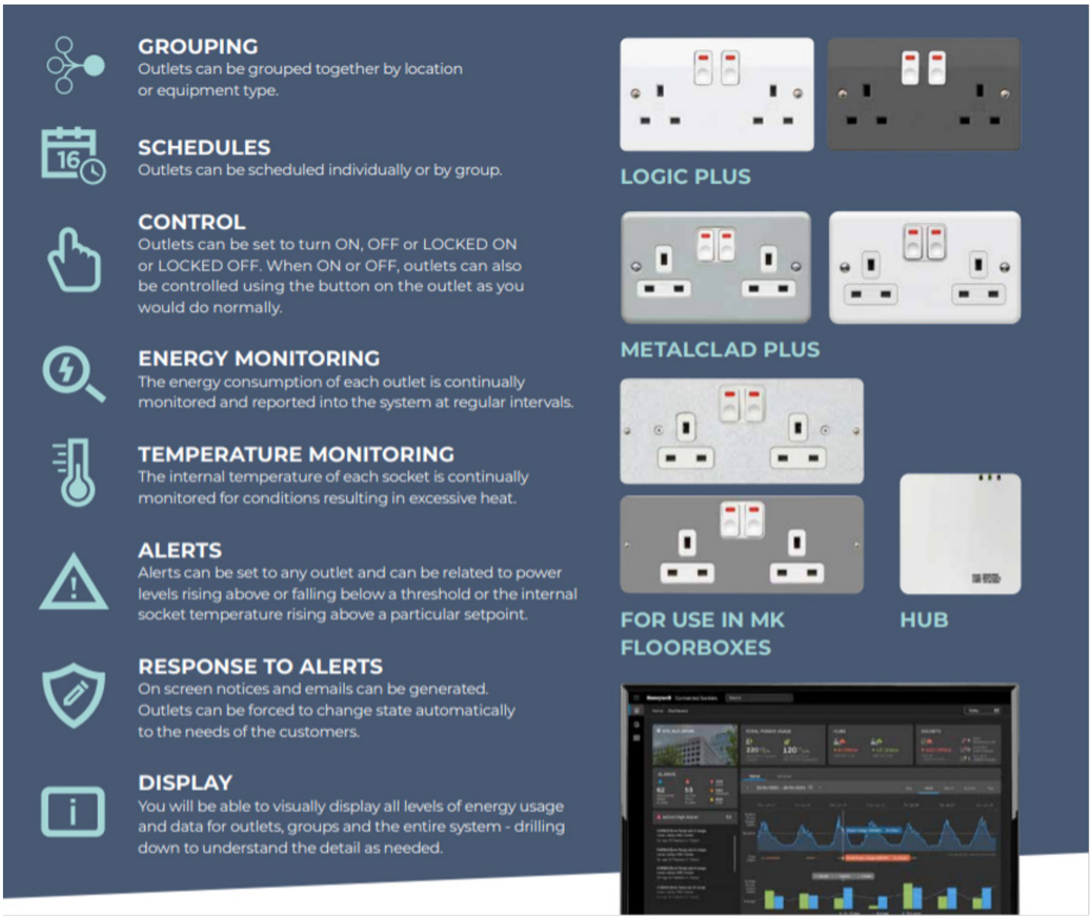


Figure 5.1: Honeywell Connected Power

Antagonistic loads are best addressed in the building design phase, e.g., by providing separate ventilation systems for high temperature equipment. Some antagonistic loads can be addressed in the operation phase by relocation of equipment or operations or by introduction of separate ventilation systems. In some situations, it may make sense to provide separate ventilation of equipment that creates high antagonistic loads. An example is ovens or other high temperature heaters that require large extractor fans: pulling all the required air from the building means all the air is supplied through the HVAC intake and conditioned to the building temperature set point. Providing local make-up air vent ducts allows the high-temperature area to be ventilated with outside air that has not been fully conditioned and separates the ventilation requirement from the building HVAC load. It can also reduce heat losses from the equipment and potential improve heater efficiency. Make-up air ducts are also important in situations where multiple extractor fans compete to extract air, potentially leading to depressurization of the building and possibly undesired backdraft in some locations with resulting impact on indoor air quality.



GROUPING
Outlets can be grouped together by location or equipment type.

SCHEDULES
Outlets can be scheduled individually or by group.

CONTROL
Outlets can be set to turn ON, OFF or LOCKED ON or LOCKED OFF. When ON or OFF, outlets can also be controlled using the button on the outlet as you would do normally.

ENERGY MONITORING
The energy consumption of each outlet is continually monitored and reported into the system at regular intervals.

TEMPERATURE MONITORING
The internal temperature of each socket is continually monitored for conditions resulting in excessive heat.

ALERTS
Alerts can be set to any outlet and can be related to power levels rising above or falling below a threshold or the internal socket temperature rising above a particular setpoint.

RESPONSE TO ALERTS
On screen notices and emails can be generated. Outlets can be forced to change state automatically to the needs of the customers.

DISPLAY
You will be able to visually display all levels of energy usage and data for outlets, groups and the entire system - drilling down to understand the detail as needed.

Figure 5.2: Honeywell Connected Power capabilities

GHG EMISSIONS MONITORING AND REPORTING

> **All decarbonization plans require comprehensive and accurate measurement, verification and reporting (MV&R) systems in order to identify and prioritize opportunities, validate the performance of mitigation projects and track progress towards goals.**

Emissions monitoring and reporting are required by law in some regions and may be needed in order to comply with emissions-based tariffs such as the EU carbon border adjustment mechanism (CBAM).

SCOPE 1 EMISSIONS

Scope 1 emissions are direct emissions of GHGs from the factory or production site. The majority of scope 1 emissions almost always comes from the combustion of fuels in boilers, furnaces, engines, generators and other site manufacturing equipment. Scope 1 emissions also include emissions from vehicles used on site, emissions from flare stacks, thermal oxidizers (e.g. for volatile organic carbon emissions mitigation) and other on-site waste incineration and fugitive emissions of high global-warming potential gases from process operations.

For sites that import all of their fuel and do not have any process emissions, flaring or VOC mitigation, scope 1 emissions can be determined relatively easily from the site fuel bill using an appropriate emissions factor for the type of fuel used. Sites that generate a portion of their fuel from process off gases or byproducts require additional measurement systems and may require reconciliation of estimates from different sources.

Figure 6.1 is a schematic illustration of a typical chemical plant or oil refinery fuel gas header system. Various process off-gases are vented into the fuel system, which distributes fuel gas to multiple heaters around the site. The fuel gas header pressure is maintained by drawing make-up natural gas from the gas grid, and any overpressure is relieved by venting to a flare system.

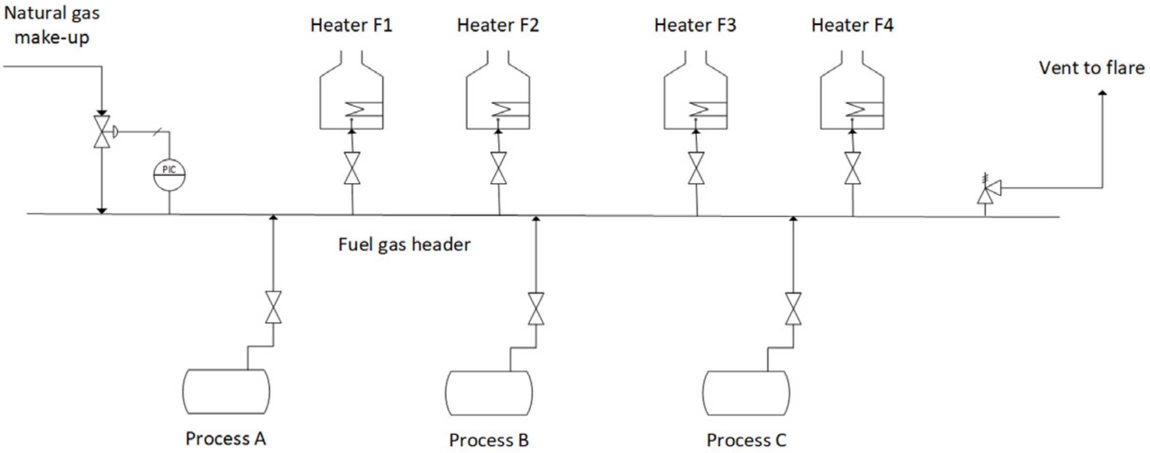


Figure 6.1: Schematic of a site fuel gas distribution system

With this type of fuel gas system, the exact composition of fuel that is being consumed at each of the burners can vary considerably depending on how the processes are operating. Unless the fuel gas header is instrumented with composition analyzers the composition of the gas may not even be known. This is generally not a problem for operation of the fired heaters, as the firing rate is usually controlled to meet a required process heating duty and most gas burners are designed to handle a range of fuel compositions. Compounding the problem, the flowrates of off-gases into the header and the flow of surplus gas to the flare system are usually not metered, and in many cases the flow of fuel gas to small heaters is also not measured. If the heaters are natural-draft type, the air flow to the burners and stack gas flow rate are also not measured and so furnace efficiency cannot be accurately determined.

If the fuel gas system is under-instrumented, scope 1 emissions must be estimated and it may be necessary to reconcile different methods of estimation to arrive at a best answer. Several approaches are commonly used:

- Estimation from gas utility bill: calculating the scope 1 emissions from the make-up rate of natural gas and ignoring the contribution of process off gases will generally underestimate emissions but may be acceptable if the process gas vent rates are known to be very small compared to the gas import flow rate.
- Estimation from design basis: the initial design of a process probably calculated the flow of process off gases in order to size the vent systems and process piping. While subsequent process operation may deviate substantially from the design case, these values can be used as an indication of the expected composition and flow of off gases.
- Estimation from process heat duties: if process flows and heat duties are known from plant historian data then the fired heater firing rates can be calculated based on an assumed (or measured) furnace efficiency. While furnace efficiency may not be accurately known, it can be approximately estimated from stack gas temperature detectors when these are available. Adding the firing rates of all the heaters gives the total site fired heat duty. This should be larger than the duty expected based on natural gas imports, with the difference corresponding to the fuel value of the process off gases. This method can overestimate emissions if the process off gases contain significant amounts of hydrogen or oxygenated light hydrocarbons such as solvents (in which case the composition and flow rate of each of the off gases must be known in order to calculate the corresponding emissions factor).
- Estimation from sub-metering data: if the site has gas flow meters or composition analyzers on the fuel gas header system then data from these instruments can be

used to build a fuel gas system model that can be reconciled against process heater estimates.

All of these approaches are further complicated by real-time variation in process flow rates and heater firing rates based on business needs, plant maintenance issues, etc., making real time monitoring and data reconciliation critical to accurate reporting.

Fuel gas composition monitoring: Honeywell EnCal gas chromatographs
The EnCal 3000 is a gas chromatograph specially designed for natural gas energy measurements, which can be used to monitor the composition (and hence carbon intensity) of mixed fuel gases. This state-of-the-art analyzer uses chromatography components based on micro electro-mechanical systems (MEMS) and capillary column technique, resulting in highly repeatable and accurate analysis results.

The compact, explosion proof design includes the analytical hardware, stream selection and all required electronics for standalone operation. Optimum peak separation in combination with a very sensitive and linear TCD detector results in a system with a high accuracy over a large range of gases. Since the carrier gas pressure is electronically controlled, ambient temperature changes have no influence on peak retention times. The design of the EnCal 3000 is such that the unit can be placed outdoors close to the sample point without the need of an expensive temperature controlled environment. The modular design of the EnCal 3000 enables the servicing of the analyzer by nonspecialist personnel and keeps instrument down-time very short. The use of the MEMS based components results in far lower consumption of utilities like the Helium carrier gas. All of this helps contribute to lower operational costs compared to traditional gas chromatographs.

MAIN FEATURES

- C_{6+} within 3 minutes*
- C_6 within 3 minutes*
- $C9_+$ within 3 minutes*
- Repeatability (on Heating Value <0.005%
- Double block and bleed
- Stream select for 5 streams
- TCP/IP communication
- Data storage in accordance with API 21.1 standard
- IP66 outdoor housing
- Calculations in accordance with
- ISO 6976, GPA2172 or GOST 22667

*Detailed analysis up to n-C_8(C_{6+}) respectivly n-C_9(C_{9+}) including all isomers and other hydrocarbons, no backflush

Figure 6.2: Honeywell EnCal 3000 gas chromatograph

Process and fugitive emissions
Emissions from process vents, flares, relief gas systems and thermal oxidizers can occur as part of normal operation but more commonly are associated with upset conditions such as plant shutdowns. Reporting of infrequent releases of greenhouse gases might be required by local environmental regulations but the emissions involved are often not material in comparison with scope 1 emissions from heaters and other steady-state combustion sources. If it is determined that process emissions could be a significant contributor to the site carbon footprint the installation of additional measurement systems to confirm the magnitude of the emissions is usually justified before proceeding to deploy larger amounts of capital in mitigation equipment.

Fugitive emissions of GHGs such as methane or refrigerants can be a significant part of scope 1 emissions due to the high global warming potential (GWP) of these compounds relative to carbon dioxide. These emissions are usually not visible and have to be identified and mitigated through a leak detection and repair (LDAR) program. A common approach is to deploy workers to periodically inspect a site, using handheld leak monitors to identify the sources of leaks and arrange for later repair. This approach is time- and people-intensive, is subject to human error, often discovers inconsequential pinhole leaks versus major releases, and, importantly, only catches those leaks that occur during scheduled inspections. Leaks that happen between inspections will go unnoticed until the next check.

A more effective approach is to deploy gas cloud imaging (GCI), which uses fully automatic video cameras that can be stationed throughout an industrial site to provide continuous, 24/7 monitoring in all weather conditions, detecting leaks as soon as they happen. GCI cameras combine a visual sensor, hyperspectral sensor, analytics, and software to provide an easy-to-interpret colored video, which shows the gas type, location, direction, size, and concentration of a gas leak, enabling plant managers to respond with the appropriate level of urgency and coordinate repair. The hyperspectral sensor is a critical component of the system, as it can see the optical fingerprint of the gas cloud – thus making it possible to differentiate high GWP molecules from common "false alarm" molecules such as steam or water vapor. GCI technology detects and measures leaks in minutes and with precision — including location, size, concentration and direction. That means companies can use GCI monitoring software to definitively see the source of a leak, such as the tubing connector on a certain pipe, so they can diagnose the problem, quantify it and repair it. Honeywell has a decade of experience in advanced hyperspectral gas imaging systems for the oil and gas, petrochemical and power industries. Honeywell's Rebellion cameras provide wide area/ site level coverage and can monitor over 20 gases (including methane).

SCOPE 2 EMISSIONS

Scope 2 emissions are indirect emissions due to production of energy that is brought into the factory or site. In most cases, the only scope 2 emissions are those attributable to the electricity imported from the local grid; however, some multi-tenant sites also have scope 2 emissions due to supply of steam from a central boiler plant.

Since scope 2 emissions are due to energy imports, they by definition do not include any emissions associated with on-site cogeneration (which would instead fall under scope 1). Deployment of cogeneration along with CCS (or low GHG-intensity fuel) can therefore be used as a means of reducing scope 2 emissions.

Accurate estimation of scope 2 emissions is relatively straightforward, as energy transfers into the site must be paid for and so are almost always accurately metered. Electric power grids also routinely report the carbon intensity of the electricity they supply. The carbon intensity of grid electricity can vary substantially on an hourly, daily and seasonal basis, so if process electricity consumption also varies over time it can be worthwhile to accurately match site power demand against the grid C-intensity profile so as to avoid overestimating emissions. For example, in a region where summer air conditioning demand is high and solar electricity production is high, using annual average C-intensity of grid power to calculate emissions from a factory whose power consumption peaks in the summer will overestimate emissions (because the annual average grid C-intensity includes winter months when solar power is less available).

Attribution of scope 2 emissions to specific operations within the factory or site is less straightforward and depends on the level of sub-metering and equipment power monitoring that is available. While power consumption of major equipment such as arc furnaces, ovens, compressors, crushers, grinders and centrifuges is usually monitored, many sites are not adequately instrumented to fully attribute electricity consumption by operation and would benefit from deployment of additional sub-metering systems. Monitoring of power consumption can identify operating cost savings due to underperforming equipment as well as opportunities to avoid peak power surcharges by demand scheduling and demand response management. If a site is pursuing a strategy of decarbonizing industrial heating through electrification these efficiency improvements play a critical role in minimizing peak power consumption and hence the need for additional electric power substations and infrastructure.

ACCURATE EMISSIONS MONITORING AND REPORTING

Regulatory requirements for emissions reporting vary around the world, but over time are becoming more stringent. Even in regions where emissions reporting is not required by law it might still be necessary to track and report emissions to provide data requested by customers or to claim tax or import duty benefits such as under the EU carbon border adjustment mechanism (CBAM). Increased scrutiny of the accuracy of emissions data, the potential need for external audits and tax implications are causing many companies to move accountability for emissions reporting from the manufacturing / HSE area to the Financial Controllership department.

Most regulations and voluntary reporting frameworks only require emissions to be stated on an annual site-wide or enterprise-wide basis. Annual site-level data gives insight into the geographic distribution of a company's GHG emissions but is not particularly actionable when it comes to planning an emissions reduction strategy for any given site. For this, a detailed breakdown of scope 1 and 2 emissions by plant operation (or unit operation in process plants) is needed. The data also needs to encompass emissions from discrete vents such as releases of GHGs and hourly, daily and seasonal variations in energy use that will determine the peak demand rates and hence size of equipment needed for mitigation.

Honeywell Forge Sustainability+ for Industrials

Honeywell Forge Sustainability+ for Industrials is an enterprise-level, technology agnostic, near real-time emissions monitoring, accounting and visualization framework that can be used to measure, monitor, report and reduce emissions (Figure 6.3). Honeywell Forge Sustainability+ for Industrials | Emissions Management, provides an accurate GHG emissions inventories through digital and direct measurement technologies, near real-time enterprise-wide visualization for improved transparency, and AI/ ML driven insights that empowers customers decarbonization journey.

Honeywell is building upon its existing Emissions Management portfolio, including integrated IoT measurement devices (sensors and cameras), Enterprise Software Platform (Honeywell Forge Sustainability+), and Outcome-based Services (E360) to deliver a value creation engine for customers, by leveraging emissions data to improve Operations and

Financial performance. Honeywell can deliver high-value outcomes by collecting real-time, quantitative & granular emissions data to not only enable cost-effective compliance, but also help deliver improved operations, asset performance improvements, and increased financial performance.

Honeywell Forge Sustainability+ Emissions Management ("Emissions Management" or "EM") is a cloud-based solution – which can also be delivered as a Software-as-a-Service (SaaS) for automated data collection, model contextualization, calculation, and reporting. The Emissions Management application provides enterprise-wide greenhouse gas emissions tracking, accounting, visualization, and reporting using a near real-time Scope 1 and 2 emissions for HSE professionals and executive teams.

The core vision of Honeywell Forge Sustainability+ Emissions Management is to help organizations meet their sustainability needs, by operating in a more energy-efficient manner and with a lower carbon footprint. Honeywell Forge Sustainability+ Emissions Management helps industrial leaders meet these goals and commitments through emissions measuring, monitoring, and by providing reduction insights.

Honeywell Forge Sustainability+ for Industrials integrates with both Honeywell and third-party measurement devices or other data sources (e.g., plant historians) to foster rapid reconciliation or comparisons between measurement methods for verification, enabling auditability and helping instill confidence for stakeholders in the calculated emission profiles.

The platform makes it easier to:

- Integrate and reconcile data from multiple and disparate sources
- Make the data available for existing workflows, and create and deploy new, improved workflows
- Perform greenhouse gas calculations, including methane, for emission inventories, intensities, tracking against targets and key performance indicators, as well as select reporting standards published by agencies and sustainability disclosure frameworks (e.g., UN OGMP 2.0.)
- Identify the unit operations or events that are the largest contributor to emissions and thereby develop more robust decarbonization plans.

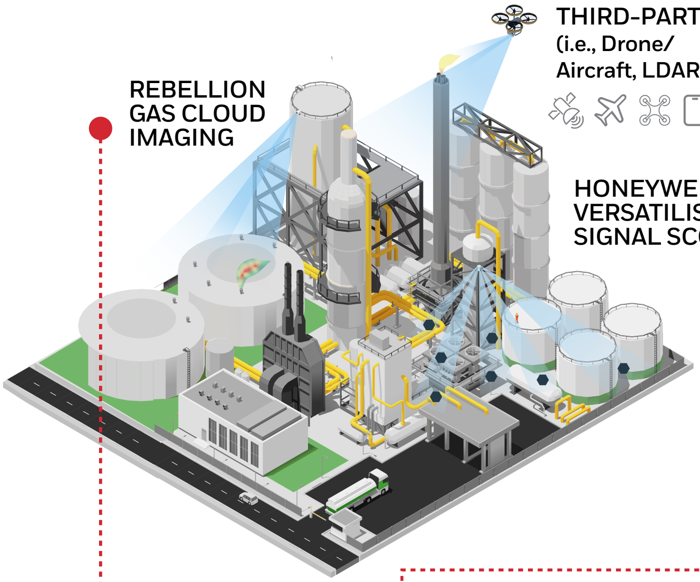
Emissions Management's advanced analytics, artificial intelligence, and machine learning, combine near real-time raw data and emissions information to train and generate an emissions model that helps to predict year-end emissions, month-on-month, based on planned production data. Users can course-correct production and/or emissions reduction activities if an organization's presently and predicted emissions inventories exceed regulatory thresholds or forecasted year-end targets.

A key feature of Honeywell Forge Sustainability+ for Industrials is the ability to navigate enterprise-wide visualization in near real-time with drill-down capabilities for granular visibility into emission sources and gain insights across core emission functions. Customers can then drive insights into plans-of-action with Honeywell's portfolio of reduce by data offerings (APC, APM, Digital Twin); reduce by technology offerings (carbon capture utilization & storage, hydrogen portfolio, battery energy storage solutions); or both, as in the case of Honeywell's burner management solutions and flare solutions portfolio.

Honeywell Forge Sustainability+ for Industrials | Emissions Management balances the versatility of a centralized emissions information solution for governing existing and future mission-specific software and equipment, with the specificity to tailor needs per a company's industry and respective applications. Emissions Management is one facet in an ecosystem of decarbonization and emissions reduction solutions.

MEASURE

Automated Near Real-Time Emissions Coverage



REBELLION GAS CLOUD IMAGING

THIRD-PARTY DATA (i.e., Drone/ Aircraft, LDAR)

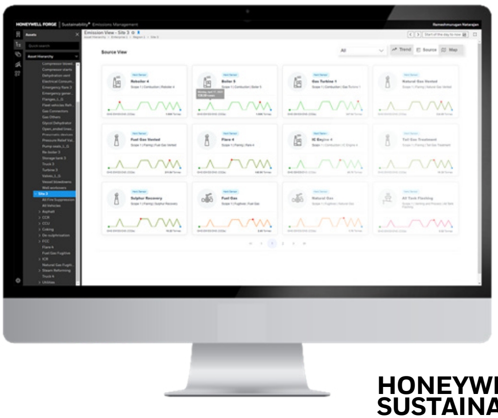
HONEYWELL VERSATILIS™ SIGNAL SCOUT™

MONITOR

Source, Site, Region and Enterprise Level Trending and Visualization

REPORT

Compiled Insights and Data Address Emissions Reduction Goals



HONEYWELL FORGE SUSTAINABILITY FOR INDUSTRIALS

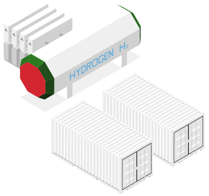
EMISSIONS MANAGEMENT

REDUCE

Enable Automated and Manual Emissions Actions

ENERGY EFFICIENCY & OPTIMIZATION

- Combustion Controls
- Digital Twin
- Advanced Process Control (APC)
- Process Optimization
- Asset Performance Management (APM)



- HYDROGEN (H_2) TRANSITION
- CARBON CAPTURE (CCUS)
- ENERGY STORAGE
- RENEWABLE FUELS

EMISSIONS 360 OUTCOME AND KPI BASED SERVICE PROGRAM

(CLOSE THE LOOP)

Figure 6.3: Honeywell Forge Sustainability+ for Industrials

CONCLUSIONS

The wide range of industrial heating applications calls for a portfolio of solutions to meet future energy needs.

Industrial heating is a major contributor to global warming, accounting for roughly a fifth of all anthropogenic greenhouse gas emissions. Manufacturing plants use heat across a wide range of temperatures for a variety of process applications, so there is no simple "one-size-fits-all" solution for mitigating the emissions impact of industrial heat. The optimal path to decarbonization of a manufacturing site will depend on the local availability and cost of alternative fuels such as biogas or hydrogen, low GHG-intensity electricity and access to CO_2 sequestration sites or pipelines. The cost of decarbonization will also be substantially affected by local regulations and permit requirements, government incentives and national and international tax penalties.

In general we expect that:

- **High temperature heating** will be addressed by switching fired heaters to low GHG-intensity fuels (initially from oil and coal to natural gas then later to clean hydrogen or biogas), or by deployment of carbon capture and sequestration on very large point sources. Electric arc heating will be used for some very high temperature processing (e.g. in metalworking) and electrification will also be used for small duty high temperature heat applications where it will be lower cost than fuel switch or CCS.
- **Medium temperature heating** will continue to rely heavily on steam systems, with the boilers / cogeneration plants achieving emissions abatement by deploying the approaches listed for high-temperature heating. Smaller fired heaters for medium temperature heat will probably switch to electric heating unless part of a large site that is pursuing a fuel-switch strategy. Heat pumps (particularly chemical heat pumps) will also be used to recover low-grade heat for medium temperature applications.
- **Low temperature heating** will be able to take more advantage of heat pumps and electrification, but will also use steam systems and low-GHG intensity fired heat in some applications that call for specific process temperature profiles (e.g. some types of food processing)
- **Energy efficiency** should be the first step in all industrial heating decarbonization plans as it generates immediate savings as well as reducing the investment required in abatement technology. Ensuring that automatic process control systems are operating correctly and have appropriately priced energy to include full emissions costs is a key requirement.
- **Emissions tracking and monitoring** software will be used to drill into the emissions profile of a site and go from the high-level data reported for regulatory purposes to a detailed understanding of the daily and seasonal variation in operations that underlies the site emissions and hence identify the governing loads and prioritize abatement approaches.

Reducing the emissions from industrial heating requires capital investments while also increasing operating costs, and so will not be undertaken unless manufacturers either see an opportunity to sell low GHG-intensity products at a premium price (allowing them to recover the cost) or are legally required to reduce their GHG emissions. Current levels of carbon taxes are not high enough to incentivize widespread decarbonization of industrial heating and relatively few companies practice green procurement and are willing to pay higher prices for low GHG-intensity products, so adoption of these technologies is currently limited to sectors where energy costs are a very low part of total production costs and regions where governments create incentives to accelerate decarbonization. We believe this situation will evolve over the next decade as more countries take steps to meet their obligations under the Paris Agreement.

REFERENCES

- ASHRAE 62.1-2022 (2022) ANSI/ASHRAE Standard 62.1-2022, Ventilation and Acceptable Indoor Air Quality. ASHRAE, Georgia, USA.
- ASHRAE 90.1-2022 (2022) ASHRAE Standard 90.1-2022, Energy standard for sites and buildings except low-rise residential buildings. ASHRAE, Georgia, USA.
- ASHRAE 241-2023 (2023) ASHRAE Standard 241-2023, Control of infectious aerosols. ASHRAE, Georgia, USA.
- BNEF (2022) Microgrids Rise in Popularity as Firms Worry About Outages, BNEF Sep 13, 2022.
- EIA (2021) "Electric Power Monthly, Capacity Factors for Utility Scale Generators Primarily Using Non-Fossil Fuels" https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_b
- EIA (2021b) Annual Energy Outlook 2021 (US Energy Information Administration)
- EIA (2023) Electric Power Monthly, February 2023, Appendices Table B.1 Major disturbances and unusual occurrances. (US Energy Information Administration).
- Energy Institute (2024) Statistical Review of World Energy, 73rd Edition (Energy Institute)
- Engel-Cox, J. (2020) "Renewable Energy for Resilience & Adaptation: Workshop on Adaptive Actions Toward a Sustainable and Resilient Future" 10 January 2020, NREL/PR-6A50-75738. (National Renewable Energy Laboratory)
- European Commission (2024) Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions 'Towards an ambitious Industrial Carbon Management for the EU'.
- Honeywell (2023) Press release https://pmt.honeywell.com/us/en/about-pmt/newsroom/press-release/2023/02/exxonmobil-to-deploy-honeywell-carbon-capture-technology
- IEA (2023), World Energy Outlook 2023, https://www.iea.org/reports/world-energy-outlook-2023 (International Energy Agency, Paris).
- IEA (2024), CCUS Projects Database, https://www.iea.org/data-and-statistics/data-product/ccus-projects-database
- IPCC (2014): "Climate Change 2014: Mitigation of Climate Change." Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Edenhofer, O., R. Pichs-Madruga, Y. Sokona, E. Farahani, S. Kadner, K. Seyboth, A. Adler, I. Baum, S. Brunner, P. Eickemeier, B. Kriemann, J. Savolainen, S. Schlömer, C. von Stechow, T. Zwickel and J.C. Minx (eds.)]. (Cambridge University Press)
- IPCC (2022): Climate Change 2022: Mitigation of Climate Change. Contribution of Working Group III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [P.R. Shukla, J. Skea, R. Slade, A. Al Khourdajie, R. van Diemen, D. McCollum, M. Pathak, S. Some, P. Vyas, R. Fradera, M. Belkacemi, A. Hasija, G. Lisboa, S. Luz, J. Malley, (eds.)]. Cambridge University Press, Cambridge, UK and New York, NY, USA.
- ISO (2015) ISO 14644:2015(en) Cleanrooms and associated controlled environments. ISO, Geneva, Switzerland.
- Kalnes, T. N., McCall, M. M., Shonnard, D. R. (2011) Renewable Diesel and Jet-Fuel Production from Fats and Oils. In Crocker, M (Ed.) Thermochemical Conversion of Biomass to Liquid Fuels and Chemicals. (pp. 468-495) Royal Society of Chemistry. https://doi.org/10.1039/9781849732260-00468
- Lin, X., and Lau, J. (2016) Applying demand-controlled ventilation. ASHRAE Journal, **58**(1), 30–36.
- Millard, R. and Pickard, J. (2024) UK pledges £22bn in funding for carbon capture and storage projects. Financial Times, Oct 3, 2024.
- Ministry of Economy Trade and Industry Japan (2023) CCS Long-Term Roadmap.
- NFPA 45-2019, NFPA 45 Standard on Fire Protection for Laboratories Using Chemicals, 2019 edition. NFPA.
- NREL, 2021. Annual Technology Baseline. https://atb.nrel.gov/electricity/2021/utility-scale_pv (National Renewable Energy Laboratory).
- S.1017 (2021) Clean hydrogen production incentives act of 2021 (US Senate).
- Smith, R. (2016) Chemical Process Design and Integration, 2nd Edn. (Wiley).
- UNEP (2024) United Nations Environment Programme. Global status report for buildings and construction. Beyond foundations: mainstreaming sustainable solutions to cut emissions from the building sector. Nairobi https://doi.org/10.59117/20.500.1182/45095.
- Wilson, J.D., Zimmermann, Z. and Gramlich, R. (2024) Strategic Industries Surging: Driving US Power Demand. https://gridstrategiesllc.com/wp-content/uploads/National-Load-Growth-Report-2024.pdf (Grid Strategies)

APPENDICES

APPENDIX 1: GLOSSARY AND TERMINOLOGY

- **AI/ML = artificial intelligence / machine learning**: computational systems that use statistical algorithms and other probabilistic methods to continuously and automatically learn from data and hence develop capabilities that are not deterministically specified by a human designer and in some cases could not have been foreseen by a human designer due to the size and disparate nature of data involved. Many AI/ML systems are hybrid deterministic-probabilistic and combine both deterministic (e.g., obey laws of physics) and probabilistic (e.g., continuously regress models to fit operational data) approaches.
- **Anthropogenic greenhouse gas emissions**: emissions of greenhouse gases due to human activity, i.e., excluding natural sources, but not excluding agriculture and land use impacts.
- **AR = Assessment Report**: periodic reports issued by the Intergovernmental Panel for Climate Change (IPCC), summarizing the consensus state of scientific opinion on the extent, impact and potential mitigation of global warming.
- **Battery electric vehicles (BEV)**: electric vehicles that run solely on battery power and do not consume liquid transportation fuels. Often confounded with plug-in hybrid electric vehicles (PHEVs) that can consume significant amounts of liquid hydrocarbon fuel depending on how they are operated.
- **Battery energy storage system (BESS)**: an integrated system comprising batteries, electrical switchgear, power conditioning equipment necessary to accept and deliver AC power (inverters, transformers, etc.) and a supervisory control and management system.
- **Behind the Meter (BTM)**: energy storage systems deployed by electricity consumers (buildings, manufacturing sites, etc.) to provide backup power in the event of outages, integrate on-sire renewable power, reduce demand-based surcharges or allow exploitation of load-shedding power contracts.
- **Building control system (BCS)**: any system for automatic control of key building operational equipment that controls multiple pieces of equipment at building level (rather than each piece of equipment having its own individual controls).
- **Building energy management system (BEMS)**: a system for automatic control of building energy consumption.
- **Building information modeling (BIM)**: a digital representation of a building typically created during design or renovation that allows for modeling of space use, layout and HVAC system performance. The BIM can be updated with operational data when the building enters service and used as a digital twin to evaluate changes in usage and future renovation projects.
- **Building management system (BMS)**: a building control system that typically integrates multiple subsystems for managing HVAC, lighting, access, security and safety systems.
- **Building performance standards (BPS)**: minimum building performance levels typically specified by local building codes, city or national energy authorities.
- **Carbon border adjustment mechanism (CBAM)**: an import duty that will affect certain energy-intensive products and materials imported into the EU beginning in 2026 and that is designed to ensure that the carbon price of imports is equivalent to the carbon price of EU domestic production so that EU manufacturers are not unfairly impacted by the cost of the EU countries meeting their decarbonization goals. Under the CBAM, importers of certain products into the EU will have to declare their embedded emissions.
- **Carbon capture and storage (CCS)**: collection of carbon dioxide from any source and permanent sequestration of the carbon dioxide in geological storage so that it does not enter the atmosphere.
- **Carbon capture, utilization and storage (CCUS)**: collection of carbon dioxide from any source followed either by geological sequestration (CCS) or conversion of the carbon dioxide into durable materials that are not subsequently combusted with re-release of the carbon dioxide to the atmosphere.
- **Carbon dioxide equivalent (CO_{2e})**: the equivalent amount of carbon dioxide that would cause the same global warming impact. This is a measure used to report other GHG emissions on a carbon dioxide equivalent basis and allows for the fact that other GHGs can have stronger warming effects or be more persistent in the atmosphere.
- **Carbon footprint**: shorthand term used for carbon dioxide emissions footprint (more strictly GHG emissions footprint) – the carbon dioxide emissions associated with a given activity.
- **Carbon intensity of energy (C-intensity)**: shorthand for carbon dioxide intensity (or more strictly GHG intensity) of energy. The amount of CO_2 (strictly CO_{2e}, including actual carbon dioxide as well as other GHG on a carbon dioxide equivalent basis) emitted per unit energy consumed.

- **Carbon-negative technology**: strictly, GHG emissions negative technology. Applies to any technology that permanently removes more GHG from the atmosphere than the entire carbon footprint associated with installation, operation and decommissioning of the technology over the entire service life of the technology.
- **Carbon-neutral**: widely used but imprecise term, strictly meaning carbon dioxide emissions neutral. Since all activities that consume energy or materials have some emissions impact, the term carbon-neutral strictly applies only to systems that have offset all their GHG emissions footprint with an equivalent amount of permanent carbon dioxide sequestration from the atmosphere.
- **Clean hydrogen**: defined in the US Federal Infrastructure bill and Clean Hydrogen Production Incentives Act of 2021 (S.1017) as "hydrogen produced with a carbon intensity equal to or less than 2 kilograms of carbon dioxide-equivalent produced at the site of production per kilogram of hydrogen produced". Note that steam methane reforming typically produces about 7 kg CO_2 per kg H2, so the US definition of clean hydrogen requires at least 72% carbon capture and sequestration if applied to conventional hydrogen production.
- **Combined heat and power (CHP)**: plants that produce electricity using a heat engine and recover heat from the engine exhaust for generation of steam or for process or building heating purposes.
- **Computational fluid dynamics (CFD)**: a method for computer modeling of fluid flow inside or outside a defined 2-dimensional or 3-dimensional boundary, used in design and modeling of building HVAC systems.
- **Critical peak pricing (CPP)**: a form of time of use pricing for electricity that allows consumers to be charged considerably higher prices during defined periods of very high peak demand as an incentive to encourage demand reduction.
- **Decarbonization**: strictly, "removal of carbon from". Generally used in the context of decarbonization of the energy supply. Note that it is correct to say "decarbonization of the energy used for light duty transportation", implying the continued use of light duty transportation with energy sources that do not contain carbon, but it is incorrect to say "decarbonization of gasoline" as gasoline intrinsically contains carbon. Note also that decarbonization describes any level of removal of carbon. We therefore use the term "full decarbonization" to describe the complete removal of carbon from a particular energy supply.
- **Demand-controlled ventilation (DCV)**: an HVAC control method that monitors carbon dioxide and/or air pollutants and controls ventilation levels and outdoor air make-up to maintain indoor air quality within acceptable limits.
- **Direct air capture (DAC)**: strictly, direct air capture of carbon dioxide. CCS or CCUS applied to carbon dioxide that is already in the atmosphere, thereby actually reducing the atmospheric concentration of carbon dioxide.
- **Energy efficiency**: the proportion of energy consumed that is converted into useful mechanical work or required heat, as opposed to waste heat or other non-usable forms of energy.
- **Greenhouse effect**: global warming caused by the accumulation of anthropogenic greenhouse gas emissions in the atmosphere.
- **Greenhouse gases (GHG)**: gas species such as carbon dioxide, methane, nitrogen oxides and some fluorinated gases that absorb infra-red radiation and consequently reduce the ability of the earth to cool itself by radiation to outer space.
- **Guarantee of Origin (GO or GoO)**: a certification introduced under the EU renewable energy directive in 2001 that certifies 1MWh of electric power was produced from a renewable (or non-renewable) source.
- **Heating ventilation and air conditioning (HVAC)**: systems for managing the flow of air in a building, ensuring sufficient ventilation is provided to meet indoor air quality standards and sufficient heating or cooling is provided to meet occupant comfort expectations.
- **Indoor air quality (IAQ)**: the quality of air in and around buildings, particularly as it relates to the health and comfort of building occupants.
- **Intergovernmental Panel on Climate Change (IPCC)**: United Nations body for assessing the science related to climate change. The IPCC is required to publish periodic assessment reports to establish the scientific consensus on climate change, its impacts and potential mitigation and adaptation strategies.
- **Levelized cost of electricity (LCOE)**: cost of production of delivered electricity including capital and operating costs over the full life of an electricity producing or storage asset.
- **Lifecycle analysis (LCA)**: a method for analyzing the full environmental impact of a product or service by considering all the inputs of materials and energy.
- **Low-carbon energy**: strictly "lower carbon-intensity energy". Energy sources that have reduced GHG emissions when compared to conventional energy sources used in the same application.
- **Marginal abatement cost (MAC)**: the marginal cost of reducing GHG emissions, calculated by dividing the lifetime (or annualized) cost of deploying the approach by the avoided lifetime (or annual) emissions to express the cost in $/tCO$_{2e}$.
- **Measurement, verification and reporting (MV&R)**: systems that are put in place to measure energy consumption and verify the performance of energy-saving equipment, typically implemented as part of energy service contracts to track results and verify paybacks on investments, or to measure, validate and report the impact of emissions mitigation techniques.

- **Mechanical vapor recompression (MVR)**: a form of heat pump cycle typically using steam as the working fluid.
- **Minimum energy performance standard (MEPS)**: a performance standard specifying a minimum acceptable energy efficiency for a building or for a piece of equipment or electrical appliance.
- **Nationally determined contribution (NDC)**: the goal that a country that has signed the Paris Agreement on climate change sets for reducing its GHG emissions.
- **Net-zero economic zone (NZEZ)**, **also Eco-industrial park, near-zero economic zone, net zero industrial area, near-zero industrial region, net zero business park, etc.**: a geographically demarcated region that is able to demonstrate that it is served only by net-zero GHG emissions electricity and fuels (or that has a clear defined path to reach net-zero status within a defined time).
- **Net-zero emissions**: strictly, net-zero GHG emissions. Somewhat stricter than carbon-neutral, a net zero GHG condition applies to a system that has offset all GHG emissions with an equal amount of carbon dioxide sequestration from the atmosphere.
- **Non-intrusive load monitoring (NILM)**: monitoring of electric loads through sensors in the outlets or circuit panel, without requiring additional instrumentation within the appliances or power-consuming devices connected to the outlet.
- **PV = photovoltaic**: the most common form of solar power
- **Power purchase agreement (PPA)**: a long-term contract between an electric power producer and a consumer such as a power retailer or end-user that includes specified price terms.
- **Renewable energy**: energy sources that are replenished by solar power or heat from the earth's core over non-geological timescales. This term can be used for wind power, wave power, solar power, hydroelectric power, geothermal power, ocean thermal power and energy from biomass sources that are grown sustainably.
- **Renewable energy certificate (REC)**: a tradable market-based instrument that represents property rights to the environmental attributes of 1 MWh of renewable power generated in the USA. RECs are the accepted legal instrument through which renewable energy generation and use claims are substantiated in the USA.
- **SCADA (Supervisory control and data acquisition)**: simple control systems for automatic operation of processes or operations with relatively few measured and controlled parameters.
- **Sustainable aviation fuel (SAF)**: strictly, a paraffinic jet fuel feedstock derived from sustainable biomass sources that can be blended 50% with conventional petroleum jet fuel to meet the Jet A specification for commercial jet fuel in accordance with ASTM D7566. More recently, the term "100% SAF" is being used to describe aviation fuels that are 100% derived from biomass sources, but still able to comply with the Jet A specification owing to the incorporation of an aromatic component derived from biomass in the blend so as to meet the aromatics and lubricity requirements of jet fuel.
- **Sustainable distillate fuel**: a distillate-range fuel (kerosene, jet or diesel) derived from sustainable biomass sources.
- **Time of use (ToU) pricing**: electricity price schedules that impose higher charges for electricity consumed during peak demand periods and typically offer some level of discount for power consumed away from peak hours, to incentivize consumers to shift electricity demand away from peak hours and thereby debottleneck the transmission and distribution system.
- **Variable frequency drive (VFD)**: a driver used for example in HVAC systems, which adjusts blower flowrate by changing the machine speed (as opposed to less energy efficient legacy systems that run constant speed and control flowrate by opening or closing dampers or valves).
- **Variable renewable energy (VRE)**: electricity produced from renewable sources such as wind and solar power that are intrinsically subject to daily and seasonal variability.
- **Virtual power plant (VPP)**: a network of distributed energy resources that aggregate supply to achieve a greater scale and advantageously sell surplus power generation capacity.
- **Volatile organic compound (VOC) emissions**: gas-phase process emissions of organic compounds (e.g. evaporated solvents) that must usually be abated by methods such as thermal oxidation, possibly offering potential for heat recovery.
- **WG = Working Group**: refers to the three working groups of the IPCC climate change assessment. WG1 studies the scientific basis of global warming. WG2 addresses impacts on society and ecosystems and adaptation. WG3 addresses mitigation approaches.
- **Zero-emissions process**: strictly, a technology that captures and sequesters an amount of GHG emissions sufficient to offset all the GHG emissions associated with installation, operation and decommissioning of the technology.

THE
FUTURE
IS
WHAT
WE
MAKE IT

Honeywell International
855 South Mint Street Charlotte,
NC 28202
www.honeywell.com

WPR-25-02-EN | 05/25

Honeywell