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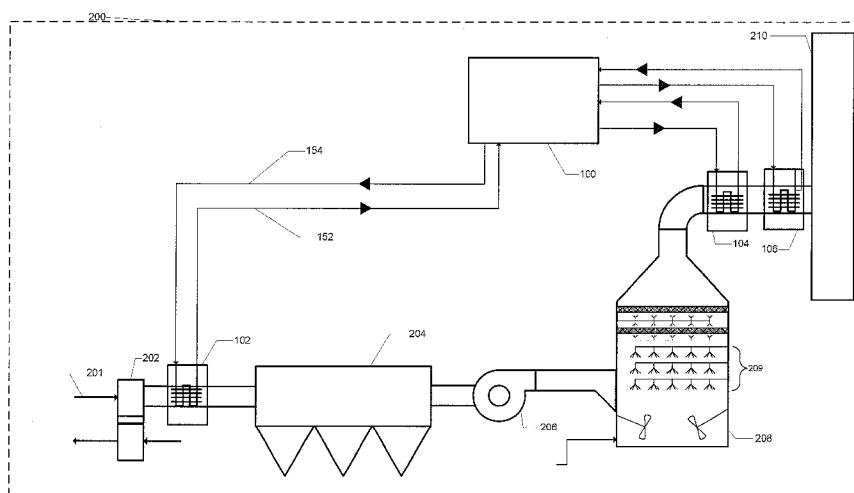


FIGURE 2

(57) Abstract: A method of reducing flue gas emissions that may include: cooling a flue gas upstream of a first emission control device with at least one heat exchange device; and transferring heat directly or indirectly from the at least one heat exchange device to an absorption chilling or other heat-activated chilling system. The method may also include cooling the flue gas at one or more additional locations using the absorption chilling or other heat-activated chilling system and/or rejecting heat from the absorption chilling or other heat-activated chilling system to one or more locations. Methods and apparatus disclosed herein may be used to effectively decrease pollutant levels in flue gas streams, such as mercury, particulate matter, and hydrogen chloride, and some embodiments may also be used to recover water from the flue gas stream.

EMISSION CONTROL SYSTEM

FIELD OF THE DISCLOSURE

[0001] Embodiments disclosed herein relate generally to flue gas cooling methods and apparatus. In particular, embodiments disclosed herein relate to flue gas cooling methods and apparatus incorporated into power plants to reduce emissions, reduce consumption, and recover water used in power plants.

BACKGROUND

[0002] A fossil-fuel power station is a type of power station that burns fossil fuels such as coal, natural gas, petroleum (*i.e.*, oil) or petroleum byproducts (*i.e.* pet coke) to produce electricity. These various fuels are referred to collectively herein as “fossil fuel” or “fossil fuels.” Central station fossil-fuel power plants may be designed on a large scale for continuous operation. In many countries, such plants provide most of the electrical energy used.

[0003] Fossil fuel power plants have rotating machinery to convert the heat energy of combustion into mechanical energy, which then operates an electrical generator. The prime mover may be a steam turbine, a gas turbine, or in smaller plants, a reciprocating internal combustion engine. All plants use the energy extracted from expanding gas – steam or combustion gases.

[0004] Byproducts of thermal power plant operation must be considered in their design and operation. Waste heat energy, which remains due to the finite efficiency of the Carnot, Rankine, or Diesel power cycle, is released directly to the atmosphere, directly to river or lake water, or indirectly to the atmosphere using a cooling tower with air or water used as a cooling medium. The flue gas from combustion of the fossil fuels is discharged to the air. This gas contains carbon dioxide, water vapor, as well as substances such as elemental nitrogen, nitrogen oxides, sulfur oxides, mercury, traces of other metals, and, for coal-fired plants, fly ash. Solid waste ash from coal-fired boilers must also be removed, some of which may sold for beneficial use.

[0005] Fossil fuel power stations include environmental control technologies for air pollutants such as nitrogen oxides, sulfur oxides, particulate and mercury compounds. These control technologies have been employed in the United States and other parts of the world to reduce the environmental impact from the combustion of coal, including acid rain and air pollution. The world's power demands are expected to rise by 60% by 2030. With the worldwide number of active coal plants rising, the International Energy Agency (IEA) estimates that fossil fuels will account for 85% of the energy market by 2030. World organizations like the IEA are concerned about the environmental impact of burning fossil fuels, and coal in particular and are advocating stricter environmental controls on power plants.

[0006] Due to the chemical composition of coal and other fossil fuels, there are difficulties in removing impurities from the fuels prior to combustion. Modern-day coal power plants pollute less than older designs due to environmental control technologies, e.g., electrostatic precipitators, "scrubbers," that treat and filter the exhaust flue gas before the gas exits the stacks. However, emission levels of various pollutants for coal-fired power plants are still on average greater than natural gas power plants. Further, regulatory entities are routinely decreasing the amounts of pollutants that may be emitted.

[0007] Fossil fuel fired facilities are also, in many cases, large consumers of water. In certain facilities, water may be used for plant cooling, for scrubbing flue gas or for both.

SUMMARY OF THE DISCLOSURE

[0008] Embodiments disclosed herein may provide a pollution control system for coal-fired, oil-fired, and other fossil fuel fired power plants, as well as for fossil fuel-fired boilers, kilns, autoclaves and other similar equipment serving a variety of other industries, to reduce or aid in the reduction of air pollutant emissions from the flue gas generated at these facilities.

[0009] In one aspect, embodiments disclosed herein relate to a method of reducing flue gas emissions. The method may include: cooling a flue gas upstream of a first emission control device with at least one heat exchange device; and transferring heat

directly or indirectly from the at least one heat exchange device to an absorption chilling or other heat-activated chilling system. The method may also include cooling the flue gas at one or more additional locations using the absorption chilling or other heat-activated chilling system and/or rejecting heat from the absorption chilling or other heat-activated chilling system to one or more locations. Rejecting heat may include at least one of heating the flue gas upstream of a flue-gas stack or drying coal with heat rejected from the absorption chilling or other heat-activated chilling system. Cooling the flue gas upstream of the first emission control device may include reducing the temperature of the flue gas a temperature differential sufficient to increase removal of at least one of sulfuric acid, Mercury, Particulate Matter, and Hydrogen chloride (HCl) in the first emission control device by at least 5% greater than without cooling of the flue gas upstream of the first emission control device. The method may include reducing at least one of the following pollutants in the flue gas to below the level indicated: mercury, 1.2 lb/TBtu or 0.013 lb/GWh; particulate matter, 0.03 lb/MMBtu or 0.3 lb/MWh; hydrogen chloride (HCl), 0.002 lb/MMBtu or 0.02 lb/MWh. Cooling the flue gas upstream of the first emission control device may also include reducing the temperature of the flue gas a temperature differential sufficient to decrease the consumption rate of a sorbent used to remove at least one of sulfuric acid, mercury, and hydrogen chloride (HCl) in the first emission control device by at least 5% less than without cooling of the flue gas upstream of the first emission control device.

[0010] In another aspect, embodiments herein relate to a flue gas treatment system. The system may include: at least one emission control device; a heat exchange device that removes heat from a flue gas upstream of the emission control device and transfers heat directly or indirectly to an absorption chilling or other heat-activated chilling system; and the absorption chilling or other heat-activated chilling system.

The system may further include a heat exchange device that receives heat rejected from the absorption chilling or other heat-activated chilling system and reheats the flue gas upstream of a flue-gas stack.

[0011] In another aspect, embodiments disclosed herein relate to a method of reducing flue gas emissions. The method may include: cooling a flue gas with a first heat exchange device at a first location; and cooling the flue gas with a second heat

exchange device at a second location; and transferring heat from the first and second heat exchange devices to an absorption chilling or other heat-activated chilling system. The method may also include cooling the flue gas at one or more third locations using the absorption chilling or other heat-activated chilling system. In some embodiments, the first location is upstream of a first emission control device. The second location may be downstream of a second emission control device in some embodiments. Cooling the flue gas upstream of the first emission control device may include reducing the temperature of the flue gas a temperature differential sufficient to increase removal of at least one of sulfuric acid, Mercury, Particulate Matter, and Hydrogen chloride (HCl) in the first emission control device by at least 5% greater than without cooling of the flue gas upstream of the first emission control device. The method may include reducing at least one of the following pollutants in the flue gas to below the level indicated: mercury, 1.2 lb/TBtu or 0.013 lb/GWh; particulate matter, 0.03 lb/MMBtu or 0.3 lb/MWh; h chloride (HCl), 0.002 lb/MMBtu or 0.02 lb/MWh. The method may further include heating the flue gas at a fourth location with heat rejected from the absorption chilling or other heat-activated chilling system. Cooling the flue gas upstream of the first emission control device may also include reducing the temperature of the flue gas a temperature differential sufficient to decrease the consumption rate of a sorbent used to remove at least one of sulfuric acid, mercury, and hydrogen chloride (HCl) in the first emission control device by at least 5% less than without cooling of the flue gas upstream of the first emission control device.

[0012] In another aspect, embodiments disclosed herein relate to a flue gas treatment system. The system may include: a first heat extraction coil that removes heat from a flue gas; a second heat extraction coil that removes heat from a flue gas; and an absorption chilling or other heat-activated chilling system, wherein heat from at least one of the first and second heat extraction coils is transferred to the absorption chilling or other heat-activated chilling system. The system may also include a heating coil that receives heat rejected from the absorption chilling or other heat-activated chilling system and heats the flue gas upstream of a flue-gas stack.

[0013] In another aspect, embodiments disclosed herein relate to a method of reducing flue gas emissions. The method may include: cooling a flue gas upstream of an emission control device with a first heat extraction coil; cooling the flue gas

upstream or downstream of a flue gas desulfurization (FGD) absorber with a second heat extraction coil; and transferring heat from the first heat extraction coil to an absorption chilling or other heat-activated chilling system. The method may also include providing cooling from the absorption chilling or other heat-activated chilling system to the second heat extraction coil. The method may also include rejecting heat from the absorption chilling or other heat-activated chilling system to one or more locations. In some embodiments, the first emission control device may include at least one of an electrostatic precipitator and a fabric filter. Cooling the flue gas with at least one of the first and second heat extraction coils may include reducing the temperature of the flue gas a temperature differential sufficient to increase removal of at least one of sulfuric acid, Mercury, Particulate Matter, and Hydrogen chloride (HCl) in the first emission control device by at least 5% greater than without cooling of the flue gas. The method may also include reducing at least one of the following pollutants in the flue gas to below the level indicated: Mercury, 1.2 lb/TBtu or 0.013 lb/GWh; Particulate Matter, 0.03 lb/MMBtu or 0.3 lb/MWh; Hydrogen chloride (HCl), 0.002 lb/MMBtu or 0.02 lb/MWh. In some embodiments, the method may also include heating the flue gas with heat rejected from the absorption chilling or other heat-activated chilling system upstream of a flue gas stack. Cooling the flue gas upstream of the first emission control device may also include reducing the temperature of the flue gas a temperature differential sufficient to decrease the consumption rate of a sorbent used to remove at least one of sulfuric acid, mercury, and hydrogen chloride (HCl) in the first emission control device by at least 5% less than without cooling of the flue gas upstream of the first emission control device.

[0014] In another aspect, embodiments disclosed herein relate to a flue gas treatment system. The system may include: an emission control device; a first heat extraction coil that removes heat from a flue gas upstream of the emission control device at a first location and transfers the heat to an absorption chilling or other heat-activated chilling system; the absorption chilling or other heat-activated chilling system, wherein the heat from the first heat extraction device is transferred to the absorption chilling or other heat-activated chilling system to thereby provide chilling at a second heat extraction coil; a flue gas desulfurization (FGD) absorber for removing pollutants from the flue gas; and the second heat extraction coil at a second location for

removing heat from the flue gas downstream of the first location. The system may also include a heating coil that receives heat rejected from the absorption chilling or other heat-activated chilling system and heats the flue gas upstream of a flue-gas stack. In some embodiments, the first emission control device may be at least one of an electrostatic precipitator and a fabric filter. The second heat extraction coil may cool the flue gas upstream or downstream of the FGD absorber.

[0015] In another aspect, embodiments disclosed herein relate to a method of reducing flue gas emissions. The method may include: cooling a flue gas with a first heat extraction coil upstream of an electrostatic precipitator or fabric filter; cooling the flue gas with a second heat extraction coil upstream of the electrostatic precipitator or the fabric filter; and transferring heat from at least one of the first and second heat extraction coils to an absorption chilling or other heat-activated chilling system. In some embodiments, the method may include one or more of: cooling the flue gas at one or more additional locations using the absorption chilling or other heat-activated chilling system; rejecting heat from the absorption chilling or other heat-activated chilling system to one or more locations; and heating the flue gas with heat rejected from the absorption chilling or other heat-activated chilling system in a heating coil upstream of a flue-gas stack.

[0016] In another aspect, embodiments disclosed herein relate to a flue gas treatment system. The system may include: an electrostatic precipitator or fabric filter; a first heat extraction coil that removes heat from a flue gas upstream of the electrostatic precipitator or fabric filter at a first location; a second heat extraction coil at a second location that removes heat from the flue gas upstream of the electrostatic precipitator or fabric filter at a second location downstream of the first location; an absorption chilling or other heat-activated chilling system, wherein heat from the first heat extraction device is transferred to the absorption chilling or other heat-activated chilling system to thereby provide chilling at the second heat extraction coil. The system may also include a heating coil that receives heat rejected from the absorption chilling or other heat-activated chilling system and heats the flue gas upstream of a flue-gas stack.

[0017] In another aspect, embodiments disclosed herein relate to a method of reducing flue gas emissions. The method may include: extracting heat from a flue gas with a heat extraction coil at a first location upstream of an electrostatic precipitator or fabric filter or both; transferring the extracted heat to an absorption chilling or other heat-activated chilling system; providing cooling from the absorption chilling or other heat-activated chilling system to a second location. The method may also include at least one of: rejecting heat from the absorption chilling or other heat-activated chilling system at a third location; and heating the flue gas with heat rejected from the absorption chilling or other heat-activated chilling system in a heating coil upstream of a flue-gas stack. In some embodiments, cooling the flue gas with the first and second heat extraction coils comprises reducing the temperature of the flue gas a temperature differential sufficient to increase removal of at least one of sulfuric acid, Mercury, Particulate Matter, and Hydrogen chloride (HCl) in the first emission control device by at least 5% greater than without cooling of the flue gas. The method may include reducing at least one of the following pollutants in the flue gas to below the level indicated: mercury, 1.2 lb/TBtu or 0.013 lb/GWh; particulate matter, 0.03 lb/MMBtu or 0.3 lb/MWh; hydrogen chloride (HCl), 0.002 lb/MMBtu or 0.02 lb/MWh. Cooling the flue gas upstream of the first emission control device may also include reducing the temperature of the flue gas a temperature differential sufficient to decrease the consumption rate of a sorbent used to remove at least one of sulfuric acid, mercury, and hydrogen chloride (HCl) in the first emission control device by at least 5% less than without cooling of the flue gas upstream of the first emission control device.

[0018] In another aspect, embodiments disclosed herein relate to a flue gas treatment system. The system may include: an electrostatic precipitator or fabric filter; a heat extraction coil that removes heat from a flue gas upstream of the electrostatic precipitator or fabric filter at a first location; and an absorption chilling or other heat-activated chilling system, wherein heat from the first heat extraction device is transferred to the absorption chilling or other heat-activated chilling system to thereby provide water or other cooling media to a second location. The system may also include a heating coil that receives heat rejected from the absorption chilling or other heat-activated chilling system and reheats the flue gas upstream of a flue-gas stack.

[0019] Other aspects and advantages of the embodiments will be apparent from the following description and the appended claims.

BRIEF DESCRIPTION OF DRAWINGS

[0020] Figure 1 is a schematic of an absorption chilling system in accordance with one or more embodiments of the present disclosure.

[0021] Figure 2 is a schematic of an absorption chilling system incorporated within a fossil fuel-fired power plant's flue gas system in accordance with one or more embodiments of the present disclosure.

[0022] Figure 3 is a schematic of an absorption chilling system incorporated within a fossil fuel-fired power plant's flue gas system in accordance with one or more embodiments of the present disclosure.

[0023] Figure 4 is a schematic of an absorption chilling system incorporated within a fossil fuel-fired power plant's flue gas system in accordance with one or more embodiments of the present disclosure.

DETAILED DESCRIPTION

[0024] The following is directed to various exemplary embodiments of the disclosure. The embodiments disclosed should not be interpreted, or otherwise used, as limiting the scope of the disclosure, including the claims. In addition, those having ordinary skill in the art will appreciate that the following description has broad application, and the discussion of any embodiment is meant only to be exemplary of that embodiment, and not intended to suggest that the scope of the disclosure, including the claims, is limited to that embodiment. Further, it should be understood by one having ordinary skill in the art that temperatures, pressures, and flow rates used throughout this description are merely examples, and may vary from those given herein without departing from the scope of one or more embodiments disclosed herein. While the present description includes various temperature, pressures, etc., one skilled in the art would readily understand that temperatures, pressures, flow rates, etc., may vary based on the type of facility, the type of fuel(s) being used, plant capacity, location, and other factors.

[0025] Also, it should be understood by one having ordinary skill in the art that while examples shown herein relate principally to power plants, the embodiments disclosed herein are equally applicable to any number of facilities generating heat and pollution from the burning of fossil fuels. Such facilities may include, but are not limited to smelters, cement plants, kilns, petrochemical facilities, paper mills, and other industrial facilities known to those skilled in the art.

[0026] In one aspect, embodiments disclosed herein relate to systems for cooling a flue gas to reduce overall facility emissions. In other aspects, embodiments disclosed herein relate to processes for cooling a flue gas to improve operation of pollution control equipment. Improvements in operation may include increased operating efficiency, effectiveness, or reduced consumption of reagents, water, or electrical power. In other aspects, embodiments disclosed herein relate to a process for removing waste heat from flue gas to produce chilled water or other cooling media available for use in a variety of applications in a facility. In other aspects, embodiments disclosed herein relate to a process for reducing water requirements and/or recovering water used in a facility. In other aspects, embodiments disclosed herein relate to reducing auxiliary or parasitic loads in a facility. In other aspects, embodiments disclosed herein relate to improving performance and reducing wear, tear, and maintenance on equipment located in a facility.

[0027] Cooling systems described herein may include one or more heat exchangers or heat extraction coils located either upstream or downstream of an emission control devices or in some cases heat exchangers located in facility operating systems not in the flue gas path. The one or more heat exchangers and heat extraction coils are configured to cool the flue gas or remove heat from the flue gas to improve the efficiency or operation of the one or more emission control devices or other plant operating systems or to accomplish the other benefits noted herein.

[0028] In certain embodiments, it may be useful to cool a flue gas leaving or entering an emission control device by locating a heat exchanger downstream or upstream from the emission control device, respectively. As an example, a heat exchanger placed downstream of flue gas desulfurization ("FGD") absorbers (also called spray towers) to cool flue gas leaving the FGD absorber may result in one of the noted

benefits of embodiments herein. Alternatively, in some embodiments, it may be useful to have a heat exchanger located upstream of the FGD absorber to cool a flue gas prior to entering the FGD absorber. In some cases, it may be beneficial to have heat exchangers in both locations. FGD absorbers are emission control technology common in fossil fuel-fired power plants and in some other fossil fuel-fired facilities. In some embodiments, it may be useful to cool the flue gas entering and/or leaving an emission control device, such as, for example, an electrostatic precipitator (ESP), by locating one or more heat exchangers upstream and/or downstream from the ESP. As an example, electrostatic precipitators (“ESPs”) and/or filter fabrics filters (“FF”) are emission control devices that may benefit from having one or more heat exchangers placed upstream to cool a flue gas before the flue gas enters the ESP or FF (individual and collectively referred to as “ESP/FF”). ESP/FFs are particulate removal devices used to remove particulate matter and other pollutants. Cooling the flue gas upstream of the ESP/FF may result in more efficient pollutant removal due to a reduction in the volumetric flow rate of the flue gas through the ESP/FF. In addition, cooling flue gas entering an ESP decreases the resistivity of the ash entering the ESP allowing the ESP to operate more efficiently and remove more pollutants. In addition, cooling the flue gas creates a greater affinity between the ash and other pollutants causing certain other pollutants to be attached to and captured with the ash particles in the flue gas and removed by the ESP, FF or other downstream pollution control equipment. In some embodiments, it may be useful to cool flue gas effluent from one emission control device prior to the flue gas entering a second emission control device (e.g., an FGD Absorber) by locating a heat exchanger upstream from the second emission control device. Cooling the flue gas also reduces its volumetric flow rate which decreases amount of work (power) done by a facility’s induced draft fans. This in turn allows the fans to operate more efficiently, saving plant auxiliary electric loads and maintenance requirements, as well as on capital cost if new fans are required for another purpose.

[0029] ESPs are the type of particulate emissions control technology most widely used on coal-fired power generating facilities. Most ESPs are cold side (dry) ESPs, where the ESP is located after an air preheater and operated in a temperature range of about 130°C-180° C (about 266°F-356°F). Alternatively, ESPs may be a hot side

(dry) ESP, where the ESP is located before the air preheater where the operating temperatures may be about 300°C-450°C (about 572°F-842°F). Those skilled in the art will appreciate further various configurations and placements of ESPs in units with and without flue gas desulfurization (“FGD”) systems.

[0030] As an alternative to ESPs, fabric filters, also known as baghouses, which generally operate in the temperature range of about 120°C-180°C (about 248°F-356°F), may also be used. The choice between ESP and fabric filtration may generally depend on the fuel or coal type, plant size, and boiler type and configuration and the required levels of pollutant removal.

[0031] In still further embodiments, it may be useful to cool the flue gas leaving an emission control device, for example an FGD absorber, by locating a heat exchanger downstream from the emission control device. When the emission control device is an FGD absorber, this configuration will condense water and capture other pollutants that may not get trapped by the upstream pollution control devices, and/or will reduce water consumption and/or aid in water recovery.

[0032] In further embodiments, it may be useful to re-heat the flue gas prior to the flue gas leaving the system, for example prior to the flue gas entering a flue-gas stack or any similar structure, such as a vertical pipe, chimney, or similar structure through which combustion product gases are exhausted to the outside air. Heating of the flue gas prior to being exhausted to outside air may be useful to increase buoyancy of the flue gas and/or to reduce or diminish the visible plume of the flue gas upon exiting the stack. Heating of the flue gas may be accomplished using any type of heating system, or any heat rejection or waste heat processes that may be harnessed and used to provide heating prior to the flue gas exiting. In further embodiments described herein, the waste heat produced by the flue gas cooling system may be used to reheat the flue gas to provide the benefits described above. In such embodiments, the system used to cool the flue gas at selected points in the flue gas path may also provide flue gas heating at later points in the flue gas path.

[0033] In additional embodiments, it may be useful to cool the flue gas leaving a first emission control device, *e.g.*, an ESP or FF, with a heat exchanger located downstream from the ESP or FF, and thereby cooling flue gas prior to entering a

second emission control device, *e.g.*, an absorber, and then, if desirable, heating flue gas prior to the flue gas being exhausted to outside air through, for example, a flue gas stack or chimney.

[0034] Referring initially to Figure 2, a schematic of a fossil fuel-fired power plant's flue gas system 200 is illustrated. Dirty flue gas 201 enters the emissions control portion of the plant, which may include an ESP or FF 204, to remove particulates and other components of the dirty flue gas, an FGD absorber 208 to remove water-soluble pollutants from the flue gas, and a stack 210 for dispersing the clean exhaust to the atmosphere. The system may also include a feed / effluent exchanger 202 to cool gas leaving the combustion zone and preheat air being fed to the combustion zone or to heat air for coal drying system.

[0035] Emissions reductions and/or water recovery may be attained by placing a heat exchanger 104 at the outlet of FGD absorber 208. Heat exchanger 104 may reduce the temperature of the flue gas exiting FGD absorber 208 and result in the condensing of certain pollutants (sulfuric acid, for example) and water vapor from the flue gas. In some embodiments, the collection of this condensation may result in a significant reduction in the plant's overall water requirements. This reduction in water requirements may be achieved by the condensation of water that was present in the flue gas, both from hydrogen and water in the fuel and from water added to the flue gas in the absorber. In addition, in some embodiments, water consumption may be reduced by cooling the flue gas entering the FGD absorber because a cooler inlet flue gas evaporates less water in the FGD absorber.

[0036] Although Figure 2 illustrates additional heat exchangers, such as 106, 102, the advantages of only cooling the flue gas exiting the FGD absorber may be significant to plant operations. The additional aspects of Figure 2 and their impact on flue gas emissions will be described further below.

[0037] As described above, flue gas cooling may, in certain embodiments, be performed using one or more heat exchangers. The one or more heat exchangers may be separate heat exchangers that operate independently of one another. Alternatively, the one or more heat exchangers may be separate heat exchangers that operate in conjunction or in series with each other and together form an integrated cooling

system. In some embodiments, cooling systems may be formed by individual heat exchangers run off absorption chilling or other heat-activated chilling systems, which may utilize waste heat from the flue gas and/or other sources of waste heat located within a power plant (or other facility). The heat exchangers may be located in any plant waste heat streams known by one having ordinary skill in the art. In other examples, there may be an independent source of waste heat such as where a power plant operates at a refinery or chemical plant; waste heat from a petrochemical process may be used as the required waste heat source to drive the absorption chilling or other heat-activated chilling system.

[0038] Various chilling systems may be used in accordance with embodiments disclosed herein, including, but not limited to, absorption chilling systems, evaporative chilling systems, other heat-activated chilling system, and mechanical chilling (*i.e.*, vapor compression) systems. For example, plants located in hot, dry climates, which are not water-constrained and run a very limited number of hours per year (such as less than about 200 hours) may use evaporative cooling. As another example, mechanical chilling systems may be used, and may include any of the following types of compressors: reciprocating compression, scroll compression, screw-driven compression, and centrifugal compression, all of which may be powered by electric motors, steam, gas turbines, or other engines.

[0039] Particularly, embodiments disclosed herein may relate to absorption chilling or other heat-activated chilling systems incorporated into any number of facilities to reduce overall emissions and/or to reduce and/or recover water used in those facilities and in association therewith providing the various other benefits described herein. For example, any absorption refrigeration or chilling system that uses a heat source to provide the energy needed to drive the chilling system may be used in accordance with one or more embodiments disclosed herein. The absorption chilling or other heat-activated chilling systems may use waste heat generated as part of the normal operation of a power plant or other facility (*i.e.*, cement plants, petrochemical plants, etc.) to power the absorption cycle/process and as a result they are, where sufficient waste heat is present, able to generate chilling at a fraction of the cost and parasitic load of more conventional chilling systems and/or processes.

[0040] Referring to Figure 1, a schematic of a closed-loop ammonia/water absorption system 100 in accordance with one or more embodiments of the present disclosure is shown. Alternatively, lithium bromide absorption systems may also be used in accordance with one or more embodiments of the present disclosure. Referring to Figure 1, the ammonia/water absorption system includes a first heat exchanger 102 that takes waste heat from a heat source 30, which may be any source of adequate waste heat, and sends the heated solution into a rectifier 42. At a high side pressure (such as about 230 psig), the ammonia boils but the water does not. The liquid water pools up at the bottom of the rectifier 42 (roughly 20% ammonia in water) and the vapor ammonia (roughly 98.5% ammonia) exits the rectifier 42 via flow line 43. In some embodiments, the ammonia concentrate may be indirectly heated, for example, by having a separate heat exchange system (*e.g.*, glycol or other fluid) that removes heat from the heat source by the first heat exchanger 102, and which provides heat exchange through a second heat exchanger (not shown) to the ammonia concentrate circulating through the rectifier 42.

[0041] The superheated vapor in flow line 43 is sent to a condenser 44 (which may be dry, hybrid, or wet cooling) where an amount of sensible heat is removed (de-superheated) as well as some latent heat. The effluent 45 from condenser 44 may be a liquid at saturation temperature, which is approximately 110°F at 230 psig. This liquid ammonia is sent to an ammonia receiver 46. The ammonia receiver 46 has some vapor space due to the ammonia being at saturation. From the bottom of the ammonia receiver 46, the liquid ammonia goes through the one side (*e.g.*, tube side or shell side) of a Refrigerant Heat Exchanger (“RHX”) 48 and the temperature is reduced from 110°F to roughly 50°F. This sub-cooled ammonia is sent to one or more Temperature Control Valves (“TCVs”) 50. The TCVs serve as expansion valves and the pressure is reduced from high side pressure (such as about 230 psig) to low side pressure (such as about 40 psig). The rapid depressurization causes flash gas to form (some of the ammonia vaporizes) and the temperature of the refrigerant is reduced from roughly 50°F to roughly 34°F. The flash gas comprises roughly 70% of the volume of the refrigerant, but only 5% of the mass (which is why ammonia is such an effective refrigerant).

[0042] The 34°F refrigerant flows through a second heat exchanger, evaporator coils 104. Evaporator coils 104 may be used to draw heat from a heat sink 32, heating the refrigerant. The majority of the ammonia is boiled off, but the heat transfer is primarily latent, so only a small amount of sensible heat is absorbed. The refrigerant leaves the second heat exchanger 104 at approximately 40°F. This relatively cold refrigerant then passes through the other side (shell side or tube side, as appropriate) of the RHX 48 and sub-cools the ammonia on the tube side going to the TCV's 50. This process also evaporates any liquid ammonia left in the refrigerant stream.

[0043] The water from the bottom of the rectifier 42, flow line 51, after passing through one or more heat exchangers, is recombined with the refrigerant ammonia at this stage, such as via mixing at a tee or other means for mixing liquid water and ammonia vapor. Ammonia has a very high affinity for water, so the vapor ammonia is absorbed into the liquid water very readily. This is an exothermic process, so an absorber heat exchanger 52 may be used to reject the heat to a heat sink. The ammonia/water solution then flows into a spray receiver vessel 54.

[0044] From here, the solution is pumped via one or more Low Pressure ("LP") pumps 56 into an aqua cooler 58, which is another heat exchanger rejecting heat to a heat sink. From the aqua cooler 58, the solution flows back into the spray receiver 54 via spray nozzles 53, which serve to mix the ammonia/water solution and ensure as homogenous a mixture as possible. These three components (*i.e.*, spray receiver 54, LP pumps 56, and aqua cooler 58) cycle roughly 70% of the solution through this mixture loop. A 30% slip stream may be taken from the LP pump discharge and sent to one or more High Pressure ("HP") pumps 60. These pumps raise the system pressure from low side pressure (such as about 40 psig) back up to high side pressure (such as about 230 psig). This solution flows through one or more internal heat exchangers to preheat it, and then back into the first heat exchanger 102 to complete the cycle.

[0045] Further, in certain circumstances, a facility may, at certain times, have need of heat as opposed to cooling for certain plant system (*i.e.*, anti-icing, or performance heating). In those circumstances, the 110°F vapor from the top of the ammonia receiver 46 may be sent directly to the evaporator coils 104, the flow of which may be

controlled by valve 47. The evaporator coils 104 may then serve as a condenser, transferring heat to the incoming air or to another heat exchanger while condensing the vapor ammonia to a liquid.

[0046] Moreover, heat rejected from the condenser 44, the absorber 52, and/or the cooler 58 may be used for a variety of purposes in a power plant, including, but not limited to, reheating flue gas (as described above and in more detail later), heating boiler feed water heating air for various purposes, including the drying of coal and/or heating other incoming gas or liquid streams of varying compositions used elsewhere in the power plant. For example, this waste heat may be used to preheat natural gas entering the plant in certain circumstances.

[0047] Referring again to Figure 2, a schematic of a fossil fuel-fired power plant's flue gas system 200 having an absorption chilling system 100 is shown in accordance with one or more embodiments of the present disclosure. Emission control devices of the plant 200 include, but are not limited to, an ESP (or FF) 204 and an FGD absorber 208. Processes involving reduction of emissions from the plant using absorption chilling are now described in accordance with Figure 2. The schematic includes a flow diagram that describes a process of using an absorption chilling system 100 with a wet flue gas desulfurization ("FGD") system to reduce air pollutant emissions, to reduce water consumption, to recover water that is used in the plant, to improve efficiency of the plant fans and other equipment, to reduce auxiliary/parasitic loads in the plant and to reduce overall maintenance costs.

[0048] Dirty flue gas 201 enters the system, shown at Location 1, after exiting the boiler (not shown), and where present in the facility after exiting the air preheater 202, at an elevated temperature, which may be 250°F or higher. For example, in certain embodiments, the flue gas enters the system in the range from about 300°F to about 350°, such as about 329°F. From Location 1 to Location 2, the flue gas may be cooled by the absorption chilling system 100 to a temperature below the sulfuric acid dew point, and the collected acid may condense on the fly ash in the flue gas stream. For example, in certain embodiments, the flue gas may be cooled to between approximately 170°F and 210°F at Location 2. In other embodiments, the flue gas

may be cooled to between approximately 180°F and 200°F, such as approximately 190°F, at Location 2.

[0049] The flue gas is cooled using the first heat exchanger 102 of the absorption chilling system 100, described in detail in reference to Figure 1, located upstream from the ESP/FF 204. In addition, some of the waste heat taken away in the process of cooling the flue gas (by heat exchanger 102) may be used in whole or in part to drive the absorption chilling system 100, shown by hot line 152 and cold return line 154. The resultant cold refrigerant returning from the absorption chilling system 100 may be used either a) to further cool the air heater outlet/ESP inlet flue gas at Location 2, and/or b) to further cool the flue gas upstream of a wet FGD system, and/or c) to cool the flue gas downstream of a wet FGD system 208 using a second heat exchanger 104 as described in Figure 2, if present, to a temperature equal to or lower than the water dew point, resulting in the condensing and recovery of water from the flue gas. In addition to condensing the water in the flue gas, the heat exchanger 102 may also condense other pollutants in the flue gas, for example, including, but not limited to, H_2SO_4 , HCl, and HF.

[0050] The cooled flue gas then enters the ESP/FF 204 for removal of ash and any condensates or compounds that adhere to the ash. After removal of ash and any condensates or compounds that adhere to the ash in the ESP/FF 204, the flue gas may pass through an induced draft fan 206. By cooling the flue gas prior to it entering the fan, the mechanical work that the fan imparts to the flue gas may be reduced and, as a result, the horsepower required to power the fan may be reduced. In addition, removal of various pollutants in the ESP/FF as a result of cooling the flue gas may reduce or eliminate pollutants that damage internal components of the fan 206. As a result, the service duty and life of the fan 206 may be improved, thereby increasing the life and reliability of the fan 206.

[0051] In certain embodiments, the ESP/FF may be used in conjunction with an Activated Carbon Injection System (“ACI”) and/or Dry Sorbent Injection Systems (“DSI”). In other embodiments, the improved performance of the ESP/FF as a result of cooling the entering flue gas may allow the ACI and/or DSI systems to be eliminated altogether. In other embodiments, the improved performance of the

ESP/FF as a result of cooling the entering flue gas may allow the ACI and/or DSI systems to reduce the amount of activated carbon or sorbent that must be injected / consumed in the process and as a result, the operating cost of the plant is reduced.

[0052] Upon leaving the fan 206, the flue gas enters the FGD absorber 208, as shown at Location 6. In some embodiments, a heat exchanger (not shown) may be located downstream of the fan 206 and upstream of the FGD absorber 208, such that upon leaving the fan 206, the flue gas enters the heat exchanger and is cooled prior to entering the FGD absorber 208. Generally, absorbers use large amounts of water, principally in the form of evaporative losses arising out of the water that is sprayed in the FGD absorber via nozzles 209. By cooling the flue gas upstream of the FGD absorber with the heat exchanger (and in certain cases a second heat exchanger such as 104 located downstream of the absorber 208, the amount of water consumed in the FGD absorber may be reduced.

[0053] In addition, absorbers are expensive vessels because of their size and materials of construction. The diameter of the FGD absorber is driven in large part by the need to maintain a certain flue gas velocity in the FGD absorber. By cooling the flue gas with one or more heat exchangers prior to the flue gas entering the FGD absorber, the volume of flue gas may be reduced and as a result, the size of the FGD absorber may be reduced while still maintaining a desired flue gas velocity.

[0054] As the flue gas leaves the FGD absorber 208, it rises to Location 8, at which point the second heat exchanger 104 of the absorption chilling system 100 located downstream from the FGD absorber 208 may be used to further cool the flue gas. In some embodiments, the second heat exchanger 104 may be located within the FGD absorber 208. For example, in certain embodiments, the flue gas may rise and exit from the FGD absorber 208 at about 126°F, or higher. The heat exchanger 104 may cool the flue gas to between approximately 90°F and 130°F. In other embodiments, the heat exchanger 104 may cool the flue gas to between approximately 100°F and 130°F. Depending on the temperature at which the flue gas exits the FGD absorber 208, the amount of cooling may be between approximately 5°F and 15°F. For example, for a flue gas exiting the FGD absorber at 126°F, cooling the flue gas to 119°F, in this example, may result in condensation and return of water to the FGD

absorber 208. The return of water to the FGD absorber 208 reduces water consumption by recovering water from the water contained in the flue gas exiting FGD absorber 208. Some of the water contained in the flue gas may be generated from the combustion process of burning fossil fuels containing hydrogen or water.

[0055] In addition to the various pollutants contained in flue gas, one of the naturally occurring byproducts of the combustion process is water vapor. This water vapor is contained within the flue gas. By cooling the flue gas and condensing water as described above, both water sprayed into the FGD absorber and the water formed as a byproduct of the combustion process may both be captured. As a result, the FGD process may use less water than the conventional system.

[0056] One having ordinary skill in the art will understand other temperature drops may provide greater water savings as well. For example, the temperature may be decreased by up to about 20°F, such as about 5-15°F or about 10°F, resulting in decrease in flue gas water content. Overall, cooling the flue gas at Location 8 helps enhance water recovery in the FGD absorber 208 by removing a substantial amount of water at Location 8, which allows the water to return to the FGD absorber 208 or flow to another location in the facility.

[0057] In some embodiments where increased flue gas buoyancy is required, a flue gas heater 106 located downstream of the second heat exchanger 104 may use heat from the heat rejection inherent to the absorption chilling system 100 (that is, heat rejected by the condenser 44, the absorber 52, and/or the cooler 58 described in reference to Figure 1 of the absorption chilling system 100) or other chilling process to heat the flue gas between Location 9 and Location 10, which ensures that the gas has adequate buoyancy to leave the stack 210 and properly disperse into the atmosphere. For example, in certain embodiments, the flue gas may be heated by the Gas Heating Exchanger (GHX) 106 to a temperature sufficient to provide the flue gas adequate buoyancy to leave stack 210, such as to a temperature greater than about 125°F or as appropriate to local conditions.

[0058] Referring now to Figure 3, a schematic of a fossil fuel-fired power plant's flue gas system 300 having an absorption chilling system 100 is shown in accordance with one or more embodiments of the present disclosure, where like numerals represent

like parts. Emission control devices of the plant 300 may include, but are not limited to, an ESP (or FF) 204. As shown, a first heat exchanger or heat extraction coil 102 may be located upstream from the ESP/FF 204 and configured to remove heat from the flue gas.

[0059] Likewise, a second heat exchanger or heat extraction coil 104 may be located upstream of the ESP/FF 204 (and downstream of the first heat exchanger 102) to cool flue gas prior to entering the ESP/FF 204. Waste heat taken away in the process of cooling the flue gas (by the first heat exchanger 102) may be used in whole or in part to drive the absorption chilling system 100. The resultant cold refrigerant returning from the absorption chilling system 100 may be used to further cool the flue gas with the second heat exchanger 104 upstream of the ESP/FF 204 prior to the flue gas entering the ESP/FF 204. The cooling of the flue gas via exchangers 102 and 104 may provide benefits to the operation of ESP/FF 204 as described above with respect to Figure 2. In other embodiments, the first heat exchanger 102 and the second heat exchanger 104 may be located in a single casing or the coils of the first heat exchanger 102 and the second heat exchanger 104 may be located in the flue gas duct.

[0060] Further, in some embodiments where increased flue gas buoyancy is required, a flue gas heating device 106 may be located downstream from the ESP/FF 204 and induced draft fan 206, and upstream from the stack 210. The flue gas heating device uses heat from the heat rejection inherent to the absorption chilling system 100 (that is, heat rejected by the condenser 44, the absorber 52, and/or the cooler 58 described in reference to Figure 1 of the absorption chilling system 100) to heat the flue gas prior to the flue gas entering the stack 210, which ensures that the gas has adequate buoyancy to leave the stack 210 and properly disperse into the atmosphere.

[0061] In some embodiments, a flue gas heating device may not be included to reheat the flue gas prior to the flue gas exiting through the stack 210. In the absence of a flue gas heating device 106, heat may be rejected from the absorption chilling system 100 to one or more cooling towers (not shown), which may be any of a wet cooling tower, a dry cooling tower, and/or a hybrid cooling tower. In further embodiments, heat may be rejected to a boiler feed water preheat system. In still further embodiments, heat may be rejected to a plant heating system. In other embodiments,

heat may be rejected to an inlet coil upstream of the air preheater for combustion air preheating or coal drying air heating. In yet other embodiments, a portion of the heat may be rejected via a heating device 106 and the remainder of the heat may be rejected to one or more additional locations in the plant.

[0062] Referring now to Figure 4, a schematic of a fossil fuel-fired power plant's flue gas system 400 having an absorption chilling system 100 is shown in accordance with one or more embodiments of the present disclosure, where like numerals represent like parts. Emission control devices of the plant 300 may include, but are not limited to, an ESP (or FF) 204. As shown, a first heat exchanger or heat extraction device 102 may be located upstream from the ESP/FF 204 and configured to remove heat from the flue gas.

[0063] Further, a second heat exchanger 104 may be included to provide chilling to the plant. Waste heat taken away in the process of cooling the flue gas (by the first heat exchanger 102) may be used in whole or in part to drive the absorption chilling system 100. The resultant cold refrigerant returning from the absorption chilling system 100 may be used to provide chilling to various components of the power plant. For example, in certain embodiments the second heat exchanger 104 may provide chilling to the inlet air of a gas turbine (if any) on site. In other embodiments, the second heat exchanger 104 may provide chilling to one or more thermal energy storage tanks. In still further embodiments, the second heat exchanger 104 may provide chilling to one or more condensers. Those skilled in the art will appreciate other uses for chilling provided by the second heat exchanger 104.

[0064] Additionally, a heating device 106 may be included, which uses heat from the heat rejection inherent to the absorption chilling system 100 (that is, heat rejected by the condenser 44, the absorber 52, and/or the cooler 58 described in reference to Figure 1 of the absorption chilling system 100). In certain embodiments, heat may be rejected (through heating device 106) to one or more cooling towers (either wet, dry, or hybrid). In further embodiments, heat may be rejected to a boiler feed water preheat system. In still further embodiments, heat may be rejected to a plant heating system or a coal drying system. In other embodiments, heat may be used for inlet air preheating.

[0065] Cooling systems described in accordance with one or more embodiments disclosed herein may help a fossil fuel-fired plant or other fossil fuel-fired facility realize the various benefits and advantages noted herein, including avoiding installation of expensive new equipment such as a Pulse Jet Fabric Filter (“PJFF”), Induced Draft Fan (“ID Fan”) or Booster Fan, Activated Carbon Injection System (“ACI”), Dry Sorbent Injection Systems (“DSI”), and/or ESP Flue Gas Conditioning systems.

[0066] Advantageously, embodiments of the present disclosure provide a system that may reduce or aid in reduction of air pollutant emissions and/or reduce or eliminate consumption of various feedstocks and reagents, and/or reduce water consumption and/or capture water present in the flue gas, and/or reduce the capital cost of emission control equipment and the materials and other costs of construction and/or reduce the time required to install required emissions control equipment and/or reduce or eliminate the interruption of operations/service associated with retrofits of existing facilities, and/or reduce the power consumption associated with operating a facility, and/or improve the safe operation of a facility (and safety during construction retrofit), when used alone or in combination with primary air quality control standalone devices such as electrostatic precipitators (ESP), activated carbon injection systems, dry sorbent injection systems, or fabric filter or wet FGD system or any combination of the above.

[0067] In addition, specific benefits may include one or more of the following: improved reduction of SO_3 (H_2SO_4), HCl, HF, or certain forms of acid gases; reduction of unoxidized; oxidized and precipitated forms of mercury (Hg) emissions; reduction of particulate matter (PM) emissions; reduction of ammonia slip or ammonium sulfate or ammonium bisulfate emissions; reduced or eliminated sorbent or reagent or activated carbon consumption for the reduction of acid gas emissions and mercury emissions; use of more economical carbon steel type materials of construction for any equipment or ductwork exposed to flue gas downstream; use of “dry” type in lieu of “wet” type stacks if wet FGD is involved; elimination of “blue plume” or acid formation issues for plants with high H_2SO_4 stack emissions; reduction of the visible water plume from the stack of plants with wet FGD; reduction of the flue gas volumetric flow rate; reduced fan power consumption; reduction of

operations and maintenance costs; reduction of stack opacity; improvement of life of the fans and their components; reduced wear and tear and reduced fan vibration; reduction of the makeup water consumption in a wet FGD system; capture/reclamation/recovery of water from the flue gas that otherwise would be lost to the atmosphere; elimination of the need for wet stack liner liquid removal system and corresponding piping or troughs; and reduction in the size of the heat exchangers relative to the other designs from use of absorption chilling, elimination of the need for Wet ESPs.

[0068] Some of these specific benefits may allow a plant to achieve the limits of the Mercury and Air Toxics Standards (MATS) also known as the National Emission Standards for Hazardous Air Pollutants: Utility NESHAP. For example, implementation of the embodiments disclosed herein may achieve or help a plant achieve the following stack emissions: mercury, ≤ 1.2 lb/TBtu or 0.013 lb/GWh; particulate matter, ≤ 0.03 lb/MMBtu or 0.3 lb/MWh; hydrogen chloride (HCl), ≤ 0.002 lb/MMBtu or 0.02 lb/MWh. In some embodiments, cooling the flue gas with the first and second heat extraction coils may include reducing the temperature of the flue gas a temperature differential sufficient to increase removal of at least one of sulfuric acid, mercury, particulate matter, and hydrogen chloride (HCl) in the first emission control device by at least 5% greater than without cooling of the flue gas.

[0069] In other embodiments, the cooling the flue gas upstream of the first emission control device may provide for decreased sorbent removal. For example, cooling the flue gas upstream of the first emission control device may include reducing the temperature of the flue gas a temperature differential sufficient to decrease the consumption rate of a sorbent used to remove at least one of sulfuric acid, mercury, and hydrogen chloride (HCl) in the first emission control device by at least 5% less than without cooling of the flue gas upstream of the first emission control device.

[0070] Embodiments disclosed herein may advantageously provide a system or systems to reduce water consumption and/or recover water used in facilities of the type described in the previous paragraph. Embodiments disclosed herein may advantageously provide a system or systems to reduce the auxiliary or parasitic loads associated with operating a facilities of the type described above. Embodiments

disclosed herein may advantageously provide a system or systems to reduce the duty or service requirements on certain pieces of equipment associated with operating facilities of the type described above, thereby extending the useful life of certain equipment and/or minimizing the maintenance burden associated therewith. Embodiments disclosed herein may advantageously provide a system or systems to provide a source of cooling for equipment, buildings and/or to the reduce the load/duty associated with other cooling systems already in operation in facilities of the type described above, thereby reducing auxiliary or parasitic loads and/or otherwise improving the efficiency of other pieces of equipment.

[0071] While the present disclosure has been described with respect to a limited number of embodiments, those skilled in the art, having benefit of this disclosure, will appreciate that other embodiments may be devised which do not depart from the scope of the disclosure as described herein. Accordingly, the scope of the disclosure should be limited only by the attached claims.

CLAIMS

What is claimed is:

1. A method of reducing flue gas emissions, the method comprising:
cooling a flue gas upstream of a first emission control device with at least one heat exchange device; and
transferring heat directly or indirectly from the at least one heat exchange device to an absorption chilling or other heat-activated chilling system.
2. The method of claim 1, further comprising cooling the flue gas at one or more additional locations using the absorption chilling or other heat-activated chilling system.
3. The method of claim 1 or claim 2, further comprising rejecting heat from the absorption chilling or other heat-activated chilling system to one or more locations.
4. The method of claim 3, wherein the rejecting heat comprises at least one of heating the flue gas upstream of a flue-gas stack or drying coal with heat rejected from the absorption chilling or other heat-activated chilling system.
5. The method of any one of claims 1-4, wherein the cooling the flue gas upstream of the first emission control device comprises reducing the temperature of the flue gas a temperature differential sufficient to increase removal of at least one of sulfuric acid, mercury, particulate matter, and hydrogen chloride (HCl) in the first emission control device by at least 5% greater than without cooling of the flue gas upstream of the first emission control device.
6. The method of claim 5, further comprising reducing at least one of the following pollutants in the flue gas to below the level indicated: mercury, 1.2 lb/TBtu or 0.013 lb/GWh; particulate matter, 0.03 lb/MMBtu or 0.3 lb/MWh; hydrogen chloride (HCl), 0.002 lb/MMBtu or 0.02 lb/MWh.
7. The method of any one of claims 1-6, wherein the cooling the flue gas upstream of the first emission control device comprises reducing the temperature of the flue gas a temperature differential sufficient to decrease the consumption rate of a sorbent used to remove at least one of sulfuric acid, mercury, and hydrogen chloride (HCl) in the first emission control device by at least 5% less than without cooling of the flue gas upstream of the first emission control device.
8. A flue gas treatment system comprising:
at least one emission control device;

a heat exchange device that removes heat from a flue gas upstream of the at least one emission control device and transfers heat directly or indirectly to an absorption chilling or other heat-activated chilling system; and
the absorption chilling or other heat-activated chilling system.

9. The system of claim 8, further comprising a heat exchange device that receives heat rejected from the absorption chilling or other heat-activated chilling system and reheats the flue gas upstream of a flue-gas stack.
10. A method of reducing flue gas emissions, the method comprising:
cooling a flue gas with a first heat exchange device at a first location;
cooling the flue gas with a second heat exchange device at a second location; and
transferring heat from the first and second heat exchange devices to an absorption chilling or other heat-activated chilling system.
11. The method of claim 10, further comprising cooling the flue gas at one or more third locations using the absorption chilling or other heat-activated chilling system.
12. The method of claim 10 or claim 11, wherein the first location is upstream of a first emission control device.
13. The method of claim 12, wherein the second location is downstream of a second emission control device.
14. The method of any one of claims 10-13, wherein the cooling the flue gas upstream of the first emission control device comprises reducing the temperature of the flue gas a temperature differential sufficient to increase removal of at least one of sulfuric acid, mercury, particulate matter, and hydrogen chloride (HCl) in the first emission control device by at least 5% greater than without cooling of the flue gas upstream of the first emission control device.
15. The method of claim 14, further comprising reducing at least one of the following pollutants in the flue gas to below the level indicated: mercury, 1.2 lb/TBtu or 0.013 lb/GWh; particulate matter, 0.03 lb/MMBtu or 0.3 lb/MWh; hydrogen chloride (HCl), 0.002 lb/MMBtu or 0.02 lb/MWh.
16. The method of any one of claims 10-15, further comprising heating the flue gas at a fourth location with heat rejected from the absorption chilling or other heat-activated chilling system.
17. The method of any one of claims 10-16, wherein the cooling the flue gas upstream of the first emission control device comprises reducing the temperature of the flue gas a

temperature differential sufficient to decrease the consumption rate of a sorbent used to remove at least one of sulfuric acid, mercury, and hydrogen chloride (HCl) in the first emission control device by at least 5% less than without cooling of the flue gas upstream of the first emission control device.

18. A flue gas treatment system comprising:
 - a first heat extraction coil that removes heat from a flue gas;
 - a second heat extraction coil that removes heat from a flue gas; and
 - an absorption chilling or other heat-activated chilling system, wherein heat from at least one of the first and second heat extraction coils is transferred to the absorption chilling or other heat-activated chilling system.
19. The system of claim 18, further comprising a heating coil that receives heat rejected from the absorption chilling or other heat-activated chilling system and heats the flue gas upstream of a flue-gas stack.
20. A method of reducing flue gas emissions, the method comprising:
 - cooling a flue gas upstream of an emission control device with a first heat extraction coil;
 - cooling the flue gas upstream or downstream of a flue gas desulfurization (FGD) absorber with a second heat extraction coil; and
 - transferring heat from the first heat extraction coil to an absorption chilling or other heat-activated chilling system.
21. The method of claim 20, further comprising providing cooling from the absorption chilling or other heat-activated chilling system to the second heat extraction coil.
22. The method of claim 20 or claim 21, further comprising rejecting heat from the absorption chilling or other heat-activated chilling system to one or more locations.
23. The method of any one of claims 20-22, wherein the first emission control device comprises at least one of an electrostatic precipitator and a fabric filter.
24. The method of any one of claims 20-23, wherein the cooling the flue gas with the first and second heat extraction coils comprises reducing the temperature of the flue gas a temperature differential sufficient to increase removal of at least one of sulfuric acid, Mercury, Particulate Matter, and Hydrogen chloride (HCl) in the first emission control device by at least 5% greater than without cooling of the flue gas.

25. The method of claim 24, further comprising reducing at least one of the following pollutants in the flue gas to below the level indicated: mercury, 1.2 lb/TBtu or 0.013 lb/GWh; particulate matter, 0.03 lb/MMBtu or 0.3 lb/MWh; hydrogen chloride (HCl), 0.002 lb/MMBtu or 0.02 lb/MWh.
26. The method of any one of claims 20-25, further comprising heating the flue gas with heat rejected from the absorption chilling or other heat-activated chilling system upstream of a flue gas stack.
27. The method of any one of claims 20-26, wherein the cooling the flue gas upstream of the first emission control device comprises reducing the temperature of the flue gas a temperature differential sufficient to decrease the consumption rate of a sorbent used to remove at least one of sulfuric acid, mercury, and hydrogen chloride (HCl) in the first emission control device by at least 5% less than without cooling of the flue gas upstream of the first emission control device.
28. A flue gas treatment system comprising:
an emission control device;
a first heat extraction coil that removes heat from a flue gas upstream of the emission control device at a first location and transfers the heat to an absorption chilling or other heat-activated chilling system;
the absorption chilling or other heat-activated chilling system, wherein the heat from the first heat extraction device is transferred to the absorption chilling or other heat-activated chilling system to thereby provide chilling at a second heat extraction coil;
a flue gas desulfurization (FGD) absorber for removing pollutants from the flue gas;
and
the second heat extraction coil at a second location for removing heat from the flue gas downstream of the first location.
29. The system of claim 28, further comprising a heating coil that receives heat rejected from the absorption chilling or other heat-activated chilling system and heats the flue gas upstream of a flue-gas stack.
30. The system of any one of claims 28-29, wherein the first emission control device comprises at least one of an electrostatic precipitator and a fabric filter.

31. The system of any one of claims 28-30, wherein the second heat extraction coil cools the flue gas upstream or downstream of the FGD absorber.
32. A method of reducing flue gas emissions, the method comprising:
cooling a flue gas with a first heat extraction coil upstream of an electrostatic precipitator or fabric filter;
cooling the flue gas with a second heat extraction coil upstream of the electrostatic precipitator or the fabric filter; and
transferring heat from at least one of the first and second heat extraction coils to an absorption chilling or other heat-activated chilling system.
33. The method of claim 32, further comprising cooling the flue gas at one or more additional locations using the absorption chilling or other heat-activated chilling system.
34. The method of claim 32 or claim 33, further comprising rejecting heat from the absorption chilling or other heat-activated chilling system to one or more locations.
35. The method of claim 34, further comprising heating the flue gas with heat rejected from the absorption chilling or other heat-activated chilling system in a heating coil upstream of a flue-gas stack.
36. A flue gas treatment system comprising:
an electrostatic precipitator or fabric filter;
a first heat extraction coil that removes heat from a flue gas upstream of the electrostatic precipitator or fabric filter at a first location;
a second heat extraction coil at a second location that removes heat from the flue gas upstream of the electrostatic precipitator or fabric filter at a second location downstream of the first location; and
an absorption chilling or other heat-activated chilling system, wherein heat from the first heat extraction device is transferred to the absorption chilling or other heat-activated chilling system to thereby provide chilling at the second heat extraction coil.
37. The flue gas cooling system of claim 36, further comprising a heating coil that receives heat rejected from the absorption chilling or other heat-activated chilling system and heats the flue gas upstream of a flue-gas stack.

38. A method of reducing flue gas emissions, the method comprising:
extracting heat from a flue gas with a heat extraction coil at a first location upstream
of an electrostatic precipitator or fabric filter or both;
transferring the extracted heat to an absorption chilling or other heat-activated chilling
system; and
providing cooling from the absorption chilling or other heat-activated chilling system
to a second location.
39. The method of claim 38, further comprising rejecting heat from the absorption
chilling or other heat-activated chilling system at a third location.
40. The method of claim 38 or claim 39, further comprising heating the flue gas with heat
rejected from the absorption chilling or other heat-activated chilling system in a heating coil
upstream of a flue-gas stack.
41. The method of any one of claims 38-40, wherein the cooling the flue gas with the first
and second heat extraction coils comprises reducing the temperature of the flue gas a
temperature differential sufficient to increase removal of at least one of sulfuric acid,
mercury, particulate matter, and hydrogen chloride (HCl) in the first emission control device
by at least 5% greater than without cooling of the flue gas.
42. The method of claim 41, further comprising reducing at least one of the following
pollutants in the flue gas to below the level indicated: mercury, 1.2 lb/TBtu or 0.013
lb/GWh; particulate matter, 0.03 lb/MMBtu or 0.3 lb/MWh; hydrogen chloride (HCl), 0.002
lb/MMBtu or 0.02 lb/MWh.
43. The method of any one of claims 38-42, wherein the cooling the flue gas upstream of
the first emission control device comprises reducing the temperature of the flue gas a
temperature differential sufficient to decrease the consumption rate of a sorbent used to
remove at least one of sulfuric acid, mercury, and hydrogen chloride (HCl) in the first
emission control device by at least 5% less than without cooling of the flue gas upstream of
the first emission control device.
44. A flue gas treatment system comprising:
an electrostatic precipitator or fabric filter;
a heat extraction coil that removes heat from a flue gas upstream of the electrostatic
precipitator or fabric filter at a first location; and

an absorption chilling or other heat-activated chilling system, wherein heat from the first heat extraction device is transferred to the absorption chilling or other heat-activated chilling system to thereby provide water or other cooling media to a second location.

45. The system of claim 44, further comprising a heating coil that receives heat rejected from the absorption chilling or other heat-activated chilling system and reheats the flue gas upstream of a flue-gas stack.

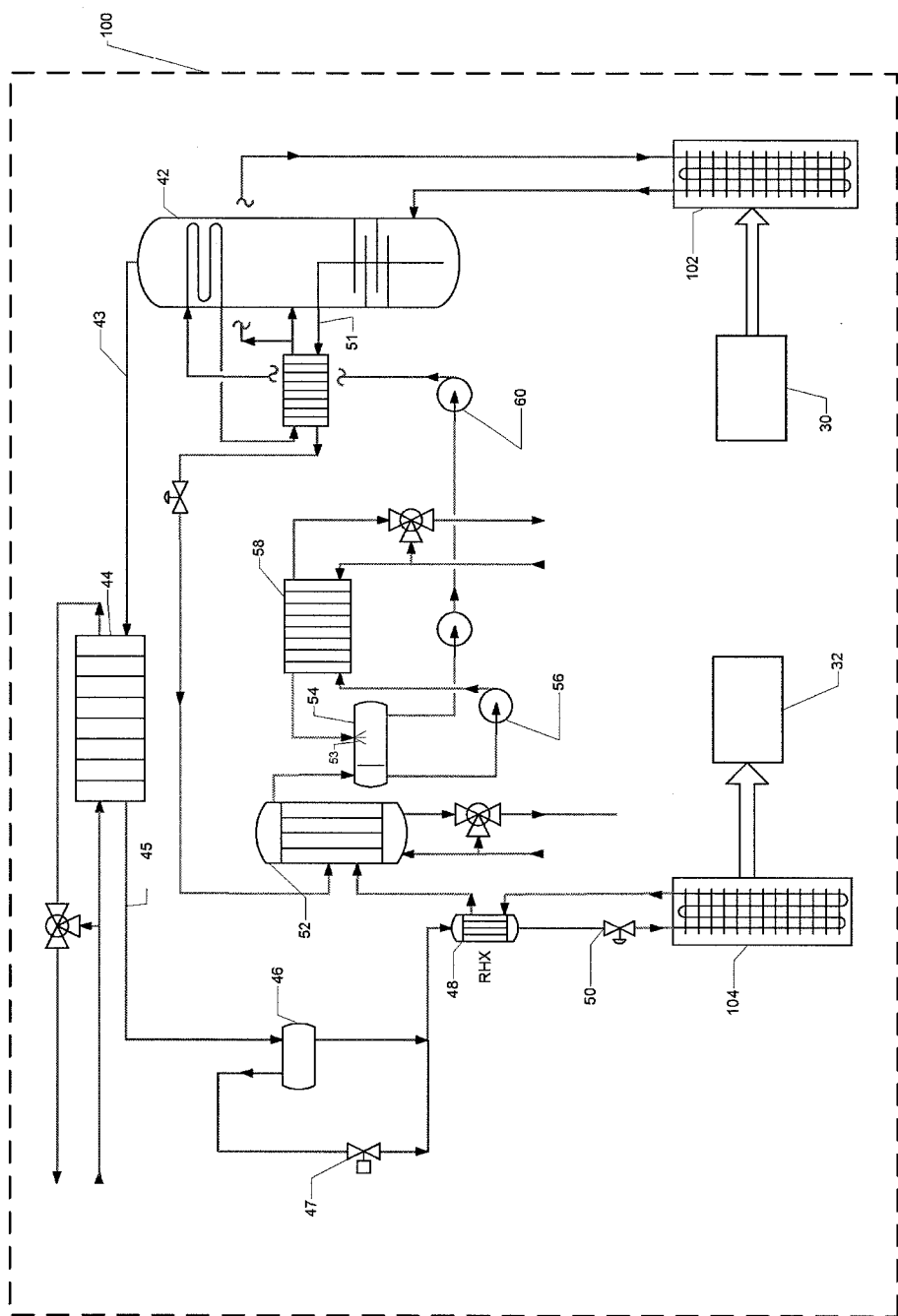


FIGURE 1

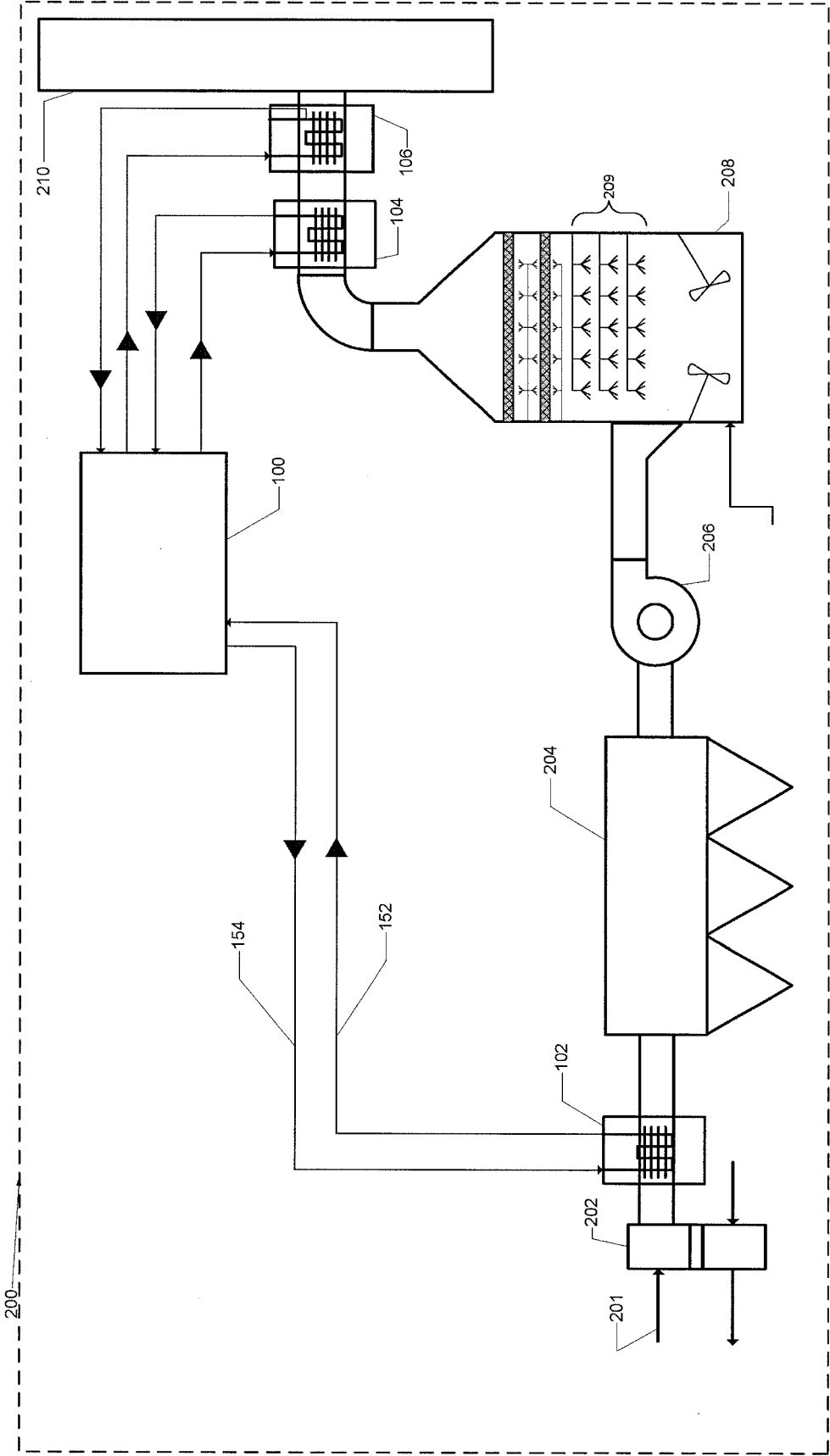


FIGURE 2

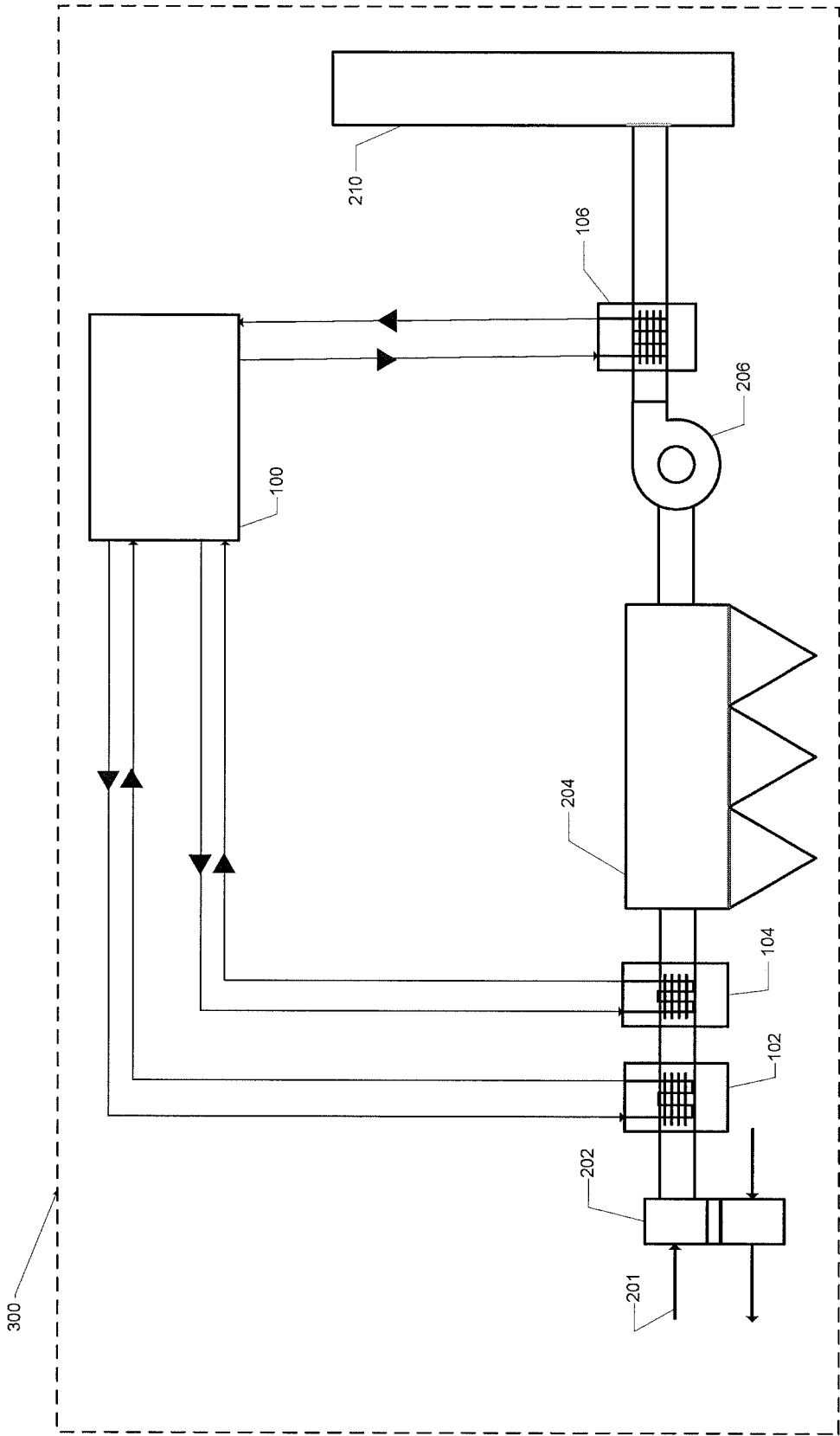


FIGURE 3

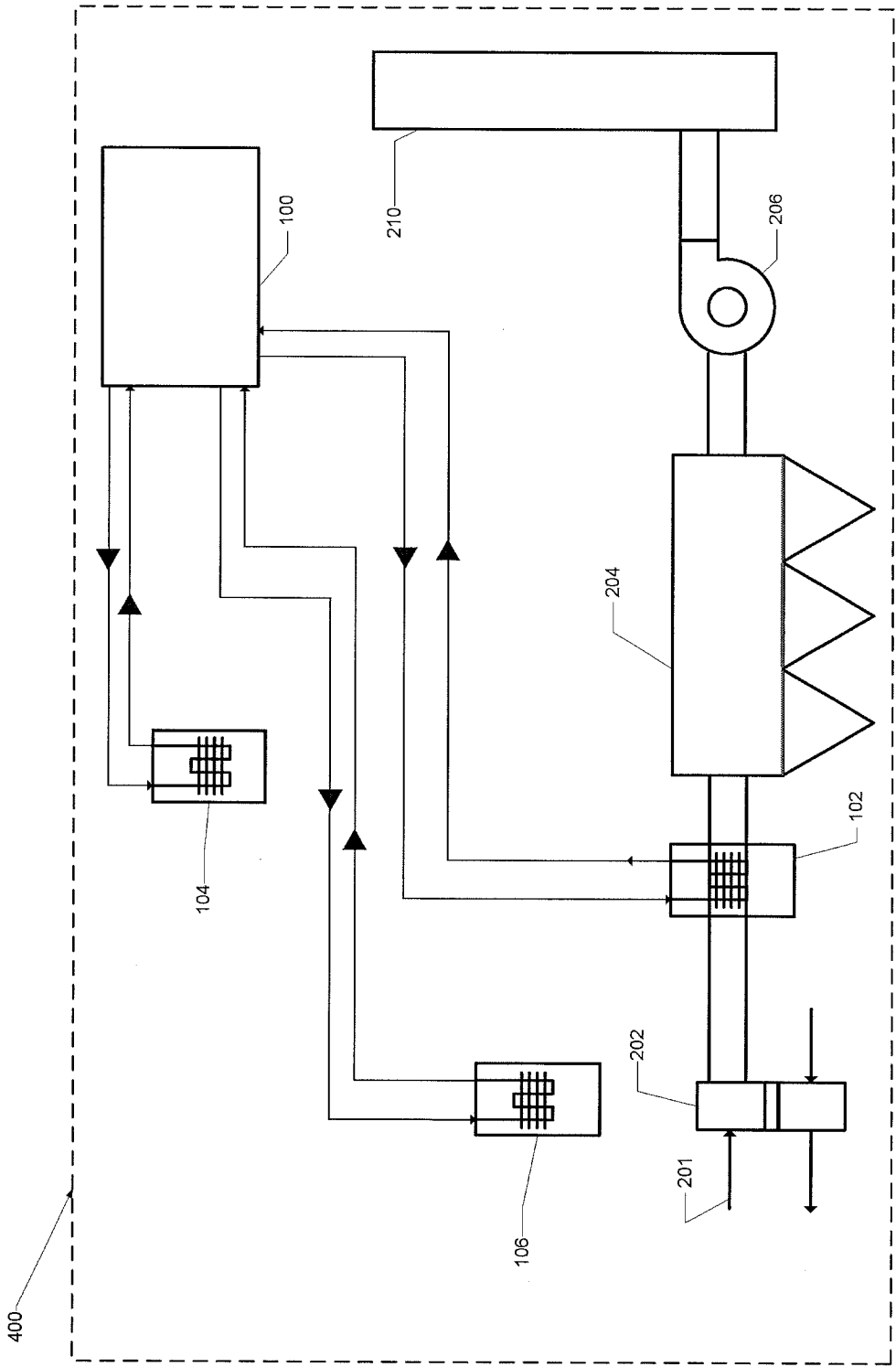


FIGURE 4

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2014/020346

A. CLASSIFICATION OF SUBJECT MATTER

B01D 53/74(2006.01)i, B01D 5/00(2006.01)i

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)

B01D 53/74; B01D 50/00; F25J 3/08; B01D 53/86; F23J 15/00; B03C 3/155; B01D 19/00; B01D 53/14; B01D 49/02; F25D 17/02; G05D 23/00; B03C 3/16; B01D 5/00

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Korean utility models and applications for utility models

Japanese utility models and applications for utility models

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)

eKOMPASS(KIPO internal) & Keywords: flue gas, emission, heat, cooling, chilling

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 2011-0061528 A1 (TAYLOR, R. W. et al.) 17 March 2011 See abstract; and paragraphs [0008]-[0011], [0018]-[0027]; and figures 1, 2.	1,8
A		2-4, 9-13, 18-22 , 28-30, 32-40, 44-45
A	US 2009-0078401 A1 (CICHANOWICZ, J. E.) 26 March 2009 See abstract; paragraphs [0009], [0011], [0092]-[0096], [0166]-[0168]; and figures 9, 10.	1-4, 8-13, 18-22 , 28-30, 32-40, 44-45
A	US 2012-0180521 A1 (ERICKSON, D. C.) 19 July 2012 See abstract; claims 13-18; and paragraph [0027].	1-4, 8-13, 18-22 , 28-30, 32-40, 44-45
A	US 2011-0052453 A1 (MCLARNON, C. et al.) 03 March 2011 See abstract; claim 3; and paragraph [0003].	1-4, 8-13, 18-22 , 28-30, 32-40, 44-45
A	US 2011-0165042 A1 (ABRAMS, R. F. et al.) 07 July 2011 See abstract; claims 1, 16; and paragraph [0006].	1-4, 8-13, 18-22 , 28-30, 32-40, 44-45
A	KR 10-1999-0072635 A (MITSUBISHI HEAVY INDUSTRIES LTD.) 27 September 1999 See abstract; and pages 5, 6.	1-4, 8-13, 18-22 , 28-30, 32-40, 44-45

☐ Further documents are listed in the continuation of Box C.

☒ See patent family annex.

* Special categories of cited documents:

"A" document defining the general state of the art which is not considered to be of particular relevance

"E" earlier application or patent but published on or after the international filing date

"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)

"O" document referring to an oral disclosure, use, exhibition or other means

"P" document published prior to the international filing date but later than the priority date claimed

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art

"&" document member of the same patent family

Date of the actual completion of the international search

12 June 2014 (12.06.2014)

Date of mailing of the international search report

12 June 2014 (12.06.2014)

Name and mailing address of the ISA/KR



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INTERNATIONAL SEARCH REPORTInternational application No.
PCT/US2014/020346**Box No. II Observations where certain claims were found unsearchable (Continuation of item 2 of first sheet)**

This international search report has not been established in respect of certain claims under Article 17(2)(a) for the following reasons:

1. ☐ Claims Nos.:
because they relate to subject matter not required to be searched by this Authority, namely:
2. ☒ Claims Nos.: 6, 15, 25, 42
because they relate to parts of the international application that do not comply with the prescribed requirements to such an extent that no meaningful international search can be carried out, specifically:
Claims 6, 15, 25 and 42 are unclear since they refer to claims which are not searchable due to not being drafted in accordance with the second and third sentence of Rule 6.4(a).
3. ☒ Claims Nos.: 5, 7, 14, 16, 17, 23, 24, 26, 27, 31, 41, 43
because they are dependent claims and are not drafted in accordance with the second and third sentences of Rule 6.4(a).

Box No. III Observations where unity of invention is lacking (Continuation of item 3 of first sheet)

This International Searching Authority found multiple inventions in this international application, as follows:

1. ☐ As all required additional search fees were timely paid by the applicant, this international search report covers all searchable claims.
2. ☐ As all searchable claims could be searched without effort justifying an additional fees, this Authority did not invite payment of any additional fees.
3. ☐ As only some of the required additional search fees were timely paid by the applicant, this international search report covers only those claims for which fees were paid, specifically claims Nos.:
4. ☐ No required additional search fees were timely paid by the applicant. Consequently, this international search report is restricted to the invention first mentioned in the claims; it is covered by claims Nos.:

Remark on Protest

- ☐ The additional search fees were accompanied by the applicant's protest and, where applicable, the payment of a protest fee.
- ☐ The additional search fees were accompanied by the applicant's protest but the applicable protest fee was not paid within the time limit specified in the invitation.
- ☐ No protest accompanied the payment of additional search fees.

INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No.

PCT/US2014/020346

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INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No.

PCT/US2014/020346

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