



- (51) International Patent Classification:
F23J 7/00 (2006.01) *F23J 15/02* (2006.01)
F23J 15/00 (2006.01)
- (21) International Application Number: PCT/IB2016/050514
- (22) International Filing Date: 2 February 2016 (02.02.2016)
- (25) Filing Language: English
- (26) Publication Language: English
- (30) Priority Data:
14/622,247 13 February 2015 (13.02.2015) US
14/658,950 16 March 2015 (16.03.2015) US
- (71) Applicants: DÜRR SYSTEMS GMBH [DE/DE]; Carl-Benz-Str. 34, 74321 Bietigheim-Bissingen (DE). CLEAR-CHEM DEVELOPMENT LLC [US/US]; 1882 Manor View Circle NW, Acworth, Georgia 30101 (US).
- (72) Inventors: RIEDER, Erhard; Im Seele 68, 71083 Herrenberg (DE). SCHRÖTER, Martin; 1821 Pontiac Trail, Ann Arbor, Michigan 48105 (US). RADWAY, Jerrold; 1882 Manor View Circle NW, Acworth, Georgia 30101 (US).
- (74) Agent: PRÜFER & PARTNER MBB PATENTANWÄLTE RECHTSANWÄLTE; Sohnckestr. 12, 81479 München (DE).
- (81) Designated States (unless otherwise indicated, for every kind of national protection available): AE, AG, AL, AM, AO, AT, AU, AZ, BA, BB, BG, BH, BN, BR, BW, BY, BZ, CA, CH, CL, CN, CO, CR, CU, CZ, DE, DK, DM, DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID, IL, IN, IR, IS, JP, KE, KG, KN, KP, KR, KZ, LA, LC, LK, LR, LS, LU, LY, MA, MD, ME, MG, MK, MN, MW, MX, MY, MZ, NA, NG, NI, NO, NZ, OM, PA, PE, PG, PH, PL, PT, QA, RO, RS, RU, RW, SA, SC, SD, SE, SG, SK, SL, SM, ST, SV, SY, TH, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, ZA, ZM, ZW.
- (84) Designated States (unless otherwise indicated, for every kind of regional protection available): ARIPO (BW, GH, GM, KE, LR, LS, MW, MZ, NA, RW, SD, SL, ST, SZ,

[Continued on next page]

(54) Title: METHOD AND APPARATUS TO INCREASE INDUSTRIAL COMBUSTION EFFICIENCY

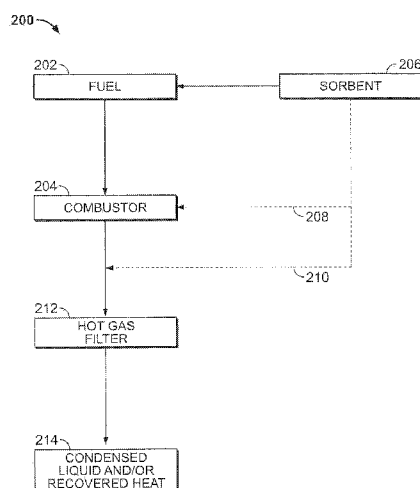


FIG. 2

(57) Abstract: Methods and apparatus to improve industrial combustion efficiency are disclosed. One disclosed example method includes providing sorbent (206) to a combustor (204; 306) and/or to flue gas exiting the combustor (204; 306) after a combustion process. The disclosed example method also includes providing the flue gas to a hot gas filter (212; 320) after the flue gas exits the combustor (204; 306).



TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, RU, TJ, TM), European (AL, AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LT, LU, LV, MC, MK, MT, NL, NO, PL, PT, RO, RS, SE, SI, SK, SM, TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, KM, ML, MR, NE, SN, TD, TG).

Published:

- *upon request of the applicant, before the expiration of the time limit referred to in Article 21(2)(a)*
- *without international search report and to be republished upon receipt of that report (Rule 48.2(g))*

METHOD AND APPARATUS TO INCREASE INDUSTRIAL COMBUSTION EFFICIENCY

5 FIELD OF THE DISCLOSURE

The present invention relates generally to combustion systems such as industrial and utility boiler plants and, more particularly, to methods, materials, and apparatus to reduce fireside slagging and fouling, fuel consumption, emissions, (including SO_x, NO_x, HCl, Hg, Se, As, toxic metals and acid-forming compounds) and capital cost for new plants, while
10 recovering useful amounts of water, and increasing the overall efficiency of existing and new boiler plants.

BACKGROUND

Boiler plants are typically used to generate steam and/or electricity from combusting solid
15 fuels such as coal. Typically, such combustion processes necessitate combustion byproducts (particulate and gaseous) are removed from the resulting flue gas to meet certain environmental and/or regulatory standards. In many combustion processes, acid-forming compounds may be present in the resultant flue gas. Such acid-forming compounds may require special materials in the boiler plant and/or precautions for acid
20 resulting from acid-forming compounds in the flue gas. In many boiler plants, a wet flue gas desulphurization ("FGD") process is used to remove acid-forming compounds. Though sometimes effective for SO₂ removal, they are not as effective in capturing the much lesser quantities of the acid precursor SO₃, which can present an environmental problem. These processes are also very capital intensive, consume large quantities of
25 water, and generate significant quantities of CaSO₃ and gypsum for sale or land fill disposal.

SUMMARY OF THE INVENTION

It is an object of the present invention to provide improved methods and apparatus
30 achieving increased industrial combustion efficiency.

This object is achieved by a method comprising the features of appending claim 1 and an apparatus comprising the features of appending claim 19, respectively. Advantageous configurations of the present invention are defined in the dependent claims.

The inventive method comprises a step of providing at least one type of sorbent to a combustor and/or to flue gas exiting the combustor after a combustion process; and at least one method step of a) providing the flue gas after exiting the combustor to a hot gas filter, and b) cooling the flue gas to a temperature below at least a highest dew point of any condensable component remaining after the flue gas exits the combustor or condensing at least one vaporized component from the flue gas after the flue gas exits the combustor to form a condensate.

10 In one aspect of the invention, the inventive method comprises providing sorbent to one or more of a combustion chamber or to flue gas exiting the combustion chamber after a combustion process, and providing the flue gas to a hot gas filter after the flue gas exits the combustion chamber.

15 In another aspect of the invention, the inventive method comprises providing sorbent to a combustion chamber, wherein the sorbent is provided to fuel, combustion air, or a mixture of fuel and combustion air prior to being provided to and combusted in the combustion chamber, and providing flue gas from the combustion chamber to a catalytic filter.

20 In another aspect of the invention, the inventive method comprises providing at least one type of sorbent to one or more of a combustion chamber or to flue gas exiting the combustion chamber after a combustion process, and condensing at least one vaporized component from the flue gas after the flue gas exits the combustion chamber to form a condensate. The condensing step may be carried out in various ways. Especially, one or
25 more of the following processes can be used to condense at least one vaporized component from the flue gas: lowering temperature of the flue gas, increasing pressure of the flue gas, injecting condensation nuclei into the flue gas, inducing shock waves into the flue gas, irradiating electromagnetic waves into the flue gas, irradiating ionizing waves into the flue gas.

30 In still another aspect of the invention, the inventive method comprises providing at least one sorbent to one or more of a combustion chamber of a boiler plant or to flue gas exiting the combustion chamber after a combustion process, and cooling the flue gas to a temperature below at least the highest dew point of any condensable component remaining after

the flue gas exits the combustion chamber. By cooling the flue gas in such a way, at least one vaporized component from the flue gas exiting the combustor is condensed to form a condensate.

- 5 Preferably, the flue gas is cooled to a temperature below at least a highest dew point of a vaporized component after the flue gas exits the hot gas filter to form a condensate.

In an advantageous configuration of the invention, the method further comprises providing the condensate to a boiler feed or a boiler feed water processing system.

10

In an advantageous configuration of the invention, heat released from condensing the condensate may be provided to the combustor or transferred to other parts of a steam cycle.

- 15 In an advantageous configuration of the invention, the flue gas is provided with a dry sorbent prior to being provided to the hot gas filter.

In an advantageous configuration of the invention, the method may further comprise activation of an ash removal device or an ash removal mechanism, or back-pulsing on at
20 least a subset of filter elements of the hot gas filter to remove cake formed on the hot gas filter to provide further control of residence time of the sorbent.

- In an advantageous configuration of the invention, the sorbent is provided to the combustor, and the method further comprises a step of adjusting an amount of the sorbent to
25 be provided to the combustor.

In this configuration, the amount of the sorbent to be provided to the combustor may preferably be based on a flow rate of fuel into the combustor.

- 30 In an advantageous configuration of the invention, the hot gas filter comprises a catalytic filter or a ceramic catalytic filter. Preferably, the catalytic filter comprises filter elements, each of the filter elements comprising fibers or fabric, and a catalyst material. Preferably, these fibers have catalyst material embedded within. In addition or alternatively, the catalytic filter may further comprise a surface barrier.

In an advantageous configuration of the invention, the sorbent is provided to fuel, combustion air, or a mixture of fuel and combustion air prior to being provided to and combusted in the combustor.

5

In an advantageous configuration of the invention, the method may further comprise a step of providing a reducing agent, or a liquid, liquidized, dissolved or dispersed agent to the flue gas prior to the flue gas entering the hot gas filter.

- 10 In an advantageous configuration of the invention, the method may further comprise a step of providing the flue gas to a heat recovery steam generator after the flue gas exits the hot gas filter.

15 Preferably, the flue gas is provided to the hot gas filter before condensing or cooling the flue gas.

In an advantageous configuration of the invention, the method may further comprise a step of providing the condensate to a boiler feed or a boiler feed water processing system.

- 20 In an advantageous configuration of the invention, heat released from cooling the flue gas may be provided to the combustor or transferred to other parts of a steam cycle.

25 The inventive apparatus comprises a combustor of a boiler plant wherein sorbent is provided to the combustor and/or to flue gas after the flue gas exits the combustor during a combustion process, and a hot gas filter of the boiler plant to receive the flue gas and reduce acid-forming compounds or pollutants from the flue gas and/or a condenser to condense at least one vaporized component from the flue gas to form a condensate. The condensate may optionally be provided to a boiler feed (via fluid treatment means, if appropriate), an additional heat exchanger or an alternative condensate consuming
30 process.

In one aspect of the invention, the inventive apparatus comprises a combustion chamber of a boiler plant wherein sorbent is provided to the combustion chamber or provided to flue gas after the flue gas exits the combustion chamber during a combustion process,

and a hot gas filter of the boiler plant to receive the flue gas and reduce acid-forming compounds or pollutants from the flue gas.

5 In another aspect of the invention, the inventive apparatus comprises a combustion chamber wherein sorbent is provided to the combustion chamber or provided to flue gas after the flue gas exits the combustion chamber during a combustion process, and a condenser to condense at least one vaporized component from the flue gas to form a condensate, whereby the condensate is optionally provided to a boiler feed (via fluid treatment means, if appropriate), an additional heat exchanger or an alternative
10 condensate consuming process.

Preferably, the hot gas filter is arranged upstream the condenser.

15 In an advantageous configuration of the invention, at least a subset of filter elements of the hot gas filter may be provided with an ash removal device or an ash removal mechanism, or back-pulsed to remove cake formed on the hot gas filter to control a residence time of the sorbent and especially increase the utilization efficiency of the sorbent, thereby enhancing the capture of SO_x by the sorbent.

20 In an advantageous configuration of the invention, the fuel comprises solid fuel and the sorbent is mixed with the solid fuel or combustion air prior to the solid fuel being combusted in the combustor.

25 In an advantageous configuration of the invention, the hot gas filter may comprise a catalytic filter, wherein the catalytic filter comprises fibers, catalyst material and a surface barrier.

30 In an advantageous configuration of the invention, the condenser may comprise synthetic materials or plastics. Preferably, at least a heat exchanging section comprises synthetic materials and/or plastics. Preferably, the condenser comprises a tube bundle heat exchanger, wherein the heat exchanging tubes comprise synthetic materials or plastics.

In an advantageous configuration of the invention, the apparatus may further comprise a branch line to enable a portion of the flue gas to bypass the hot gas filter. Preferably, the branch line may comprise an electrostatic precipitator or an electromagnetic separator.

5 BRIEF DESCRIPTION OF THE DRAWINGS

FIGS. 1A-1C are schematic illustrations of known boiler plants.

FIG. 2 is a schematic overview of an example process in accordance with the teachings of this disclosure.

10 FIG. 3A is a schematic illustration of an example boiler plant to implement the example process of FIG. 2.

FIG. 3B is a schematic illustration of an alternative example boiler plant to implement the process of FIG. 2.

FIG. 4 illustrates an example catalytic filter of the example boiler plants of FIGS. 3A and 3B.

15 FIG. 5 is a detailed view of a filter element of the example catalytic filter of FIG. 4.

FIG. 6 is a flowchart representative of an example method that may be used to implement and/or control the example boiler plant of FIG. 3A, for example.

20 FIG. 7 is a flowchart representative of another example method that may be used to implement and/or control the example boiler plant of FIG. 3A, for example.

FIG. 8 is a block diagram of an example processor platform capable of executing machine readable instructions to implement the example methods of FIGS. 6 and 7.

25 The figures are not to scale. Instead, to clarify multiple layers and regions, the thickness of the layers may be enlarged in the drawings. Wherever possible, the same reference numbers will be used throughout the drawing(s) and accompanying written description to refer to the same or like parts. As used in this patent, stating that any part (e.g., a layer, film, area, or plate) is in any way positioned on (e.g., positioned on, located on, disposed on, or formed on, etc.) another part, means that the referenced part is either in contact with the other part, or that the referenced part is above the other part with one or more intermediate part(s) located therebetween. Stating that any part is in contact with another part means that there is no intermediate part between the two parts.

30

DETAILED DESCRIPTION

Methods, materials, and apparatus to reduce emission of particulates, toxic metals, gaseous pollutants, and condensable acid-forming compounds in flue gas from industrial combustion process equipment, such as coke calciners, iron or steel processing furnaces, incinerators, gasifiers, limestone production furnaces, refinery systems industrial ovens or furnaces and/or power plant equipment, and more specifically in boiler plant flue gas are disclosed herein. Typically, flue gas resulting from the combustion of most fuels (e.g., gas exiting a combustion chamber or furnace in a boiler plant) may contain fine ash particles, gaseous pollutants, and acid-forming compounds such as sulfur oxides and/or halogen containing compounds, etc. Such acid-forming compounds may cause damage and/or require special construction materials that may be relatively expensive, for example, to guide and/or contain the flue gas containing acid-forming compounds. In known examples, flue gases are kept above the highest dew point of the acid-forming compound(s) and/or vaporized components. In particular, the flue gas may be maintained at temperatures above approximately 320°F (160°C) to prevent acid-forming compounds from condensing.

In known examples, a flue gas desulphurization (FGD) process is used to remove a significant fraction of the acidic compounds from the flue gas. In particular, an FGD scrubber, which may utilize a spray (e.g. a spray of -325 mesh limestone slurry or $\text{Ca}(\text{OH})_2$, etc.) to remove compounds containing both sulfur and oxygen (e.g., SO_x compounds), is applied to flue gas kept at a temperature above the dew point of the acid compounds in the flue gas. Usually, the application of the spray causes the flue gas to be cooled rapidly in the FGD scrubber, thereby resulting in a significant loss of heat from the flue gas and vaporization of significant amounts of water.

A number of other emission control technologies (Dry Sorbent Injection and Dry Scrubbers, etc.) have been deployed that are somewhat less capital intensive and somewhat less efficient. Each of those technologies have their pros and cons and have been deployed commercially. The least costly and least capital intensive emission control technology, Furnace Sorbent Injection (FSI), has not been widely deployed, but will likely increase in use with the examples disclosed herein. In an early unsuccessful version of the technology employed, what was viewed by industry as fine powder (-325 mesh)

powder was inefficient and consumed large quantities of the powdered calcium compounds and produced significant quantities of solid waste for disposal. The examples disclosed herein bypass these shortcomings by employing micronized sorbents, some of which are waste or byproducts and others are commercially available and widely used in other industries.

Because power plant flue gases normally contain low concentrations of condensable acids which may quickly corrode heat exchangers and ducting and force the plant off line, industry practice has been to discharge the flue gas up the stack without capturing roughly 20% of the fuel energy. Both the latent heat of the gases and the heat of vaporization for the significant amounts of water in the flue gas are normally lost. The industry has for years applied small quantities additives (primarily calcium, magnesium, and fly ash) to mitigate some of the fouling and corrosion caused by the condensable acids

Generally, little effort has been made in known examples to capture the bulk of acid as solids so that the temperatures can be safely lowered to make it feasible to reap the benefits of capturing a significant fraction of the wasted energy and the vaporized water. The examples disclosed herein circumvent problems encountered with the early efforts to control SO₂ emissions by furnace injection. The examples disclosed herein also provide a relatively large stoichiometric excess of micronized bases (as much as 50 to 1) to capture a significant amount or essentially all of the condensable acids as filterable solids and employs one or both of two methods, for example, to concurrently enhance capture of the SO₂. In particular, the two methods are staged Condensing Heat Exchangers (CH_x) and hot catalytic filters. The hot catalytic filters function to increase efficiency of the micronized reagent (e.g., sorbent) by increasing the residence time of the sorbent particles in the flue gas path, preferably at or near optimum operation conditions, and then once essentially all the acid gases have been removed, the supplemental condensing heat exchange surface brings the flue gas below the acid dewpoint.

The examples disclosed herein further enhance the power plant economics by supplementing commercially produced micronized CaCO₃ with waste or byproduct micronized materials such as water softening sludges, beet lime, micronized fly ash, etc. These materials may be used separately or in combination with wet processed micronized

reagents converted into discrete particles for furnace injection by employing commercially available equipment such as the Hosokawa Drymeister, for example.

The examples disclosed herein enable reduction of acid-forming compounds in flue gas while reducing (e.g., eliminating) the need for rapid cooling of the flue gas, and reducing (e.g., eliminating) the dissipation of significant amounts of useful/usable energy during the vaporization of water, as seen in known FGD systems. The examples disclosed herein allow for less expensive materials to be used with flue gas due to effective upstream reduction (e.g., removal) of acid-forming compounds from the flue gas. Even further, the examples disclosed herein allow significant improvements in energy efficiency and, thus, boiler plant operating costs by enabling efficient recovery of heat from the flue gas by recovering heat from both the cooling of the gas and avoiding the unnecessary expenditure of energy in evaporating water, for example. The examples disclosed herein also allow recovery of heated water condensed from the flue gas to be provided after a polishing purification for various plant uses, as a boiler feed and/or a boiler feed processing system, for example, thereby allowing reduced overall water consumption, and possibly for reduced necessary heating of the water for later use. Additionally, the examples disclosed herein require a smaller footprint (e.g., are significantly more compact) than known FGD systems. Thus, the examples disclosed herein enable lower cost boiler plants and/or lower capital expenditures to build boiler plants (e.g., less expensive materials required because of effective reduction of acid-forming compounds, simpler and less bulky hardware, etc.) along with significantly reduced operating costs via energy savings and/or water recovery and thereby reduce the amount of CO₂ released per unit of energy produced by the boiler.

As used herein, in regards to adding a sorbent to a combustion chamber for example, "provided to" may include injecting and/or ad-mixing to fuel, combustion air and/or a mixture thereof before providing the resulting mixture to the combustion chamber and also includes direct injection into the combustion chamber.

FIGS. 1A-1C are schematic illustrations of known boiler plants that have wet flue gas desulphurization ("FGD") and separate DeNO_x systems to remove acid-forming compounds and/or nitrogen-oxides from flue gas. These known boiler plants use various

systems to remove compounds from the flue gas so that the flue gas may exit the boiler plant system to the external environment.

Turning to FIG. 1A, a known selective catalytic reduction (SCR) high dust system 100 is shown. The SCR system 100 includes a steam generator (e.g., a two draft boiler) 102, a DeNOx reactor 104, an air preheater 106, a dust remover 108, an FGD scrubber 112, and a stack (e.g., an exhaust stack, etc.) 114. The steam generator 102 is where carbon fuels, are combusted in order to produce steam, which, in turn, is used to generate electricity by turning a steam turbine. The FGD scrubber 112 is used to reduce SO₂ and part of acid-forming compound(s) from the flue gas. It is common on most scrubbers for much of the SO₃ to pass through the FGD system exiting as an acid mist of fine droplets that is visible once the steam plume evaporates. The DeNOx reactor 104 is used to reduce and/or remove nitrogen oxides (NO_x, mono-nitrogen oxides, etc.) from the flue gas.

In operation, as a result of the combustion process and fuels used in the combustion process, the resultant flue gas may contain acid-forming compounds such as sulfur oxides, hydrochloric acid (HCl) and/or halogen containing compounds, nitrogen oxides, and/or dust, etc. As the flue gas exits the steam generator 102, ammonia (NH₃) is added to the flue gas prior to the flue gas entering the DeNOx reactor 104. The ammonia typically is added to the flue gas to reduce NO₂ in the flue gas, which may result from nitrogen in the air used in combustion. Problems with air heater fouling by ammonium bisulfate are common and due in part to reaction of the excess ammonia required for NO_x control with the combustion derived SO₃. The furnace sorbent injection of micronized carbonate disclosed herein tends to scavenge the SO₃ and mitigate the air heater fouling. The flue gas leaving the DeNOx reactor 104 is used to heat furnace combustion air, for example, by the air preheater 106. In some known examples, the temperature of the flue gas is maintained at a higher temperature than the dew point of acid-forming compounds in the flue gas. The flue gas is then provided to the dust remover 108, whereby dust is removed from the flue gas. Prior to entering the FGD scrubber 112, the flue gas is kept above the highest dew point of acid-forming compounds contained within the flue gas.

The flue gas is then provided to the FGD scrubber 112 to remove fly ash and/or acid-forming compounds such as sulfur-dioxide (SO₂), for example. The flue gas is rapidly cooled in the FGD scrubber 112 to a temperature such as 175°F (80°C) by a spray (e.g., a

spray column of an aqueous solution such as hydrated lime ($\text{Ca}(\text{OH})_2$), etc.) that is used to remove sulfur-dioxide in the flue gas, for example. Thus, the heat energy of the flue gas is lost to the spray and, thus, lost and/or generally unrecoverable for the purposes of energy conservation.

5

The flue gas then leaves the FGD scrubber 112 and exits the SCR system 100 via the stack 114. Because the FGD scrubber is used later in the process of the SCR system 100, the flue gas is kept at a relatively high temperature that is above the dew point of any of the acid-forming compounds present in the flue gas. The known systems of FIGS. 1A-
10 1C have numerous stages that may require significant amounts of space (e.g., have a large footprint). In known examples where the flue gas is not constantly heated, significant capital expenditures may be required (e.g., stronger and more expensive materials and/or components, etc.) to withstand the formation of acid resulting from condensation of fluid containing acid-forming compounds in these systems.

15

Turning to FIG. 1B, a known SCR system 124, which is an SCR low dust system and similar to the SCR high dust system 100 described above in connection with FIG. 1A, is shown. In this known example and in contrast to the SCR high dust system 100, the dust remover 108 is upstream relative to the DeNOx reactor 104. In this example, a reheat of
20 the flue gas is necessary prior to the flue gas entering the FGD scrubber 112 and, thus, requires additional energy and/or running expense.

25

Turning to FIG. 1C, a known SCR tail-end system 140, which is similar to the SCR high dust systems 100 and SCR low dust system 124 described above in connection with
FIGS. 1A and 1B, respectively, is shown. In this known example, the flue gas used to preheat air for the steam generator 102 by the air preheater 106 prior to flowing into the dust remover 108. A low temperature economizer 142 is used prior to the flue gas flowing into the FGD scrubber 112. The flue gas is then reheated at a hot steam fuel-gas pre-heater 144, which may require hot steam. The numerous stages and/or cycles of cooling
30 and reheating the flue gas may lead to significant energy losses throughout known FGD systems.

As set forth herein, FIG. 2 is a schematic overview of an example process 200 in accordance with the teachings of this disclosure. In this example, fuel (e.g., solid fuel,

coal, etc.) 202 is provided to a combustor (e.g., a combustion chamber, a furnace, etc.) 204 of an example boiler plant where the fuel 202 is combusted. The combustion of the fuel 202 releases energy that is used to generate steam and move a turbine, thereby generating electricity.

5

In this example, a sorbent 206, such as calcium carbonate (CaCO_3), for example, is provided to (e.g., injected to, ad-mixed to or mixed with) the fuel 202 prior to the fuel 202 being combusted in the combustion chamber (e.g., a furnace sorbent injection (FSI) process). For example, the sorbent 206 may be injected or admixed to the fuel, the combustion air and/or to a mixture of fuel and combustion air provided to the combustor. As shown by the line 208, in some examples, additionally or alternatively, the sorbent 206 is injected directly into the combustion chamber as the fuel is combusted in the combustion chamber via a direct furnace injection process, for example. Likewise, additionally or alternatively, a line 210 illustrates another example process step where sorbent may be injected into flue gas after exiting the combustion chamber via a dry sorbent injection (DSI) process, for example. In some examples, the sorbent used in a DSI process is hydrated lime. It should be noted that the examples described are not exhaustive and any appropriate process or combination of FSI and DSI processes to provide sorbent to the example process 200 may be utilized. The hot gas filter of the illustrated example is deployed not only to address NO_x , but to also provide increased contact time in the optimum temperature range (e.g., above 480°F (250°C) to 1,110°F (600°C), and more preferably 570°F (300°C) to 750°F (400°C)) of the pollutant scavenging particles and thereby enhanced capture efficiency and utilization of the injected sorbent. A less capital-intensive bag house dust collector may also be used to increase sorbent flue gas contact, but at lower temperatures below 500°F (300°C) where capture reactions are slower. Substituting the bag house for the hot catalytic filter results in separating the NO_x control function from the dust collector. Though feasible, this option may be less economically attractive because two distinct stems are used instead of one and a greater space requirement.

30

Whichever option is chosen, a sorbent 206 is provided to the example process 200, prior to a hot gas filter 212, in which the flue gas enters, of the example boiler plant. The hot gas filter of the illustrated example may be a catalytic gas filter a ceramic catalytic gas filter, or any appropriate type of filter. In other examples, the type of filtration used after

sorbent is provided may vary and, additionally or alternatively, include a dust/particle separator (e.g., a particulate removal device or stripper, a cyclone, and/or a filter stage, scrubber etc.). Additionally or alternatively, any selected combination to apply or deliver sorbent (e.g., an FSI process, a DSI process and/or a direct furnace injection process, etc.) prior to filtering hot flue gas may be applied (e.g., DSI with catalytic filtration, FSI with ceramic catalytic filtration, DSI with dust/particle separator filtration, etc.).

As a result of the flue gas being filtered at the hot gas filter 212, the flue gas, in some examples, is used to provide a condensate from condensable liquids and/or vapors and/or recoverable heat energy 214. In some examples, the condensed water from the flue gas is provided to a steam cycle after a "purity polishing step" for use as a boiler feed or for other plant use, thereby resulting in conservation of water and/or reduced water consumption of the boiler plant. In some examples, the condensate is provided to an alternate consuming process. Additionally or alternatively, the water provided to the boiler feed still retains heat and, thus, requires less heating when the water is reused (e.g., heat is recovered).

Alternatively, in some examples, it is advantageous to stage the condensing heat exchangers to enhance pollution control and/or avoid moisture issues in the dust collector or air heater depending on the configuration. In particular the condensing heat exchangers may have multiple stages including a first stage and a second stage. The first stage, which has materials to withstand acids, may cool the flue gas to just below the acid dew point, thereby allowing the acids and/or acid-forming compounds to condense on the sorbent particles and be removed from the system. The second stage, which has ordinary materials is upstream from the stack, is used to condense relatively clean water (e.g., water with minimal or eliminated acids and/or acid-forming compounds).

Both the hot gas filter and the CHXs enhance the pollutant capture performance of the sorbent. They may be used together or separate from one another.

In some examples, heat recovered from the condensation process is substituted for the steam used to heat boiler feed water allowing more steam to be delivered to the turbine to generate additional electricity, thereby resulting in energy recovery and/or less energy (e.g., heat energy) required to be provided to the combustion process and/or reduced

operating costs. It has been determined that in some of the examples in accordance with the teachings of this disclosure that an average reduction in energy required to operate the boiler plant of significantly greater than 3% over known boiler plant systems may be seen. Additionally or alternatively, the heat recovered might be provided to the combustion
5 chamber and/or furnace via an additional heat exchanger to pre-heat the fuel and/or combustion air. Additionally or alternatively, the heat recovered may be provided to any appropriate portion(s) of the example process 200 or, more generally, the example boiler plant or external to the boiler plant, etc. In some examples it may be beneficial to provide the recovered heat or at least a fraction of the recovered heat to a heat supply network
10 (e.g., a long-distance or district heating), an organic Rankine cycle (ORC) system, and/or an industrial heat consuming process (e.g. dryer, roaster, other ovens).

FIG. 3A is a schematic diagram of an example boiler plant 300 to implement the example process 200 of FIG. 2. In order to more clearly illustrate the process, the figure shows
15 components of a typical boiler as if they are external to rather than enclosed within the boiler structure. The example boiler plant 300 of the illustrated example includes a coal feed 302, a fuel sorbent injection (FSI) device 304, a combustion chamber (e.g., a furnace) 306 (e.g., the water walls of the furnace are for steam generation and are part of the furnace), the steam superheater and reheater heat exchangers 308, an air preheater
20 (e.g., an economizer) 310, a dry sorbent injection (DSI) device 312, an ammonia injection device 314, a dust separation device (e.g., a catalytic hot gas filter) 320, an ash removal mechanism 322, a heat recovery steam generator 324, a boiler water feed 326, a condenser (e.g., a heat exchanger) 328, resulting condensate 330 and a stack feed 332. Since the ash removed from the filter will be at roughly the temperature of the entering
25 flue gas, the heat can be returned to the system via any of the mechanisms typically used with hot ESP's to capture that energy.

In this example, the coal feed 302 is provided with sorbent via the FSI device 304. In particular, solid fuel such as coal of the coal feed 302, for example, is provided with
30 calcium carbonate (CaCO_3) from precipitated or ground forms, which, for maximum pollutant capture, may be finely ground, preferably micronized under 3 microns median, or nominally minus 325 mesh for DSI. Additionally or alternatively, materials from waste processes such as fly ash, water softening sludges, sugar beet processing wastes, etc. may be used as sorbent. While coal is shown in this example, any appropriate fuel,

especially liquid fuel and/or solid fuel may be used. In some examples, solid fuel is pre-mixed and/or pre-processed with the sorbent material. In this example, the coal mixed with the sorbent is combusted in the combustion chamber 306. During the combustion process, sulfur dioxide (SO_2), an acid forming compound, and calcium oxide (CaO), amongst others, are formed. In this example, the combustion process occurs at greater than 570°F (300°C). Providing the sorbent into the combustion chamber 306 allows the sulfur dioxide to be reduced by 80% of flue gas exiting the combustion chamber 306 (e.g., a removal efficiency of approximately 80%). Additionally, providing the sorbent to the fuel allows greater effectiveness of the sorbent and/or reduced amounts of unutilized sorbent, thereby reducing the required amount of provided sorbent relative to known examples (e.g., known FGD systems, etc.).

The flue gas is then provided to the steam generator 308, thereby reducing the temperature of the flue gas. More specifically, while the flue gas passes through, the boiler heat is recovered by the superheater and reheater heat exchangers of the steam generator 308, thereby reducing the temperature of the flue gas. Next, the air preheater 310 uses the flue gas to heat air for the combustion chamber 306 and/or the steam generator 308 (e.g., a heat recovery process) after the flue gas exits the steam generator 308. Additionally or alternatively, the flue gas is provided with sorbent via the dry sorbent injection (DSI) device 312, which may provide hydrated lime or calcium hydroxide ($\text{Ca}(\text{OH})_2$) to the flue gas, for example. In some examples, a reducing agent such as ammonia is provided by the ammonia injector 314 to the flue gas to reduce NO_x compounds in the flue gas by selectively converting the NO_x compounds to nitrogen and water vapor, for example. In some examples, reducing agent, and/or a liquid, liquidized, dissolved or dispersed agent is provided to the flue gas.

Next, in this example, the flue gas is provided to the dust separation device 320, which is a catalytic hot gas filter in this example, where SO_x is allowed to react with the sorbent (e.g., quick lime or hydrated lime) and ash (e.g., CaO , CaSO_2 and/or unreacted DSI $\text{Ca}(\text{OH})_2$) is reduced and/or removed from the flue gas, thereby greatly reducing the amount of acid-forming SO_x compounds (e.g., SO_2 , SO_3 , etc.) in the flue gas. In particular, in this example, the amount of SO_2 is reduced to less than 1%, and the amount of SO_3 is reduced to less than 1 part per million (ppm). The ash collected from the hot gas filter may be discharged to the ash removal mechanism 322 of one of the types of recovery systems

that have been developed for and deployed in conjunction with hot electrostatic pre-
cipitators (ESPs). The dust separation device 320 of the illustrated example is described
in greater detail below in connection with FIGS. 4 and 5. This effective removal of the
condensable acid compounds in the flue gas enables relatively inexpensive materials (e.g.,
5 steel, stainless steel, etc.) to be used with the flue gas, thereby reducing or eliminating the
need for more expensive materials (e.g., high strength and/or acid-resistant materials or
alloys are no longer required due to the effective and substantial removal of acid gas
compounds).

10 In some preferred examples, the ash removal mechanism 322 comprises a back-pulsing
device, whereby pulses of compressed air are injected into at least a subset of filter
elements of a hot gas filter in a direction that is substantially opposite to a nominal flow
direction of fluid to be filtered. For example, the pulses of compressed air will blow at least
portion of the settled ash or dust off the filter elements. Alternatively or in addition, the ash
15 removal mechanism 322 may include a mechanic and/or sonic vibration device causing at
least a subset of the filter elements of the hot gas filter to vibrate at a frequency causing
the ash or dust to drop-off the surface of the filter elements. In a preferred example, the
sonic vibration device may include or be driven by a supersonic source. Additionally or
alternatively, the ash removal mechanism 322 may include a striking or hammer device
20 capable of acting on at least a subset of the filter elements by short tips or kicks to cause
the ash or dust to fall off the surface of the filter elements. Additionally or alternatively, the
ash removal mechanism 322 may comprise a suction device causing a reverse flow of a
flushing medium through at least a subset of the filter elements, whereby reverse flow
means a flow in the opposite direction of a nominal fluid flow through the filter elements.

25 In this example, the flue gas is then provided to the heat recovery steam generator 324,
whereby the flue gas is further cooled down. Typically, the flue gas leaving the heat
recovery steam generator 324 may have temperatures below 446°F (230°C), preferably
below 392°F (200°C) and down to approximately 320°F (160°C). After leaving the heat
30 recovery steam generator 324, the flue gas is provided to a condenser 328 in this
example. Within the condenser 328, the flue gas is further cooled to at least a temperature
below the dew point of one condensable fluid or vapor component (e.g., below at least the
highest dew point of a vaporized component, especially to a temperature below the dew
points of the most prominent or frequent condensable fluid or vapor components of the

flue gas carrying at least 50%, especially at least 75%, preferably at least 90% of the latent thermal energy releasable by condensation, preferably to a temperature below the lowest dew point of one of its condensable fluid or vapor components). In some examples, the flue gas exiting the condenser 328 may have a temperature of approximately 140°F (60°C). The heat recovered from the flue gas at the steam generator 324 and/or the condenser 328 may be used and/or provided to other portions of the example boiler plant 300 such as the combustion chamber 306 and/or the steam generator 308, thereby reusing energy that would have been otherwise lost and, thus, reducing overall energy needs of the boiler plant 300 and, thus, also reducing operating costs of the boiler plant 300. As a result, this reduction in energy needs also allows the boiler plant 300 to have a reduced carbon dioxide footprint per unit of electrical energy produced. Further, because acid-forming compounds in the flue gas have been significantly reduced, the flue gas may be cooled significantly during a heat recovery process and relatively inexpensive materials may be used and/or implemented in the condenser 328 or any heat exchangers, for example.

In a boiler plant 300 according to the example of FIG. 3A, where the flue gas temperature after the recovery steam generator 324 is below 446°F (230°C), the condenser 328 and/or a section of the condenser 328 may be produced with synthetic materials or plastics. The condenser 328 may be construed in close relation and/or similar to a plastic evaporator known from WO 2010/079148 A1, which is hereby incorporated by reference, and/or a heat exchanger, especially a tube bundle heat exchanger known from WO 2009/007065 A1, which is also hereby incorporated by reference. A condenser 328 in accordance with this approach further decreases costs of the system due to the use of cheaper and/or lighter materials than steel or other metals. Furthermore, in some examples, a synthetic or plastic material may also be robust enough against residual acid-forming components remaining in the flue gas.

Additionally or alternatively, heated water condensate 330 condensed from the condenser 328 is provided after polishing purification, for example, to other portions of the boiler plant 300 such as the boiler water feed 326 to reduce a need for water to be provided to the boiler plant 300, thereby reducing overall water consumption and/or recovering heat energy to reduce overall operating costs, for example. In particular, the effective removal of acid-forming compounds in the flue gas and, thus, the resultant condensed liquid

facilitates the reuse of the water. Additionally, the heat of the condensed water may be recovered for the boiler feed (e.g., utilized in the boiling process of the steam generator 308), for example.

5 While the illustrated example of FIG. 3A describes a boiler plant, any of the examples disclosed may instead be applied to a kiln, a coke calciner, a steel furnace, a refinery and/or ore processing, etc. In other words, any of the examples disclosed herein including the examples disclosed with respect to the example boiler plant 300, may be applied to other appropriate types of applications. Further, any other appropriate gas
10 filtration systems may be used instead.

FIG. 3B is a schematic illustration of an alternative example boiler plant 333 to implement the process of FIG. 2. The example boiler plant 333 is similar to the boiler plant 300, but includes a side stream. In this example, at least the dust separation device 320 and/or the
15 heat recovery steam generator 324 and/or the condenser 328 is bypassed by the side stream, whereby the side stream is directed by a bypass or shunt pipe, or more generally a branch line. Preferably, the side stream is split off the flow of the exhaust gas after the exhaust gas has left the furnace 306 or after a passage of the exhaust gas through the steam superheater and reheater heat exchangers 308 or the air preheater 310. In this
20 example, the flow of the side stream is controlled by a valve 334 in the branch line to allow treatment of a partial flow of the flue gas for complete acid compound removal and condensation of its moisture. After treatment, the partial flow is provide back to (e.g., mixed with) the main flue gas flow before entering the stack. In some examples, especially retrofitting such branch lines to combustion chambers, combustion systems and/or boiler
25 plants with existing air pollution control equipment, the branch lines may utilize or include already existing exhaust pipe or exhaust line.

Such examples are especially advantageous for retrofit in or to combustion chambers, combustion systems and/or boiler plants with existing air pollution control equipment, such
30 as an instance electrostatic precipitator (ESP) 336 used for de-dusting and/or dust reduction, for example. Additionally or alternatively, the existing air pollution control equipment may comprise a flue gas scrubber, exhaust scrubber, exhaust gas conditioner, electro-magnetic separator, a stripper and/or a cyclone, for example, or any other appropriate air pollution control equipment. While the electrostatic precipitator 336 is used

in this example, any of the above-mentioned air pollution control equipment may be used. These examples allow effective removal of SO₂ at reduced sorbent consumption as well as partial NO_x reduction, while simultaneously increasing the performance of the existing air pollution control equipment, which can be continuously operated in partial load.

- 5 Additionally or alternatively, such examples are especially advantageous for retrofit with existing NO_x reduction equipment, such as a selective non-catalytic reduction (SNCR) appliance or a SNCR system, for example. Such examples may allow effective reduction of ammonia feed rate as well as ammonia slip to the stack.
- 10 Additionally, energy consumption of the main flue gas fan 338 is reduced at partial load, while a fan (e.g., a relatively smaller fan, etc.) 340 with lower energy consumption can be used for the side stream at lower temperature.

- In some examples, an additional gas valve may be provided after the gas fan 338 to prevent a backflow into the branch line or to allow for improved control of the flow of the side stream. While the DSI device 312 is shown in the illustrated example, in some examples, the DSI 312 device may not be provided because the dust separation device 320 provides the additional contact time needed for the CaO generated in the furnace will be provided by the dust separation device 320 while allowing reduced overall use of reagents and/or lower cost reagents.
- 15
- 20

- FIG. 4 illustrates the example dust separation device 320, which is a catalytic filter in this example, of the example boiler plant 300 of FIG. 3A and the example boiler plant 333 of FIG. 3B. The example dust separation device 320 has an inlet 402, a filtration area 404, a valve 405, filter elements 406, a clamping plate 408, a manifold 409, a jet tube 410, a plenum 412 and an outlet 416. In this example, the filter elements 406 are positioned and/or held in place by the clamping plate 408, which has openings to allow the flue gas exiting the filter elements 406 (e.g., the filtered flue gas) to flow into the plenum 412.
- 25

- 30 In operation, flue gas of the illustrated example enters the inlet 402 of the dust separation device 320 and moves into the filtration area 404. In some examples, the dust separation device 320 operates at a temperature between 570-700°F (300-400°C). The flue gas then enters the filter elements 406, whereby compounds such as ash and CaO, CaSO₄, CaSO₃, and/or Ca(OH)₂ are filtered out of the flue gas to greatly reduce and/or effectively

eliminate SO_x compounds in the flue gas. In this example, the manifold 409 and the jet tube 410 are used to control the flow of pulse air to frequently clean the filter elements from compounds such as ash (e.g., CaO, CaSO₃ and/or Ca(OH)₂). After the filtered flue gas flows into the plenum 412, the flue gas exits the dust separation device 320 via the exit 416.

In some examples, the ash built up on the filter elements 406 falls to the bottom of the filtration area 404 to the valve 405, where the ash may exit the dust separation device 320. As mentioned above, in some examples, the filter elements 406 and/or a subset (e.g., a portion) of the filter elements 406 are back-pulsed (e.g., periodically back-pulsed and/or back-pulsed based on condition(s) of the filter elements 406, etc.) to cause the ash to fall into the valve 405 for removal from the boiler plant 300, for example, and/or to control the residence time of the sorbent. In some examples, a subset or portion of the filter elements 406 are back-pulsed and/or alternating portions of the filter elements 406 are back-pulsed to remove filter cake from the filter elements 406. Alternatively or in addition, the filter elements 406 are provided with an ash removal device (e.g. mechanic and/or sonic such as a supersonic ash remover, etc.), such as the ash removal devices described in conjunction with the ash removal mechanism 322 described above in connection with FIG. 3A, to cause the ash to fall away from the filter elements 406 when activating the ash removal device on the filter elements 406 and/or a subset of the filter elements 406.

FIG. 5 is a detailed view of the example filter element 406 of the example catalytic filter of FIG. 4. The filter element 406 includes a surface barrier 502, fibers 504 and catalyst particles 506 within the fibers 504. In other examples, the filter element 406 contains additional layers, fibers and/or catalyst materials, etc. Additionally or alternatively, the filter element 406 may be fabric.

In operation, alkali aerosols 508 of the illustrated example that are contained in flue gas move in a direction generally indicated by an arrow 510, thereby forming a filter cake 512 as the flue gas flows through the surface barrier 502. The filter cake 512 of the illustrated example increases the residence time of the sorbent to increase removal efficiency of compounds such as SO_x, halogens, and toxic metals (e.g., Hg, As, and Se) by the sorbent. In preferred examples, the controlling of the ash layer on the filter elements 406

or the filter cake 512 via a dedicated activation of the back-pulsing and/or ash removal device can allow for a control of the removal efficiency of the injected sorbent. In particular, the removal efficiency will be influenced by the surface area of the injected sorbents and may range from 90 to 99%, for example. As the flue gas of the illustrated example flows through the fibers 504, additional SO_x molecules are removed. Next, in this example, the flue gas flows exits the filter element 406 and, more generally, the dust separation device 320 and flows through the remaining portions of the example boiler plant 300. In some examples, the filter cake also facilitates removal of NO_x compounds by increasing removal efficiency of these compounds when ammonia is provided to the flue gas.

Flowcharts representative of example machine readable instructions for implementing or controlling the example boiler plant 300 of FIG. 3A or the example boiler plant 333 of FIG. 3B are shown in FIGS. 6 and 7. Controlling the example boiler plant 300 or the example boiler plant 333 may be accomplished by manually adjustable equipment, such as a rotary valve to provide sorbent at a relatively constant rate to comply with desired SO_x reduction at the outlet of a furnace (e.g., the furnace 306), which has to be occasionally verified at the exit flow of the furnace and continuously verified in the exit flow of the filter by, for instance, EPA Test Methods 6C, 8 and 8A. Such controls may additionally exist by a valve controlling the flow of a reducing agent, such as ammonia or urea, at a rate adjusted to the mass flow of the flue gas to be continuously verified by for instance EPA Test Method 2 and 2F and to the concentration of NO_x to be verified by for instance EPA Test Method 7 upstream of the injection point in order to comply with the desired concentration of NO_x to be verified by, for instance, EPA Test Method 7 in the exit flow of the filter. Such controls may additionally use membrane valves controlling the time of flow of pressurized reverse pulse air to a relatively clean side of the filter, which is verified by a maximum allowable difference of the pressure between the inlet flow and the outlet flow of the filter. Such controls may additionally result from a valve controlling the flow of water to the tube inlet of a condensing heat exchanger to be verified by the measurement of a minimum allowable temperature of the exit flow of the shell side of the heat exchanger. Such controls may additionally exist with a valve controlling the height of a liquid filling in the liquid collector of the shell side of the heat exchanger.

In the examples of FIGS. 6 and 7, the machine readable instructions comprise a program for execution by a processor such as the processor 812 shown in the example processor platform 800 discussed below in connection with FIG. 8. The program may be embodied in software stored on a tangible computer readable storage medium such as a CD-ROM, a floppy disk, a hard drive, a digital versatile disk (DVD), a Blu-ray disk, or a memory associated with the processor 812, but the entire program and/or parts thereof could alternatively be executed by a device other than the processor 812 and/or embodied in firmware or dedicated hardware. Further, although the example program is described with reference to the flowcharts illustrated in FIGS. 6 and 7, many other methods of implementing the example boiler plant 300 may alternatively be used. For example, the order of execution of the blocks may be changed, and/or some of the blocks described may be changed, eliminated, or combined.

As mentioned above, the example processes of FIGS. 6 and 7 may be implemented using coded instructions (e.g., computer and/or machine readable instructions) stored on a tangible computer readable storage medium such as a hard disk drive, a flash memory, a read-only memory (ROM), a compact disk (CD), a digital versatile disk (DVD), a cache, a random-access memory (RAM) and/or any other storage device or storage disk in which information is stored for any duration (e.g., for extended time periods, permanently, for brief instances, for temporarily buffering, and/or for caching of the information). As used herein, the term tangible computer readable storage medium is expressly defined to include any type of computer readable storage device and/or storage disk and to exclude propagating signals and to exclude transmission media. As used herein, "tangible computer readable storage medium" and "tangible machine readable storage medium" are used interchangeably. Additionally or alternatively, the example processes of FIGS. 6 and 7 may be implemented using coded instructions (e.g., computer and/or machine readable instructions) stored on a non-transitory computer and/or machine readable medium such as a hard disk drive, a flash memory, a read-only memory, a compact disk, a digital versatile disk, a cache, a random-access memory and/or any other storage device or storage disk in which information is stored for any duration (e.g., for extended time periods, permanently, for brief instances, for temporarily buffering, and/or for caching of the information). As used herein, the term non-transitory computer readable medium is expressly defined to include any type of computer readable storage device and/or storage disk and to exclude propagating signals and to exclude transmission media. As used

herein, when the phrase "at least" is used as the transition term in a preamble of a claim, it is open-ended in the same manner as the term "comprising" is open ended.

FIG. 6 is a flowchart representative of an example method that may be used to implement
5 and/or control the example boiler plant 300 of FIG. 3A, for example. The example method begins at block 602 where fuel is being provided to a combustion chamber (e.g., a furnace) such as the combustion chamber 306 of an example boiler plant (e.g., the boiler plant 300, the boiler plant 333) (block 602). In some examples, sorbent such as calcium carbonate is provided to the fuel and/or mixed in with the fuel prior to the fuel and/or the
10 sorbent being combusted in the combustion chamber. In some examples, the fuel is pre-processed with sorbent (e.g., manufactured with sorbent) prior to the sorbent being provided to the combustion chamber. In some examples, the amount of sorbent provided is adjusted by the amount of SO_x in the flue gas. Additionally or alternatively, the amount of sorbent added may be based on concentration differences of SO_x at different stages of
15 the boiler plant 300 and/or a pressure drop of a hot gas filter of the boiler plant 300.

Sorbent and/or sorbent mixed with fuel (e.g., solid fuel, etc.) is then provided to the combustion chamber (block 604). Additionally or alternatively, sorbent is injected directly into the combustion chamber when the fuel is being combusted (e.g., a direct furnace
20 injection process). Next, the fuel is combusted (block 606) to produce steam to drive a generator, for example. In some examples, additionally or alternatively, a dry sorbent is provided and/or injected into flue gas exiting the combustion chamber (e.g., a DSI process, etc.) (block 608). In particular, the dry sorbent provided to the flue gas may be calcium hydroxide (Ca(OH)₂). In some examples, ammonia (NH₃) is added to the flue gas
25 to facilitate removal of NO_x from the flue gas (e.g., a de-NO_x process) (block 610).

Next, the flue gas is provided to and/or flows into a hot gas filter. In this example, the flue gas is provided to a catalytic filtration system such as the dust separation device 320 described above in connection with FIGS. 3A and 4 for removal SO_x compounds, NO_x
30 compounds and/or ash (block 612). In this example ash caked on filter elements of the catalytic filtration system is removed by back-pulsing the filter elements (block 614). In some examples, the flue gas exiting the hot gas filter is provided to a heat recovery steam generator (e.g., the heat recovery steam generator 324) (block 616)

In this example, liquid (e.g., water, etc.) is condensed from the flue gas (block 618). This condensation process may occur by rapidly cooling the flue gas, for example. In some examples, heat from the flue gas is recovered during the condensation process and provided and/or directed towards the combustion chamber (e.g., an energy recovery system, etc.) to reduce the amount of provided energy necessary for the combustion chamber, thereby reducing the overall energy expenditure of the boiler plant.

If it is determined that the process is not to end (block 620), the liquid and/or water condensed from the flue gas may be provided to a boiler feed (block 624) and the process is restarted (block 602). In some examples, the condensed liquid and/or water is further processed (e.g., the condensed liquid undergoes a neutralization process) prior to being reintroduced into the boiler plant process. Alternatively, if it is determined that the process is to end (block 620), the process ends (block 622).

FIG. 7 is a flowchart representative of another example method that may be used to implement and/or control the example boiler plant 300 of FIG. 3A, for example. The example method begins at block 702 where fuel (e.g., solid fuel, coal, etc.) provided to a boiler plant (e.g., the boiler plant 300, the boiler plant 333) is about to be combusted to power a steam generator. In this example, sorbent (e.g., calcium carbonate) is provided to a combustion chamber (e.g., a furnace) via an FSI process, for example (block 704). Additionally or alternatively, sorbent (e.g., dry sorbent) is provided to flue gas exiting the combustion chamber (block 706) and/or ammonia is provided to the flue gas (block 708). In some examples, the amount of sorbent provided is adjusted by the amount of SO_x in the flue gas. Additionally or alternatively, the amount of sorbent added may be based on concentration differences of SO_x at different stages of the boiler plant 300 and/or a pressure drop of a hot gas filter of the boiler plant 300, for example.

In this example, the flue gas from the combustion chamber is then provided to a catalytic filter such as the dust separation device 320 described above in connection with FIGS. 3A and 4 (block 710).

Next, in this example, it is determined whether the catalytic filter and/or filter elements of the catalytic filter require cleaning and/or removal of filter cake (e.g., ash filter cake) from one or more filter elements (block 712). Such a determination may occur via a hot gas

filter controller 836 described below in connection with FIG. 8. The catalytic filter cleaning may occur at time intervals that may be regular or irregular, and/or determinations based on sensor measurements (e.g., from optical sensors, weight sensors and/or flow rate sensors, etc.).

5

If it is determined that the catalytic filter of the illustrated example requires cleaning and/or automated cake removal (block 712), in this example, the filter elements and/or a portion of the filter elements are back-pulsed and/or displaced to allow the filter cake to fall within the catalytic filter and, thus, removed from the catalytic filter via an opening or valve, for example (714). In some examples, back-pulsing of the hot gas filter (e.g., frequency, peak pressure, etc.) may be varied in relation to SO_x-concentration-difference and/or pressure drop(s) within or between an inlet and an outlet of the hot gas filter. In some examples, the flue gas is then provided to a heat recovery steam generator (block 716) and liquid and/or water is condensed from the flue gas (block 718) and may be provided to a boiler feed of the boiler plant.

15

In this example, it is then determined whether an amount and/or frequency of sorbent provided to the combustion chamber needs to be adjusted (block 720). This determination may be based on steam generator needs, flue gas flow rate, fuel delivery rate, fuel flow rate, and/or type of fuel being combusted, etc. In particular, a sorbent rate controller 834 described below in connection with FIG. 8 may be used to make the determination. If it is determined that the amount and/or frequency of sorbent to provided is to be adjusted (block 720), the amount and/or frequency of sorbent provided is adjusted (block 722) and the process repeats (block 702). The amount and/or frequency of sorbent provided may be adjusted through changing the amount of sorbent provided to the fuel, the amount of sorbent provided to the combustion chamber and/or an amount of sorbent provided to the flue gas via a dry sorbent injection (DSI) process, for example. In examples where sorbent is provided at multiple stages and/or locations, the control of sorbent delivery (e.g., frequency and/or amount of sorbent) at each of the stages and/or locations may be independently controlled by a controller (e.g., the sorbent rate controller 834). Independent control of sorbent may also allow greater use or utilization of the sorbents and/or reduce the amount of sorbent wasted, thereby reducing overall operating costs of the boiler plant. If the amount and/or frequency of sorbent is not to be adjusted (block 720), the process repeats (block 702).

20
25
30

FIG. 8 is a block diagram of an example processor platform 800 capable of executing the instructions of FIGS. 6 and 7 to implement the example boiler plant 300 of FIG. 3A or the example boiler plant 333 of FIG. 3B, for example. The processor platform 800 can be, for example, a server, a personal computer, a mobile device (e.g., a cell phone, a smart phone, a tablet such as an iPad™), a personal digital assistant (PDA), an Internet appliance, a DVD player, a CD player, a digital video recorder, a Blu-ray player, a gaming console, a personal video recorder, a set top box, or any other type of computing device.

The processor platform 800 of the illustrated example includes a processor 812. The processor 812 of the illustrated example is hardware. For example, the processor 812 can be implemented by one or more integrated circuits, logic circuits, microprocessors or controllers from any desired family or manufacturer.

The processor 812 of the illustrated example includes a local memory 813 (e.g., a cache). The processor 812 includes the sorbent rate controller 834 and the hot gas filter controller 836. The processor 812 of the illustrated example is in communication with a main memory including a volatile memory 814 and a non-volatile memory 816 via a bus 818. The volatile memory 814 may be implemented by Synchronous Dynamic Random Access Memory (SDRAM), Dynamic Random Access Memory (DRAM), RAMBUS Dynamic Random Access Memory (RDRAM) and/or any other type of random access memory device. The non-volatile memory 816 may be implemented by flash memory and/or any other desired type of memory device. Access to the main memory 814, 816 is controlled by a memory controller.

The processor platform 800 of the illustrated example also includes an interface circuit 820. The interface circuit 820 may be implemented by any type of interface standard, such as an Ethernet interface, a universal serial bus (USB), and/or a PCI express interface.

In the illustrated example, one or more input devices (e.g., sensors) 822 are connected to the interface circuit 820. The input device(s) 822 permit(s) a user to enter data and commands into the processor 812. The input device(s) can be implemented by, for example, an audio sensor, a microphone, a camera (still or video), a keyboard, a button, a

mouse, a touchscreen, a track-pad, a trackball, isopoint and/or a voice recognition system.

One or more output devices 824 are also connected to the interface circuit 820 of the illustrated example. The output devices 824 can be implemented, for example, by display devices (e.g., a light emitting diode (LED), an organic light emitting diode (OLED), a liquid crystal display, a cathode ray tube display (CRT), a touchscreen, a tactile output device, a printer and/or speakers). The interface circuit 820 of the illustrated example, thus, typically includes a graphics driver card, a graphics driver chip or a graphics driver processor.

The interface circuit 820 of the illustrated example also includes a communication device such as a transmitter, a receiver, a transceiver, a modem and/or network interface card to facilitate exchange of data with external machines (e.g., computing devices of any kind) via a network 826 (e.g., an Ethernet connection, a digital subscriber line (DSL), a telephone line, coaxial cable, a cellular telephone system, etc.).

The processor platform 800 of the illustrated example also includes one or more mass storage devices 828 for storing software and/or data. Examples of such mass storage devices 828 include floppy disk drives, hard drive disks, compact disk drives, Blu-ray disk drives, RAID systems, and digital versatile disk (DVD) drives.

The coded instructions 832 of FIGS. 6 and 7 may be stored in the mass storage device 828, in the volatile memory 814, in the non-volatile memory 816, and/or on a removable tangible computer readable storage medium such as a CD or DVD.

From the foregoing, it will be appreciated that the above disclosed method and apparatus allow boiler plants to have reduced building and/or construction costs (e.g., capital costs, material costs, etc.) and also allow reduced operating costs and/or greater efficiency (e.g., energy per unit of fuel consumed, etc.) of the boiler plants. The examples disclosed herein also allow boiler plants to have smaller footprints (e.g., have reduced necessary space) and may also reduce the carbon dioxide output per unit of energy produced (e.g., a relatively low carbon footprint, etc.).

The examples disclosed herein present implementation of the technology of this patent with respect to new power plants. However, the examples disclosed herein are suitable for retrofits including those with existing wet FGD systems, in which efficiency enhancement(s) may be desired. In an example retrofit, the filtration and cooling of sorbent
5 provided flue gas upstream from the scrubber may both recover more energy, reduce water evaporation, and/or reduce the load on the wet FGD.

Although the examples described herein demonstrate and disclose examples of boiler plant applications, the scope of coverage of this patent is not limited to boiler plants. The
10 teachings of the examples disclosed herein can be applied in analogous way to other industrial combustion processes or industrial systems based on or working with combustion processes for burning fuels, especially carbon-based fuels, which cause emission of particulates, toxic metals, gaseous pollutants, and/or condensable acid-forming compounds in their resulting flue gas. In numerous types of industrial combustion
15 of fuel, especially carbon-based fuels, the overall efficiency in energy consumption and emissions control can be enhanced by applying the teaching disclosed herein. Although certain example methods, apparatus and articles of manufacture have been disclosed herein, the scope of coverage of this patent is not limited thereto. On the contrary, this patent covers all methods, apparatus and articles of manufacture fairly falling within the
20 scope of the claims of this patent.

CLAIMS

1. A method, in particular for running industrial or utility boiler plants, comprising:
5 providing at least one type of sorbent (206) to a combustor (204; 306) and/or to flue gas exiting the combustor after a combustion process; and
at least one method step of:
 - a) providing the flue gas after exiting the combustor (204; 306) to a hot gas filter (212; 320); and
 - 10 b) cooling the flue gas to a temperature below at least a highest dew point of any condensable component remaining after the flue gas exits the combustor (204; 306) or condensing at least one vaporized component from the flue gas after the flue gas exits the combustor (204; 306) to form a condensate (330).
- 15 2. The method as defined in claim 1, wherein the flue gas is cooled to a temperature below at least a highest dew point of a vaporized component after the flue gas exits the hot gas filter (212; 320) to form a condensate (330).
3. The method as defined in claim 1 or 2, further comprising providing the condensate
20 (330) to a boiler feed or a boiler feed water processing system.
4. The method as defined in any one of preceding claims, wherein heat released from condensing the condensate (330) is provided to the combustor (204; 306) or transferred to other parts of a steam cycle.
- 25 5. The method as defined in any one of preceding claims, wherein the flue gas is provided with a dry sorbent (206) prior to being provided to the hot gas filter (212; 320).
- 30 6. The method as defined in any one of preceding claims, further comprising activation of an ash removal device or an ash removal mechanism (322), or back-pulsing on at least a subset of filter elements (406) of the hot gas filter (212; 320) to remove cake (512) formed on the hot gas filter to provide further control of residence time of the sorbent (206).

7. The method as defined in any one of preceding claims, wherein the sorbent (206) is provided to the combustor (204; 306) and further comprising adjusting an amount of the sorbent (206) to be provided to the combustor (204; 306).
- 5 8. The method as defined in claim 7, wherein the amount of the sorbent (206) to be provided to the combustor (204; 306) is based on a flow rate of fuel into the combustor (204; 306).
- 10 9. The method as defined in any one of preceding claims, wherein the hot gas filter (212; 320) comprises a catalytic filter or a ceramic catalytic filter.
10. The method as defined in claim 9, wherein the catalytic filter comprises filter elements (406), each of the filter elements (406) comprising fibers (504) or fabric, and a catalyst material (506).
- 15 11. The method as defined in claim 10, wherein the fibers (504) have catalyst material (512) embedded within.
- 20 12. The method as defined in claim 10 or 11, wherein the catalytic filter further comprises a surface barrier (502).
13. The method as defined in any one of preceding claims, wherein the sorbent (206) is provided to fuel, combustion air, or a mixture of fuel and combustion air prior to being provided to and combusted in the combustor (204; 306).
- 25 14. The method as defined in any one of preceding claims, further comprising providing a reducing agent, or a liquid, liquidized, dissolved or dispersed agent to the flue gas prior to the flue gas entering the hot gas filter (212; 320).
- 30 15. The method as defined in any one of preceding claims, further comprising providing the flue gas to a heat recovery steam generator (324) after the flue gas exits the hot gas filter (212; 320).

16. The method as defined in any one of preceding claims, wherein the flue gas is provided to the hot gas filter (212; 320) before condensing or cooling the flue gas.
17. The method as defined in any one of preceding claims, further comprising providing the condensate (330) to a boiler feed or a boiler feed water processing system.
18. The method as defined in any one of preceding claims, wherein heat released from cooling the flue gas is provided to the combustor (204; 306) or transferred to other parts of a steam cycle.
19. An apparatus, in particular for use in an industrial or utility boiler plant, comprising:
a combustor (204; 306) of a boiler plant (300; 333) wherein sorbent (206) is provided to the combustor (204; 306) and/or to flue gas after the flue gas exits the combustor during a combustion process; and
a hot gas filter (212; 320) of the boiler plant to receive the flue gas and reduce acid-forming compounds or pollutants from the flue gas and/or a condenser (328) to condense at least one vaporized component from the flue gas to form a condensate (330), whereby the condensate is optionally provided to a boiler feed, an additional heat exchanger or an alternative condensate consuming process.
20. The apparatus as defined in claim 19, wherein the hot gas filter (212; 320) is arranged upstream the condenser (328).
21. The apparatus as defined in claim 19 or 20, wherein at least a subset of filter elements (406) of the hot gas filter (212; 320) are provided with an ash removal device or an ash removal mechanism (322), or back-pulsed to remove cake (512) formed on the hot gas filter to control a residence time of the sorbent (206).
22. The apparatus as defined in any one of claims 19 to 21, wherein the fuel comprises solid fuel and the sorbent (206) is mixed with the solid fuel or combustion air prior to the solid fuel being combusted in the combustor (204; 306).

23. The apparatus as defined in any one of claims 19 to 22, wherein the hot gas filter (212; 320) comprises a catalytic filter, wherein the catalytic filter comprises fibers (504), catalyst material (506) and a surface barrier (502).
- 5 24. The apparatus as defined in any one of claims 19 to 23, wherein the condenser (328) comprises synthetic materials or plastics, and wherein at least a heat exchanging section comprises synthetic materials and/or plastics.
- 10 25. The apparatus as defined in claim 24, wherein the condenser (328) comprises a tube bundle heat exchanger, wherein the heat exchanging tubes comprise synthetic materials or plastics.
26. The apparatus as defined in any one of claims 19 to 25, further comprising a branch line to enable a portion of the flue gas to bypass the hot gas filter (212; 320).
- 15 27. The apparatus as defined in claim 26, whereby the branch line comprises an electrostatic precipitator or an electromagnetic separator.

1/9

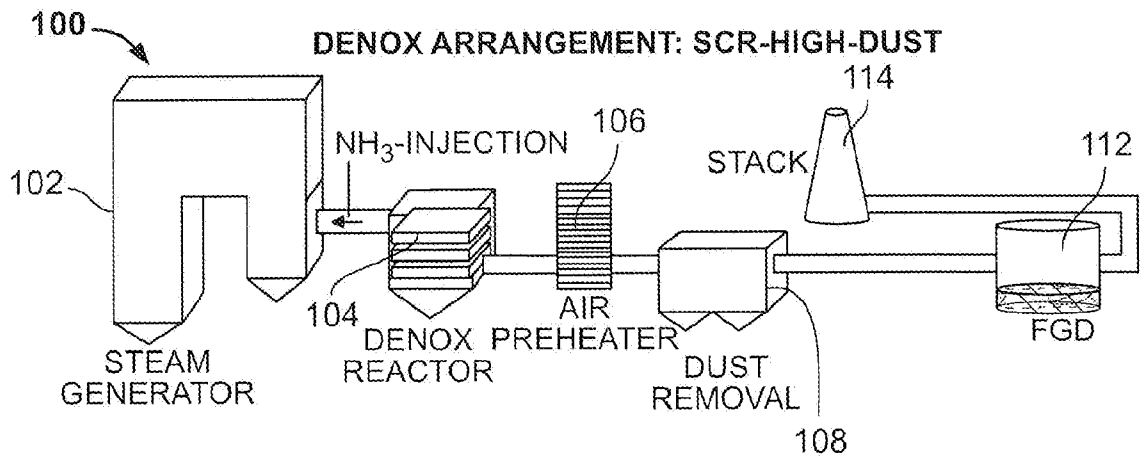


FIG. 1A (Prior Art)

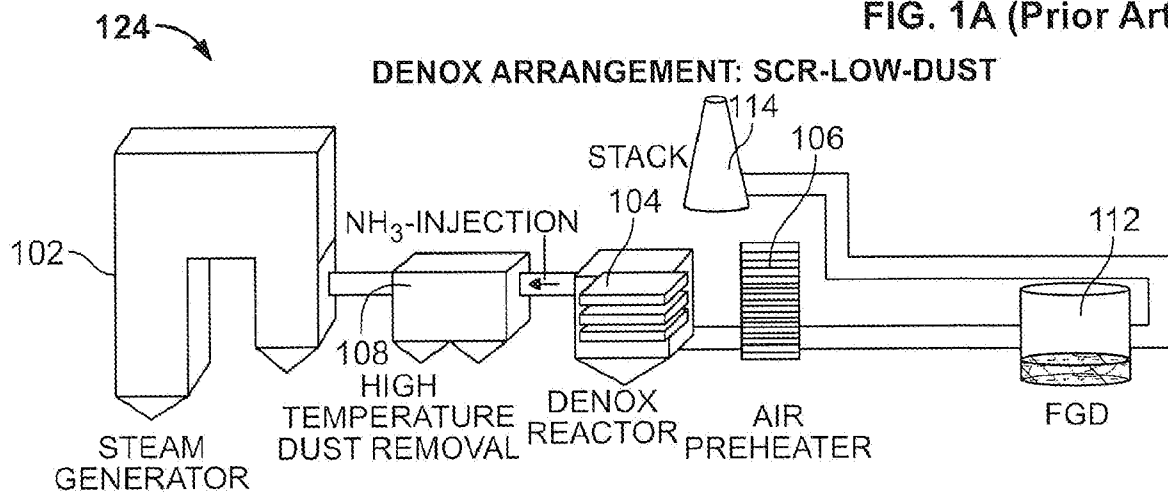


FIG. 1B (Prior Art)

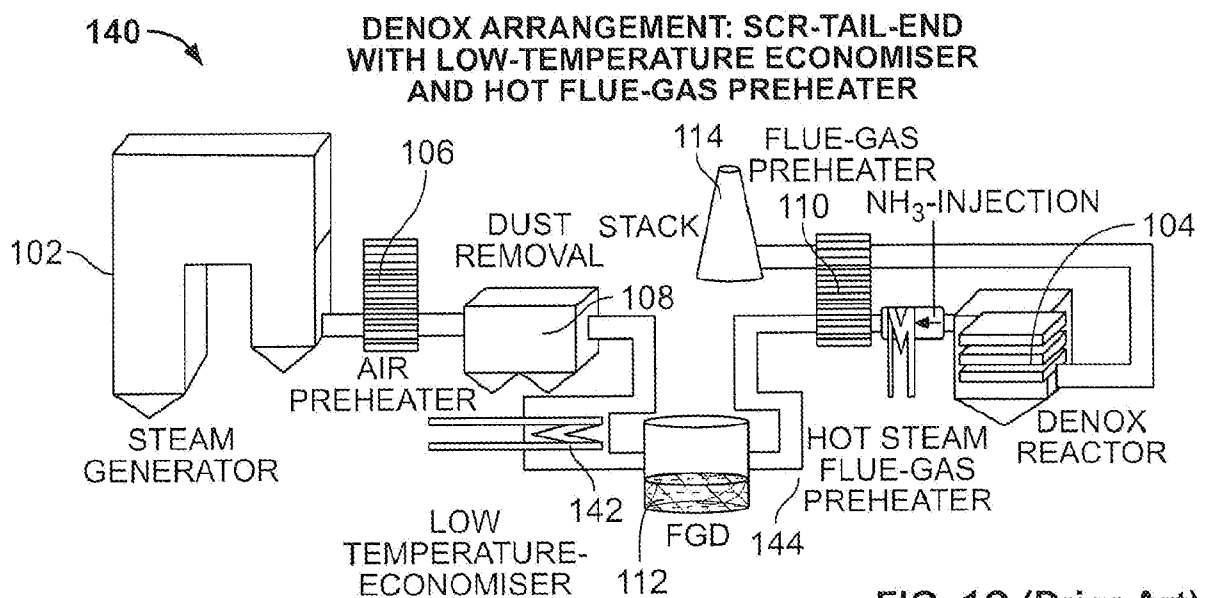


FIG. 1C (Prior Art)

2/9

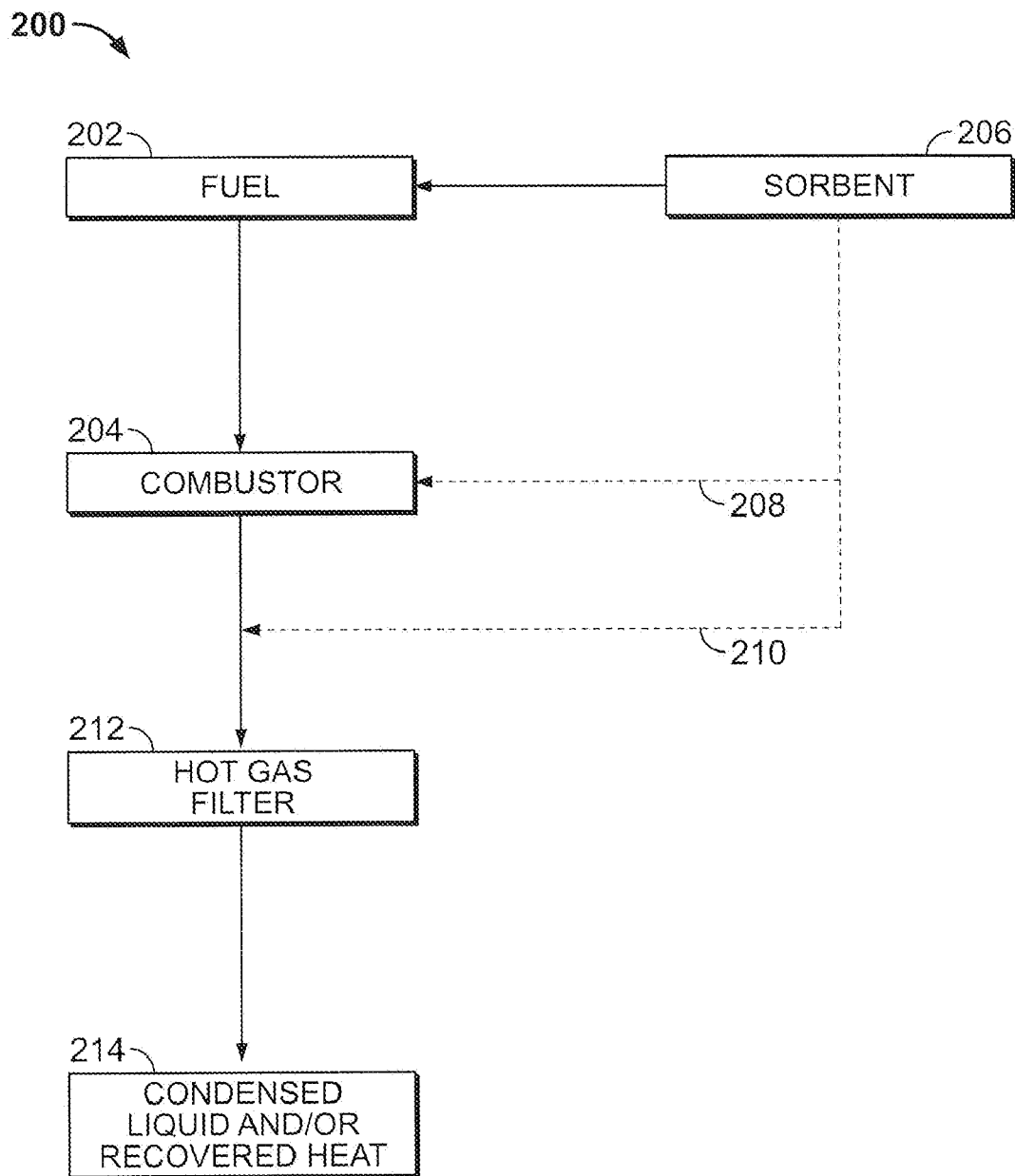
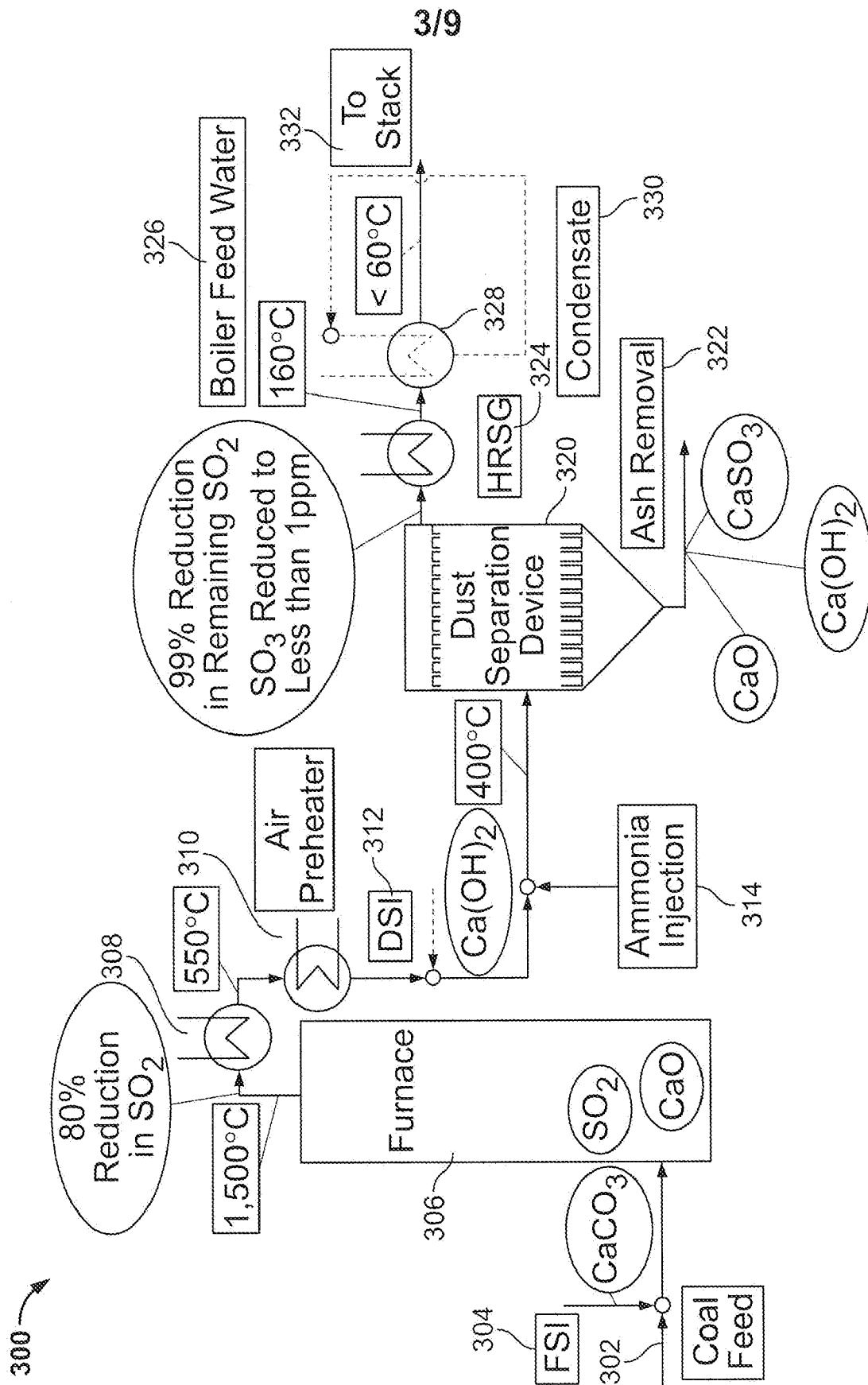
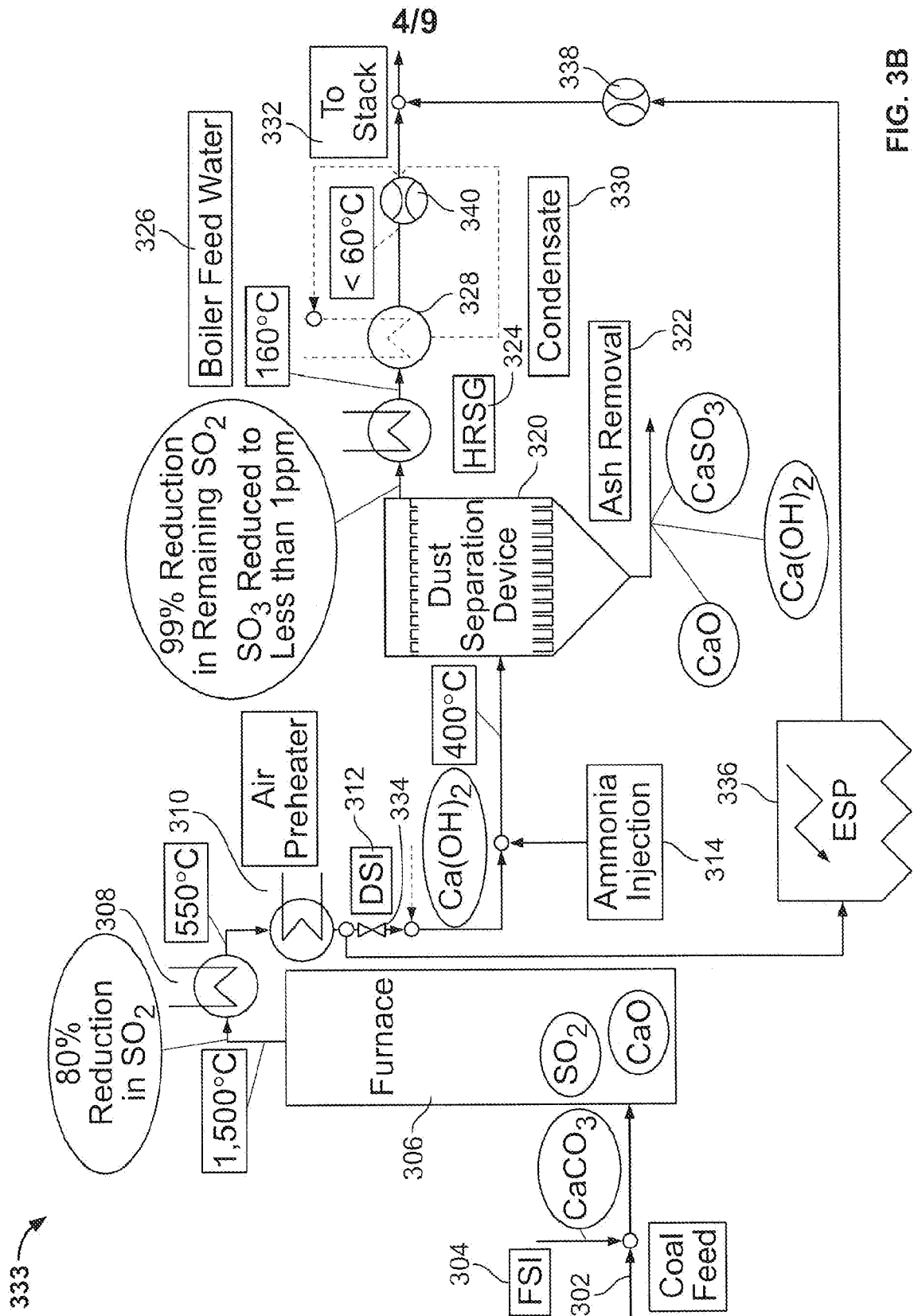


FIG. 2



3A
G.
L



5/9

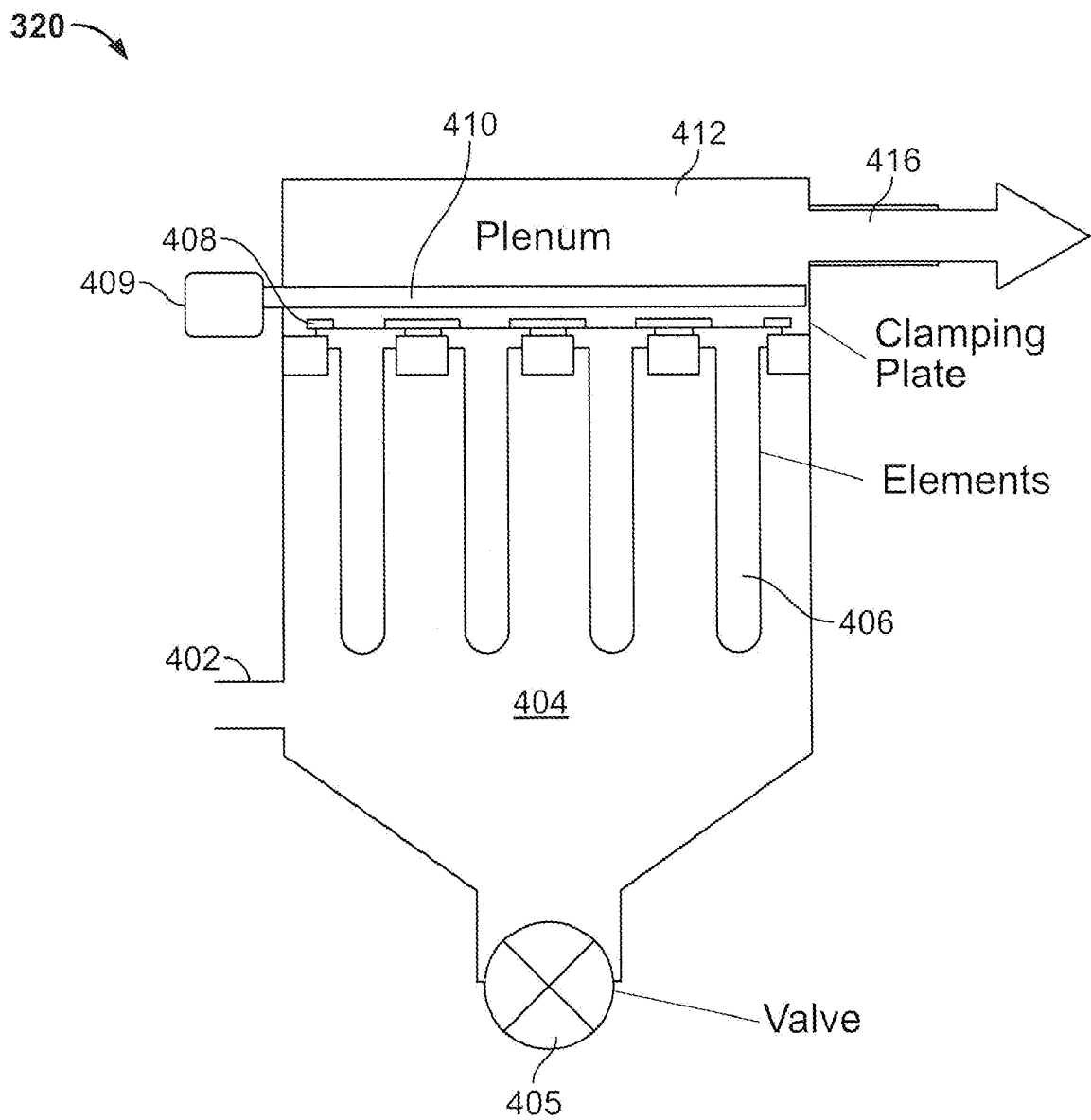
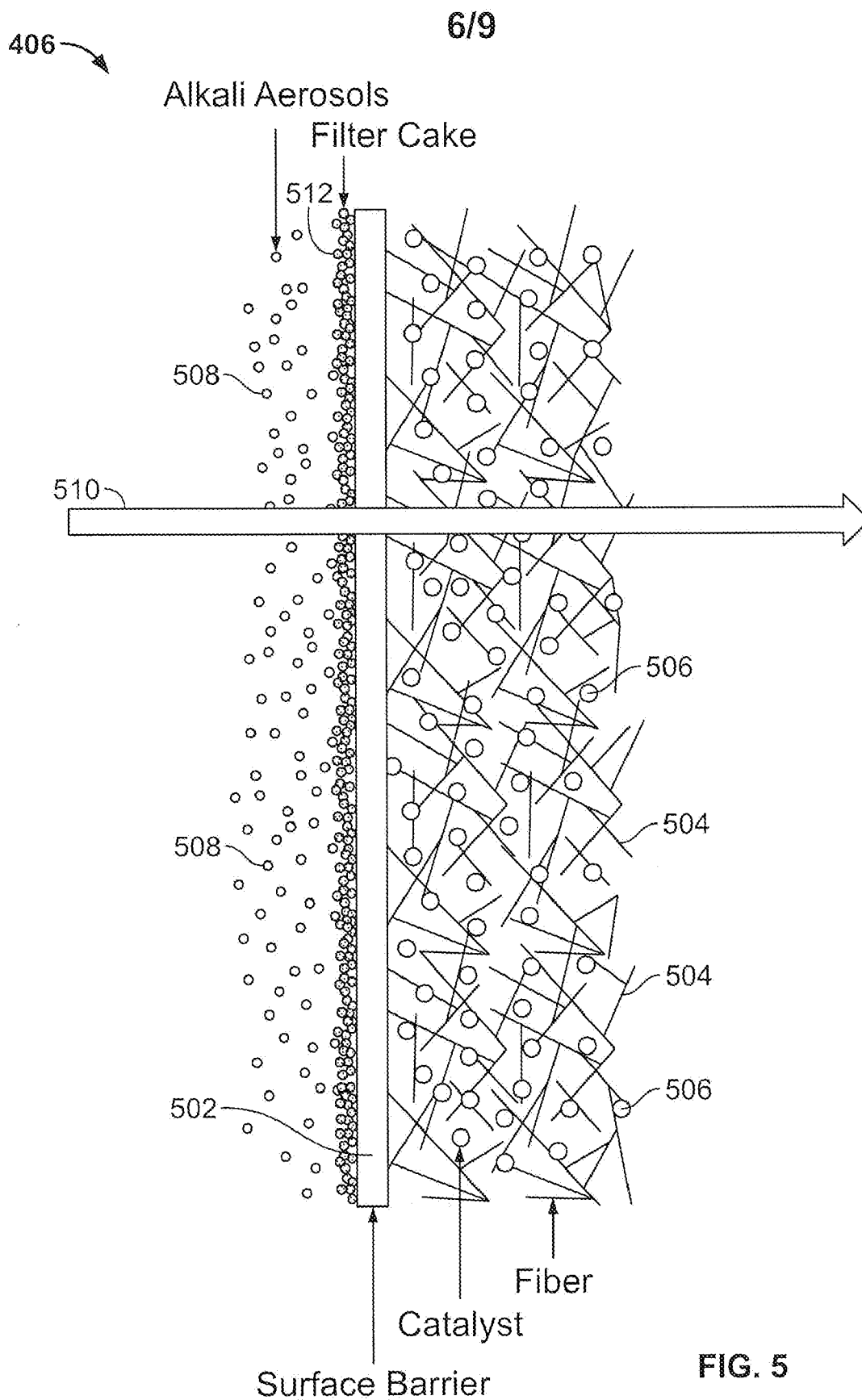
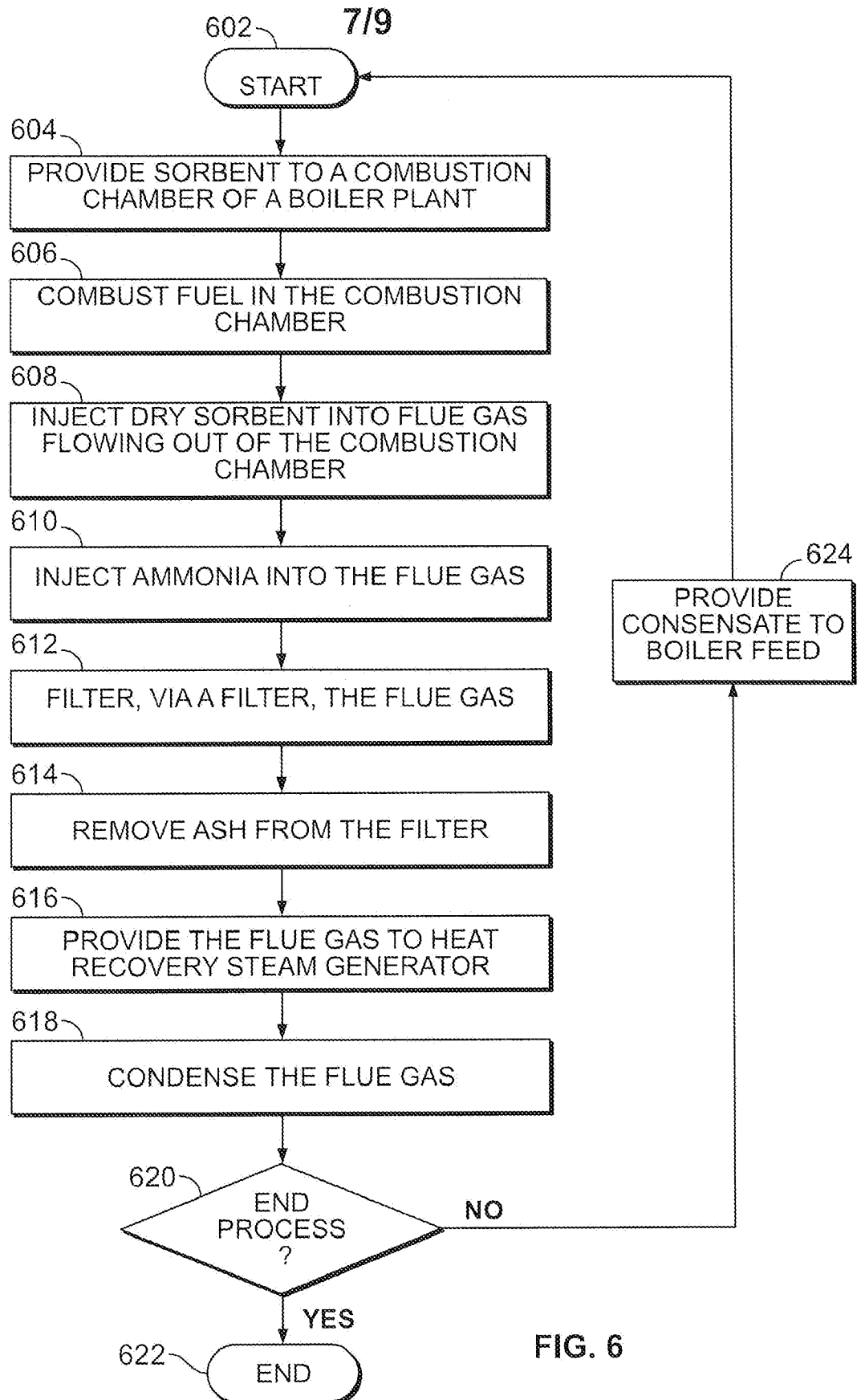
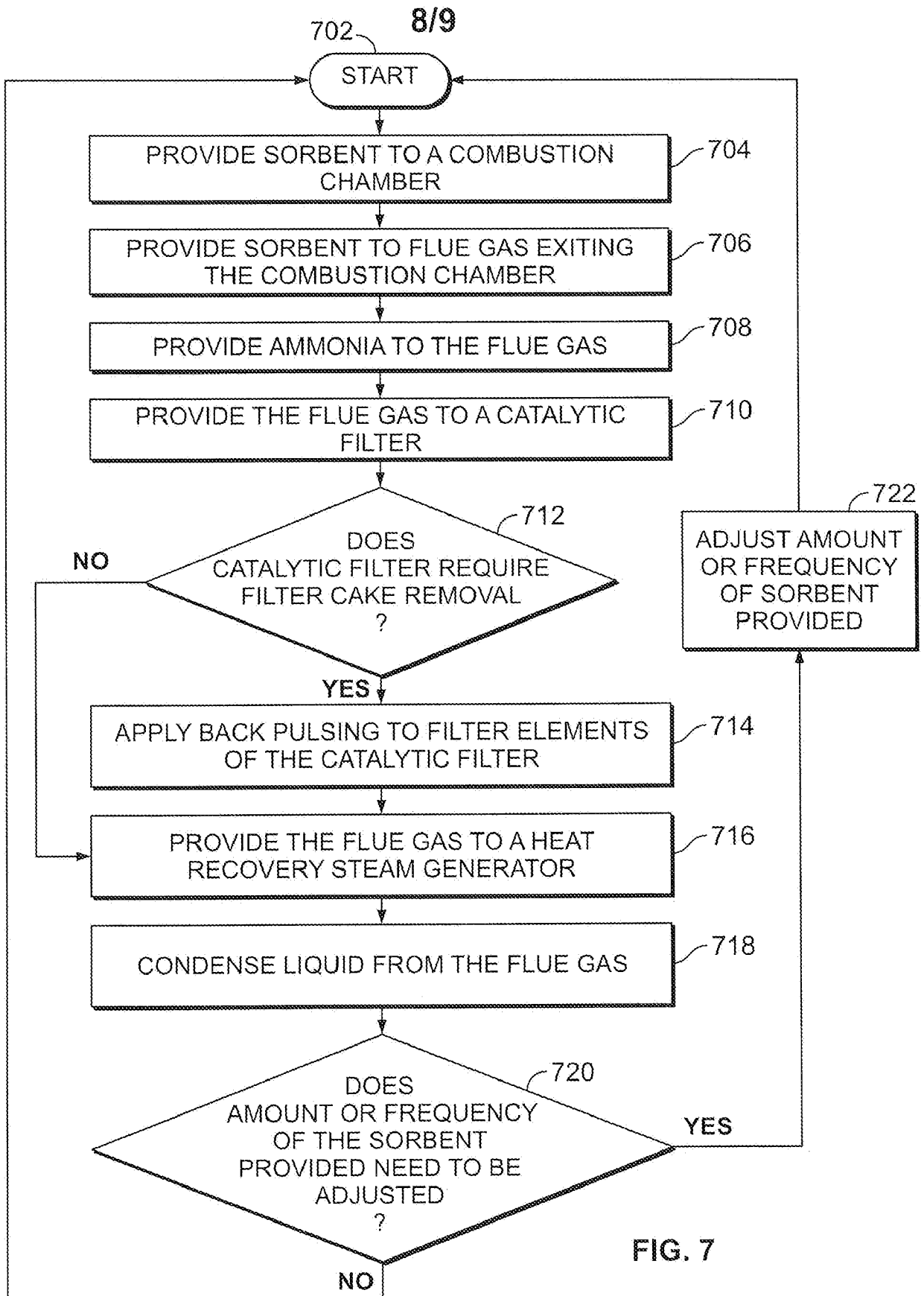


FIG. 4







9/9

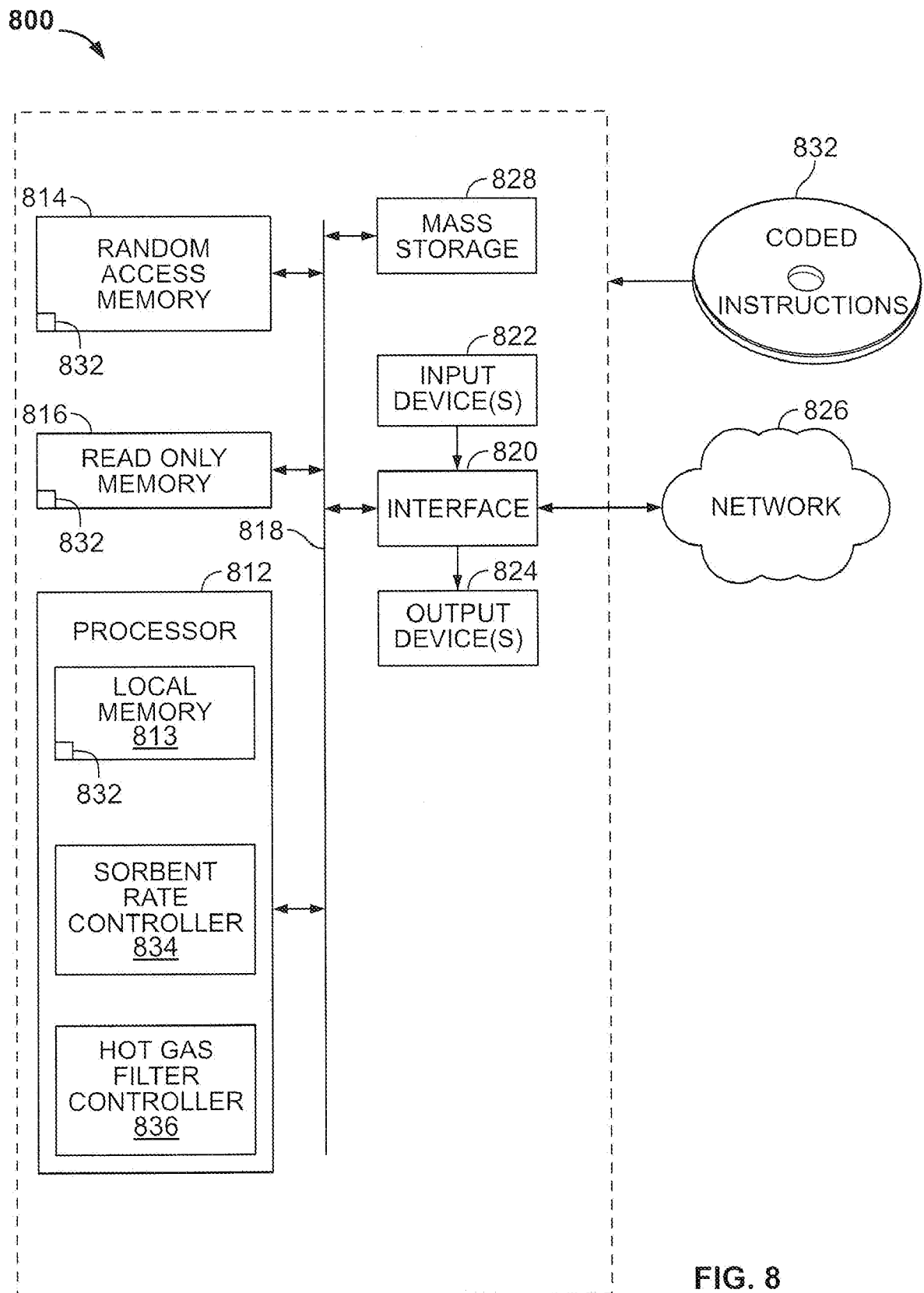


FIG. 8