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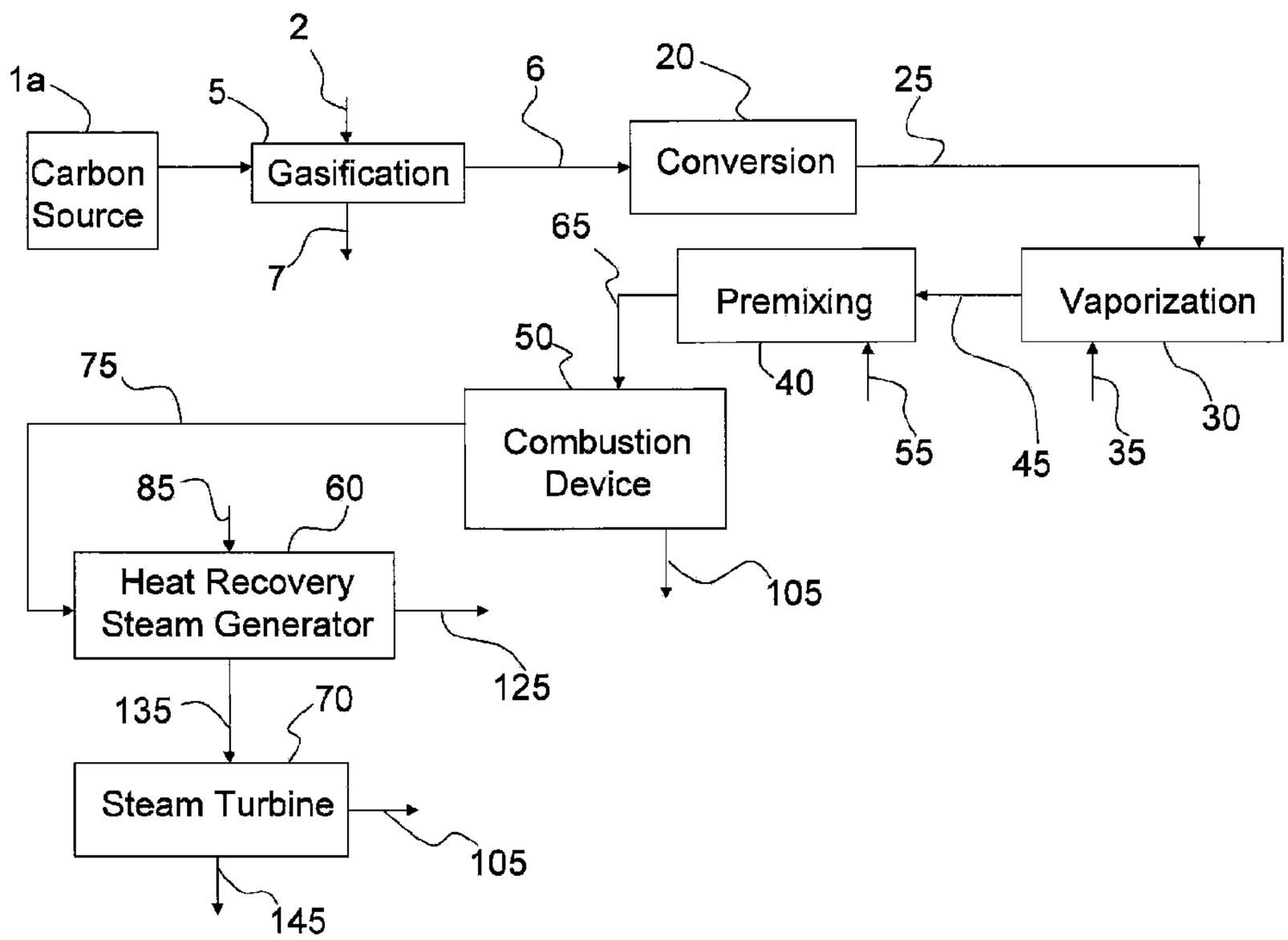
(54) **Titre : SYSTEME ET METHODE INTEGRES DE PRODUCTION ET DE VAPORISATION DE COMBUSTIBLES HYDROCARBURES LIQUIDES POUR COMBUSTION**

(54) **Title: INTEGRATED SYSTEM AND METHOD FOR PRODUCTION AND VAPORIZATION OF LIQUID HYDROCARBON FUELS FOR COMBUSTION**



(57) **Abrégé/Abstract:**
A process is provided, which comprises transforming a synthesis gas into a liquid fuel, producing a fuel gas using the liquid fuel and a first gas, the first gas having an oxygen content less than that of ambient air, and contacting the fuel gas with a second gas, the second gas comprising at least one oxidizing agent, to form a combustion gas. Systems for carrying out the process are also provided.

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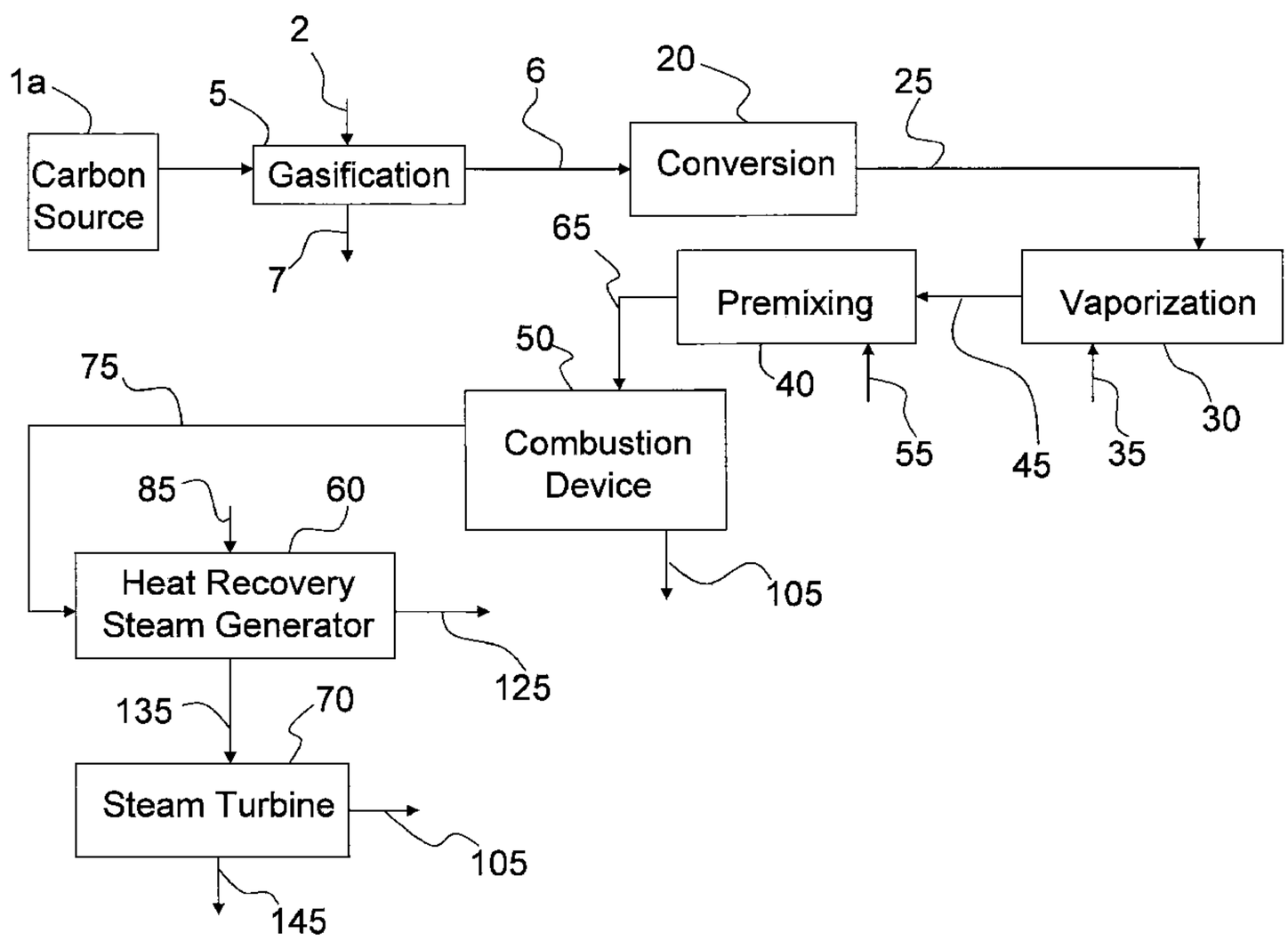

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INTEGRATED SYSTEM AND METHOD FOR PRODUCTION AND VAPORIZATION OF LIQUID HYDROCARBON FUELS FOR COMBUSTION

BACKGROUND

[001] Integrated Gasification Combined Cycle (IGCC) technology couples a complex coal gasification process plant with a synthesis gas-fired combustion turbine combined cycle power plant. The IGCC process typically involves a two-stage combustion operation, which typically includes a cleanup between the stages.

[002] The first stage employs a gasifier where partial oxidation of the coal is carried out by limiting the oxidant supply. Other methods, such as steam reforming, may also be used to produce the synthesis gas. The thus-produced synthesis gas, a mixture mostly of CO and H_2, is then typically scrubbed to remove impurities such as sulfur, and sent to a second stage. In the second stage, the synthesis gas is burned in a combustion turbine to complete the oxidation and produce energy.

[003] To produce the synthesis gas, sources of carbon other than coal may be used. This so-called gas turbine/combined cycle (GT/CC) technology operates

equally well with a variety of carbon-containing feed stocks such as liquid and solid hydrocarbons, biomass, asphalt, tires, coke residue, and the like.

[004] Of extreme importance to an IGCC plant is the integration of the entire system – the gasification unit and the combustion turbine. Because it is impractical to store significant quantities of synthesis gas, the combustion turbine must remain operational whenever the gasification plant is in operation. Shutting down the combustion turbine typically requires an immediate shutdown of the gasification plant. It is also difficult to run the gasification plant at only part load, and hence it is necessary to run the combustion turbine in at least a base load configuration. These are significant operating limitations.

[005] Coal-derived synthesis gas has a very low heating value (115-125 BTU/scf LHV) compared to that of natural gas (800-1000 BTU/scf LHV). Because of this, the combustion hardware on a synthesis gas-fired combustion turbine must be substantially modified from that normally used on a natural gas-fired, combustion turbine. The cost of these modifications can be significant, adding to the cost of the plant, and creating additional maintenance issues for the operator.

[006] Rather than burning the synthesis gas for its energy value, the synthesis gas may be converted into hydrocarbons. These so-called gas-to-liquid (GTL) and coal-to-liquid (CTL) processes are well known. Several methods are available to carry out the conversion. The Fischer-Tropsch process is but one example in which CO and H_2 are catalyzed into hydrocarbons. Hydrocarbons produced by the Fischer-Tropsch process include C_1-C_{200} or higher, with most being in the range of about C_1-C_{50}.

[007] In the past 15 years, however, liquid fuels have not been the fuels of choice for combustion turbines. This is because of the higher levels of pollution typically associated with burning liquid fuels compared to burning gaseous fuels such

as natural gas. Liquid fuels are traditionally burned in non-premixed (or diffusion) mode, which leads to regions of relatively high temperature within the combustor. Since non-premixed combustion can increase the amounts of pollutants such as NO_x, premixed combustors have been developed for gas turbines. These allow for greater control of the temperature field in the combustor. In addition, the practice of introducing water or steam into the combustor to reduce emissions of NO_x compounds when burning liquid fuels in non-premixed mode also has a detrimental effect on the efficiency and lifetime of the combustion turbine hardware.

[008] U.S. Patent No. 7,089,745 discloses a system for vaporization of liquid fuels for combustion and method of use.

BRIEF DESCRIPTION OF THE FIGURES

[009] Figure 1 shows a block diagram of a prior art IGCC plant.

[010] Figure 2 shows a block diagram of one embodiment of the invention.

[011] Figure 3 shows a block diagram of another embodiment of the invention.

[012] Figure 4 shows a block diagram of another embodiment of the invention.

[013] Figure 5 shows a block diagram of one embodiment of the invention.

[014] Figure 6 shows a block diagram of another embodiment of the invention.

[015] Figure 7 shows a block diagram of another embodiment of the invention.

[016] Figure 8 shows a block diagram of another embodiment of the invention.

[017] Figure 9 shows a block diagram of another embodiment of the invention.

DESCRIPTION OF THE SEVERAL EMBODIMENTS

[018] One embodiment of the present invention, shown in Figure 2, provides a process, comprising transforming a synthesis gas 6 into a liquid fuel 25, producing a fuel gas 45 using the liquid fuel 25 and a first gas 35, the first gas 35 having an oxygen content less than that of ambient air, and contacting the fuel gas 45 with a second gas 55, the second gas 55 comprising at least one oxidizing agent, to form a combustion gas 65. A carbon source 1a is sent to a gasification unit 5, in which O_2, air, H_2O, CO_2, or a combination thereof 2 are introduced. Impurities 7 may be removed, and synthesis gas 6 is formed. The synthesis gas 6 is transformed into liquid fuel 25 in the conversion unit 20. A fuel gas 45 is produced in vaporization unit 30 using the liquid fuel 25 and a first gas 35, the first gas 35 having an oxygen content less than that of ambient air. The fuel gas 45 is contacted with a second gas 55 in the premixing unit 40, the second gas 55 comprising at least one oxidizing agent, to form a combustion gas 65.

[019] The combustion gas 65 may be formed prior to arriving at a flame front (not shown) in a combustion device 50 (pre-mixed mode) or at a flame front in a combustion device 50 (non-premixed mode).

[020] The carbon source 1a is not particularly limited. In addition to coal 1, other carbon sources 1a may be used. Some examples of carbon sources 1a from which synthesis gas 6 may be produced include one or more of coal, lignite, brown coal, anthracite, sub-bituminous coal, particulate carbon, fossil fuels, solid hydrocarbons, liquid hydrocarbons, residual oil, low API gravity fuel oil, tar sand oil, shale oil, VacResid, petroleum coke, petroleum bottoms, asphalt, API asphalt, coke residue, natural gas, wax, waste, bitumen, ORIMULSION ™ (aqueous emulsion of bitumen), biomass, carbohydrates, cellulosistics, peat, corn, straw, wood, wood residues, manure, sewage sludge, rice hulls, rice straw, oat hulls, pine tree bark, tires and/or tire derived fuel, furfural residue, oat hulls, switchgrass, olive waste, sansa, whole tree waste, sugar cane bagasse, undigested dried sewage sludge, digested dried sewage sludge, carpet manufacturing selvage, post consumer carpet, chicken litter, turkey litter, laminate flooring dust, urban green waste, pulp sludge, corn stover, ethanol plant dried distiller's grains, and the like, and mixtures thereof.

[021] The gasification unit 5 is not particularly limited so long as it converts the carbon source 1a into synthesis gas 6. The gasification unit 5 may be a fixed bed, fluidized bed, circulating fluidized bed or entrained flow type. In the gasification unit 5, the carbon source 1a is combined with a feed 2 of O_2, air, H_2O, steam, CO_2, or a combination thereof. Although not shown, in one embodiment, the O_2 feed 2 for the gasification unit 5 may be produced in an air separator unit (ASU), as is well known. Converting the carbon source 1a can include one or more of partial oxidation, catalytic partial oxidation, steam reforming, autothermal reforming, CO_2 reforming, water gas shift, pressure swing adsorption, or a combination thereof.

[022] As shown in Figure 2, impurities 7 such as slag, mercury, alkaline metals, solids, soot, dust, ash, sulfur, acid gas, H_2S, COS, NH_3, HCN, HBr, HCl, HF,

CS_2, and the like can be removed or recovered for value. Other components such as CO_2, H_2O, CH_4, N_2, paraffins, ethane, propane, and olefins, ethane, propene, tars, organic compounds, and the like may be removed and/or recovered for value if desired. Methods of removing these are known in the art. The synthesis gas 6 can also include the so-called "biosyngas", produced from the gasification of biomass. The thus produced synthesis gas 6, which is predominantly a mixture of H_2 and CO, may be clean and dry for supplying to the conversion unit 20. In this regard, the gasification unit 5 and the conversion unit 20 are fluidly connected.

[023] As shown in Figure 2, the synthesis gas 6 may be sent to conversion unit 20 and transformed into liquid fuel 25. Methods for transforming synthesis gas 6 into hydrocarbons are well known. In one embodiment, the conversion unit 20 comprises a Fischer-Tropsch reactor. The Fischer-Tropsch ("FT") process is but one example in which CO and H_2 are catalyzed into hydrocarbons. FT products and products made from similar reactions between CO and H_2 include C_1-C_{200} or higher hydrocarbons, with most being in the range of about C_1-C_{50}, straight chain, high boiling hydrocarbons, medium boiling oils, diesel oil, green diesel, L-P gas, naphtha, kerosene, jet fuel, JP-5, JP-8, JP-4, oil #1, fuel oil #2, oxygenated compounds, coal liquids, tailgas, wastewater, and the like, and mixtures thereof.

[024] The type of Fischer-Tropsch reactor for conversion unit 20 such as shown in Figure 2 is not particularly limited. Some examples of FT reactors include tubular fixed bed reactors, Arge reactors, Sasol advanced synthol (SAS) reactors, Sasol slurry phase distillate (SSPD) reactors, high temperature Fischer-Tropsch (using a fluidized catalyst at 300 - 330°C), low temperature Fischer-Tropsch (using tubular fixed bed reactors at 200 - 230 °C), entrained bed reactors, fixed-fluidized bed reactors, and slurry bubble column reactors.

[025] In one embodiment, not shown, the tailgas, which may arise as a byproduct of the FT or similar process, and which may contain one or more of CO, H_2, CO_2, CH_4, C_2H_6, H_2O, N_2, Ar and other gaseous hydrocarbons, may be recovered for value or recycled to one or more units or steps herein as appropriate. In another embodiment, one or more of the above components of the tailgas may be recovered for value or recycled to one or more units or steps herein.

[026] So long as they are derived from synthesis gas, many liquid fuels 25 are suitable for use in the system and process described herein. The term, "liquid fuel" should be understood to include hydrocarbons that are normally in a liquid state at ambient conditions, as well as gaseous hydrocarbons that have been liquified by cooling and/or pressurization. Such liquid fuels 25 may comprise one or more liquid and/or liquifieded gaseous hydrocarbons, liquified natural gas with elevated higher hydrocarbon content, liquified C_2, C_3, C_4, liquid C_5, C_6, C_7, C_8, C_9, and higher hydrocarbons, straight chain medium and high boiling hydrocarbons, "higher hydrocarbon fuel" having at least 50% by weight of the hydrocarbon molecules have at least two carbons, diesel, green diesel, L-P gas, naphtha, kerosene, jet fuel, JP-5, JP-8, JP-4, fuel oil #1, fuel oil #2 oxygenated compounds, coal liquids, and the like, and mixtures thereof. In one embodiment, the liquid fuel 25 includes hydrocarbons that are normally in a liquid state at ambient conditions. In another embodiment, the liquid fuel 25 includes gaseous hydrocarbons that have been liquified by cooling and/or pressurization. In yet another embodiment, the liquid fuel 25 includes a mixture of hydrocarbons that are normally in a liquid state at ambient conditions and gaseous hydrocarbons that have been liquified by cooling and/or pressurization.

[027] As shown in Figure 2, the liquid fuel 25 is sent to a vaporization unit 30. A fuel gas 45 is produced in the vaporization unit using the liquid fuel 25 and a

first gas 35. In the vaporization unit 30, the liquid fuel 25 is contacted with and mixes with the first gas 35. The liquid fuel 25 is also vaporized. The order in which the contact and vaporization occurs is not particularly limited. In some embodiments, the contact and vaporization occur simultaneously, such as when the first gas 35 is preheated to a temperature sufficient to vaporize the liquid fuel 25. In other embodiments, the liquid fuel 25 is partially or completely vaporized, e.g., by heating the liquid fuel 25 prior to contacting the first gas 35. In some embodiments, the first gas 35 is pressurized and/or heated prior to contact and vaporization. An example of a suitable vaporization unit 30 is described in U.S. Patent 7,089,745.

[028] Although not shown in Figure 2, in one embodiment, the liquid fuel 25 can be sent to and stored in a storage vessel for a period of time prior to sending it to the vaporization unit 30. In another embodiment, not shown in Figure 2, the liquid fuel 25 can be transported by truck, rail, pipeline, or ship to the vaporization unit 30. In another embodiment, the liquid fuel 25 can be sent to the vaporization unit 30 via a combination of storage vessel and transport by truck, rail, pipeline or ship. In another embodiment, the liquid fuel 25 is fed directly to the vaporization unit 30. In this regard, the conversion unit 20 is fluidly connected to vaporization unit 30.

[029] The first gas 35 has an oxygen content less than that of ambient air. In one embodiment, the first gas 35 has an oxygen content of less than about 21% O_2 at ambient temperature and pressure. In one embodiment, the first gas 35 has an O_2 content of zero or substantially zero to less than about 21% at ambient temperature and pressure. This range includes all values and subranges therebetween, including 0, substantially zero, 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20 and less than about 21%.

[030] In one embodiment, the first gas 35 has an O_2 content below the limiting oxygen index. The limiting oxygen index (LOI) is the concentration of oxygen in the local environment below which a material will not support combustion and varies for different types of liquid fuels. The LOI is typically between about 10% and about 14% and is approximately 13% for many higher hydrocarbon fuels. In one embodiment, the first gas 35 has an O_2 content below 14%. This includes all values and subranges therebetween, including below 14, 13, 12, 11, 10, 9, 8, 7, 6%, and below.

[031] Limiting the amount of oxygen in the first gas 35 will delay or suppress the onset of autoignition. The more the oxygen content of the first gas 35 is reduced, the more autoignition is suppressed or delayed. However, more work (i.e., energy) is required to produce a gas stream with a lower oxygen content, which reduces the overall efficiency of the system. Thus, in some embodiments, the oxygen content in the first gas 35 is sufficiently low to suppress or delay autoignition.

[032] In one embodiment, the oxygen content in the first gas 35 is sufficiently low such that combustion of the fuel gas 45 is not supported. In one embodiment, the oxygen content in the first gas 35 is sufficiently low such that autoignition of the combustion gas 65 is delayed or reduced.

[033] So long as it contains a reduced amount of oxygen, the composition of the first gas 35 is not particularly limited. Nonlimiting examples of the first gas 35 include one or more of inert gas, nitrogen, argon, hydrogen, carbon monoxide, carbon dioxide, NOx, SOx, hydrocarbon, methane, ethane, propane, butane, ammonia, gas supplied by an air separator unit, exhaust gas, hot exhaust gas 75, cold exhaust gas 125, synthesis gas 6, or a combination thereof. In one embodiment, the first gas 35 can be supplied from one or more of the units or combustion devices herein.

[034] In one embodiment, the first gas 35 is N_2 produced by an air separator unit (not shown). This provides a beneficial use of what would otherwise be a waste product. Most gasification processes use nearly pure oxygen in the partial oxidation of coal to produce synthesis gas. This oxygen is produced by an air separation unit (ASU) that separates the oxygen and nitrogen from ambient air. The nitrogen produced by the ASU is typically considered to be a waste product, and is sometimes injected into clean synthesis gas burned by a synthesis gas-fired combustion turbine in an attempt to reduce NOx emissions. However, in one embodiment it is contemplated that all or a portion of the nitrogen gas can be utilized in the first gas 35 to create the fuel gas 45. By using waste nitrogen already available from the ASU, the energy requirements of the present process are substantially reduced. It is also notable that the low NOx combustion hardware present in a natural gas-fired combustion turbine does not require the addition of supplemental nitrogen, in contrast to the hardware requirements of a synthesis gas-fired combustion turbine.

[035] In one embodiment, one or more of the amount, pressure, temperature and composition of the first gas 35 can be metered and controlled. Methods of controlling and/or metering gases are known.

[036] Once produced, as shown in Figure 2, the fuel gas 45 is fed to the premixing unit 40. In the premixing unit 40, the fuel gas 45 is contacted with a second gas 55 to form a combustion gas 65.

[037] The second gas 55 contains at least one oxidizing agent. In one embodiment, the second gas 55 contains at least one oxidizing agent in an amount sufficient to support combustion in the combustion gas 65. The oxidizing agent is not particularly limited. Non-limiting examples of oxidizing agent include ambient air, oxygen gas, nitrogen dioxide, ozone, and the like, and combinations thereof. The

second gas 55 may have oxygen present in an amount equal to or greater than that of ambient air, or about 21%. This range includes all values and subranges therebetween, including 21%, greater than 21%, 22, 23, 24, 25, 26, 27, 28, 29 30, 35, 40, 50, 60, 70, 80, 90, 95, 96, 97, 98, 99, substantially 100%, and 100% oxygen (O_2).

[038] In one embodiment, the second gas 55 is supplied by an ASU. In another embodiment, the second gas 55 may be ambient air. In another embodiment, the second gas 55 may be supplied by a compressor. The second gas 55 may, alternatively, be a combination of these.

[039] Although not shown, in one embodiment, in addition to supplying the second gas 55 to the premixing unit 40 for mixing with the fuel gas 45, or, in addition to contacting the fuel gas 45 and the second gas 55 at a flame front in the combustion device 50, the oxidizing agent, compressed oxidizing agent, compressed oxygen-containing gas or oxygen can be added downstream of fuel burning in the combustion device 50. Feeding the additional oxidizing agent, for example, oxygen, into a post combustion emission stream can reduce the pollutants by enhancing the oxidation of unburned fuel and/or carbon monoxide in the exhaust stream (75 in Figure 3).

[040] In one embodiment, the combustion device 50 is configured to contact the fuel gas 45 with a second gas 55 at a flame front. In this way, the combustion gas 65 may be formed at the flame front. In another embodiment, when a premixing unit 40 is utilized, the combustion gas 65 is formed prior to arrival at a flame front (not shown), the flame front being in the combustion device 50. In one embodiment, the flame front occurs in a primary combustion zone (not shown) of the combustion device 50. The premixed mode, wherein the combustion gas 65 is formed prior to arriving at the flame front, may result in lower emissions of pollutants due to enhanced mixing and lower temperatures. The non-premixed mode, wherein the fuel

gas 45 and second gas 55 are contacted at a flame front of the combustion device 50, may result in higher emissions of pollutants.

[041] The combustion device 50 may be configured for either premixed mode or non-premixed mode. The combustion device 50 may be a gas turbine, for example. The combustion device may be configured for diffusion combustion, Rich Quench Lean (RQL) combustion, or a premixed combustion. When in non-premixed mode, the combustion device 50 may be configured to run in diffusion combustion mode. In these cases, a diffusion combustor is utilized. When in pre-mixed mode, the combustion device 50 may utilize a "Rich Quench Lean" ("RQL") or a premixed combustor. These types of combustors are known in the art.

[042] The combustion gas 65 in Figure 2 may be fed as desired to the combustion device 50.

[043] Another embodiment provides a system, comprising a conversion unit 20 configured to transform a synthesis gas 6 into a liquid fuel 25, a vaporization unit 30 configured to produce a fuel gas 45 using the liquid fuel 25 and a first gas 35, the first gas 35 having an oxygen content less than that of ambient air, and a premixing unit 40 configured to contact the fuel gas 45 with a second gas 55, the second gas 55 comprising at least one oxidizing agent, and form a combustion gas 65. One example of this embodiment is shown in Figure 3.

[044] As shown in Figure 3, in one embodiment, the liquid fuel 25 can be sent to and stored in a storage vessel for a period of time prior to sending it to the vaporization unit 30. In another embodiment, the liquid fuel 25 can be transported by truck, rail, pipeline, or ship to the vaporization unit 30. In another embodiment, the liquid fuel 25 can be sent to the vaporization unit 30 via a combination of storage

vessel and transport by truck, rail, pipeline or ship. The liquid fuel 25 can be easily stored and shipped, and an advantage is gained in that the need for integrating the gas-to-liquid or coal-to-liquid process with the power generation process is significantly reduced. This also has the advantage of eliminating the need to co-locate the gas to liquid or coal to liquid process and the power generation process. In another embodiment, such as shown in Figure 4, the liquid fuel 25 is fed directly to the vaporization unit 30. In this regard, the conversion unit 20 is fluidly connected to vaporization unit 30.

[045] As shown in Figure 3, a combustion device 50, which may be a natural gas combustion device, is fed the combustion gas 65. Electrical power 105 is produced. A hot exhaust gas 75 is fed to a heat recovery steam generator 60.

[046] Optionally, as an alternative, all or a portion of the hot exhaust gas 75 can be utilized as the diluent gas in the first gas 35. In one embodiment, a portion of the exhaust gas 75 provides heat for the heat recovery steam generator 60, and a portion is utilized as the diluent gas in the first gas 35. In addition, the exhaust gas 75 can be used to heat or vaporize the fuel gas 45.

[047] The heat recovery steam generator 60 heats a water feed 85 to produce high pressure steam 135 and cold exhaust 125. The cold exhaust 125 can be fed to a stack (not shown) and discarded, or it may be recycled to one or more units described herein as desired. For example, the cold exhaust may be utilized as a diluent in the first gas 35.

[048] The high pressure steam 135 is fed to a steam turbine 70 to produce electrical power 105 and low pressure steam 145. The low pressure steam, may, if

desired, be utilized in one or more units described herein. For example, the low pressure steam may be utilized in the feed 2 to gasification unit 5.

[049] Another embodiment provides a process, comprising separating a synthesis gas 6 into first and second portions 6a and 6b, transforming the first portion 6a of synthesis gas 6 into a liquid fuel 25, producing a fuel gas 45 using the liquid fuel 25 and a first gas 35, the first gas 35 having an oxygen content less than that of ambient air, contacting the fuel gas 45 with a second gas 55, the second gas 55 comprising at least one oxidizing agent, to form a combustion gas 65, and combusting the second portion 6b of synthesis gas 6 with a modified combustion device 80. An example of a modified combustion device is a modified gas turbine 80a. One embodiment in accordance with this process is depicted in Figure 7.

[050] Another embodiment provides a system, comprising a separator unit 100 configured to separate a synthesis gas 6 into first and second portions 6a and 6b, a conversion unit 20 configured to transform the first portion 6a of synthesis gas 6 into a liquid fuel 25, a vaporization unit 30 configured to produce a fuel gas 45 using the liquid fuel 25 and a first gas 35, the first gas 35 having an oxygen content less than that of ambient air, a premixing unit 40 configured to contact the fuel gas 45 with a second gas 55, the second gas 55 comprising at least one oxidizing agent, and form a combustion gas 65, and a modified combustion device 80 configured to combust the second portion 6b of synthesis gas 6. One example of a modified combustion device 80, which is modified to combust synthesis gas 6, is a modified gas turbine 80a. One embodiment in accordance with this system is depicted in Figure 7.

[051] As shown in Figure 7, a separator 100 is provided, which separates the synthesis gas 6 into first and second portions 6a and 6b. An advantage is gained in

the polygeneration of electrical and steam power from both a synthesis gas-fired combustion device 80 and combustion fuel fired combustion device 50.

[052] Another embodiment provides a system, comprising a switching unit configured to send all or a portion of a stream of synthesis gas 6 to one or both of a first combustion device and a conversion unit 20, the conversion unit 20 being configured to transform the synthesis gas 6 into a liquid fuel 25, a vaporization unit 30 configured to produce a fuel gas 45 from the liquid fuel 25 and a first gas 35, the first gas 35 having an oxygen content less than that of ambient air, and a premixing unit 40 configured to contact the fuel gas 45 with a second gas 55, the second gas 55 comprising at least one oxidizing agent, and form a combustion gas 65. An example of such a system is shown in Figure 8.

[053] Another embodiment provides a process, comprising sending a first stream of a synthesis gas 6 to a first combustion device for combustion, and thereafter switching all or a portion of the first stream away from the first combustion device, to produce a second stream of synthesis gas 6, transforming the second stream of synthesis gas 6 into a liquid fuel 25, producing a fuel gas 45 using the liquid fuel 25 and a first gas 35, the first gas 35 having an oxygen content less than that of ambient air, and contacting the fuel gas 45 with a second gas 55, the second gas 55 comprising at least one oxidizing agent, to form a combustion gas 65.

[054] Another embodiment provides a process, comprising separating a synthesis gas 6 into first and second portions 6a and 6b, transforming the first portion 6a of synthesis gas 6 into a liquid fuel 25, producing a fuel gas 45 using the liquid fuel 25 and a first gas 35, the first gas 35 having an oxygen content less than that of ambient air, contacting the fuel gas 45 with a second gas 55, the second gas 55

comprising at least one oxidizing agent, to form a combustion gas 65, and combusting the second portion 6b of synthesis gas 6 with a modified combustion device 80.

[055] Liquid fuel 25 produced by the coal-to-liquid (CTL) process are in many ways superior, in terms of combustion properties and pollutant emissions, to equivalent fuels refined from crude oil (see Table I).

[056] Table I. Fischer-Tropsch Diesel Fuel Characteristics

	Low Sulfur D-975	California CARB	Rentech (FTD)	EU (2005)	EPA (2006)
Cetane Index	>40	>48	72	>50	>40
Aromatics (vol %)	<35	<10	<4	<10	<35
Sulfur (ppm)	<500	<500*	<1	<10	<15
Biodegradable	No	No	Yes	No	No

[057] Contacting the liquid fuel 25 with the first gas 35 and vaporizing (sometimes referred to herein as the LPP process) transforms the liquid fuel 25 into a fuel gas 55 (sometimes called synthetic natural gas or "LPP GAS™") which may be burned in conventional natural gas dry low emissions combustion hardware. The present process and system make it possible to avoid the need of water or steam to achieve low NOx emissions levels.

[058] By using the synthesis gas 6 to create combustion gas 65, the gasification unit 5 would no longer require continuous or base-load operation of the combustion turbine 80. If the combustion turbine 80 load is reduced, the excess liquid fuels 25 produced would be stored as necessary in nearby tanks, or would be distributed via pipeline, truck or train, etc. If the combustion turbine 80 is shutdown altogether, the gasification and conversion units 5 and 20 could continue to operate,

storing or distributing the fuel liquids 25 produced as described for part-load operation.

[059] By the present invention, it is possible to utilize one or more conventional natural gas-fired combustion turbines, each combined with an LPP skid (or vaporization unit 30) to transform the liquid fuel 25 into LPP GAS^{TM} which will be burned by the conventional combustion turbine. The LPP^{TM} skid/conventional combustion turbine hardware could operate in "peaking mode" as necessary, and would allow the overall plant to respond to electrical load changes without having to change the rate of production of synthesis gas 6. The gas turbine could be operated in a combined cycle mode, as depicted in Figures 7 and 8, or in simple cycle configuration.

[060] It is also possible to completely decouple the gasification/coal-to-liquids (CTL) plant and the power plant (see Figure 9). The coal liquids would be produced at the gasification/CTL plant and shipped to stand-alone combustion turbines that are equipped with the LPP^{TM} technology. This would provide the added benefit of allowing the gasification/CTL plant to be sited at any location, including a location in close proximity to the coal source. A site within close proximity to the coal source would reduce the transportation cost for the coal, and would facilitate disposal of the slag waste product resulting from the gasification plant.

[061] By the present invention, excess coal liquids could be easily transported to stand-alone combustion turbines that include the LPP^{TM} technology.

[062] The present invention inheres additional advantages. It is possible to significantly reduce the plant capital cost if a spare gasifier is not needed for the coal gasification plant. The gasifier hardware portion of a coal gasification plant operates

at a very high temperature and pressure. It has been found that the reliability of the gasifier hardware is such that plant economics may require that a spare gasifier be built as a "hot standby" in case the primary gasifier fails or requires maintenance. The standby gasifier is needed because there is a long lead time required to repair the gasifier, and the synthesis gas 6 produced cannot be stored for use while the gasifier is being repaired. The gasifier hardware can cost tens or hundreds of millions of dollars in a typical IGCC plant.

[063] Another advantage is that ownership and operation of the CTL and power plants may be separated. One of the concerns with IGCC plants is that the coal gasification process is a complex chemical process for which the power industry does not have extensive experience. By the present invention, the coal gasification/CTL plant can be decoupled from the power generation plant. This allows a process plant company to own and operate the gasification/CTL plant, while a utility or independent power producer can operate a combustion turbine plant, along with the LPP^{TM} skid.

[064] Dry Low Emissions (DLE) systems employing lean, premixed combustion have been successfully used with natural gas in combustion turbines to meet stringent emissions standards. However, the burning of liquid fuels in DLE systems is still a challenging task due to the complexities of fuel vaporization and air premixing. In one embodiment, Lean, Premixed, Prevaporized (LPP^{TM}) combustion achieves low pollutant emissions while burning liquid fuels such as kerosene and fuel oil.

[065] In another embodiment, the liquid fuel 25 can be produced by direct conversion methods, which avoid the use of synthesis gas intermediates and which avoid the need for conversion using FT or other processes. Accordingly, in one

embodiment, these direct conversion processes may be used in place of gasification 5 and conversion 20. These direct conversion methods are known in the art.

[066] Non-limiting examples of direct conversion methods include direct conversion of coal, solvent refining of coal, liquid solvent refining of coal, direct conversion of biomass, direct conversion of wood waste, and the like. In the direct conversion of biomass, wood waste, and the like, pyrolysis oil may be produced from the pyrolysis of biomass, wood waste, and the like in an inert atmosphere. Non-limiting examples of the types of liquid fuel 25 that result from these direct conversion methods include solvent-refined coal fuel, liquid solvent-refined coal fuel, pyrolysis oil, and the like, and combinations thereof.

[067] Key to Figures:

[068] Coal 1

[069] Carbon source 1a

[070] Feed 2

[071] Synthesis gas 6

[072] Synthesis gas 6 first portion 6a

[073] Synthesis gas 6 second portion 6b

[074] Impurities 7

[075] Conversion unit 20

[076] Liquid fuel 25

[077] Vaporization unit 30

[078] First gas 35

[079] Premixing unit 40

[080] Fuel gas 45

[081] Combustion device 50

[082] Combustion turbine 50a

[083] Second gas 55

[084] Heat recovery steam generator 60

[085] Combustion gas 65

[086] Steam turbine 70

[087] Hot exhaust gas 75

[088] Modified combustion device 80

[089] Modified combustion turbine 80a

[090] Water 85

[091] O_2 95

[092] Separator unit 100

[093] Electrical power 105

[094] Cold exhaust gas 125

[095] High pressure steam 135

[096] Low pressure steam 145

[097] Switching unit 200

Claims

1. A process for operating an integrated gasification combined cycle (IGCC) plant, the IGCC plant comprising a gasifier for gasifying coal to produce syngas, a syngas combustion system for combusting the syngas to produce electricity, and a premixed natural gas combustion system, the process comprising:

operating the gasifier to produce synthesis gas at a constant rate;

when a current demand for electricity is below a base load corresponding to the output of the gasifier at the constant rate,

convert some of the syngas from the gasifier to a liquid and store the liquid; and

when a current demand for electricity is above the base load corresponding to the output of the gasifier at the constant rate,

convert some of the stored liquid to a fuel gas using an Lean, Pre-mixed, Pre-Vaporized (LPP) skid or vaporization unit to vaporize the liquid fuel and combine it with a first gas, the first gas having an oxygen content less than that of ambient air, and use the fuel gas in the premixed natural gas combustion system to produce sufficient electricity to meet the portion of the current electrical demand that is above the base load corresponding to the output of the gasifier at the constant rate.

2. The process of claim 1, further comprising producing the synthesis gas from a carbon source selected from the group consisting of coal, lignite, brown coal, anthracite, sub-bituminous coal, particulate carbon, fossil fuels, solid hydrocarbons, liquid hydrocarbons, residual oil, low API gravity fuel oil, tar sand oil, shale oil, VacResid, petroleum coke, petroleum bottoms, asphalt, API asphalt, coke residue, natural gas, wax, waste, bitumen, aqueous emulsion of

bitumen (ORIMULSION™), biomass, carbohydrates, cellulosistics, peat, corn, straw, wood, wood residues, manure, sewage sludge, rice hulls, rice straw, oat hulls, pine tree bark, tires and/or tire derived fuel, furfural residue, switchgrass, olive waste, sansa, whole tree waste, sugar cane bagasse, undigested dried sewage sludge, digested dried sewage sludge, carpet manufacturing selvage, post consumer carpet, chicken litter, turkey litter, laminate flooring dust, urban green waste, pulp sludge, corn stover, ethanol plant dried distiller's grains, and a mixture thereof.

3. The process of claim 1, wherein transforming the synthesis gas into liquid fuel comprises a Fischer-Tropsch process.

4. The process of claim 1, wherein the liquid fuel is vaporized before contacting it with the first gas.

5. The process of claim 1, wherein liquid fuel is vaporized by contacting it with the first gas.

6. The process of claim 1, wherein the first gas stream comprises one or more of inert gas, nitrogen, argon, hydrogen, carbon monoxide, carbon dioxide, NOx, SOx, hydrocarbon, methane, ethane, propane, butane, ammonia, gas supplied by an air separator unit, exhaust gas, hot exhaust gas, cold exhaust gas, synthesis gas or a combination thereof.

7. The process of claim 1, wherein the oxygen content in the first gas stream is below a level needed to support combustion of the fuel gas.

8. The process of claim 1, wherein the first gas stream contains substantially no oxygen.

9. The process of claim 1, wherein the oxygen content in the first gas stream is at or below a level at which autoignition of the combustion gas is delayed or reduced.

10. The process of claim 1, further comprising, prior to producing the fuel gas, sending the liquid fuel to a storage vessel, storing the liquid fuel in the storage vessel for a period of time, and removing the liquid fuel from the storage vessel.

11. The process of claim 1, further comprising, prior to producing the fuel gas, transporting the liquid fuel by truck, rail, pipeline, or ship, or a combination thereof.

12. The process of claim 1, wherein the combustion gas is formed prior to arrival at a flame front in a combustion device.

13. The process of claim 1, wherein the IGCC plant further comprises an air separation unit, the process further comprising:

supplying an oxygen-rich gas stream from the air separation unit to the gasifier; and

using a nitrogen-rich gas stream from the air separation unit as the first gas when producing the fuel gas.

14. The process of claim 1, wherein the IGCC plant includes a single gasifier.

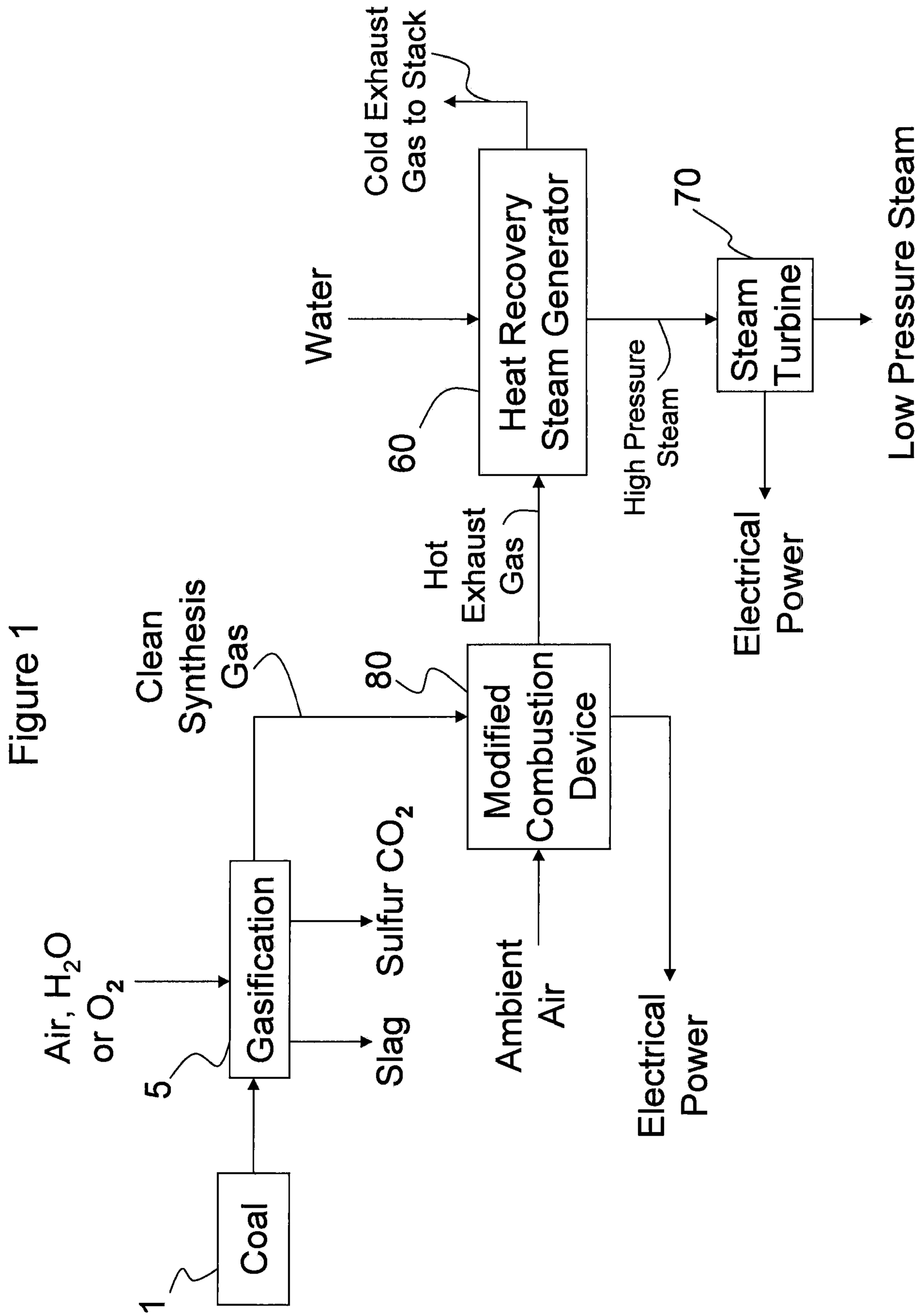
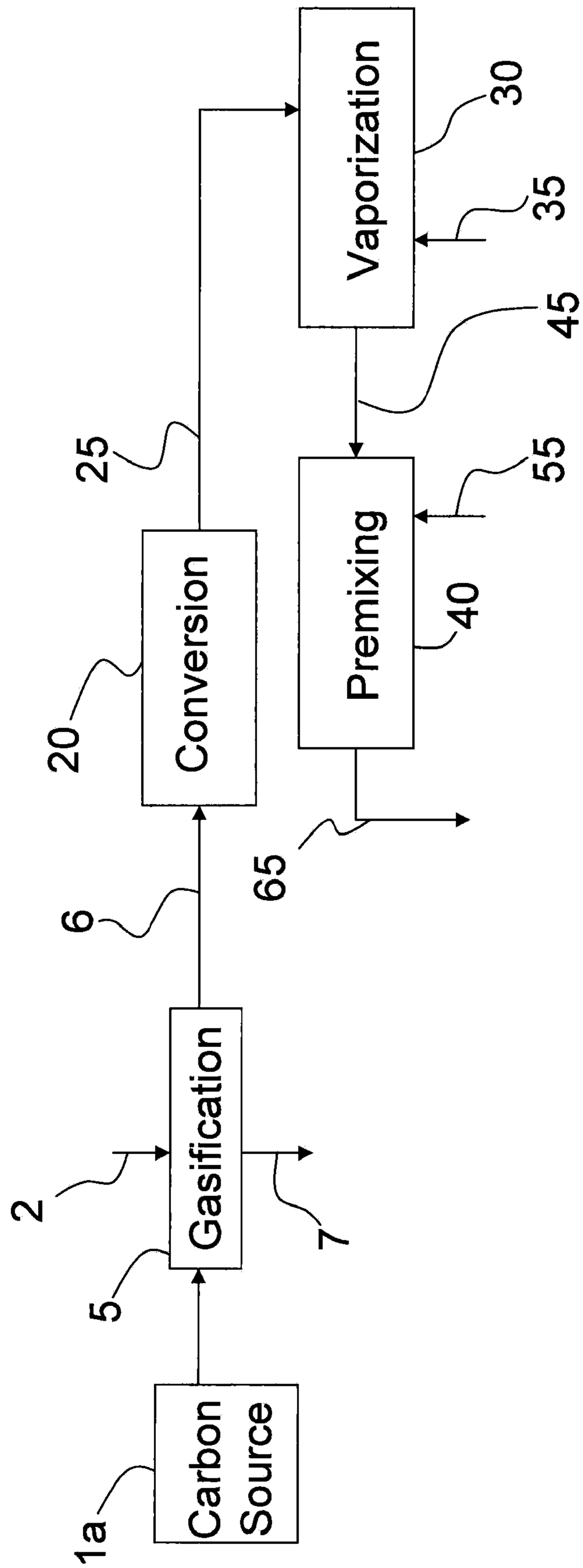

Coal
1
Air, H_2O or O_2
Gasification
5
Slag
Sulfur CO_2
Clean Synthesis Gas
Hot Exhaust Gas
Modified Combustion Device
80
Ambient Air
Electrical Power
Water
Heat Recovery Steam Generator
60
Cold Exhaust Gas to Stack
High Pressure Steam
Steam Turbine
70
Electrical Power
Low Pressure Steam

Figure 1


Carbon Source
Gasification
Conversion
Premixing
Vaporization
1a
5
2
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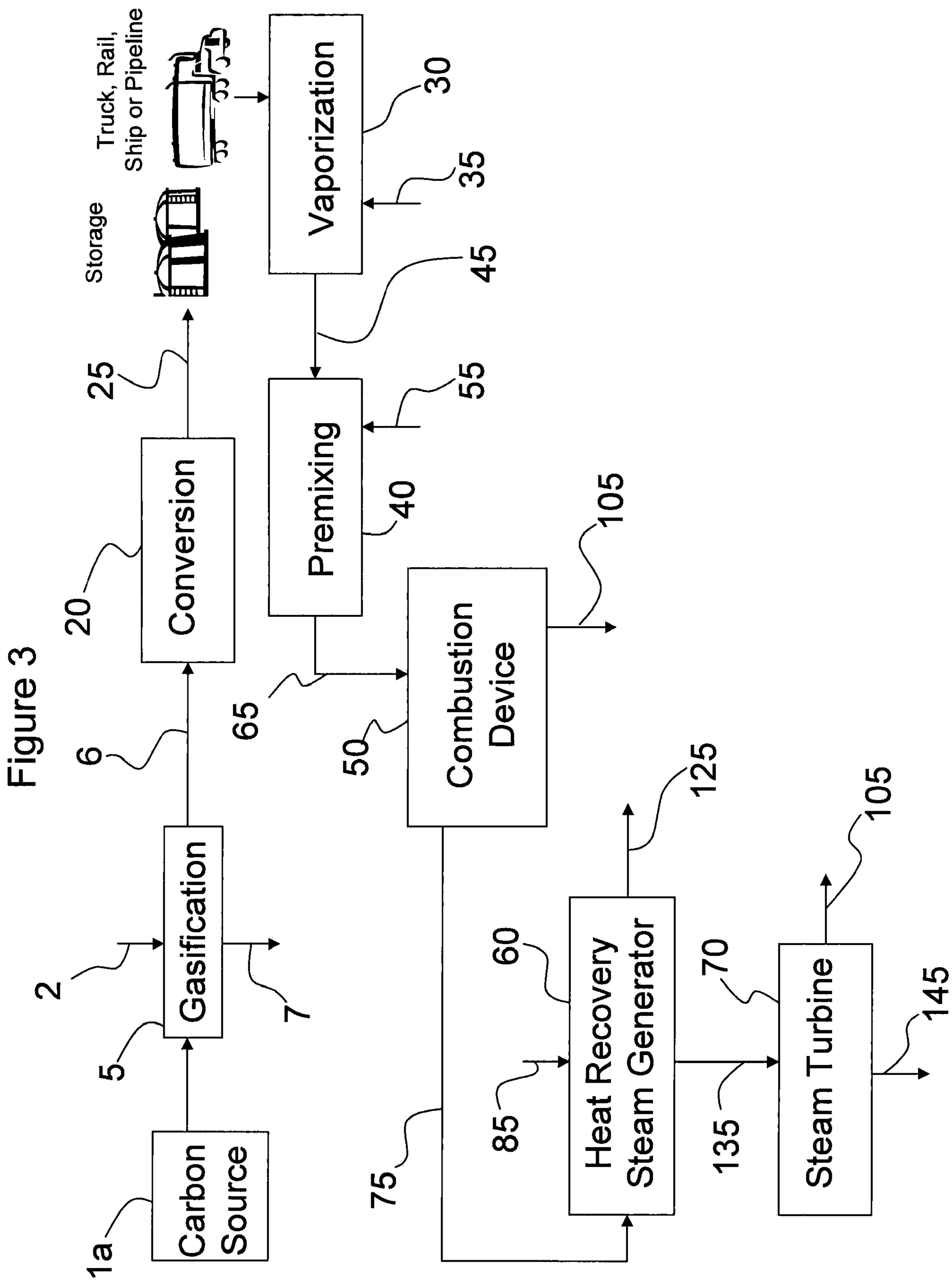
45
35
30

Figure 2


Carbon Source
Gasification
Conversion
Storage
Truck, Rail, Ship or Pipeline
Vaporization
Premixing
Combustion Device
Heat Recovery Steam Generator
Steam Turbine
1a
2
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75
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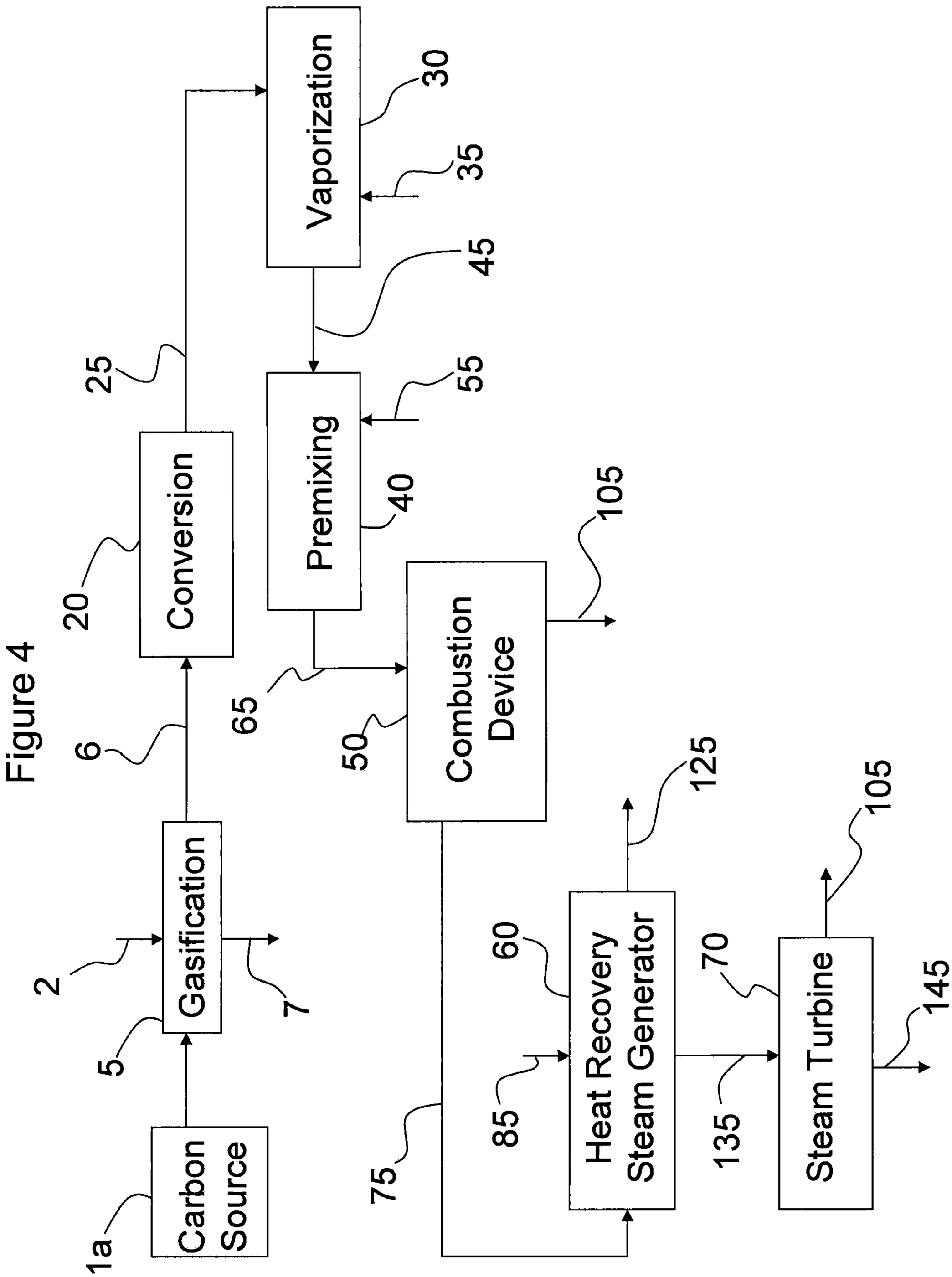
105
125
135
145

Figure 3


Carbon Source
Gasification
Conversion
Vaporization
Premixing
Combustion Device
Heat Recovery Steam Generator
Steam Turbine
1a
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75
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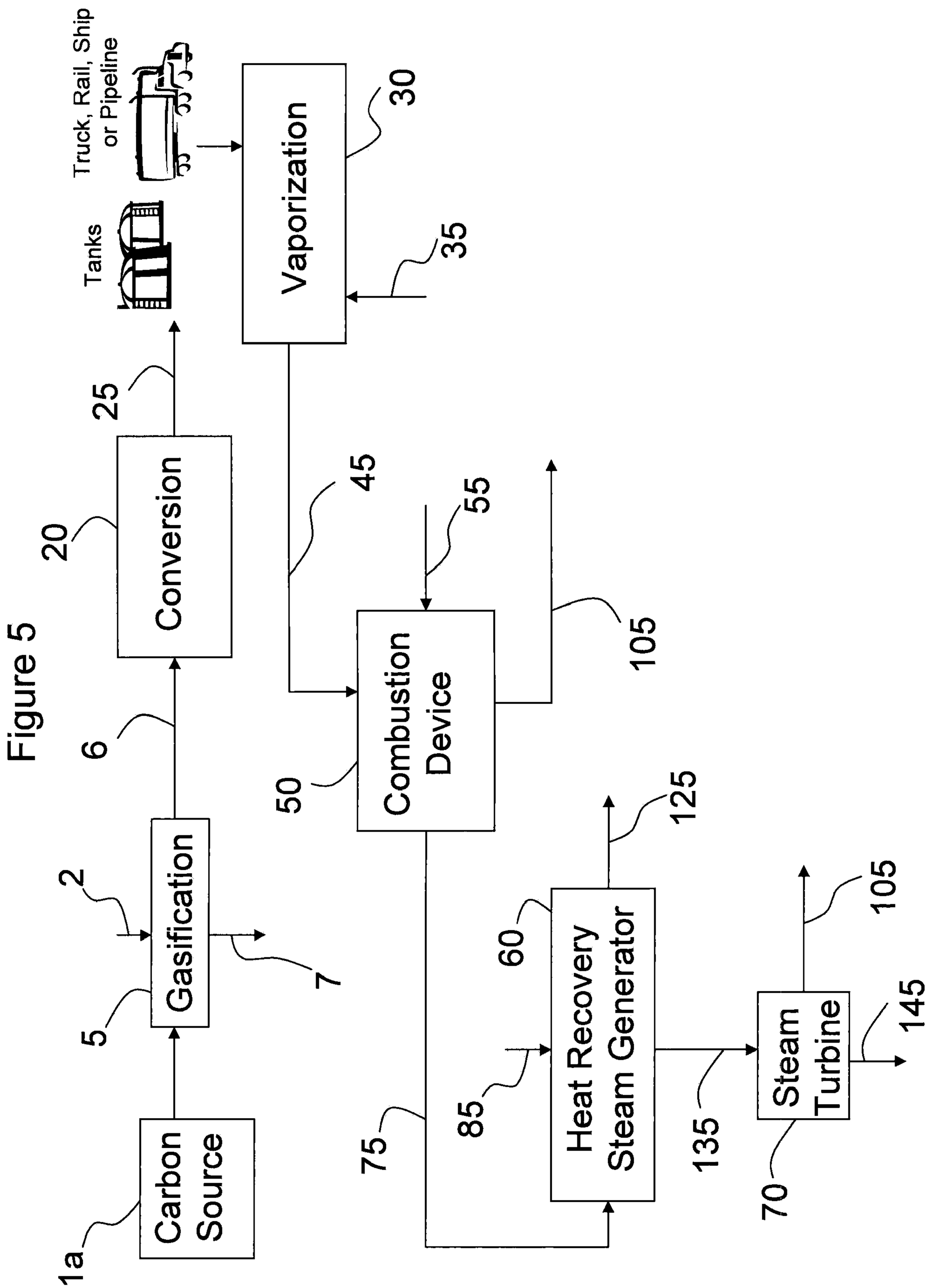
125
135
145

Figure 4


Carbon Source
Gasification
Conversion
Tanks
Truck, Rail, Ship or Pipeline
Vaporization
Combustion Device
Heat Recovery Steam Generator
Steam Turbine
1a
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7
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25
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75
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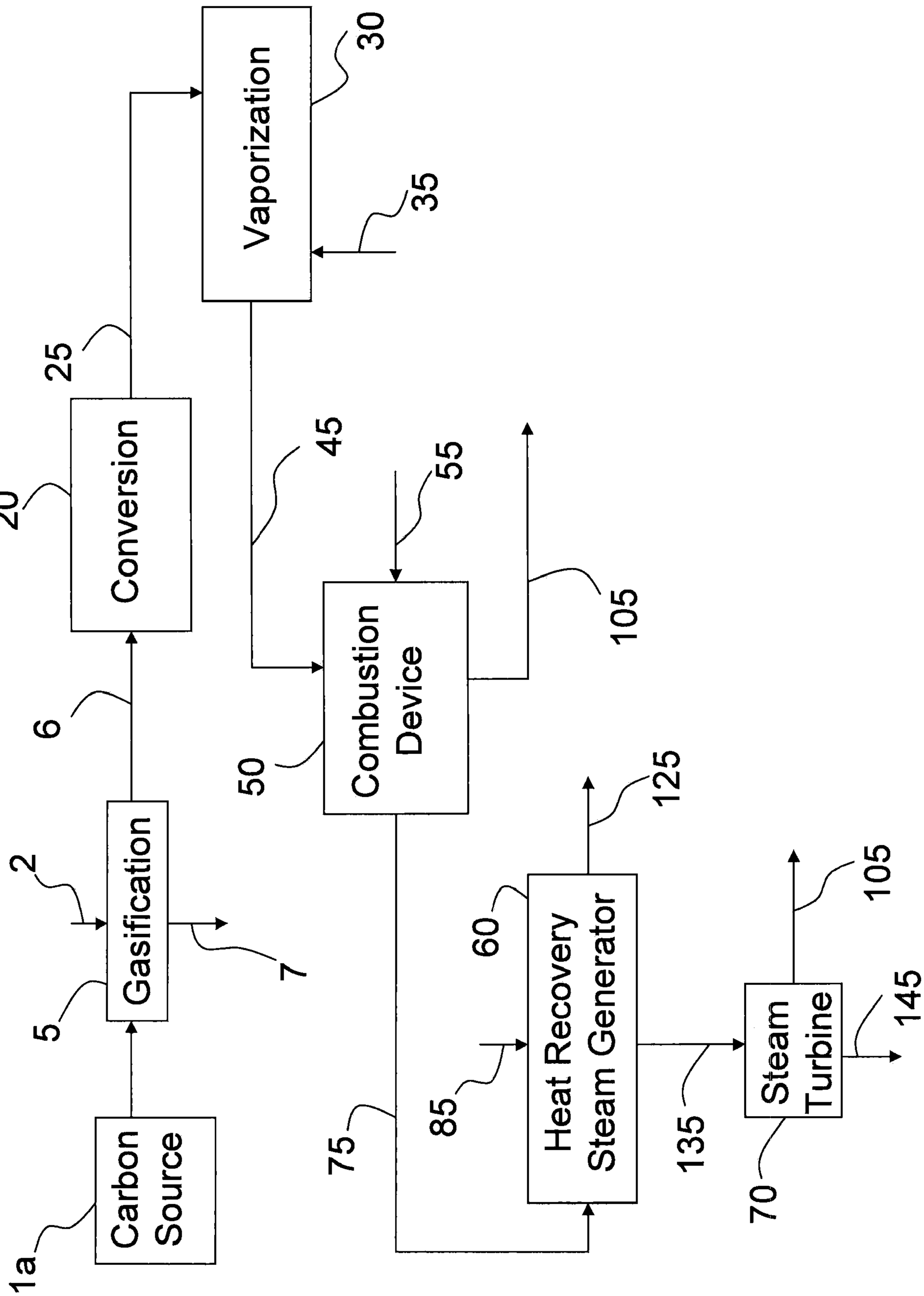
125
135
145

Figure 5


Carbon Source
Gasification
Conversion
Vaporization
Combustion Device
Heat Recovery Steam Generator
Steam Turbine
1a
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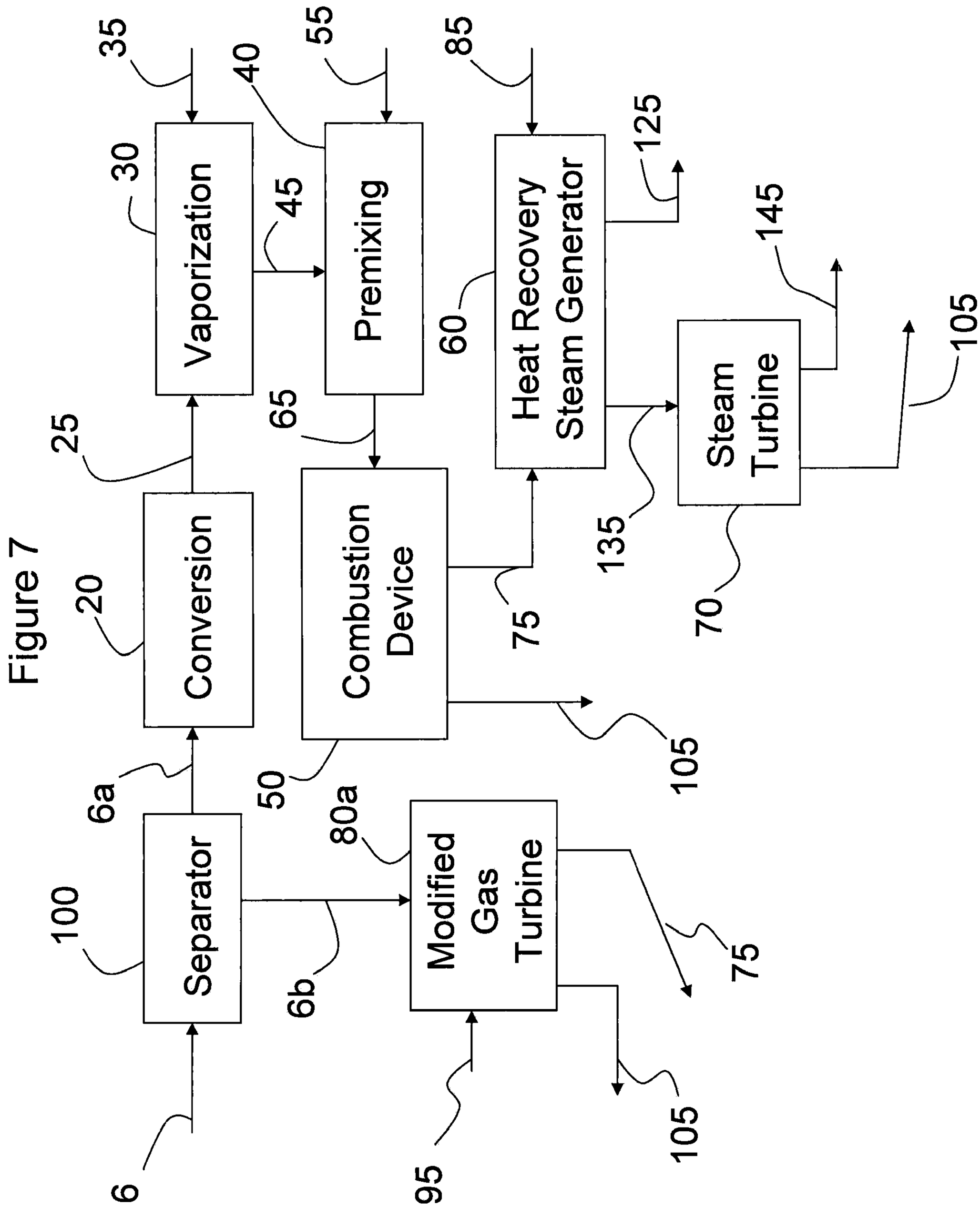
145

Figure 6


Vaporization
Premixing
Heat Recovery Steam Generator
Steam Turbine
Conversion
Combustion Device
Separator
Modified Gas Turbine
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55
85
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125
145
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105
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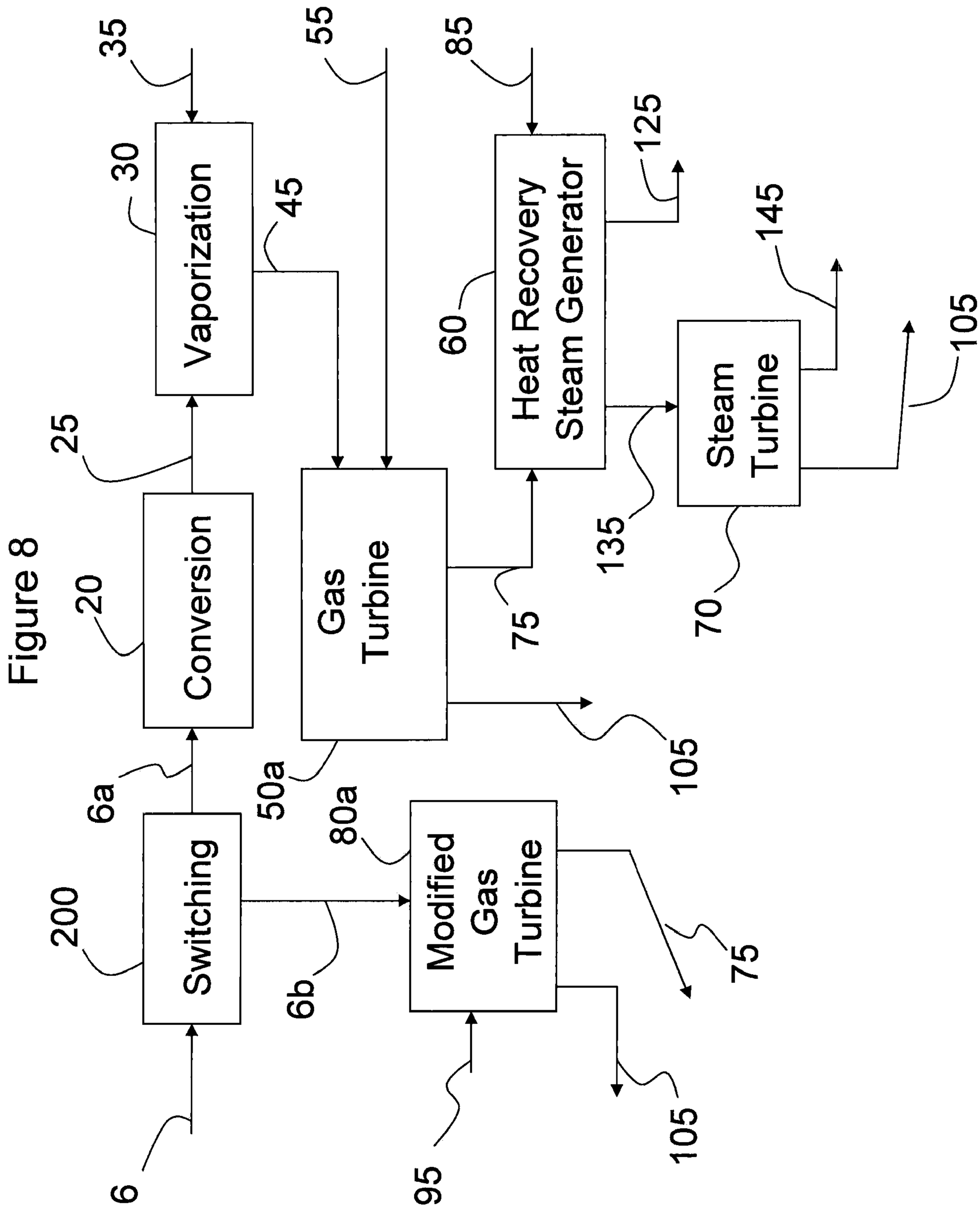
65
135
75
70
200
50
105
6a
80a
100
6b
75
6
95
105

Figure 7


Vaporization
Conversion
Gas Turbine
Heat Recovery Steam Generator
Steam Turbine
Switching
Modified Gas Turbine
35
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85
30
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145
105
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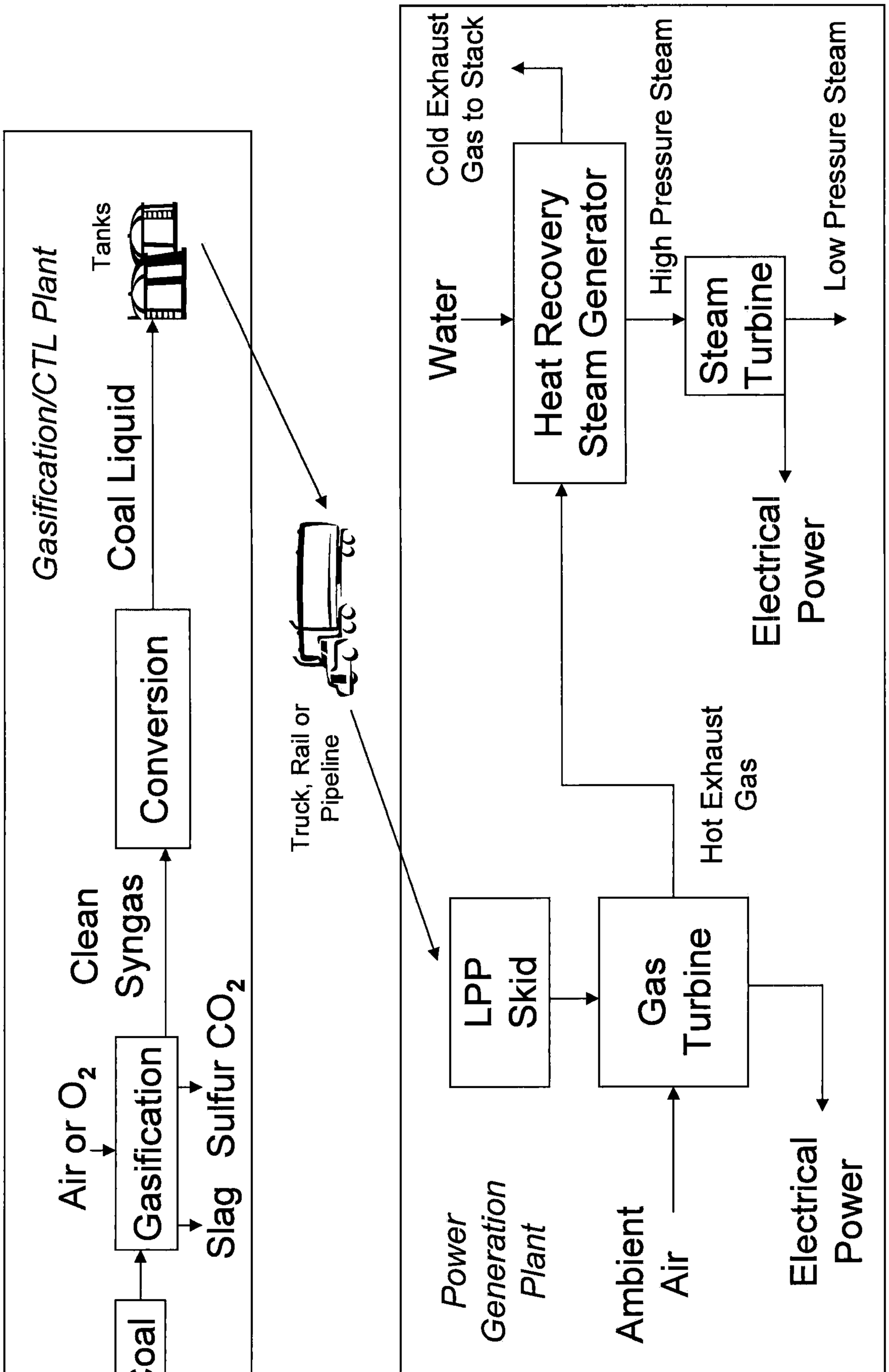
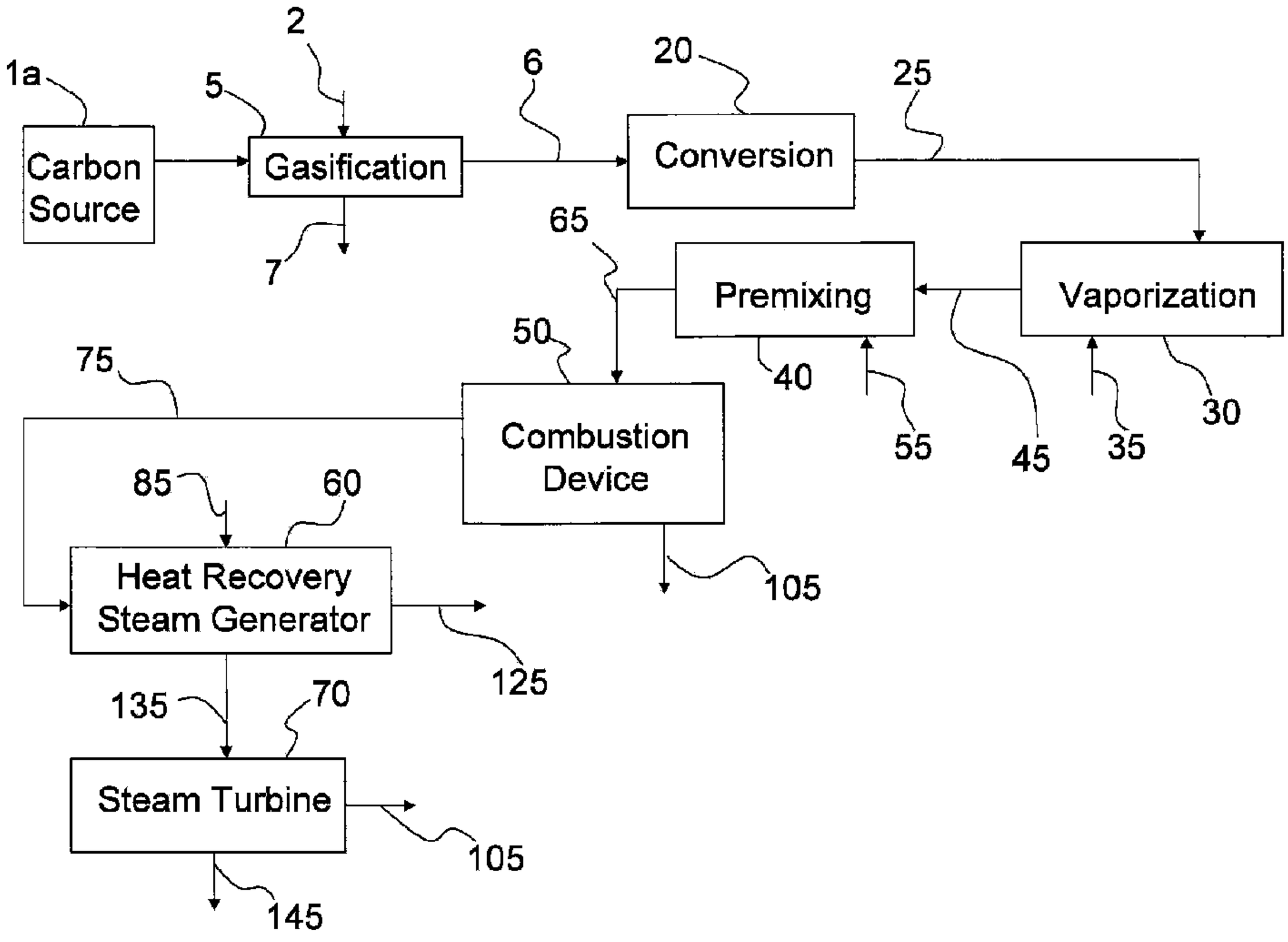
6a
50a
80a
200
6b
75
6
95
105

Figure 8

Figure 9


Gasification/CTL Plant
Coal
Air or O_2
Gasification
Slag
Sulfur CO_2
Clean Syngas
Conversion
Coal Liquid
Tanks
Truck, Rail or Pipeline
Power Generation Plant
LPP Skid
Ambient Air
Gas Turbine
Electrical Power
Hot Exhaust Gas
Steam Turbine
Electrical Power
High Pressure Steam
Low Pressure Steam
Heat Recovery Steam Generator
Water
Cold Exhaust Gas to Stack


1a
Carbon Source
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Gasification
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Conversion
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65
Premixing
Vaporization
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50
Combustion Device
105
75
85
60
Heat Recovery Steam Generator
125
135
70
Steam Turbine
105
145