

KREBS & SISLER L.P.
RESEARCH and DEVELOPMENT
Partnership Established 1972

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November 30, 2007

A. J. Sontag
Senior Buyer
Utilities Purchasing
Gainesville Regional Utilities
301 S.E. 4th Avenue
Gainesville, Florida 32601

RE: Gainesville Regional Utilities (GRU)
RFP 2007-135
Biomass Fueled Generation Facility

Dear Mr. Sontag:

Many thanks for providing a copy of the RFP 2007-135 which has been studied with great interest to determine any possible fit for our high efficiency and low emission closed Rankine cycle O₂/CO₂ combustion system.
See www.krebsandsislerlp.com.

Unfortunately for us, you have a selection rule which excludes a prototype commercial scale 100 to 300 megawatt plant. Also the all-biomass fuel rule defeats the purpose of our very high efficiency system. The high biomass fuel moisture of 30% to 40% greatly lowers efficiency.

However, if you do not receive suitable proposals, we invite you to consider our unique technology for its many advantages including:

- O₂/CO₂ combustion efficiency to 68% for the first plant at 100 MW scale and eventually 80% to 83% when fully optimized and when also combined with sewage treatment.
- Complete capture of CO₂.
- Use of CO₂ in sewage treatment to grow biomass in an "enhanced photosynthesis" process.
- Conversion of sewage biomass to ethanol.
- Wastewater purification by the "enhanced photosynthesis" process.

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- 50% Federal funding is possible under DOE clean coal initiatives, directed at developing high efficiency and low emission combustion systems since 1993, with none yet found.

Although Gainesville presently prohibits your consideration of coal as the primary fuel under your RFP, it is probably the best fuel for our new closed Rankine cycle system. We could use all of the Gainesville municipal solid waste as RDF because the total amount stated in your RFP does not exceed our recommended 20% limit where the primary fuel would be coal, oil or natural gas. RDF and natural gas could be the fuel mix because you indicate enough spare gas capacity at Deerhaven Generating Station. Our fuel need is estimated to be 12 billion Btu's per 24 hours at baseload capacity for 100 megawatts and 68% net efficiency.

If sewage-to-ethanol would be included, enough biomass should be available for about 50,000 gallons per day ethanol output and possibly much more, depending on the conversion efficiency, yet to be determined. The ethanol could be used as supplementary boiler fuel but this would be a rather wasteful end use compared to coal or even natural gas at present delivered costs.

We would be pleased to consider licensing these new proprietary methods to GRU. Compared to all other known concepts for baseload power production, sewage treatment, water purification and ethanol production, we believe that these will be the most economical when combined and should gradually displace many state-of-art systems.

We look forward to learning the outcome of your search under GRU RFP 2007-135.

Very truly yours,



William P. Krebs
General Partner

WPK:es
Enclosures

100 MEGAWATT PROTOTYPE POWER PLANT PROPOSAL
FOR THE HIGH EFFICIENCY O₂/CO₂ COMBUSTION
METHOD DETAILED IN U.S. PATENT NO. 6,907,845
GRANTED JUNE 21, 2005

A search is underway for a site to install the first commercial scale high efficiency closed-cycle O₂/CO₂ combustion system. Cost-reducing synergies suggest that the best sites would be adjacent to municipal sewage treatment facilities or liquified natural gas (LNG) receiving terminals, in oilfields or petroleum refineries. Please refer to the Website www.krebsandsislerlp.com for applications and technology comparison information.

The first installation of this technology is projected to cost \$120,000,000 or \$1,200 per kilowatt (kw) of an average capability of 100,000kw/hr or 100 megawatts (MW): variable from 87MW net after deducting 13MW of parasitic power, up to 126MW and 110MW net output after deducting 16MW of parasitic power; the differential due primarily to more oxygen production needed from cryogenic air separation for increased fuel combustion at higher power. This cost estimate assumes attainment of a 68% net plant efficiency for base-load operation, at least 8,000 hours per year, using most fuels including natural gas, coal, petroleum coke, heavy oil or lignite with the potential for some fuel blending with biomass and refuse-derived fuel (RDF).

Additional power units installed on the same site are projected to cost \$100,000,000 per 100MW or \$1,000 per kilowatt hour of average capability.

The first plant is preferably to be designed for a nominal 100MW electric output with up to 1,000,000 pounds steam per hour, subcritical steam conditions at 1,050°F/1,800 to 2,400 psi, variable over a power range of 87MW to about 110MW net output.

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**COST ESTIMATE PER KILOWATT HOUR FOR
100 MEGAWATT PROTOTYPE HIGH EFFICIENCY
O₂/CO₂ COMBUSTION POWER PLANT**

A \$0.0375 per kilowatt hour municipal electric power cost should be attainable for this plant fueled by \$30 per ton 20 million Btu (10,000 Btu/lb) coal. See cost table below. These levelized costs assume a minimum 8,000 hour operating year (out of 8,760), 91%. Plant efficiency is 68% for a heat rate of 5,000 Btu per kilowatt hour of output. The \$1,200 per kw of capital cost assumes 20 year amortization at 8% interest, which basis is used to allow comparison with an advanced combined cycle power concept disclosed in the Rollins U.S. Patent No. 7,131,259 granted November 7, 2006.

Levelized Costs, 100MW Coal-Fueled Plant

	<u>\$ Per Kilowatt Hour</u>	<u>Annual Charges</u>
Plant Capital Cost	\$0.0150	\$12,000,000
Fuel: Coal \$30/ton, 10,000 Btu/lb.	0.0075	6,000,000
Non-Personnel O&M	0.0050	4,000,000
Personnel O&M-40 Employees	<u>0.0050</u>	<u>4,000,000</u>
Personnel Training	\$0.0325	\$26,000,000
Estimated First Year Costs	<u>0.0050</u>	<u>4,000,000</u>
	\$0.0375	\$30,000,000
Extra Contingencies Allowance For Prototype Plant	<u>0.0075</u>	<u>6,000,000</u>
	\$0.0450	\$36,000,000

If natural gas is substituted for coal, the fuel cost for \$6.00 gas will be \$.03 per kw; for \$10.00 gas, \$.05 per kw (gas per 1000 cu.ft., one million Btu's) with a 5000 Btu/kw plant heat rate.

Krebs & Sisler L.P.
December 2006

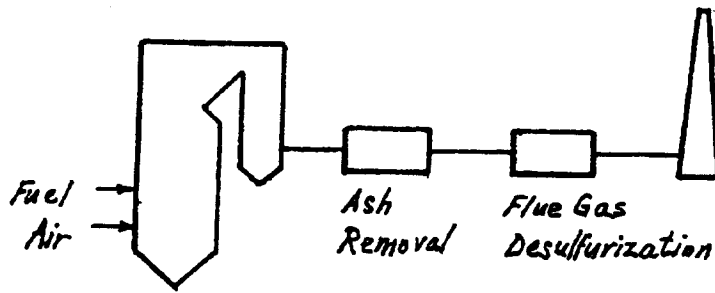
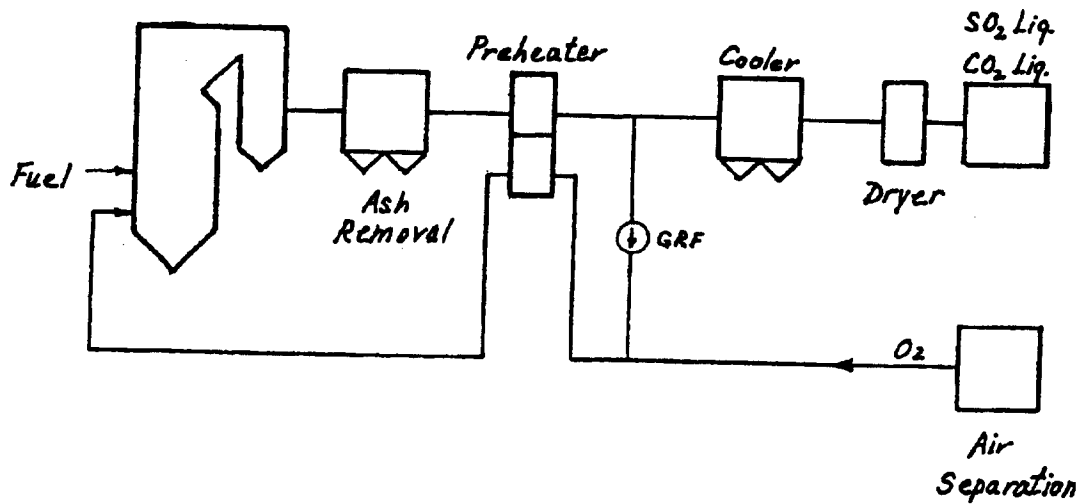


Figure 1
Prior Art



GRF = Gas Recirculation Fan

Figure 2
Prior Art



US006907845B2

(12) **United States Patent**
Krebs

(10) **Patent No.:** **US 6,907,845 B2**
(45) **Date of Patent:** **Jun. 21, 2005**

(54) **BOILER IMPROVEMENTS WITH OXYGEN-ENRICHED COMBUSTION FOR INCREASED EFFICIENCY AND REDUCED EMISSIONS**

(75) Inventor: **William P. Krebs**, Winnetka, IL (US)
(73) Assignee: **Krebs & Sisler L.P.**, Winnetka, IL (US)
(*) Notice: Subject to any disclaimer, the term of this patent is extended or adjusted under 35 U.S.C. 154(b) by 0 days.

OTHER PUBLICATIONS

Nakayama, S., et al.; "Pulverized Coal Combustion in O₂ / CO₂ Mixtures on a Power Plant for CO₂ Recovery"; *Energy Convers. Mgmt.*, vol. 33, No. 5-8, pp. 379-386, 1992; 1992 Pergamon Press Ltd, Great Britain.

* cited by examiner

(21) Appl. No.: **10/887,003**

(22) Filed: **Jul. 7, 2004**

(65) **Prior Publication Data**

US 2004/0237909 A1 Dec. 2, 2004

Related U.S. Application Data

(63) Continuation of application No. PCT/US03/032402, filed on Oct. 14, 2003.
(60) Provisional application No. 60/422,601, filed on Oct. 30, 2002.
(51) **Int. Cl.**⁷ **B09B 3/00**
(52) **U.S. Cl.** **122/7 R; 122/4 D; 110/204; 110/216; 110/234; 110/345; 60/670**
(58) **Field of Search** **122/7 R, 4 D, 122/7 C, 7 D; 237/8 B, 9 R, 58; 60/653, 670; 110/204**

(56) **References Cited**

U.S. PATENT DOCUMENTS

4,355,601 A * 10/1982 Hattiangadi 122/4 D
4,542,114 A * 9/1985 Hegarty 502/39
4,803,958 A * 2/1989 Erickson 122/21
5,732,571 A * 3/1998 Maerz et al. 62/611
6,702,570 B2 * 3/2004 Shah et al. 431/11

FOREIGN PATENT DOCUMENTS

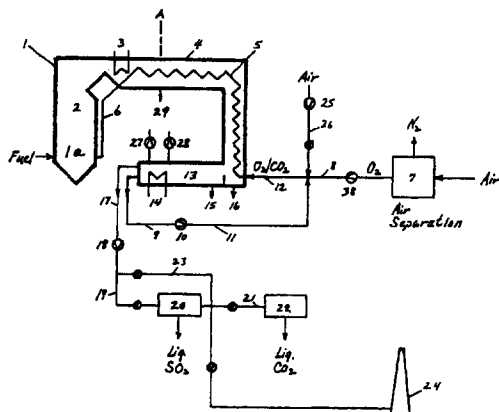
JP 19026 2/1975

Primary Examiner—Gregory Wilson
(74) *Attorney, Agent, or Firm*—Fitch, Even, Tabin & Flannery

(57) **ABSTRACT**

A method and apparatus to conduct O₂/CO₂ combustion or oxygen-enriched combustion. The boiler exhaust gas passes through a Gas Primer Sector (GPS) combined with the boiler to effect heat transfer to the combustion gas in indirect counter-flow heat exchange. Sharply reduced gas flows result from using largely moisture-free CO₂ as diluent for O₂ in the combustion gas which allows long residence time at low velocity for maximum heat transfer from the exhaust gas to the combustion gas. Most particulate drops out and most moisture is condensed from the cooled mostly CO₂ exhaust gas. The larger portion is blended with oxygen for the combustion gas and reheated and returned to the boiler through the integrated GPS; the smaller portion is cleaned and separated, the CO₂ released or recovered. The complete exhaust gas-combustion gas cycle may be 30 to 90 seconds and preferably about 60 seconds. The high heat capacity of CO₂ allows a much higher oxygen content in the combustion gas compared to open-cycle air combustion with a large nitrogen content of lower heat capacity. Efficiency is increased. Final exhaust gas separation and recovery is simplified. Condensate is processed to boiler feedwater or potable water quality. NO_x is eliminated, mercury fume captured and CO₂ output reduced.

21 Claims, 2 Drawing Sheets



BOILER IMPROVEMENTS WITH OXYGEN-ENRICHED COMBUSTION FOR INCREASED EFFICIENCY AND REDUCED EMISSIONS

This application is a continuation of International Application No. PCT/US03/032402 filed Oct. 14, 2003 which claims priority from U.S. Provisional Application Ser. No. 60/422,601, filed Oct. 30, 2002.

FIELD OF THE INVENTION

This invention relates to a method and apparatus integrated with a boiler for recovering sensible and latent heat from hot exhaust gas in heat exchange with cooled exhaust gas blended with oxygen for fuel combustion. The method allows the flexibility to burn virtually any fuel using oxygen-enriched air or pure oxygen and mostly CO₂ mixtures while recovering fuel sulfur as liquid SO₂. Highest efficiency is attained in 100% O₂/CO₂ combustion.

BACKGROUND OF THE INVENTION

References of Interest

U.S. Patents

- U.S. Pat. No. 4,354,925 October 1982 Schorfheide
- U.S. Pat. No. 4,542,114 September 1985 Hegarty
- U.S. Pat. No. 5,732,571 March 1998 Maerz et al.
- U.S. Pat. No. 6,202,574 March 2001 Liljedahl et al.
- U.S. Pat. No. 6,418,865 July 2002 Marin et al.

Foreign Patent

Japanese Patent No. 50-19026 June 1973

Publications

The Steam Engine, D. Lardner; A. Hart, Philadelphia 1852, pp. 73-79; First Edition London, 1827.

Argonne National Laboratories:

A. "Two-Dimensional Modeling of Fossil-Fueled Power Plant Behavior When Using CO₂-O₂ or CO₂-H₂O-O₂ Mixtures, Instead of Air, to Support Combustion," Richter et al, June 1987, ANL/CNSV-TM-187.

B. "An Experimental Program to Test the Feasibility of Obtaining Normal Performance from Combustion Using Oxygen and Recycled Gas Instead of Air," ANL/CNSV-TM-204, Abele et al, December 1987.

C. "Carbon Dioxide from Flue Gases for Enhanced Oil Recovery," ANL/CNSV-65, Sparrow and Wolsky et al, June 1988.

"Final Report on CO₂ Recovery from Power Plants." U.S. Department of Energy, DOE/ER 30194, July 1993.

"Pulverized Coal Combustion in O₂/CO₂ Mixtures on a Power Plant for CO₂ Recovery," Nakayama et al, *Energy Conversion and Management*, Vol. 33, pp. 379-386, 1992.

"Experimental Studies on Pulverized Coal Combustion with Oxygen/Flue Gas Recycle for CO₂ Recovery," Kimura et al, JSME-ASME International Conference on Power Engineering, Vol. 1, pp. 487-492, Tokyo, September 1993.

"The Characteristics of Pulverized Coal Combustion in O₂/CO₂ Mixtures for CO₂ Recovery," Kimura et al, *Energy Conversion and Management*, Vol. 36, pp. 805-808, 1995.

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"Availability Analysis of Combustion Flue Gases-A Case Study," M. Abu-Arabi and A. Tamimi, *Energy Conversion and Management*, Vol. 36, pp. 1133-1137, 1995.

The Entropy Law and the Economic Process, N. Georgescu-Roegen, Harvard University Press, 1971.

"What Is Heat?" G. P. Beretta and E. P. Gyftopoulos, *American Society of Mechanical Engineers*, Vol. 20, pp. 33-41, 1985.

"Fundamentals of Analyses of Processes," E. P. Gyftopoulos, *Energy Conversion and Management*, Vol. 38, pp. 1525-1533, 1997.

Oxygen enrichment of air combustion and oxygen/carbon dioxide (O₂/CO₂) combustion have been studied by researchers as means to provide a greater concentration of CO₂ in the exhaust gas. The higher concentration would allow a more economical method of recovering CO₂ for sequestration, should this become necessary due to global warming of the atmosphere chargeable to excessive CO₂ buildup. See particularly Patent No. 50-19026, Japan, 1973; Argonne National Laboratories research, Richter et al, 1987 and Abele et al, 1987; and Nakayama et al, 1992. Coal-fueled power plants are considered to be at risk because their emissions generally consist of 12% to 15% CO₂ versus about 7% to 8% for gas-fueled plants when compared at similar efficiencies, for example a 10,000 Btu (10,550 kJ) heat rate per net kilowatt (kw) of power output, an efficiency of 34%. Most studies have concluded that oxygen enrichment of air combustion or O₂/CO₂ combustion is not economical due to the high cost of purchased and delivered oxygen. Alternatively, including an air separation plant requires a relatively high capital cost and the electric power load is about 225 kw of power per ton of oxygen or approximately 20% of the total output of a 10,000 Btu (10,550 kJ) heat rate plant, using 97% to 100% purity oxygen with recycled mostly CO₂ exhaust gas as the diluent for fuel combustion. Along with other auxiliary power requirements, total parasitic power can be 25% if both CO₂ and sulfur dioxide (SO₂) are completely separated and liquefied for shipment or disposal, CO₂ going into an underground reservoir, for example.

Research on O₂/CO₂ combustion in Japan, as illustrated in FIG. No. 2, resulted in identifying an efficiency gain of 4.5% by wet recycling a CO₂-H₂O-rich exhaust gas through the boiler as diluent and excluding nitrogen (N₂), which improvement is considered due to the greater density of CO₂ compared to N₂. Less diluent for O₂ is needed when substituting CO₂ for N₂. However, the improvement has not been enough to justify commercialization of the technology.

Marin et al. in U.S. Pat. No. 6,418,865, for a Method For Operating A Boiler Using Oxygen-Enriched Oxidants, show data which indicate limited efficiency improvement from oxygen enrichment. The efficiency improvement is similar to the 4.5% gain found by Nakayama et al., 1992. This gain must be limited by the high moisture content in the recirculated flue gas, which has the adverse effect of increasing gas velocity through the boiler; also to system heat losses through the convection sector of the boiler and air heater and ducting; to heat losses in the processes of ash removal and flue gas desulfurization; and also due to large sensible and latent heat losses in the flue gas exhausted to the atmosphere. The advantage claimed by Marin et al depends on the relative costs of fuel and oxygen. High cost fuel saved by low cost oxygen enrichment may yield an economic benefit. Low cost fuel and high cost oxygen enrichment may yield little or no advantage because the total efficiency improvement potential in Marin is only 4 to 5%.

The Argonne National Laboratories and Kimura et al references are instructive for elimination of NO_x in O₂/CO₂

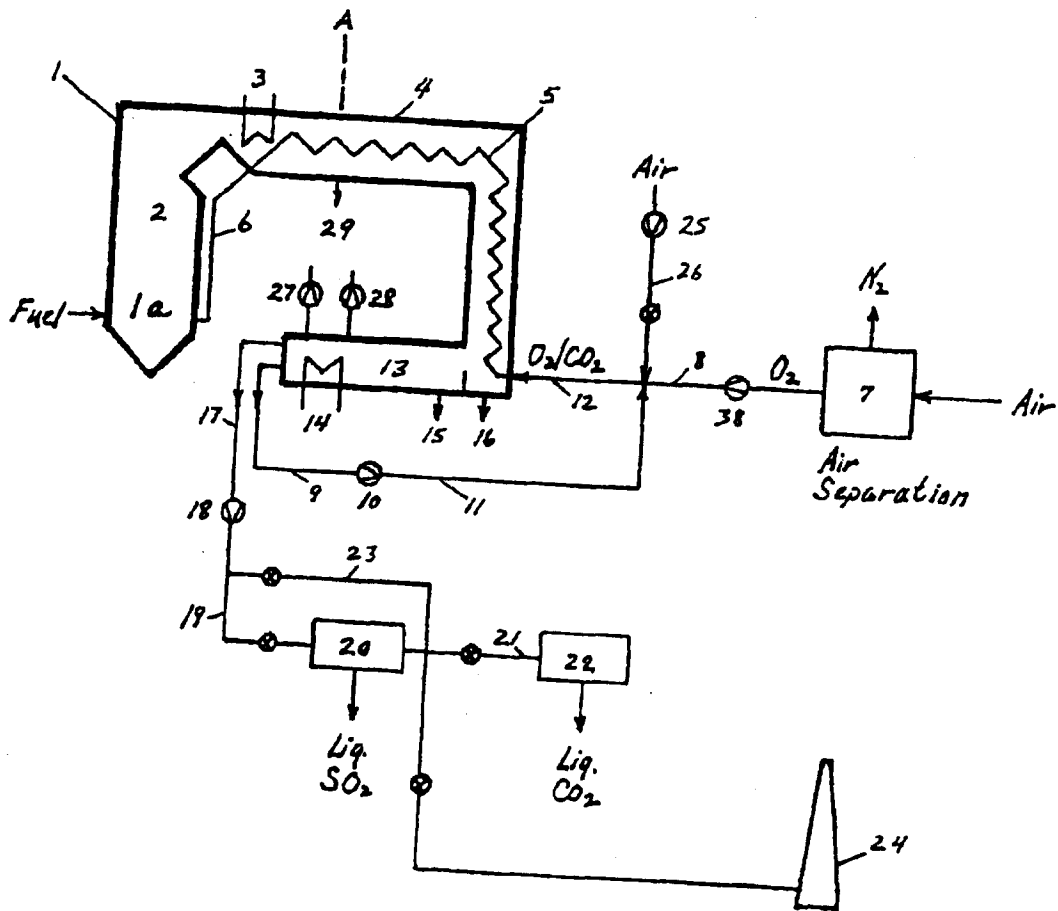


Figure 3

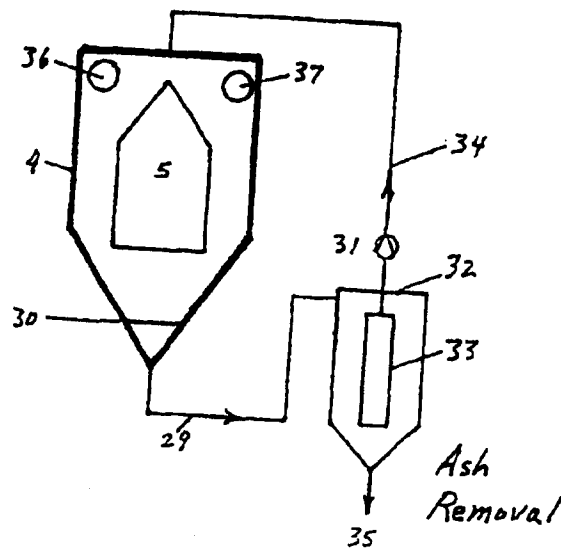


Figure 4

having a density and heat capacity 63% greater than N₂. Schorffheide, in U.S. Pat. No. 4,354,925, explains that over a temperature range of 800 to 980° F. (427–527° C.) (for coke burning to regenerate a catalyst), "carbon dioxide has an average heat capacity 63 percent greater than that of nitrogen (12.1 Btu/lb mol.⁻¹ F. for CO₂ versus 7.43 Btu/lb mol.⁻¹ F. for nitrogen) . . . carbon dioxide will absorb roughly 63% more heat than an equivalent volume of nitrogen at corresponding temperatures." Also "the concentration of oxygen can be about 63 percent greater in the case of complete carbon dioxide" and this O₂/CO₂ mixture "reduces burn time by a full 33 percent."

If the exhaust gas is cooled to ambient or below in an extended residence time, nitrogen oxide (NO) will oxidize to nitrogen dioxide (NO₂) in a slight excess of O₂ (see Hegarty, U.S. Pat. No. 4,542,114) and will convert to nitric acid (HNO₃) and drop out as condensate. Sulfur trioxide (SO₃) will convert to sulfuric acid (H₂/SO₄) and also drop out as condensate. If most moisture is condensed, blower power to move the much drier, cool exhaust gas is reduced. Blower power to move cool recycled combustion gas is also reduced. If a relatively dry <1% moisture content O₂/CO₂ combustion gas is then reheated and returned to the boiler, the velocity of the combustion gas through the boiler is sharply decreased.

CO₂ has a much greater density than H₂O. CO₂:H₂O=44:18=2.44 or CO₂ has 244% of the density and sensible heat capacity of H₂O as water vapor by mol wt. In the wet recycle O₂/CO₂-H₂O method, the exhaust gas is returned to the boiler with no moisture reduction which has the undesired effect of reducing heat capacity and sharply raising velocity. This reduces combustion gas residence time which impairs radiant heat transfer through the boiler heating surfaces. The velocity problem in the wet recycle method obscures most of the efficiency improvement opportunity related to substituting denser CO₂ for N₂ as diluent.

If a vacuum removal method can be utilized to take out particulate in a low velocity non-turbulent laminar flow heat exchange duct, no electrostatic precipitator (ESP) or baghouse is needed. If heavy insulation can be economically used to retain heat for exchange in a duct system with a low velocity combustion gas flow of blended O₂ and CO₂, then virtually 100% of the so-called waste heat lost in state-of-art combustion systems can be returned to the boiler. If most sensible and latent heat can be recycled to benefit fuel combustion, the plant parasitic power requirement and the CO₂ output may all reduce by half; and potentially more than half since most state-of-art air-fired steam generation power plants operate at net efficiencies of only 33% to 35%.

If the final exhaust gas of the O₂/CO₂ combustion process is cooled to ambient temperature or below, the volume for cleanup and separation will be less than 10% of the hot flue gas output from a state-of-art air-fired steam power plant. Gas separation and the recovery of constituents will be economical by known means. Corrosion in the condensing region is not a disabling problem due to the development and proven reliability of superaustenitic stainless steels. Condensate may be recovered and processed to boiler feedwater or potable water quality. Trace mercury fume is captured in a filter by activated carbon or other known sorbents. SO₂ is recovered as a refrigeration-grade liquid for chemicals production or feedstock to a sulfuric acid plant. If a sulfuric acid plant is added, the particulate recovered from fuel combustion can be chemically processed in an acid-leaching treatment for metals recovery and upgrading of the remainder particulate.

The foregoing discussion considers most of the changes necessary to maximize efficiency in O₂/CO₂ combustion with 97% to 100% pure oxygen, which changes have been incorporated into the preferred embodiments described in detail hereinafter.

Partial oxygen enrichment of air combustion. Air combustion with oxygen enrichment, in a boiler combined with the GPS and with moisture mostly removed from the recycled exhaust gas, has been studied. 30% or more enrichment will provide good efficiency improvement compared to complete air combustion but less than with pure oxygen. This is because of the added nitrogen and also due to air moisture of several percent which varies with ambient air conditions. By increasing the amount of lower density nitrogen displacing CO₂ in the recycling of exhaust gas to the boiler and by the addition of air moisture, gas flow volume and velocity are increased and therefore reduce residence time for heat transfer, lowering efficiency below complete O₂/CO₂ combustion.

Air combustion of clean fuels. Combining the GPS with a boiler allows air combustion of clean fuels with only trace NO_x in the emission. Efficiency is improved compared to state-of-art air-fired combustion steam generation plants. This is a once-through process with no exhaust gas recycling which uses the heat exchange method and apparatus of the GPS to condense most moisture and increase waste heat recovery. The exhaust gas temperature is reduced to about 40° F. (4° C.). The presence of an excess of oxygen at this reduced temperature with an extended residence time provides the conditions to convert NO to NO₂ which then is recovered as dilute nitric acid (HNO₃) condensate. The final exhaust gas will contain less than 1% moisture in a mixture of mostly N₂, CO₂ and O₂. Condensate may be treated to boiler feedwater or potable water quality.

SUMMARY OF THE INVENTION

Rankine cycle steam power plants may be adapted to a high efficiency and low emission combustion method by replacing most facilities after the superheater. The economizer section is reconfigured. Eliminated are the air heater, ESP or baghouse, and flue gas desulfurization (FGD) by scrubbing, all three of which dissipate heat, most of which is now recovered by the improved method and apparatus disclosed hereinafter.

Highest efficiency will be attained in a combustion gas atmosphere of a largely moisture-free mixture of pure oxygen and carbon dioxide.

A GPS is combined with a boiler to reduce the exhaust gas temperature, velocity, particulate and moisture. The exhaust gas temperature is reduced to ambient or below while the return flow combustion gas temperature is raised from ambient. Integration of the GPS with the boiler makes possible the maximum preheating of an optimally controlled mixture of O₂ and CO₂ combustion gas.

The exhaust gas and the combustion gas flows are through corrosion-resistant outer and inner superaustenitic stainless steel ducts. Most particulate in the exhaust gas drops out in the reduced velocity non-turbulent laminar flow for vacuum removal. The ducts are sized to provide an extended residence time for both the combustion gas and exhaust gas flows. The low velocity and laminar flow of the exhaust gas will beneficially promote the van der Waals force effect, which is the coalescing and agglomeration of fine particles; and the slow gas flow will benefit particulate settling by the force of gravity.

Hydrocarbon fuels may contain up to several percent sulfur and 1% nitrogen. These elements oxidize during