

The Economics of Power Generation
Via the Shell Gasification Process

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INTRODUCTION

An SGP-based power station (SGP/PS) is based on the partial oxidation of fuel and differs from a conventional power station (CPS) in the following main aspects:

1. In a CPS the fuel oil is burned with air at atmospheric pressure in a boiler where the heat of combustion is used to produce superheated high-pressure steam.

In an SGP/PS the fuel oil is first partially oxidized with air at elevated pressure, whereby the fuel oil is converted into a raw fuel gas. This gas, after removal of contaminants such as ash and sulphur, is subsequently burned in a combustor and expanded in a gas turbine.

2. In a CPS all electricity is produced by the expansion of steam in turbo-generators.

In an SGP/PS electricity is partly produced by expansion of gas in gas turbo-generators and partly by expansion of steam in steam turbo-generators.

The SGP/PS scheme shows the following interesting aspects:

- a) Recovery of up to 95% of the sulphur in fuel oil as elemental sulphur is possible with conventional, well proven gas treating and sulphur recovery processes.

- b) The high efficiency of electricity generation via the gas and steam turbine cycle compensates for the efficiency loss caused by the processing steps converting the high-sulphur, high-ash residual fuel oil into a clean fuel gas.
- c) No emission of particulate matter.
- d) Low emission of nitrogen oxides because of low flame temperature.
- e) Lower demand for cooling water than in a CPS, since only part of the electricity is raised via the steam expansion (and subsequent steam condensation) cycle.
- f) The operation at elevated pressure results in the use of compact, shop-fabricated, equipment.

The schemes discussed here are all based on the use of residual fuel oil as fuel to the power station. The SGP has been developed with special emphasis on the use of heavy residual fuel oil as feedstock and commercial operation of the SGP units has shown that the reliability and on-stream efficiency of the process is high, even in cases where high-ash fuels are being processed. An on-stream efficiency of 95% can be taken as a realistic figure.

At present close to 100 units with a total throughput exceeding 11,000 tons/d fuel have been, or are being, constructed. A power station based on the above concept but using coal as feedstock has been built in Germany.¹⁾

DISCUSSION

The conversion of the chemical energy of a fuel oil into electricity is usually effected by the following steps (Fig. 1):

- a) Complete combustion of the fuel oil with air at atmospheric pressure.
- b) Recovery of the heat of combustion by the production of superheated, high-pressure steam.
- c) Expansion of the steam through a steam turbo-generator for the production of electricity.
- d) Condensation of the steam and recycle of the condensate in the form of boiler feed water to step b).

In this process the sulphur present in the fuel oil is converted into SO_2 and emitted with the flue gas to the atmosphere unless special equipment is installed for the removal of this SO_2 ²⁾.

An SGP-based power station³⁾⁻⁷⁾ as envisaged here consists of the following steps (Fig. II):

- a) Partial oxidation of the fuel oil with air at elevated pressure (10-20 atm.) for the production of raw fuel gas.
- b) Removal of the sulphur components (mainly H₂S) from the raw fuel gas.
- c) Complete combustion of the clean fuel gas.
- d) Expansion of the combusted gas through a gas expansion turbine, coupled with an electric generator, for the production of electricity.
- e) Cooling of the gas turbine exhaust gas.
- f) Recovery of heat in steps a), c) and e) in the form of high-pressure superheated steam.
- g) Expansion of the steam through a turbo-generator for the production of electricity.
- h) Condensation of the steam and recycle of the condensate in the form of boiler feed water to steps a), c) and e).

Compared with a conventional oil-fired power station the SGP/PS shows three significant new elements. These are:

1. The fuel gas preparation step

In this step the fuel oil is first partially oxidized in a reactor at elevated pressure (15-25 atm.) with air, whereby the oil is converted into a gas with carbon monoxide and hydrogen as the main constituents.

The sulphur of the fuel oil is mainly converted into hydrogen sulphide, which component can subsequently be removed with a conventional gas-treating solvent.

In Fig. III a scheme is given of the Shell Gasification Process (SGP). The main items of the SGP are:

- a) Reactor with combustor/gun assembly.
- b) Waste-heat boiler enabling the production of high-pressure steam.
- c) Gas scrubber to clean the gas of carbon and ash.
- d) Carbon work-up and recycle section.

The operating pressure of these units ranges between atmospheric pressure and around 60 atmospheres. The pressure of the steam raised in the various waste-heat boilers ranges between 30 and 100 atmospheres.

In the case of partial oxidation with air, as envisaged for power station applications, the gas leaving the SGP will have the following composition when starting with a residual fuel oil of 4% wt sulphur:

	% vol. (dry)
H ₂	14.7
CO	22.0
CO ₂	2.5
H ₂ S	0.5
COS	0.03
CH ₄	0.3
N ₂ + A	60.0

This gas is free of soot and ash and is subsequently treated for sulphur removal. Since the gas contains CO₂ as well as the sulphur components H₂S and COS, a number of alternative methods for the removal of the sulphur components and the subsequent conversion of these components into elemental sulphur is to be considered, for instance:

a) Complete removal of COS and H₂S

This is possible by using a mixture of a physical solvent and a chemical solvent such as Sulfinol[®],

which consists of Sulfolane (tetrahydrothiophene 1.1 dioxide) and DIPA (di-iso propanol amine). Such solvent completely removes the H_2S and the COS but at the same time completely co-absorbs the CO_2 . This results in a considerable dilution of the H_2S feed to the subsequent Claus unit, where the H_2S is converted into sulphur. A special design for the Claus unit is therefore required in this case. An overall sulphur recovery of 95% can be obtained.

b) Selective removal of H_2S

This is possible by using a chemical solvent such as di-iso propanol amine (Shell Adip process)⁸, which completely removes the H_2S but only part of the CO_2 and COS . In this way a reasonable H_2S concentration in the feed to the Claus unit is obtained, making the design of the Claus unit simpler but at the cost of a lower overall sulphur removal efficiency, which will be of the order of 85-90%. By incorporating special design features in the sulphur recovery unit (Claus unit), this figure can be increased by up to 5 points.

2. The supercharged boiler

The clean fuel gas, as produced in the gasification/desulphurization section, is burnt in a supercharged boiler at about 10-20 atm. In this boiler the high-pressure saturated steam produced in the waste-heat boilers of the gasification unit is superheated.

The supercharged boiler has the following advantages:

- a) By application of such a boiler the steam conditions are made independent of the gas turbine outlet temperature. This means that the steam superheat temperature can be 540°C instead of 350 to 400°C if the steam is superheated in a non-fired gas turbine exhaust boiler installed downstream of a gas turbine with an inlet temperature of 850 to 950°C (present-day technology for industrial gas turbines). The higher steam superheat temperature results in a higher net efficiency for the power station. A fired exhaust boiler, although superior to a non-fired one, would show higher stack losses as compared with a supercharged boiler.
- b) The high gas pressure and the high heat transfer rates result in a compact boiler, which is fully shop-fabricated.

c) It is expected that the nitrogen oxides emission will be lower than in direct combustion of the gas in the gas turbine combustion chamber.

By controlling both the combustion air dosage and the amount of steam superheated in the boiler, the temperature of the gas leaving the supercharged boiler can be regulated. This gas is sent to the gas expansion turbine.

3. Gas expansion turbine

The incorporation of gas turbines in natural gas (or light distillate fuel) fired power stations is finding increasing application both because of the high efficiencies that can be obtained and/or because the capital cost for such power stations is relatively low⁹). An important aspect of using a gas expansion turbine is that the inlet temperature of such a turbine can be considerably higher (at present 850°C - 950°C) than the temperature at which a steam turbine can operate (550°C), this governed by the fact that steam-raising and superheating at higher temperatures, as well as providing suitable turbine casings for high-pressure/high-temperature steam, meets with great technical problems. The combination of a gas expansion turbine cycle with a steam expansion cycle therefore enables the conversion

of heat into electricity, starting at a very high temperature level, which favourably affects the conversion efficiency.

Another important aspect relevant to the use of gas turbines in power stations is the reliability and availability of the gas turbine. The use of gas turbines in power stations generally has been confined to those power stations that are operated for peak-shaving purposes, for which duty the low capital costs are of advantage and availability is of lesser importance. Recent reports indicate that the availability of the gas turbine cycle can be better than that of the steam turbine cycle⁹⁾ and also that long periods between maintenance are being obtained¹⁰⁾. An example of the increasing confidence in the reliability and availability of gas turbines is their use in high-capital natural gas liquefaction plants¹¹⁾. As already stated, it seems unlikely that a steam temperature above 550°C can be obtained, mainly because of very great material problems encountered in the design of the steam turbine, boiler and superheater. There are, however, promising indications that, through a combination of blade cooling techniques and blade material developments, the allowable inlet temperature of gas turbines will continuously be increased. This means that the efficiency of converting heat into electricity can be expected to gradually

increase for power stations incorporating gas turbines. In Fig. IV a forecast of gas turbine inlet temperature progression, as given by United Aircraft¹²⁾, is presented.

EFFICIENCY OF SGP-BASED POWER STATIONS

The combination of the various elements of an SGP/PS, as described above, together with a conventional steam cycle leads to a power station (Fig. V) where the efficiency loss caused by the clean fuel gas preparation step is compensated to a great extent by the high heat-to-electricity conversion efficiency obtained through the incorporation of the gas turbine. In Table I the effect of the gas turbine inlet temperature on the overall efficiency of the SGP/PS is shown.

Table I
Efficiencies of SGP-based Power Stations^{a)}

Gas turbine inlet temperature, °C	850	1000	1200	1400
Plant efficiency, %	38.5	40.8	43.0	44.7
Percentage power ex gas turbine cycle, %	24	29	35	40
Steam to be condensed, kg/kWh as % of conventional power station %	87	81	74	69

a) The efficiency of a CPS comprising steam turbines with an efficiency equal to those used in the above SGP-based power stations was calculated to be 39.5%.

From this table it can be concluded that at a gas turbine inlet temperature of around 900°C the efficiency of an SGP/PS is equal to that of a conventional oil-fired power station. This means that at 900°C the favourable effect of this high temperature level on the overall plant efficiency has fully compensated for the efficiency losses caused by the fuel gas preparation step.

An interesting aspect is that, since in the SGP/PS electricity is generated both by a gas expansion cycle and by a steam expansion cycle, considerable freedom exists in optimizing towards alternative aspects such as efficiency, capital outlay and cooling water requirement. If, for instance, thermal pollution is an important consideration, the cooling water requirement can be reduced by diverting part of the steam into the gas expansion cycle. In this way electricity generation via the gas expansion cycle is increased, and the cooling water requirement for steam condensation is decreased. This scheme would of course at the same time decrease electricity generation via the steam cycle and would result in consumption of boiler feed water. It has been calculated, for instance, that at 850°C turbine inlet temperature a steam injection into the gas turbine

inlet stream at a rate of 2.5 kg/kg power station oil feed would have the following effects (compare Table I):

Percentage power ex gas turbine cycle would increase from 24% to 36%. Steam to be condensed would be reduced from 87% to 60% (kg/kWh as % of conventional power station). Plant efficiency would be reduced from 38.5% to 37.7%.

ECONOMICS OF SGP-BASED POWER STATIONS

In Table II the economics of an SGP/PS are compared with those of a conventional power station. Some uncertainty exists about the capital cost figures used for the various SGP/PS schemes given.

This aspect is under investigation.

The additional costs incurred in the SGP/PS as compared to the costs of a conventional power station are charged in this table as a "sulphur removal cost" against the fuel oil used. In this way the operation of an SGP/PS can be compared with alternative ways of removing sulphur from fuel oil.

Such an alternative process is, for instance, the hydrodesulphurization of residual fuel oil (the so-called "direct hydrodesulphurization process"). This process results in

desulphurization costs ranging from \$200 to \$360 per ton sulphur removed, depending on crude origin¹³) (for residual oils of certain, high ash content, crude types hydrodesulphurization is not yet feasible).

Table II
Economics of SGP-based Power Stations

Basis: 200 MW unit; 6000 hours annual service period; fuel with 4% wt sulphur; 90% desulphurization.

Operating costs plus a capital charge taken as 20.5% on capital (5% for operating, maintenance and overhead, 0.5% for catalysts and chemicals, 15% for repayment of capital, tax and return on capital).

Sulphur credit: \$20/ton.

Conventional Power Station		SGP-based Power Station			
		I	II	III	IV
Turbine inlet temp., °C		850	1000	1200	1400
Plant efficiency, %	39.5	38.5	40.8	43.0	44.7
Capital US \$ x 10 ⁶ a)	40	48-46.5	48-46	48-45	48-44.5
Cost of sulphur removal ^{b)}					
\$/ton S	approx. 250 ^{c)}	165-134	130-85	96-26	70- -14
¢/barrel/% S	approx. 40 ^{c)}	26-21	20-13	15-4	11- -2

a) The capital figures are taken from a 1970 Shell/Sulzer study^{3, 7}) comparing a 200 MW CPS with a two-stage expansion SGP/PS and escalated for 1972. For Cases I,

II, III and IV two assumptions have been made:

- 1) Capital remains 48 and
 - 2) capital is reduced proportionally with the increase in the gas turbine contribution to power generation.
- b) Calculated on the basis of the difference in price between high-sulphur fuel (for the SGP/PS) and the clean fuel (for the CPS) at a constant electricity price.
- c) Hydrodesulphurization of long residue (cost can be as high as \$360/ton S or \$57/barrel/% S¹³).

From Table II it can be concluded that an SGP-based power station using currently available gas turbines with an inlet temperature of 850°C results in "sulphur removal costs" that are of the order of 60 to 70% of the costs of alternative desulphurization techniques.

A further increase in the gas turbine inlet temperature would result in a substantial reduction of the "sulphur removal costs" of the SGP-based power station.

CONCLUSIONS

Compared with a conventional oil-fired power station, the SGP/PS has the following attractive characteristics:

- 1) Some 90% to 95% of the sulphur in the fuel is not emitted to the atmosphere but is recovered as elemental sulphur. The "sulphur removal costs" compare favourably with the costs of alternative desulphurization techniques.
- 2) No emission of particulate matter.
- 3) Low flame temperatures are applied, which can be expected to result in low emission of nitrogen oxides.
- 4) Reduced cooling water requirements.
- 5) The operation at elevated pressure results in the use of compact, shop-fabricated equipment, which will have a favourable effect on construction time.

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FIG. I
BLOCK SCHEME- CONVENTIONAL POWER STATION

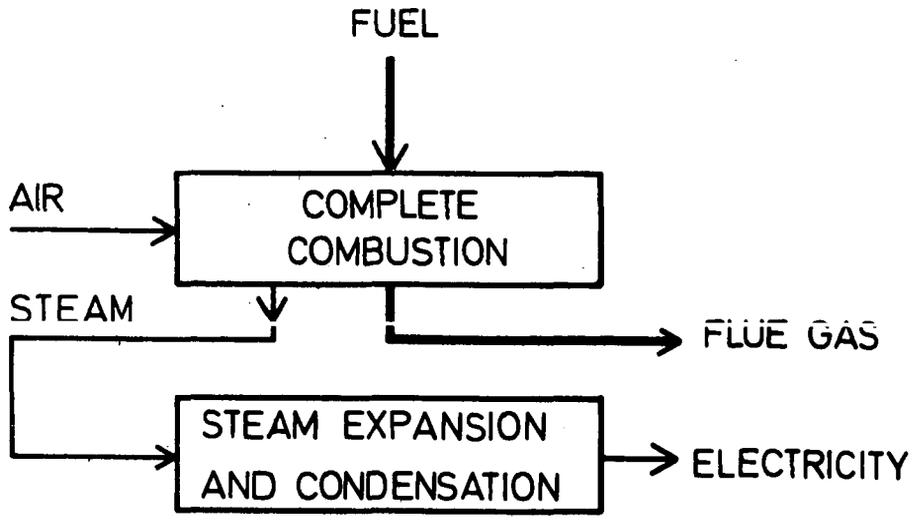


FIG. II
BLOCK SCHEME - PARTIAL OXIDATION BASED POWER STATION

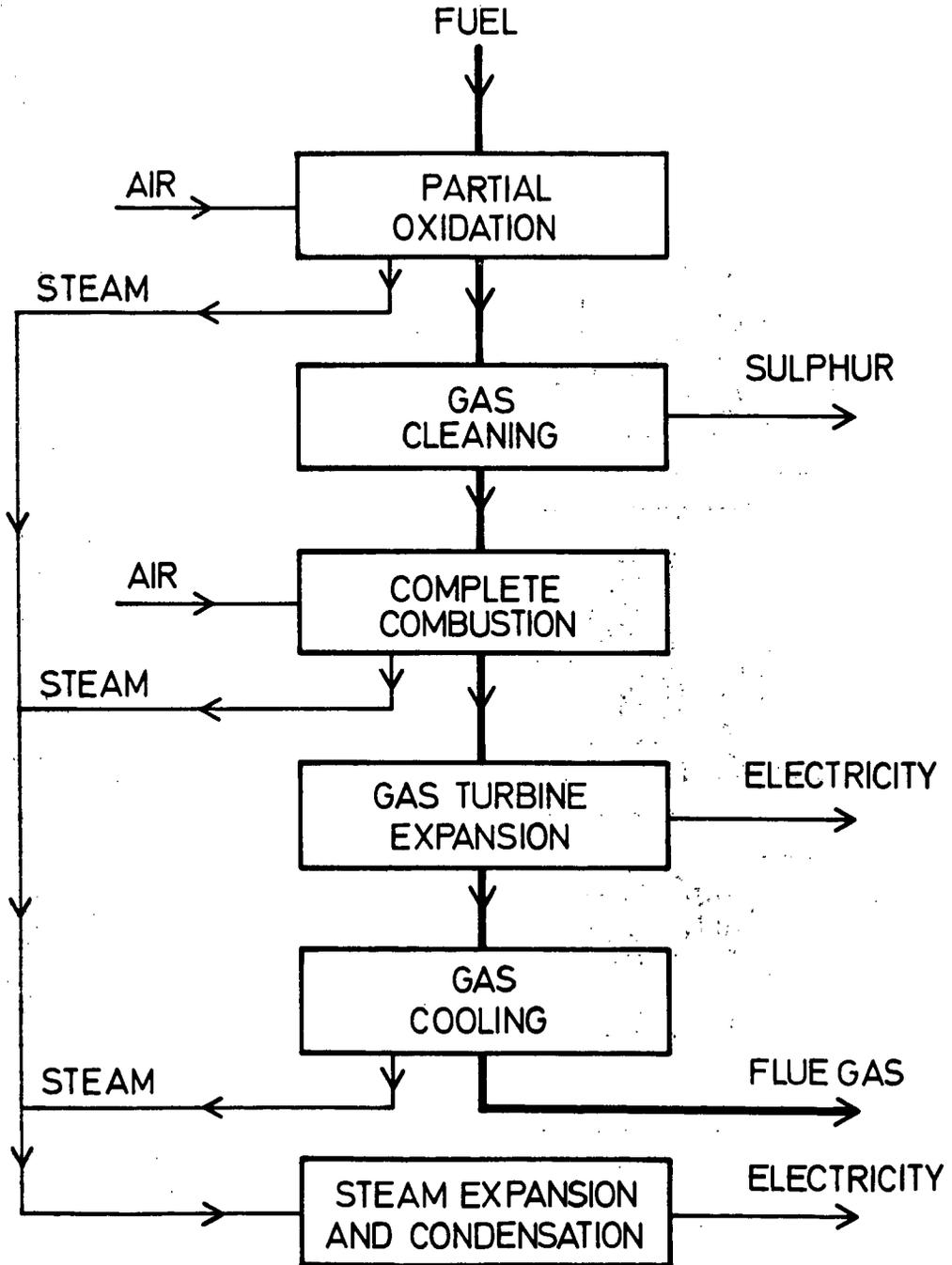


FIG. III
SGP PROCESS WITH CARBON RECYCLE

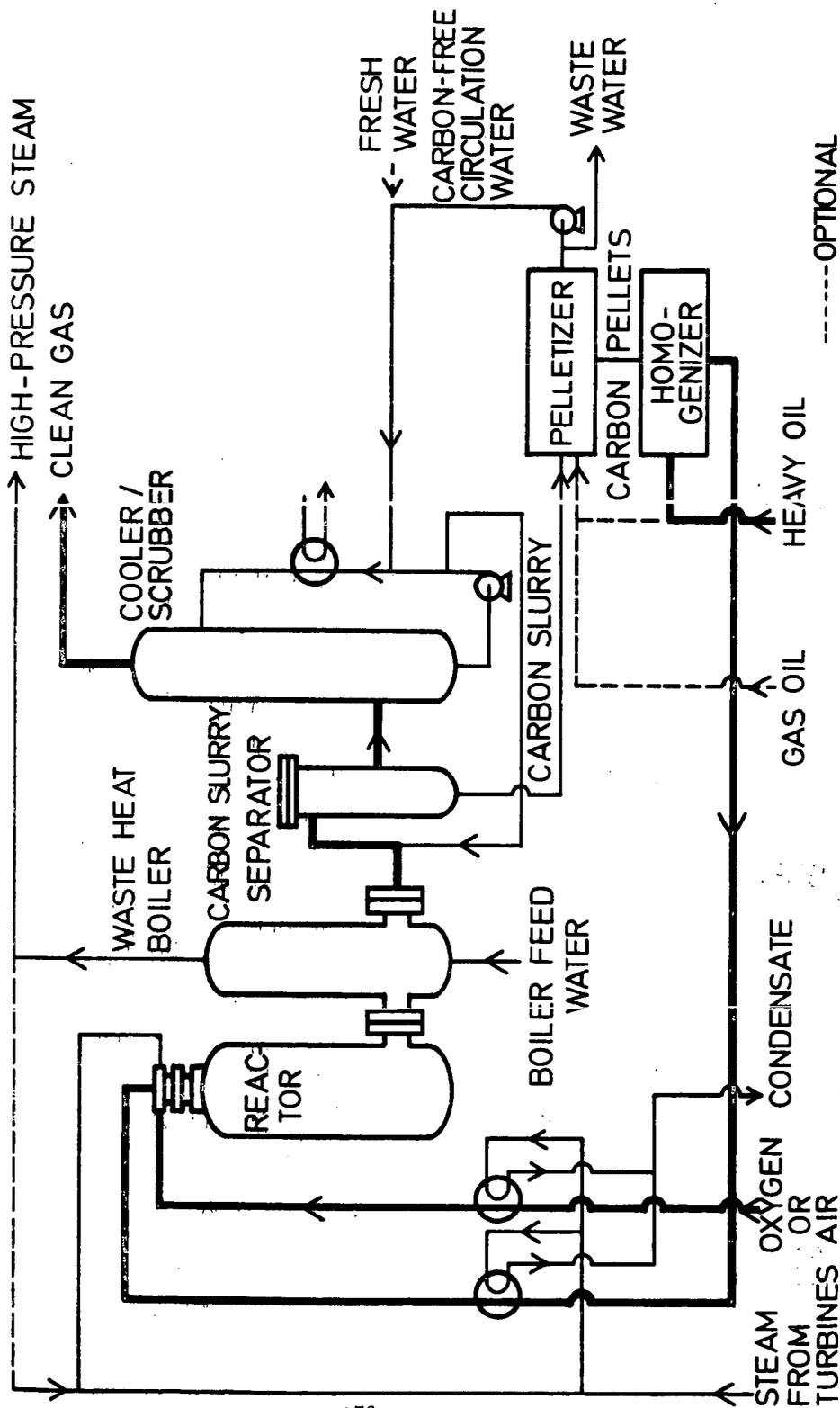


FIG. IV
 ESTIMATED TURBINE INLET TEMPERATURE PROGRESSION 8)
 (UNITED AIRCRAFT ESTIMATE)

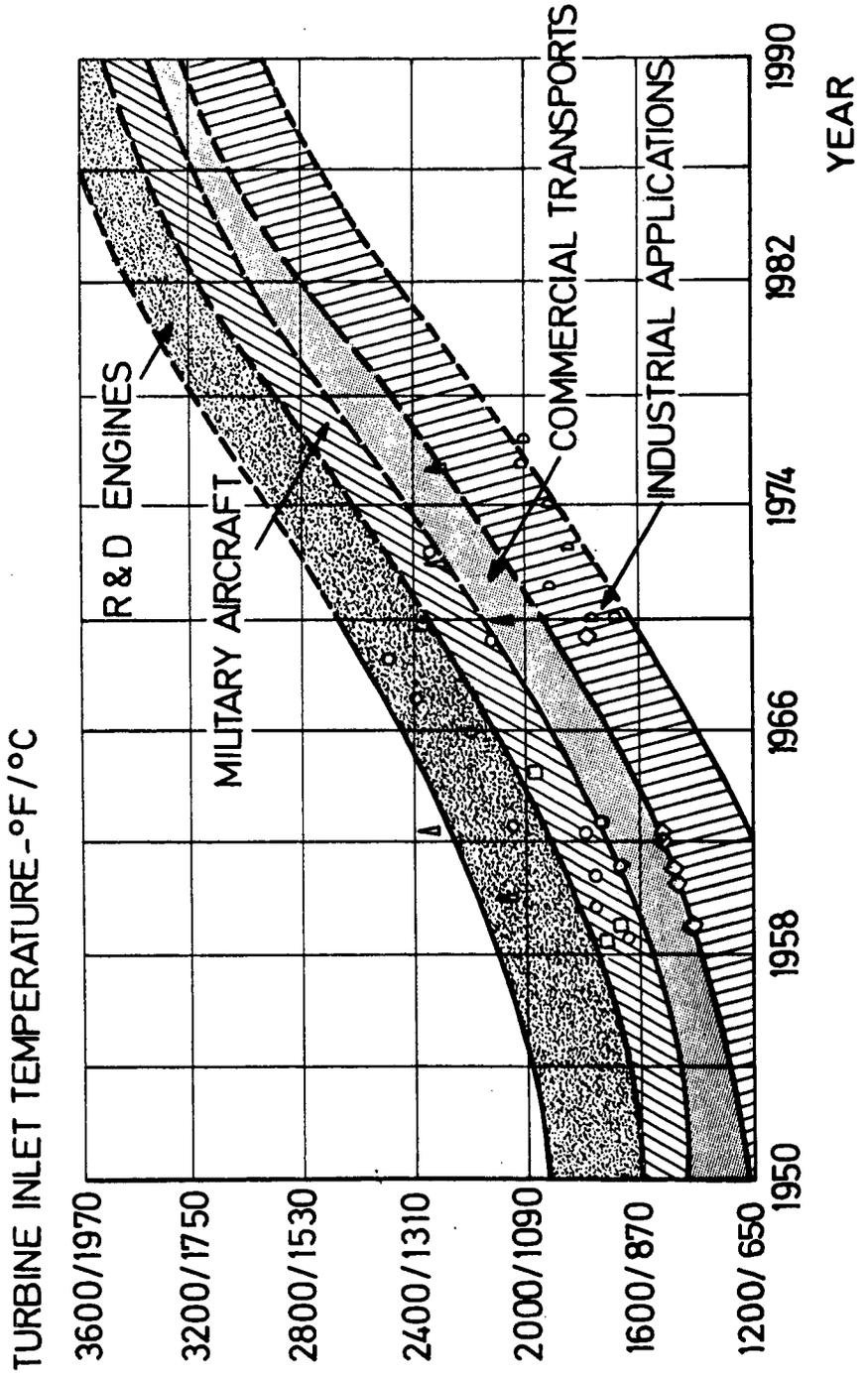
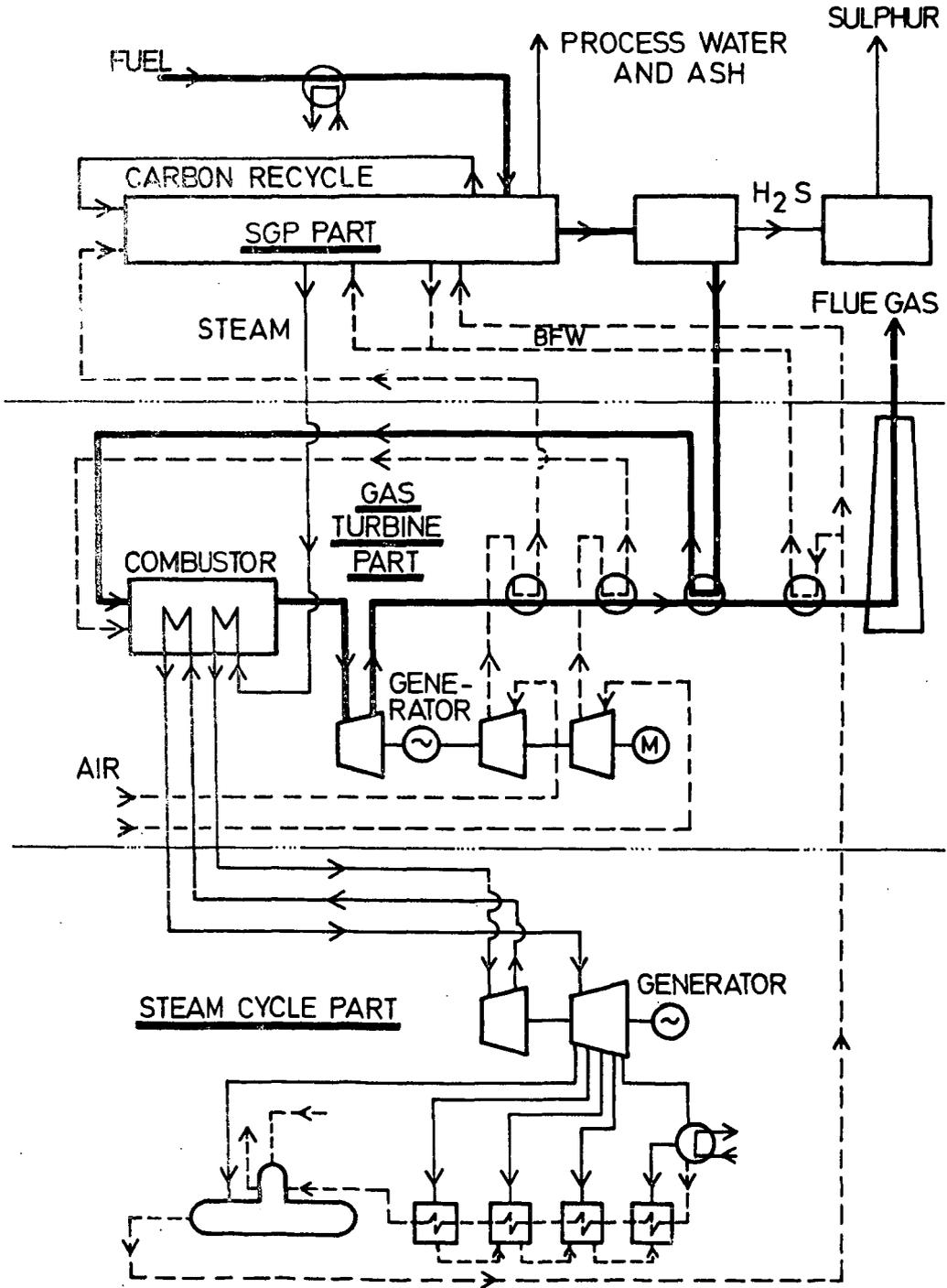


FIG. V
S.G.P.-BASED POWERSTATION



FLUIDIZED-BED COAL GASIFIER AS A LOAD-FOLLOWING CLEAN FUEL SOURCE

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INTRODUCTION

The electric power generated in the United States is growing at a rate of about 8-10%/yr. The electric load is expected to increase by a factor of 4 in the next 20 years to a total of 6.5×10^6 GWhr. It will take at least 20 years before nuclear energy, which today supplies less than 1% of our electric power, will carry the main burden of our power requirements. Therefore, for the next 15-20 years, most of the demand for electricity will have to be met by fossil fuels, i.e., coal, oil, and natural gas.

Natural gas, which is already in a short supply, will be increasingly assigned to more critical applications than combustion in large power plants. Furthermore, the available supply of natural gas may combat pollution more effectively from an overall standpoint when used for residential and small commercial needs. Coal and oil must, therefore, fill the demand for fuel for electric power generation. The use of oil for power generation must be limited to avoid heavy reliance on politically uncertain oil-producing countries. In addition, our balance of payments problems will balloon with increasing foreign oil purchases. Coal is the most logical answer to meet the growing power demand in the next 2 decades (see Figure 1).³

Coal is one of the largest fuel resources in the United States, but, when burned, it is a primary contributor to the sulfur and particulate pollutants in the atmosphere. One direct way of limiting sulfur emissions from coal combustion is to use low-sulfur coals; however, most are located in areas that do not coincide with the areas of need. When using high-sulfur coals, one alternative is to use scrubbing systems to remove sulfur dioxide produced during combustion. After spending \$300 million on a crash program to develop a scrubbing system, no viable commercial process is yet available. Their efficiency in sulfur dioxide removal is expected to be rather low, in the range of 80-90%.

Coal gasification with gas cleaning before combustion promises the greatest reduction in sulfur emissions. According to the Environmental Protection Agency,¹ a power plant using coal gasification in conjunction with an advanced combined gas turbine-steam turbine cycle promises to have the following benefits:

- Reduction of sulfur oxide emissions up to 99%
- Nitrogen oxide reductions of 90% when compared with present-day coal-fired plants
- A 40-50% reduction in thermal pollution by power stations
- Approximately 20-30% savings in both capital and operating costs over conventional plants
- An important impact on the balance of payments when the system is successfully demonstrated in the U.S. through the foreign sale of complete systems as well as additional royalties from foreign licensees of U.S. turbine manufacturers

- Elimination of the adverse effects of pollution control measures on the coal industry, thus increasing both revenues and employment in the major coal-producing states
- Reassignment of natural gas now supplied to the power industry to higher priority use
- Retention of teams of highly trained turbine designers by the gas turbine industry. These teams are a valuable national resource which might otherwise be dispersed because of the loss of the SST program and a reduction of Department of Defense support.

After a description of the Institute of Gas Technology's coal gasification plant concept for a clean fuel gas, we will show how the fluidized-bed coal gasifier will be able to follow the electric load characteristics of an intermediate-load power plant.

COAL GASIFICATION PLANT FOR UTILITY GAS

The clean gas produced from an air-based coal gasification plant is called utility gas, producer gas, or low-Btu gas. Figure 2 is a process flow diagram for IGT's proposed utility gas coal gasification plant. Values shown are for a nominal coal feed rate of 20 tons/hr.

After the coal feed is crushed to the desired size, single-stage lock hoppers are used to transfer it from atmospheric pressure to the elevated pressure of the gasifier. Steam and air are fed to the bottom of the gasifier. Heat is recovered from the hot raw gases produced in the gasifier and the gas is then cleaned of sulfur at low temperature by a selective hydrogen sulfide removal process. The gas can be scrubbed so that it contains less than 5 ppm of hydrogen sulfide. A small part of the cleaned gas is used to pressurize the lock hoppers.

The main gas stream, after cleaning, is reheated by exchange with hot raw gas from the gasifier. The gas then expands through a gas expander to the optimum pressure level for application to a combined cycle. The gas expander generates some electricity. The gas is cooled by generating steam to about 600° F to meet the gas turbine combustor's requirements. After combustion, the gas expands through the gas turbine, generating a large percentage of the total power output. Part of the energy recovered is used to drive the compressors to supply the gasifier air and the combustor air. Exhaust gas from the gas turbine is reheated by burning gas recovered from the coal feed lock hoppers. Final heat recovery generates steam in the waste-heat boiler for additional power generation. Of the total power generated, about 35% comes from the steam turbine and 65% from the expander-gas turbine.

The hydrogen-sulfide-rich gas from the hydrogen sulfide recovery process goes to a sulfur recovery plant. Ninety five percent of the total sulfur is recovered as elemental sulfur. The Claus plant tail gases still contain about 1% hydrogen sulfide. A process such as the Beavon Process is used to reduce the sulfur content of the tail gas to less than 250 ppm.

GASIFIER

The entire utility gas concept hinges on the coal gasifier's performance. The gasifier and its design concept will not be discussed here because it has been presented elsewhere.⁵ The gasifier must satisfy the following requirements:

- Operate reliably
- Gasify a high percentage of feed carbon
- Accept caking coal as feed
- Be capable of load-following

Figure 3 presents a simplified illustration of the gasifier. A single-stage lock hopper is preferred to transfer coal into the gasifier. This feed system was chosen so that the gasification plant will be simple, reliable, and cheaper. Lock hoppers tend to be attractive for utility gas production as the depressured lock hopper gas can be used without the need for recompression. The gasifier operating pressure has been set at 300 psi in this paper because the maximum operating pressure for commercially demonstrated lock hopper valves is 350 psi. We believe that higher operating pressures may be desirable; however, lock hopper valves to withstand the higher pressures have yet to be developed.

So that the utility gas process can accept the widest variety of coal feed, facilities for destroying caking properties of agglomerating coal are provided within the gasifier. We propose to pretreat at gasifier pressure and feed the hot pretreated char directly into the gasifier. The exothermic pretreatment reaction produces enough heat to generate the steam to satisfy the gasifier's requirements.

The gasifier is designed to gasify coal with air and steam in a fluidized bed. Simultaneously, the coal ash will be selectively agglomerated into larger and heavier particles for removal from the bed. The principle of ash agglomeration and separation which has been used in the gasifier design has been demonstrated both by Godel² and Jequier *et al.*⁴ The gasifier, which we call an ash agglomerating reactor (AAR), resolves the main problem of coal gasification in a fluidized bed rich in carbon—that of selectively removing low-carbon-content ash from the bed. A gas residence time of 10-15 seconds is provided above the fluidized bed so that any tars and oils which may be evolved are thermally cracked to gas and carbon.

Most of the sulfur produced by coal gasification with the gasifier will appear in the form of hydrogen sulfide. Although we selected a low-temperature sulfur removal system, it would be desirable to use a yet-to-be-developed high-temperature sulfur removal system to improve plant efficiency and decrease costs. In combined-cycle plants, a 2% increase in overall power plant efficiency is realized when a high-temperature sulfur removal system is used in place of a low-temperature system as previously discussed.

The combined gas turbine-steam turbine cycle is illustrated in Figure 4. There are many alternative ways that this basic concept can be implemented. The efficiency of combined-cycle systems depends to a major degree on the allowable gas turbine inlet temperature. Gas turbines used today operate around 1800°F. The allowable inlet temperature to gas turbines is projected to increase at 100°F/yr to a maximum of about 3100°F. United Aircraft Research Laboratories⁶ expects ultimate coal gasification-combined cycle thermal efficiencies of 57.7%.

POWER DEMAND REQUIREMENTS

The EPA¹, Division of Control Systems, characterized electrical generating capacity in three categories:

1. Base load. These units are 500 MW and larger and operate at a load factor of 75%. Base-load plants represent about 60% of total electrical generating capacity. Nuclear power plants are expected to fill most of this requirement in the future.
2. Swing or intermediate load. Capacity of these units is from 200 to 500 MW, and their load factor ranges from 40 to 50%. These plants represent about 30% of total capacity. The EPA believes that coal gasification, in conjunction with advanced power cycles, can be applied most favorably in this category.

3. Peak load. This load will probably be satisfied by gas turbines because quick response time is required. Units are less than 200 MW in size and operate at less than a 40% load factor.

If the coal gasification-combined cycle systems are to fill the intermediate load requirement, the coal gasifier must be able to vary its output over wide ranges with rapid response.

One of the large power companies has provided the following typical operating requirements for the upper and lower ends of the swing-load range. To fill the upper end of the range, the gasifier unit would operate 6 days/wk. On weekdays the gasifier would operate at full capacity for 8 hours, at one-third of capacity for 8 hours, and at an output varying from one-third to full capacity for the remaining 8 hours. On Saturday, the gasifier might operate at full capacity for periods up to 12 hours, or in other circumstances, it may operate at one-third capacity for the 24-hour period. The plant would be substantially shut down on Sunday. Desirably, the system would be designed to generate 10% of design output as needed on Sunday. These demands will occur for periods of less than 1 hour.

In the lower part of the range, the gasifier would operate from 6 to 12 hr/day on a random basis during about 3 days of the week. A fuel consumption of up to 5% of the full load requirement during standby periods may be acceptable, although fuel consumption should be as low as possible.

To follow the normal variations in electrical demand, the gasifier should be capable of adjusting at a typical rate of 1% of design capacity per minute. In an emergency situation, almost immediate shutdown is required.

AAR TURNDOWN

The following discussion describes attainable control methods for adjusting the output of a fluidized-bed gasifier without damaging process equipment. The following five possible methods are considered:

1. Change gas velocity in gasifier
2. Adjust gasifier temperature
3. Permit the bed to defluidize (no gas flow)
4. Change gasifier pressure
5. Operate gasifier at a fixed condition and vary the gas flow between the power generating plant and a parallel chemical fuel plant.

The gasifier output can be rapidly changed by adjusting the gas velocity through the fluid bed. The air and steam flows to the gasifier are adjusted while retaining a fixed ratio of steam to air, reactor pressure, and fluid-bed level. As an example, if the design velocity in the gasifier is 1 ft/sec and the minimum practical superficial velocity at the operating temperature is 0.3 ft/sec, a turndown of 3.3 can be obtained.

Another means of turndown is to reduce the coal reaction rates by lowering the gasifier's operating temperature. The temperature is altered by changing the ratio of steam to air entering the bed. Moderate temperature changes that are not made abruptly are satisfactory. Rapid changes over a wide range of temperatures may crack and spall the gasifier's internal insulation, causing both operating and mechanical problems. As the fluidized-bed temperature is reduced, the reaction rates drop off sharply. It is recognized that, in lowering the bed temperature, alterations in the air

and steam flows to the various injection points in the bed will be necessary to minimize changes in the ability to control ash agglomeration. The coal feed rate is adjusted to maintain a constant bed height. A constant superficial gas velocity can be maintained by adjusting the steam and air flow rates. The capability of turndown by this method is shown in Figure 5 for three different superficial gas velocities. The reactor could be turned down tenfold by reducing with the superficial gas velocity to 0.33 ft/sec and the gasifier's operating temperature to 1500°F. Decreasing the superficial gas velocity to one-third of design takes only minutes and gives a turndown to 30% of design. Lowering the reactor temperature to 1500°F at a rate of 100°F/hr (a recommended rate to avoid reactor refractory damage) takes 4 hours and results in a further turndown from 30% to 10% of design. Operating at these conditions, the AAR produces a gas with a heating value of 80 Btu/SCF, as compared to about 135 Btu/SCF under full load conditions. This could be used to fire boilers to produce process plant steam. As the reactor's operating temperature is reduced, the product gas heating value decreases (Figure 6) because less steam reacts with the coal to produce hydrogen and carbon monoxide. Idling conditions could be achieved by reducing the reactor temperature to 1400°F and superficial gas velocity to 0.33 ft/sec. The coal feed rate at these conditions is about 5% of the full load rate. Just enough coal is burned to heat the feed gas (mostly steam) to 1400°F.

For complete shutdown, the gasifier could be cooled to about 1400°F, which would take about 5 hours. The gas and coal flows would then be stopped and the bed allowed to collapse. For restarting, the bed is refluidized by reinjection of air and steam and the temperature slowly raised at a rate of 100°F/hr. For emergency shutdown, the bed is permitted to defluidize at temperature. In the defluidized state, the reactor would cool down at a rate of about 100°F/day. For weekend shutdowns there is no need to supply any heat to the defluidized bed. For longer shutdowns, spurts of air to briefly refluidize and reheat the bed might be injected into the bed to replace the heat lost. With controlled cooling, a hot char bed would not solidify but would maintain a free particulate form that could be refluidized with a minimum of trouble.

The gasifier pressure level can also be changed to obtain a fairly wide range of capacity in a given unit. If the gasifier is designed for 300 psi and the lowest system pressure that can be tolerated is 50 psi, the turndown ratio is 6. Although this may be extreme, one might certainly expect that the 300-psi pressure level could be dropped to 100 psi for a relatively easy-to-obtain turndown ratio of 3. In practice, some process upsets may occur if the pressure is changed too rapidly. Given sufficient time, it should be possible to turn the gasifier down safely by this method. Each incremental change in pressure requires an equivalent incremental change in steam and air injection to maintain a fixed superficial gas velocity in the gasifier.

The fifth way to reduce electrical outputs is to fix the gasifier at constant operating conditions, and, as the electrical load changes, to direct more or less of the gas output to the power-generating equipment. The rest of the gas would flow to a Fischer-Tropsch (F-T) unit designed to accept varying amounts of gas. (The unit need not be very efficient.) A reasonable percentage of the carbon monoxide and hydrogen would be converted to liquid fuels. Unconverted gas from the F-T unit would mix with the main gas flow and be used for immediate power generation. The ash-free, sulfur-free liquid products from the F-T unit would be stored and returned to fuel the power-generating equipment during peakload periods or during periods when the gasifier is shut down for maintenance. If an excess amount of liquid fuel is produced, it can be sold as a raw material for petrochemicals or it could be used as a fuel to supplement petroleum.

Addition of a Fischer-Tropsch unit will add significantly to plant capital costs. However, if no other clean fuels are available to the electric utility for use when the gasifier is shut down for maintenance, or if other fuels are not available for the peaking gas turbines, this addition is an excellent way to supply a clean synthetic liquid from coal.

In the Fischer-Tropsch Process, carbon monoxide is hydrogenated to produce mainly straight-chain hydrocarbons and water or carbon dioxide. Catalysts which may be used are cobalt, nickel, iron, or ruthenium. The purified carbon monoxide and hydrogen-containing gas must have less than 2 ppm of sulfur compounds to minimize catalyst poisoning. Branched-chain hydrocarbons, aliphatic alcohols, aldehydes, and acids are also produced in varying amounts depending on the type of catalyst and the operating conditions. The reaction is exothermic with about 7200 Btu being liberated per pound of oil produced. Optimum temperatures are 340°-400°F for cobalt and nickel catalysts, 390°-620°F for iron catalysts, and 320°-440°F for ruthenium.

The large amount of heat evolved and the relatively narrow range of operating temperatures make the problem of removing the heat of reaction most important in the design of the plant. The presence of substantial amounts of nitrogen in the feed gas should not significantly change the yield of liquids and wax produced per volume of $2\text{H}_2 + \text{CO}$ based on pilot data. Much experience in this type of operation has been gained at Sasol over the last several years.

Interestingly, in processing part of the utility gas through a Fischer-Tropsch unit, if 15% of the reacting carbon monoxide forms methane, the exiting gas heating value is 132 Btu/SCF, assuming a feed gas heating value of 153 Btu/SCF. The difference in gas heating value that will be experienced using various methods for turndown will require sophisticated firing controls in the gas turbine and combustion systems.

Figure 7 shows how the Fischer-Tropsch plant fits in. When the gasifier operation is at design conditions for a high electrical load, only a small amount of gas flows through the F-T unit. As the electrical load decreases, more gas flows through the unit and less goes to the power plant. Finally, all of the gas flows through the F-T unit.

CONCLUSION

The concept of a fluidized-bed reactor as a gas producer for a combined-cycle power plant appears practical. It is possible, as confirmed by the experience of others, to achieve high carbon utilization in such fluidized-bed reactors by rejection of agglomerated, low-carbon ash produced in the gasifier. It is now the opinion of the people in the electric industry that a) such systems should be designed for operation in the intermediate load or swing range and b) to operate satisfactorily they must be capable of load following over a rather wide range.

Several methods which could be used to achieve this flexibility were discussed. It appears at this time that, alone and in combination, these methods will enable fluidized-bed gasifiers to perform satisfactorily under the conditions that will be required by the electric industry. The fluidized-bed reactor concept for coal gasification should find practical application in supplying a clean practical fuel produced from coal for utility use for several decades to come.

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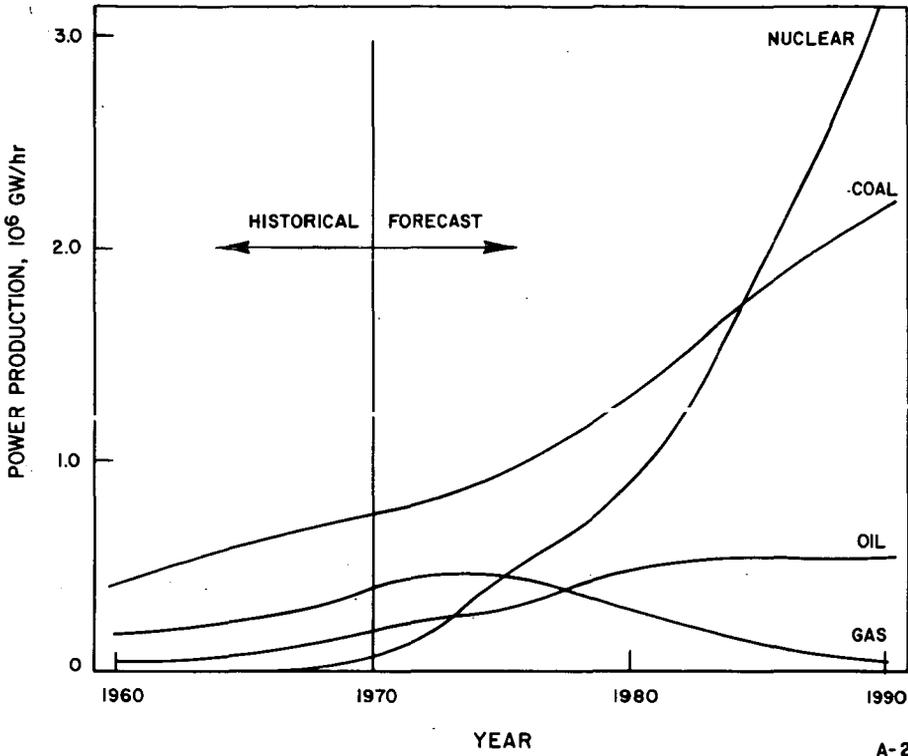


Figure 1. FORECAST OF POWER GENERATION BY FUEL IN THE U.S.

A-23-191

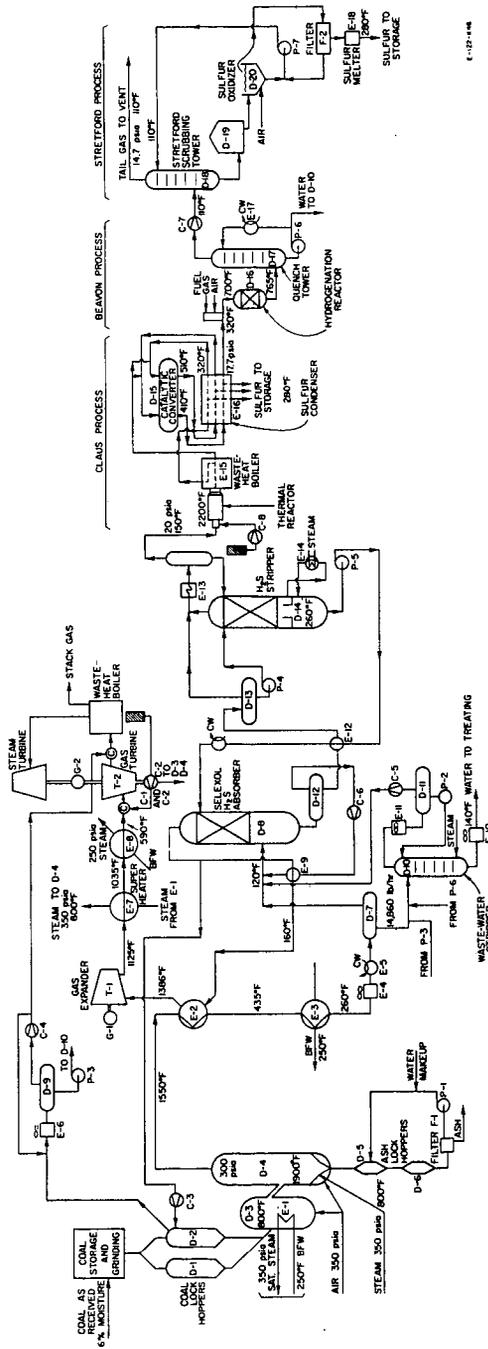


Figure 2. PROCESS FLOW DIAGRAM: UTILITY GAS FOR COMBINED-CYCLE POWER

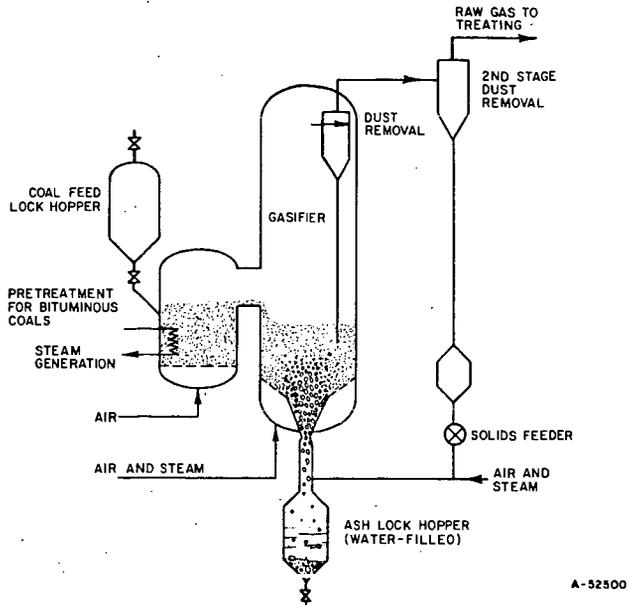


Figure 3. AGGLOMERATING BED REACTOR

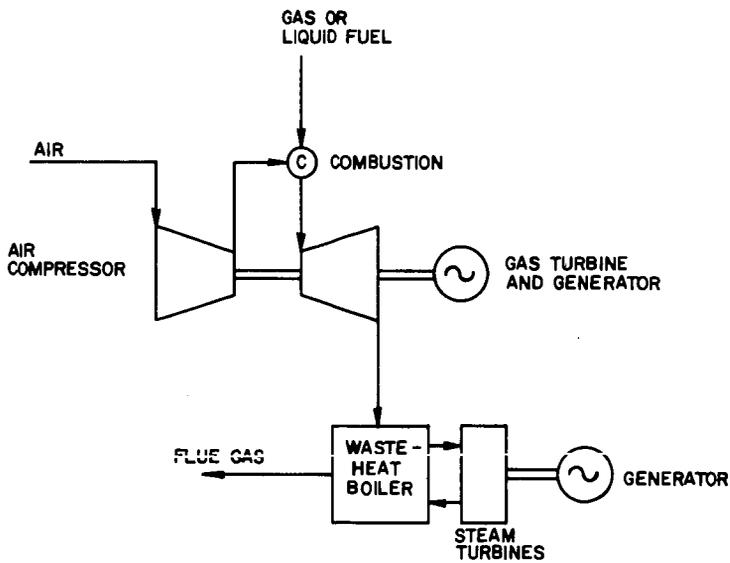


Figure 4. COMBINED-CYCLE POWER GENERATION WITH GAS AND STEAM TURBINES

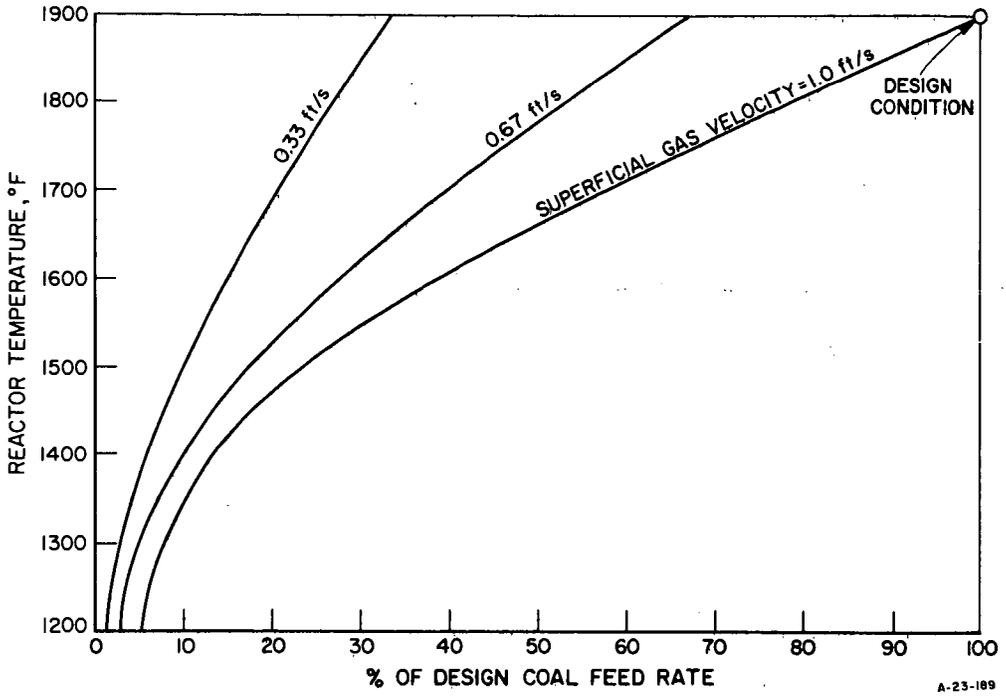


Figure 5. AAR TURNDOWN CAPABILITY

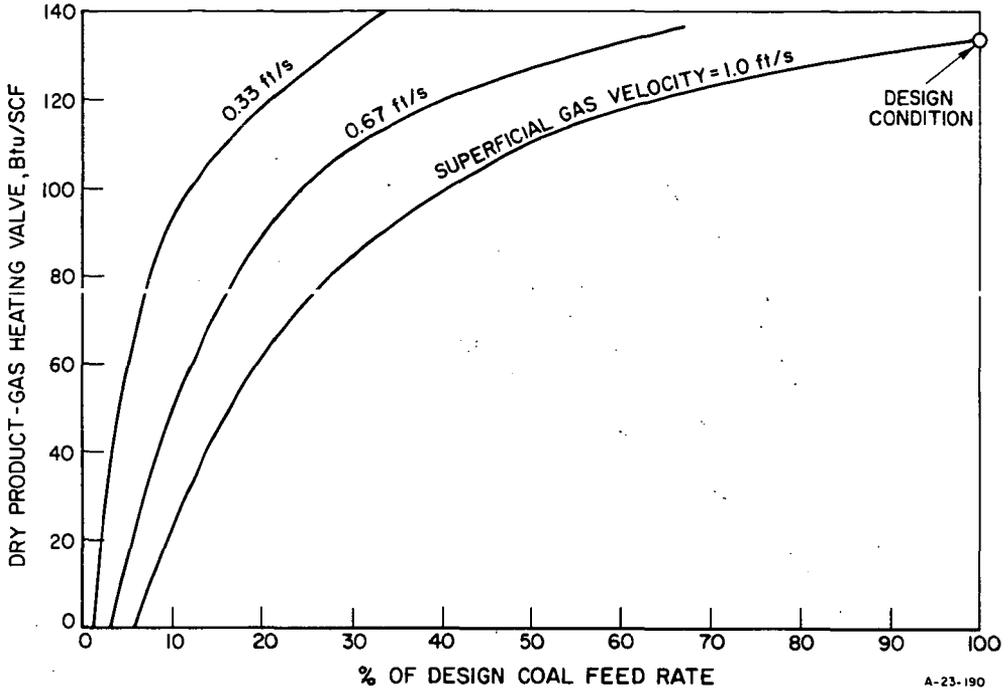
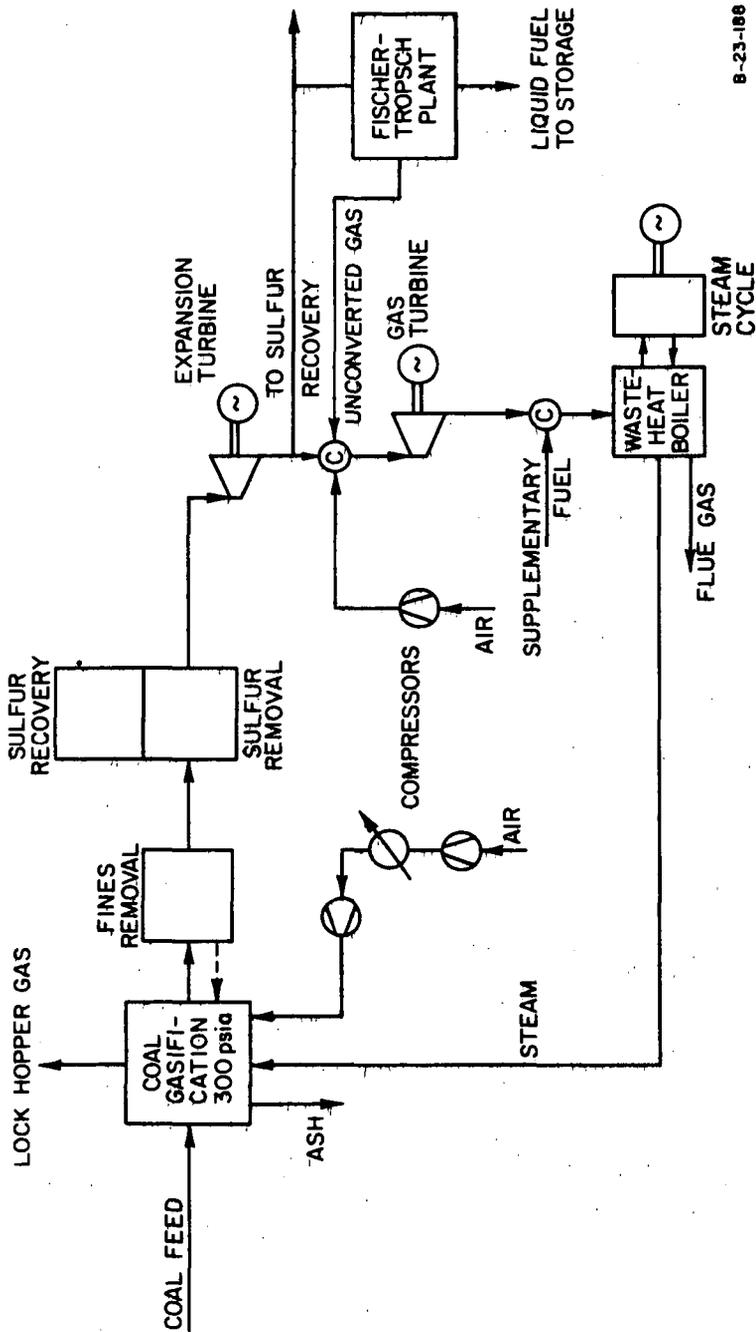


Figure 6. PRODUCT GAS HEATING VALUE AS A FUNCTION OF AAR TEMPERATURE



B-23-186

Figure 7. FISCHER-TROPSCH PLANT ADDITION TO COMBINED-CYCLE POWER GENERATION BY COAL GASIFICATION

PRODUCTION OF LOW-BTU GAS FROM RESIDUAL OIL IN COMBINATION WITH
ADVANCED POWER CYCLES. A. M. Squires, S. I. Dobner, M. J. Gluckman,
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An examination of the interface between equipment converting residual oil to low-Btu gas and power-generating equipment which combines gas- and steam-turbine cycles. Examples will be based upon Texaco or Shell "partial oxidation" followed by both conventional gas cleaning at low temperature and hot gas cleaning by means of a panel bed filter charged with half-calcined dolomite. Another example will employ cracking in a coke-agglomerating bed with production of an aromatic liquid and a coke byproduct.

ADVANCED COGAS POWER SYSTEMS FOR LOW POLLUTION EMISSIONS

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ABSTRACT

Analytical studies have been conducted to define commercially feasible, advanced-technology central power stations which would eliminate or significantly reduce utility-caused atmospheric pollution and thermal water pollution. The basic concept investigated represents a combination of (1) advanced cycle, Combined Gas And Stream (COGAS) turbine electric power generation systems based on technology spin-off from the aircraft gas turbine industry, and (2) selected processes for deriving nonpolluting gaseous fuel from high-sulfur residual fuel oil.

The results of these studies clearly indicate that advanced COGAS power systems integrated with fuel gasification systems would be more effective than future fossil steam systems in controlling emissions of ash, sulfur oxides, and waste heat. In addition, preliminary calculations indicate that emissions of nitrogen oxides could be reduced up to several orders of magnitude by using low-Btu gasified fuel compared with emissions caused by the combustion of high-Btu fuels. It appears that advanced gas turbine and COGAS power systems using low-Btu fuels could be fired to higher turbine inlet temperature to improve performance and still emit significantly less nitrogen oxides than when operating at low turbine inlet temperature with high-Btu fuels. Furthermore, prospective COGAS systems could produce electricity at lower cost than could be produced by alternative fossil steam systems with comparable air and water pollution controls. Also, despite the relatively high cost of fossil fuels, advanced COGAS power systems should offer a viable alternative to nuclear power systems for future base-load power generation.

INTRODUCTION

The electric utility industry in the United States is currently the target of numerous regulatory agencies and environmental groups whose goal is the elimination or significant reduction of objectionable emissions such as sulfur oxides, nitrogen oxides, particulate matter, and waste heat. A number of exploratory studies and demonstration projects are being carried out on methods of reducing power station

pollution. While some stack gas cleaning methods show promise, the only proven method currently available for the reduction of sulfur oxides is the use of relatively expensive, low-sulfur fuels. Similarly, the only available methods for the reduction of nitrogen oxides involve combustion modifications. All of these methods have the disadvantage of increasing the cost of generating power because of their high capital and operating costs.

An alternative method of pollution control involves the conversion and cleanup of dirty coal or residual fuel oil prior to combustion. Such fuel treatment would result in a significant increase in the cost of fuel delivered to the power generating system. In order to offset this increased fuel cost, the thermal efficiency of electric power generation should be increased as much as possible by using advanced-cycle power systems.

Several feasibility evaluation studies of advanced-cycle power systems have been conducted by the United Aircraft Research Laboratories, including one for the Environmental Protection Agency (formerly National Air Pollution Control Administration of the Department of Health, Education, and Welfare) reported in Ref. 1 and another for the Connecticut Development Commission reported in Ref. 2. The results of these studies indicate that power systems incorporating advanced-design gas turbines used in conjunction with steam turbines and gasification systems producing low-Btu fuel offer the potential of essentially eliminating the air and thermal water pollution problems of electric utilities while simultaneously producing lower-cost power than is projected for conventional steam systems. Previous papers summarizing the results of these studies have dealt primarily with the design, performance, sulfur emission control, and cost characteristics of advanced-cycle power systems operating on gasified coal (see Refs. 3 and 4, for example). This paper briefly summarizes these same characteristics for advanced-cycle systems operating on gasified residual fuel oil, with emphasis placed on the lowered nitrogen oxide emission characteristics anticipated for gas turbine systems operating on low-Btu gaseous fuels.

ADVANCED COGAS POWER STATIONS

The generic type of power system that shows the most promise for effective pollution control consists of a gasification process producing a clean, low-heat-content fuel gas for use in a Combined Gas And Stream (COGAS) turbine power system. Unlike some present-day COGAS systems in which the gas turbines are essentially air preheaters for the steam boiler, advanced-cycle COGAS systems would utilize large industrial gas turbines operating at high turbine inlet temperature. The technology basis for these gas turbines represents spin-off from the aircraft gas turbine industry. These gas turbines would produce approximately 60% of the net

station electric output, and their exhaust gases would be directed into waste-heat boilers which would generate steam for a steam turbine system producing the remaining 40% or so of the net station output.

Advanced Gas Turbine Technology

By adapting recent and continuing advances in aerospace technology to industrial turbine machinery design, substantially improved large capacity gas turbine power systems with appreciably higher thermal efficiency could result, leading to their widespread use in intermediate-load and base-load power generation applications. These advances in aerospace technology were achieved during extensive research and development efforts on military and commercial aircraft gas turbines and include improvements in materials technology, blade cooling techniques, aerodynamic flow path design, high-heat-release burners, and modular fabrication techniques.

While meaningful improvements in aerodynamic performance are projected for future gas turbines, the most significant future technological advances are expected in the area of turbine inlet temperature. Current industrial gas turbines are limited to turbine inlet temperatures of approximately 1800 F for base-load ratings. Part of the projected increase in turbine inlet temperature will be achieved by the use of improved turbine blade materials. Historically, maximum turbine blade temperatures have advanced approximately 20 F per year because of improvements in materials and coatings. Recently, however, significant increases in turbine inlet temperature approaching 70 to 80 F per year have been achieved in aircraft gas turbines through substantial improvements in turbine cooling techniques in combination with newer materials. Aircraft gas turbine engines beginning commercial operation during the early 1970s will operate at turbine inlet temperatures of approximately 2100 F during cruise and up to 2400 F during takeoff.

By applying the same sophisticated convection-cooled blade design philosophy to industrial engines and by precooling the turbine cooling air before being utilized in the turbine for cooling purposes, it should be possible to begin designing a new 2200 F industrial engine which could be put into commercial base-load operation in the near future. Further improvements in materials, oxidation-resistance coatings, and more advanced cooling concepts should permit base-load operation at turbine inlet temperatures on the order of 2600 F by the early 1980's. A conceptual design for a 100-Mw class simple-cycle gas turbine designed for 2600 F turbine inlet temperature and 20:1 compressor pressure ratio is depicted in Fig. 1. By the 1990's industrial gas turbine inlet temperatures of 3000 F or higher should be in commercial operation.

Waste-Heat Recovery in COGAS Systems

A simplified schematic diagram for an integrated COGAS/oil gasification power station is illustrated in Fig. 2. All the desulfurized fuel gas would be delivered to the gas turbine burner and the main heat recovery boiler would be unfired. In the short term, before turbine inlet temperatures are increased appreciably, it may be desirable for some applications to burn additional fuel in the boiler. This would increase output power and might result in lower emissions of nitrogen oxides per unit of output power. In the long term, however, when turbine inlet temperatures exceed approximately 2200 F, unfired heat recovery systems would result in highest overall efficiency and lowest overall cost.

During operation of an integrated COGAS/oil gasification power system, de-aerated feedwater from the main heat recovery steam cycle would be passed to the fuel gas waste heat boiler and converted into saturated steam at the same pressure as the high-pressure steam raised in the main steam cycle. Some of this high pressure saturated steam could be used to preheat the oil feed to the gasifier and some could be injected into the gasifier. The balance would be returned to the main steam cycle to be superheated along with the steam generated in the main boiler. The resulting superheated steam would be expanded in steam turbines to drive an electric generator and the booster air compressor.

Previous cycle studies (Ref. 1) have demonstrated that when the inlet gas temperature to the main boiler is below approximately 1200 F, single-pressure steam systems would result in stack temperatures in excess of 300 F. By adding a second low-pressure steam cycle, as depicted in Fig. 2, it is possible to extract additional heat from the stack gases and drop the stack temperature to 300 F, thereby improving steam cycle efficiency.

RESIDUAL FUEL OIL GASIFICATION AND CLEANUP SYSTEMS

The availability of clean, desulfurized fuel is an absolute requirement for the type of advanced gas turbines described in the previous section, and processes for producing such clean fuels from high-sulfur coal and oil are expected to become available concurrently with the advanced power systems. Processing high-sulfur residual fuel oil to produce clean, low-sulfur, gaseous fuel involves partial oxidation in a high-pressure reactor vessel to produce a hot, gaseous raw fuel (see Fig. 2). The hot, raw fuel gas would be cooled in heat exchangers and waste heat boilers, water scrubbed to remove carbon and soot particles, and then passed through an absorption system to remove sulfur compounds. The resulting fuel gas composition, after scrubbing and desulfurization, would be approximately 13-16% H₂, 20-25% CO, and 55-60% N₂ (by volume). Smaller concentrations of H₂O, CO₂, CH₄, A, sulfur

compounds, and nitrogen compounds would be present. The heating value of the clean fuel gas would vary from approximately 120 to 140 Btu/scf, depending on operating conditions. The desulfurized fuel gas would then be passed to the power system, and the sulfur compounds would be processed to produce elemental sulfur.

Partial Oxidation of Residual Fuel Oil

The partial oxidation of liquid-hydrocarbons is well-developed technology with numerous plants in operation working on a wide variety of feedstocks. The partial oxidation process was developed for the production of synthesis gas or hydrogen in the early 1950's by Texaco Development Corporation in the United States and Shell Internationale Petroleum Maatschappij N.V. in Europe. Both of these companies have made recent contributions to the technology of noncatalytic partial oxidation of hydrocarbons and have processes for license.

Generally, the partial oxidation process is very flexible in its operating characteristics. When used to produce fuel gas, feedstock (oil), air, and sometimes steam (to increase the hydrogen yield and to help control temperature) would be preheated and mixed before entering the refractory-lined reaction chamber. The oil feed would be converted into desirable products (hydrogen, carbon monoxide, and methane), undesirable products (hydrogen sulfide, carbonyl sulfide, carbon dioxide, and water vapor), diluents (nitrogen and argon), and soot (carbon) which would be recycled to extinction. The relative amounts of carbon monoxide and hydrogen would depend on the air/oil ratio, steam/oil ratio, oil composition, preheat temperatures, and pressure.

Sulfur Removal and Recovery from Raw Fuel Gas

During scrubbing and desulfurization operations, most of the H_2O , 50 to 70% of the CO_2 , and over 95% of the sulfur compounds would be removed from the fuel gas stream. The sulfur originally present in the fuel oil would appear in the raw gas principally as hydrogen sulfide, H_2S , with small but important quantities of carbonyl sulfide, COS . There is a wealth of technological data (see Refs. 5 and 6) available for the removal of H_2S from hydrocarbon gases, largely due to the development of the natural gas industry during the past 30 years.

Two types of chemical-solvent scrubbing systems look very attractive for the removal of sulfur compounds in power generation applications: hot potassium carbonate and amine scrubbing systems. The hot potassium carbonate scrubbing process was developed by the Bureau of Mines for the removal of CO_2 from coal gas to upgrade its heating value. It was discovered that H_2S and COS were also effectively removed. Amine scrubbing systems have been highly developed and are popular methods for removing CO_2 and H_2S from natural gas. These methods are based on employing monoethanolamine (MEA), diethanolamine (DEA), di-isopropanolamine, or other scrubbing solvents.

The desulfurization of fossil fuels usually requires some plan for the disposition of the sulfur compounds which are removed from the raw fuel gas. Various schemes have been developed to recover the sulfur in a form that has economic value. The most important of these schemes, which involve the selective oxidation of H_2S to elemental sulfur, have been classified together as Claus systems. By proper design of the scrubbing and Claus systems (incorporating, for example, multiple stages and improved designs), it is possible to achieve an overall sulfur removal effectiveness of 85 to 96%. By further treating or recycling of the tail gas from the Claus system it should be possible to exceed 98% overall sulfur removal effectiveness.

CHARACTERISTICS OF INTEGRATED COGAS/OIL GASIFICATION POWER STATIONS

Selected characteristics of integrated COGAS/oil gasification power systems corresponding to three levels of technology (present day plus technology projected to be available during the mid-1970's and early 1980's) are presented in Table I. The general requirements and design characteristics for the gasification system, gas turbines, and waste heat recovery steam system are summarized in the table along with selected performance data for the integrated power stations. The net station outputs range from 159 to 309 Mw, and the estimated net station thermal efficiencies range from 32% to 40%. These net station efficiency estimates could possibly be increased as much as 3 points by further cycle optimization combined with the use of higher temperature (1300-1500 F) fuel gas delivered to the gas turbine burner. Higher fuel gas temperature might be feasible in future systems by using high-temperature desulfurization and cleanup or an improved gasifier heat recovery scheme which would regenerate clean, low-temperature fuel gas against raw, high-temperature fuel gas.

Also indicated in Table I are estimated emission rates for sulfur oxides, nitrogen oxides, and thermal heat rejection to the cooling tower circuit. Sulfur emissions would be low because of the desulfurization process incorporated in the gasification system. Nitrogen oxide emissions would be low because of the favorable combustion characteristics of low-Btu gasified fuel as described in the next section.

All conventional power generating equipment (with the exception of simple-cycle gas turbines) reject heat to cooling water. The rates of heat rejection from fossil- and nuclear-fueled steam stations are approximately 4300 and 6600 Btu/kwhr, respectively. COGAS stations would have significantly lower heat rejection rates (as much as 30% lower than fossil and 50% lower than nuclear stations), as noted in Table I, due to their high thermal efficiency and increased heat rejection rate to the atmosphere. The impact of this heat rejection on cooling water supplies could be reduced for all types of power systems by the use of cooling

towers. Wet (evaporative) cooling towers might, under certain circumstances, cause objectionable fogging at ground level, and dry (nonevaporative) towers are very expensive. The environmental and economic impact of using cooling towers for COGAS systems would be significantly less than for the alternative systems because of the reduced heat rejection rate of COGAS systems.

NITROGEN OXIDE EMISSIONS FROM GAS TURBINE POWER SYSTEMS BURNING LOW-BTU FUEL GAS

Oxides of nitrogen are receiving increasing attention as air pollutants. The oxides NO (nitric oxide) and NO₂ (nitrogen dioxide) are commonly lumped together as NO_x. They are easily interconverted in the atmosphere, and their ratio changes depending on the action of sunlight, oxygen, and other oxidizing or reducing agents present. Nitrogen oxides are formed in the hot reaction zones of all air-breathing combustion engines. They are formed primarily as NO, although small quantities of NO₂ and N₂O (nitrous oxide) may also be formed.

Control of NO_x emissions from gas turbines can be accomplished in either of two ways: (1) preventing NO formation by fuel pretreatment and/or by careful design and operation of the burner, and (2) removal of NO_x compounds after combustion from the exhaust gases. This paper deals with the first alternative because removal of NO_x compounds after their formation is likely to prove far more difficult and costly (see Ref. 7).

Nitric Oxide Formation Mechanisms

Two mechanisms are known to contribute to the formation of nitric oxide in combustion systems. The most important mechanism for gas turbines and other systems which burn relatively clean fuels is referred to as the thermal or hot air mechanism. In this mechanism, nitrogen and oxygen from the atmosphere react in the hot combustion zone to form nitric oxide. The second mechanism is important when relatively dirty fuels such as coal and residual fuel oil are burned. Most dirty fuels contain small but significant quantities of organic nitrogen compounds. Because nitrogen-carbon and nitrogen-hydrogen bond energies are so much lower than that for molecular nitrogen, much of the fuel nitrogen becomes oxidized during combustion. Experimental studies (Ref. 8) of the formation of nitric oxide from fuel nitrogen indicate that the formation rates are very rapid, occurring on a time scale comparable to that of the hydrocarbon combustion reactions. This mechanism is strictly fuel dependent and proceeds at lower temperatures than needed for the thermal mechanism.

Fuel nitrogen should not be a problem in systems using gasified fuels. During gasification of dirty fuels, some fuel nitrogen would carry over into the raw fuel gas as combustible nitrogen compounds (primarily ammonia, with smaller concentrations of hydrogen cyanide, pyridine, pyridine bases, and acidic nitrogenous compounds). If retained in the fuel gas, these compounds could result in excessive emissions of nitrogen oxides. Fortunately, considerable literature on the removal of these nitrogen compounds from gaseous streams is available (Ref. 6, for example). Before the advent of synthetic ammonia processes, by-product ammonia from gasification and carbonization processes constituted the most important source of fixed nitrogen. Practically all processes in commercial use for removal of ammonia are based on washing the gas stream either with water or a strong acid. Successful attempts (see Ref. 5) have been made to develop processes for the simultaneous removal of hydrogen sulfide and ammonia, recovering both compounds in the form of ammonium sulfate and elemental sulfur. Most other nitrogen compounds would be eliminated in the normal course of removing ammonia from the gas stream.

The chemical kinetics of NO formation via the thermal mechanism are fairly well understood (Refs. 8 and 9). Three variables of primary importance in NO production are local temperature, residence time, and chemical species concentration. Unfortunately, it is extremely difficult to relate these primary variables to the geometry and operating characteristics of practical gas turbine combustors due to limitations in analytical combustor modeling techniques. Previous investigations of NO formation kinetics (Refs. 10 and 11) have identified several significant simplifying assumptions which appear to apply to gas turbine burners. The most important of these are the following: (a) the NO formation rate is very slow relative to the hydrocarbon combustion reaction rates; and (b) within the uncertainty of known rate constants and present combustor models, it appears that the hydrocarbon chemistry can be decoupled from the kinetics of NO formation, i.e., the concentrations of all species except nitrogen compounds can be assumed to be in thermodynamic equilibrium at the local temperature and fuel/air ratio.

Under these conditions, the elementary reactions of importance in NO formation are:



Reactions (1) and (2) are the principal reactions, with (1) being the rate controlling reaction. Reaction (3) is of minor importance in fuel-rich mixtures.

A simplified kinetic model based on the above reactions was programmed for solution on a digital computer and combined with a program which calculates equilibrium thermodynamic properties and species concentrations. This model can be applied to a steady flow process where the temperature-time-composition histories of the fluid elements in the flow are known.

Before presenting NO emission estimates for gas turbine burners, it is instructive to consider idealized fluid elements in the flow as combustion products of uniform temperature, pressure, and composition (with the exception of nitrogen compounds) and to investigate the increase in NO concentration with time for conditions which are considered to be typical of gas turbine burners. Typical computer results are presented in Figs. 3 and 4. Figure 3 depicts NO concentration vs time estimates for a number of different types of fuels, including a range of low-Btu fuels, all supplied at room temperature. Figure 4 depicts similar results for a single low-Btu fuel supplied at a range of temperatures. The flame temperatures denoted in these figures represent the local temperature in the primary combustion zone of a gas turbine burner and should not be confused with the turbine inlet temperature which would be much lower. The strong dependence of NO formation on temperature and fuel heating value is evident from these figures.

Nitric Oxide Emissions from Gas Turbine Burners

The local temperature, residence time, and species concentrations which govern NO production are controlled by engine operating conditions, the combustor internal flow field, fuel nozzle characteristics, and the air addition schedule to the burner can. Lack of an adequate analytical description of the combustor flow field and the fuel/air mixing characteristics has prevented accurate estimation of the temperature-time-concentration history which is essential for reliable estimation of NO formation. At the present time, several engineering and research establishments, including several groups within United Aircraft Corporation, are attempting to develop comprehensive gas turbine combustor models. The results of this modeling work have been very encouraging and are leading to a better understanding of NO emissions.

A relatively simple three-zone burner model developed by the Combustion Group at Pratt & Whitney Aircraft (Ref. 11) was modified to permit consideration of low-Btu fuel combustion. Results of preliminary NO calculations using this model are presented in Fig. 5. The predicted NO concentrations in the burner exhaust are plotted against the maximum combustion or flame temperature in the primary zone. These calculations were based on a typical burner air and fuel flow distribution for a representative industrial gas turbine. The specific NO emission predictions for CH₄ and JP-5 shown by the individual points in Fig. 5 agree reasonably well with measured data. For low-Btu fuels with combustion temperatures in the 3600 to 4200 F range NO emissions below 10 ppm, and perhaps approaching 1 ppm, appear to be feasible.

The NO emission estimates presented in Fig. 5, although preliminary, are very encouraging and suggest that the use of low-Btu fuels would provide a very effective method of NO control for gas turbines. Furthermore, it seems evident that gas turbines using low-Btu fuels could be fired to high turbine inlet temperature and still emit significantly less NO than low-temperature gas turbines using high-Btu fuels. It should also be noted that these estimates have not taken into account additional NO control techniques such as steam or water injection and off-stoichiometric combustion. Utilization of these techniques, together with low-Btu fuels, might permit even further reduction of NO emissions.

ECONOMICS OF FUTURE POWER GENERATION

Historically, the electric utility industry successfully reduced the cost of generating power by utilizing the latest available technology and taking advantage of economics associated with large-scale generation facilities. This era of decreasing costs of electricity has ended, and we are now on the threshold of a new era with rising costs. This unfortunate situation is a direct result of rapidly rising construction and fuel costs, combined with public demands for effective control of atmospheric and thermal water pollution. Rising costs plague all methods of power generation, both fossil and nuclear. At the present time, nuclear stations are more economical than fossil stations in many parts of the country. But this situation may change as advanced COGAS power stations, incorporating high-temperature gas turbines with fuel gasification and desulfurization systems, become a commercial reality.

The busbar cost of power is the annual owning and operating expense divided by the annual kwhr generated. The annual owning costs include the capital charges due to depreciation, interest, taxes, and insurance; and the operating costs include maintenance, supplies, and fuel. The estimated capital costs for integrated COGAS/oil gasification power stations are summarized in Table II for three levels of gas turbine technology. All costs are presented in terms of estimated mid-1970's dollar value. The total installed capital costs range from \$211/kw to \$303/kw, depending on technology.

Annual owning and operating cost estimates are also summarized in Table II. Maintenance costs for the fuel processing system are based upon guidelines applicable to the chemical process industry, and corresponding costs for the power equipment are based on actual experience and projections. Fuel costs are taken to be 53.4¢/10⁶ Btu for high-sulfur oil in the Northeast. The resulting busbar power cost estimates range from 11.1 to 15.5 mills/kwhr depending on technology.

The power cost estimates presented in Table II are high by today's standards, but cost estimates for alternative methods of power generation with corresponding pollution control measures could be as high or higher, as depicted in Fig. 6. The 1975 EPA and 1973 Connecticut standards could be met by using low-sulfur oil or by adding stack gas cleanup, but doing so would increase the cost of generating power by 15 to 25% relative to a conventional steam station burning high-sulfur (2.6%S) oil. The use of gasified oil in steam or COGAS systems using present-day technology would satisfy the most stringent emission regulations in large cities, but doing so would increase the cost of generating electricity by 30 to 40% (relative to stations burning high-sulfur oil). As technology advances to permit higher turbine inlet temperatures and less costly gasifiers, COGAS systems will be capable of producing lower-cost clean power than alternative fossil steam systems. Furthermore, it appears that COGAS stations based on future gas turbine technology could also compete with future nuclear power generation, despite the relatively high cost of fossil fuels.

CONCLUSION

Advanced COGAS electric power stations consisting of gas and steam turbines integrated with residual fuel oil gasification systems should offer a viable alternative for future base-load generation applications. These stations could improve the environment by essentially eliminating the air and thermal water pollution problems caused by the generation of base-load power, and do so at competitive costs.

Although there are no basic technological problems which have to be solved before COGAS power stations could be built using present-day technology, advanced design and development programs should be energetically pursued to secure the benefits in performance and economy obtainable by advanced technology. Gas turbine technology is expected to increase during future years until turbine inlet temperatures in excess of 3000 F are achieved. COGAS stations designed with these advanced gas turbines, improved heat recovery steam cycles, and improved gasification systems would be very attractive. The eventual use of gasified coal in COGAS stations would further improve the economic potential of these stations.

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TABLE I
SELECTED CHARACTERISTICS OF INTEGRATED
COGAS/OIL GASIFICATION POWER STATIONS

	Level of Technology		
	Early 1970s	Mid 1970s	Early 1980s
<u>Fuel Processing System</u>			
Number of Gasifiers	2	2	2
Residual Fuel Oil Flow, lb/hr	93,600	118,000	144,000
Clean Fuel Gas Output, lb/hr	620,000	781,000	954,000
Clean Fuel Gas Temperature, F	95	520	550
Fuel Process Hot Gas Efficiency, %	70	74	76
<u>Gas Turbines</u>			
Number of Gas Turbines	4	2	2
Nominal Output per Gas Turbine, Mw	23	66	94
Compressor Pressure Ratio	13	16	20
Turbine Inlet Temperature, F	1800	2200	2600
Gas Turbine Thermal Efficiency, % (HHV)	30	32	37
<u>Waste Heat Recovery Steam System</u>			
Number of Steam Turbine Generators	1	1	1
Gross Steam System Output, Mw	80	110	136
Throttle Steam Temperature, F	700	870	980
Throttle Steam Pressure, psia	865	1250	1500
Net Steam System Efficiency, %	27	29	30
<u>Integrated Station</u>			
Net Station Output, Mw	159	228	309
Net Station Efficiency, % (HHV oil)	32	36	40
Sulfur Oxide Emissions, lb SO ₂ /10 ⁶ Btu	0.1-0.2	0.1-0.2	0.1-0.2
Nitrogen Oxide Emissions, lb NO ₂ /10 ⁶ Btu	0.004-0.1	0.01-0.1	0.01-0.2
Heat Rejection, Btu/kwhr	4500	3700	3100

TABLE II
COST SUMMARY FOR INTEGRATED COGAS/OIL GASIFICATION POWER STATIONS

Based on Estimated Mid-1970s Dollar Value

	Level of Technology		
	Early 1970s	Mid 1970s	Early 1980s
<u>Capital Costs, 10⁶\$</u>			
Fuel Processing System (96% S removal)	14.6	15.9	16.8
Gas Turbines	8.4	9.5	12.0
Steam System	14.5	18.2	22.1
Miscellaneous Equipment	7.5	9.0	9.9
Interest During Construction (7%/yr)	<u>3.1</u>	<u>3.7</u>	<u>4.3</u>
Total Capital Cost, 10 ⁶ \$	48.1	56.3	65.1
Specific Cost, \$/kw	303	247	211
<u>Owning and Operating Costs, mills/kwhr</u>			
Capital Charges (17%/yr and 70% load factor)	8.5	7.0	5.9
Maintenance, Labor and Supplies			
Fuel Processing System	0.3	0.2	0.2
Gas Turbines	0.8	0.3	0.3
Steam System	0.2	0.2	0.2
Residual Fuel Oil (53.4 \$/10 ⁶ Btu)	<u>5.7</u>	<u>5.0</u>	<u>4.2</u>
Busbar Power Cost, mills/kwhr	15.5	12.7	11.1

FIG. 1. CONCEPTUAL DESIGN OF 100-MW CLASS BASE-LOAD GAS TURBINE

EARLY-1980S TECHNOLOGY

TURBINE INLET GAS TEMPERATURE 2600 F

COMPRESSOR PRESSURE RATIO 20:1

AIRFLOW 300 LB/SEC

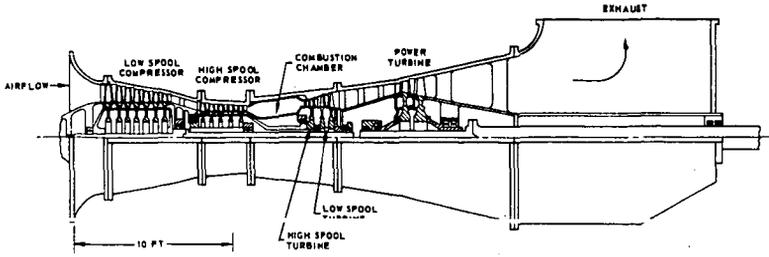


FIG. 2. SCHEMATIC DIAGRAM OF INTEGRATED COGAS/OIL GASIFICATION POWER STATION

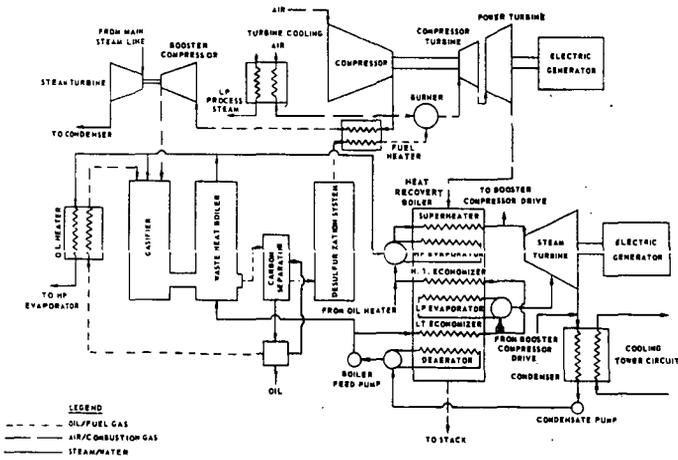


FIG. 3. NITRIC OXIDE FORMATION BY VARIOUS FUELS

PREVAPORIZED, PREMIXED, HYDROCARBON - AIR EQUILIBRIUM
 EQUIVALENCE RATIO = 1.0 AIR TEMPERATURE = 1235 R (775 F)
 PRESSURE = 14 ATM FUEL TEMPERATURE = 540 R (80 F)

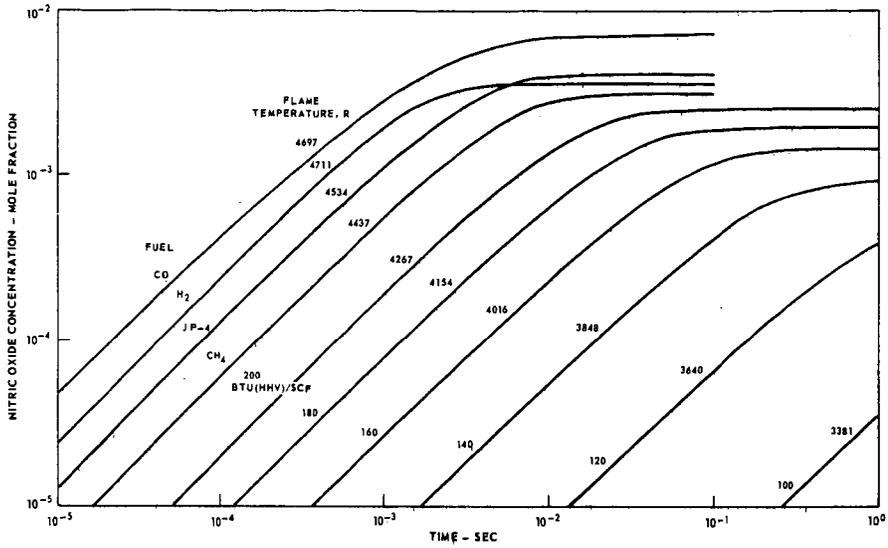


FIG. 4. EFFECT OF GASIFIED FUEL TEMPERATURE ON NITRIC OXIDE FORMATION

PREMIXED, HYDROCARBON - AIR EQUILIBRIUM
 EQUIVALENCE RATIO = 1.0 AIR TEMPERATURE = 1235 R (775 F)
 PRESSURE = 14 ATM

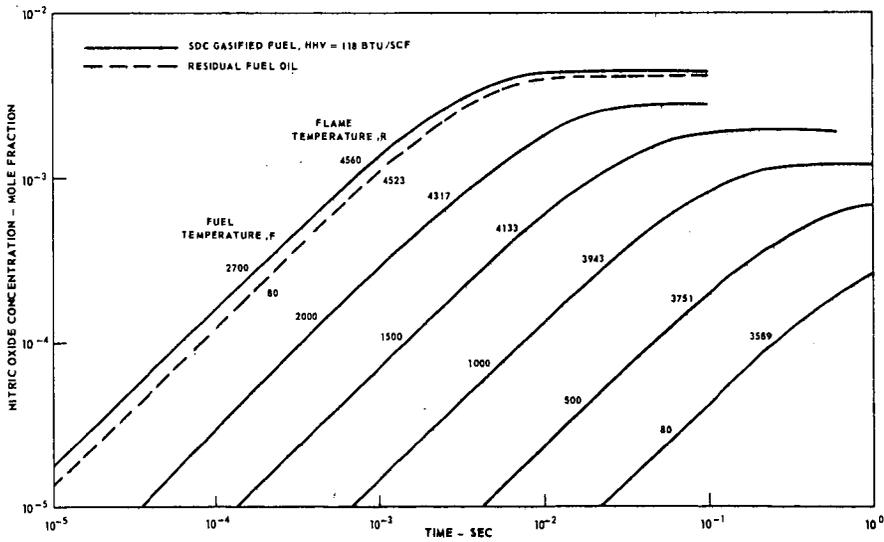


FIG. 5. NITRIC OXIDE FORMATION IN GAS TURBINE BURNER
 BASED ON PSWA THREE-ZONE BURNER MODEL

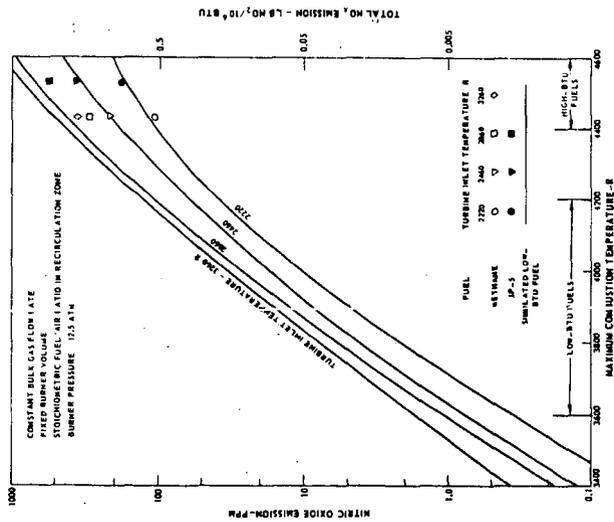


FIG. 6. IMPACT OF SULFUR POLLUTION CONTROL ON POWER COST

