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Evaluation of Technology Modifications Required to Apply Clean Coal Technologies in Russian Utilities

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EXECUTIVE SUMMARY

The operating conditions, technology development, thermal power station (TPS) equipment, and operating and maintenance methods in Russia are very much the same as in the USA. The technical knowledge and knowhow required for designing, building, and operating an ecologically clean coal fueled TPS has been acquired at great expense over a long period of time. In many cases, the associated material and intellectual "expenditures" by Russia should be added to those expenditures in other countries. Therefore, it would be practical to use, on a mutually beneficial basis, the advanced environmental protection and energy technologies which have already been proven elsewhere, such as in the U.S.A.

Although coal is not as predominant a power industry fuel in Russia as it is the U.S.A., it plays and will continue to play in the future an important role in supplying Russian TPSs. To be competitive with natural gas, coal must be efficiently produced, transported, and fired at TPSs within permissible environmental limits.

The cheap open-cut (strip-mined) coals are located mostly in the Southern part of Central and Eastern Siberia. These regions have a high potential for further economical development. The TPSs located and constructed there largely fire local coals. The Kuznetsk bituminous and Kansk-Achinsk (K-A) brown coals are railway transported to TPSs which are thousands of km away from the coal production areas. An actual problem is processing these coals (especially high-moisture K-A coals) to reduce transportation costs.

Russia is very interested in the technologies developed in the U.S.A. under the Clean Coal Technology Demonstration Program (CCTP), other programs that improve existing and newly installed TPS equipment, and naturally, new advanced energy technologies that can find application at Russian TPSs.

In reconstruction and life extension of existing Russian TPSs the following technologies, particularly those developed under the CCTP, can be applied:

- primary (technological) NO_x reduction methods;
- selective non-catalytic reduction (SNCR) of NO_x;
- simplified wet/dry de-SO_x systems.

Russia has developed it's own version of these technologies and has already implemented them at TPSs. Accordingly, in transferring U.S.A. technologies it will be necessary to consider the competition of domestic developers and manufacturers. It may be reasonable to combine the efforts and findings of the U.S.A. and Russia, and share in supplying the equipment required to implement the technologies in question.

Implementing a comprehensive, low-cost emission reduction technology at a Russian TPS would be of interest. For example, an installation using low-NO_x burners, reburning using coal dust as a reducing agent, and non-catalytic de-NO_x sorbent injection to reduce SO_2 could serve as a prototype for wide commercial implementation.

The power units (boilers) at Russian TPSs are designed for firing with both coal (fuel oil) and natural gas. Under such conditions, NO_x emissions can be reduced by gas reburning. If coal or fuel oil is used for a short period of time (e.g., emergency fuel or in the coldest winter time), a simple dry de-SO_x system using Na-containing sorbents can be used to reduce NO_x emissions.

For cleaning flue gases of SO_2, various technologies, such as, sorbent injection into the hot duct, humidifying of gases enriched with sorbents in gas ducts, or injection of sorbent slurry into gas ducts, (Bechtel, LIMB-Coolside, E-SO_x, LIDS, LIFAC etc.) can find application in Russia.

Demonstration in Russia of wet/dry fluidized-bed DeSO_x technology and combined de-SO_x-de-NO_x-ash removal systems based on SNRB technology is desirable. Both developments are also of interest to American companies.

The results of Russian developments of the AFBC boiler are less than those in the USA, and much less than the U.S.A. development of CCPs using PFBC and IGCC.

Participation of U.S.A. companies in the development, construction and operation of plants using the above technologies, and transfer of the U.S.A. experience to Russia is desirable.

CFB technology, including operation with high-ash coals, has been mastered in various countries on a large number of boilers. Of particular note, is the completed Nucla TPS project under the DOE CCTP.

Many existing Russian TPSs have old boilers with an input of 400-420 t/h of coal and corresponding lower output which should be considered for replacement with CFB combustion technology developed in the U.S.A. by F-W, ABB-CE, Pyropower, and B&W.

An important feature of these TPSs is the close location of the equipment that allows no space for installing gas cleaning systems. New CFB boilers can be adapted to the available space occupied by existing boilers of the same or lower output. Predesign (preliminary design) work done in Russia showed the B&W technology, which requires no large external cyclones, enables the installation of CFB boilers in the existing buildings. At old TPSs difficulties may arise with the arrangement of ash collectors, such as, a high efficiency ESP.

Participation of U.S.A. companies will be required in designing the CFB boilers. Manufacture of such boilers can be arranged at Russian Works. Licensing of some components for which the U.S.A. know-how is available, or direct purchase of such components (distribution screens, instrumentation and control systems, etc.) from U.S.A. manufacturers may be needed

A question remains concerning the use in Russia of combustors designed for the DOE CCTP. According to the predesign, TRW combustors can be technically applied on Kuzn coal-fired 300-MW units, however, this application needs more information and operating experience in demo plants.

The application of CFB boilers or precombustors does not reduce the specific cost or heat consumption at a TPS. The considerable improvement to the performance will be possible by the introduction of a CCP using PFBC or integrated coal gasification.

A CCP using PFBC, like the Tidd TPS or larger, can be reasonably used in Russia to retrofit/repower an existing TPS. The small size of PFBC boiler and GT can easily be installed in the available boiler space. The steam turbine and electrical equipment can be changed a bit to increase efficiency and improve automation.

Practically all of the equipment for the first generation of PFBC plants, including the GT with an inlet temperature of about 850°C, could be manufactured in Russia. U.S.A. engineering is necessary to design the entire plant and such equipment as furnaces (supercharged boilers), associated control systems, coal feeding, the fly ash removal before the gas turbine, HP gas/air duct with valves, etc.

Predesign work has been performed in Russia for 25-30, 80 and 270-MW CCP using a PCFB boiler design. One such project is under way as part of the CCTP (Project 7-14). It is reasonable to think of collaboration with the U.S.A. companies to develop these technical ideas.

IGCC plants are most complex. In this field, the U.S.A. companies have the most experience and know-how. Also, the U.S.A. has produced the largest number of high-temperature GTs required for competitively efficient IGCC plants. It is desirable to construct in due time an IGCC plant in Russia that uses American experience and equipment. The ultimate choice of a technology, partners, and terms of a cooperative agreement needs special study. It should take into account the latest available results from the DOE CCTP.

IGCC plants will probably be employed at new TPSs of relatively high capacity. In-depth consideration of such TPS projects will be possible after the operability and performance of such plants is demonstrated in the U.S.A. or other countries. The conditions for the construction and successful mastering of similar domestic technologies are unrealistic in the present-day situation in Russia.

In view of the above, start-up of the first Russian IGCC plant in 10 years would be a good result. Of course, it does not mean that work under this project should be postponed. On the contrary, work should be started now, and it would be preferred to conduct projects in co-operation with foreign partners.

By participating in such projects, U.S.A. companies with their rich experience and advanced developments could become leaders, although there is little promise of a quick return on investment. It would be of advantage to organize the work dealing with these projects now, without hurry and large expenditures, with provision for speeding up after changes in the economical situation in Russia.

Russia possesses up-to-date machines and qualified specialists to produce efficient equipment for the power industry. The power industry equipment market is not mature due to the long-term existence of the monopoly of manufacturers. In recent years, the market has narrowed. At the same time, the production capabilities of manufacturers are more than enough to satisfy all possible demands. Now, Russian power equipment manufacturers have been certified by international organizations in many fields of their activity, and manufacturers cooperate with foreign partners and supply equipment aboard. With this in mind, co-operation is reasonable when the U.S.A. clean coal technologies are being transferred to Russia. Engineering by U.S.A. companies is required to design and construct dedicated equipment and systems. Equipment can be manufactured by Russian producers. The U.S.A. companies could supply some components and materials, e.g., special valves, catalysts, atomizers, I&C equipment, etc. Of course the profit of the U.S.A. companies will not be as large as in the case of turnkey supply of complete systems. However, such cooperation is reasonable considering the competition of Russian and Western European companies.

In some cases, the use of ideas and developments of the Russian enterprises and specialists could improve the parameters and make some technologies more attractive for U.S.A. companies in domestic and foreign (not just Russian) marketing activitities. It may be reasonable for example, to demonstrate in Russia some technologies that are new to the U.S.A., as was done with EPA in demonstrating gas reburning at the Ladyzhinskaya TPS 300-MW unit.

Application of the U.S.A. clean coal technologies in Russia will raise the efficiency of Russian coal fired TPSs, reduce the environmental impact, and facilitate creation of a market for the know-how and equipment of U.S.A. companies. It will also ensure mutually beneficial cooperation of U.S.A. and Russian enterprises.

When transferring the technologies, it is desirable that the American side would make available:

- development of key technical solutions;
- consulting and technical supervision in designing the equipment and its installation at a TPS;
- the supply of individual types of equipment, the manufacture of which is impossible or unreasonable by Russian manufacturers;
- technical supervision and management in construction, erection, adjustment and testing.

The Russian side could:

- prepare the input data for design; including siting, selection of coal and mode of operation;
- design the equipment to be manufactured in Russia and its layout at the TPS;
- conduct research to validate the design in view of the peculiarities of the fuel selected and technical selections made;

- manufacture and supply equipment;
- construct and erect;
- adjust, test, and operate.

To realize each specific project it is reasonable to form a consortium of the U.S.A. and Russian enterprises including developers of the technologies and design organizations.

In the transfer of technologies the human relations, exchange of information, education and training of specialists are extremely important. Russian specialists have adequate technical knowledge and good experience. However, they are not familiar with the judicial/ legal aspects of business, and with planning and management problems.

To familiarize Russian specialists with the U.S.A. clean coal technologies it would be desirable to prepare and conduct, in Russia, a conference to present major projects or a group of projects, and, perhaps, include an exhibition of the American companies achievements.

In the field of energy generation and environmental protection many European and transnational companies have been working in Russia. Some of them have already set up joint ventures or concluded agreements with Russian producers and consumers of power industry and pollution control equipment.

Due to this fact, potential competition of Russian and European companies shall be considered in forwarding the U.S.A. technologies to the Russian market.

For the terms of application of Clean Coal Technologies at Russian TPSs see also conclusion of this study.

1. OVERVIEW OF RUSSIAN POWER INDUSTRY

1.1. General

Russia possesses rich fuel and energy resources, however the remoteness of resources from consumers present certain problems. Thermal power stations (TPS) in Russia employ modern steam-turbine unit and operate efficiently. Construction and operation of such power stations will continue in future. Among the urgent problems are life extension and further upgrading of steam-turbine power stations, and development of combined cycle (CC) plant, the latter using first gas, and then coal [1].

The industrial and municipal electricity demands (growth) in Russia are largely met by construction of TPS. In the near future, the greater portion of electricity will be produced from natural gas and coal, mostly from natural gas.

Russian power generation is characterized by the following data (bracketed are 1990 figures when electricity generation was at the maximum level) [2].

	1994	(1990)
TPS Installed capacity, GW	210	(213.3)
Electric generation, $\times 10^9$ kWh/y	876.6	(1082.2)

Power reserve in 1994 was 15 percent on the average. Nevertheless, some regions remained energy-deficient.

Per capita electricity production was 6,190 kWh/y.

The installed capacity breakdown with reference to types of power plant, are (see also Figure 1):

	GW	%
Total	210	100
Fossil-fueled,	145.6	69.3
including		
Condensing plants,	65.6	31.2
Cogeneration plants	80.0	38.1
Nuclear power plants (NPP)	21.2	10.1
Hydro-power plants	43.2	20.6
Other	0.04	-

The following thermal efficiency data are calculated using the low heating value (LHV) of fuels; in all cases, volumes in "m^3" are for standard conditions (if not indicated otherwise); masses (weight) are in metric t; pressure and pressure drops are in Pa, kPa, bar and MPa

Fossil-fueled plant generated 602.8×10^9 kWh (68.8 percent); NPP generated 97.8×10^9 kWh (11.2 percent); and hydro-power plant generated 175.3×10^9 kWh (20.0 percent). The cogeneration plant also supplied 613.2×10^6 Gcal (713.2×10^9 kWh) of heat. Specific fuel consumption for TPS was 310.3 g/kWh with 39.64 percent average efficiency (taking account of combined heat and power generation).

For electric and heat generation 383.2×10^6 t of standard fuel (tfe) was consumed. Considering a LHV of 29.3 MJ/kg (7,000 kcal/kg) this includes the following fuel mix (see also Figure 2):

Name	10^6 tfe	%
Natural gas	244.5	63.8
Coal	98.5	25.7
Fuel oil	40.2	10.5
Total	383.2	100.0

The export of electrical energy in 1994 amounted to 21.94×10^9 kWh, which includes 1.41×10^9 to the Ukraine, 4.96×10^9 to Belorussia, 0.35×10^9 to the Caucasian republics,

7.05×10^9 to Kazakhstan, and 8.17×10^9 to Finland and other foreign countries.

The technical level of the electric power industry, and TPS in particular, is sufficiently high to provide an adequate basis for solving future technological and economical problems [3].

The electric power industry is highly centralized with over 90 percent of the generation supplied to the power grid system transmission lines at 330, 500, 750 and 1150 kV.

The length of the transmission lines of all voltages classes is about 700,000 km, and the length of lines above 110 kV is 42,800 km.

The generating capability is based on condensing TPS that employ 200-, 300-, 500-, and 800-MW unit, and cogeneration plant with 50-80, 100-, 180-, and 250-MW turbines. Unit larger than 250-300 MW are designed at supercritical (24 MPa) steam pressure. In general, 85 percent of the electricity is generated at TPS using high-pressure steam (13 MPa).

Russia is located in latitudes with severe climate. Of great importance is the heating of residential, industrial, and public premises. The required heat loads and the heat and steam requirement of industrial enterprises are traditionally supplied from centralized large boiler houses and cogeneration plant. The total capacity of such plant is about 80 GW, or more then half the capacity of all TPSs. More than 80 percent of the heat supplied to consumers comes from steam extracted from steam turbines at power stations. Considering the fact that over 60 percent of the electricity in these TPS is generated in the combined mode (it is about 34 percent of the total fossil-fuel TPS generation) with an average efficiency of 46.5 percent, and a specific fuel consumption of 265 g/kWh.

Specific fuel consumption (b_e) in the cogeneration mode is generally derived from the following expression:

$$b_{e\cdot} = (Q_f - Q_h)/(N_e\ K)$$

Here, Q_f is fuel heat, Q_h is part of fuel consumed to produce heat, N_e is electrical output, K is coefficient matching unit of measurement. The equivalent efficiency = $123/b_e$.

The structure of fuel balances in various regions differ greatly. The larger portion of electricity in Western Siberia, the Urals, and the European part of the country is generated using natural gas. In Central and East Siberia the resources are hydro and coal, and in the

North-West and the Far East, they are nuclear power and coal, respectively. The consumption of coal was 133.4×10^6 t with average heating value of 16.5 MJ/kg and an ash content of 27.9 percent.

Below, are some data on coal fired condensing power unit (Figure 3):

Unit capacity, MW	800	500	300	200	150
Number of unit	2	7	27	36	17
Average load, MW	—	400	220	150	110
Efficiency, %:					
best TPS	—	36.9	36.3	35.9	35.0
worst TPS	33.2	36.2	30.1	30.4	34.0
Share of coal in the fuel consumed, %	97.0	97.7	77.5	70.0	70.5

Coal is also fired at many cogeneration plant. It share is in these cases is 20-50 percent. At numerous condensing and cogeneration plant coal is used as seasonal fuel.

The following condensing and big cogeneration units have been constructed and operated in Russia:

Unit capacity, MW	150-160	180-220	250-300	500	800
Number of units	37	89	110	7	14
including coal designed unit	27	47	31	7	5

Power units up to 200 MW and equipment for cogeneration plant using 640-670 t/h boilers are designed at subcritical parameters. Condensing units at 200-215-MW and unified cogeneration units of 180 MW are designed at 13 MPa, 540/540 °C. Cogeneration plant with smaller capacity boilers and turbines – mostly rated 60-80 and 110-115 MW – operate at 10-13 MPa, and 555 °C. Most cogeneration plant turbines extract steam for staged heating of hot water. The extraction steam pressure for that purpose ranges from 0.5-2.5 bar.

Condensing 300-, 500-, and 800-MW units and cogeneration units of 250 MW unified with 300-MW units are designed at supercritical steam parameters (24 MPa, 540/540 °C).

The total capacity of such units is about 45 GW. Their capacities and parameters are standardized. Supercritical power units with 1,000-2,650 t/h once-through boilers operate reliably and efficiently firing various fuels. The annual net efficiency of the best TPS firing gas and fuel oil is 39 percent, and in the case of coal 37 percent. The design of equipment is continuously upgraded. Four to five modifications of turbines and boilers for such units have been manufactured.

A 1,200-MW unit has been in successful operation for over 10 years with a single-shaft, 5-cylinder (stage), 3,000-rpm turbine employing welded LP rotors and a titanium last stage with 1,200-mm long bucket. This unit, firing mostly natural gas, has operated for some (many) years practically without unscheduled shutdowns at an efficiency of 39-39.5 percent and an availability factor of over 90 percent. Based on the experience with developing, constructing and operating this turbine, LMZ has designed and supplied several 1,000-MW single-shaft turbines for NPP.

For many years (up to 1992), the Russian TPS operated at heavy-duty conditions without sufficient power reserve and had rather high reliability and availability factors. Now, under a poor economical situation, substantial reserves appeared and the utilization coefficient dropped. Consequently, the duration of repair time increased and the relability of unit and TPS was somewhat reduced.

The Russian TPS have a typical low rate of equipment renewal [4]. Currently, life expiration of the equipment is 5-7 times ahead of the addition of new capacity. As of today, about 40 GW of TPS capacity has exceeded the design life. It is estimated that by the year 2000 this figure will increase to 90 GW. There are 20-30 unit of 150-160, 200 and 300 MW each that have operated approximately 200,000 hrs. Some individual 150-MW unit had been in operation over 270,000 hrs. New 800- and 1,200-MW unit have operated less than 100,000 hrs.

Many steam turbines and boilers at cogeneration plant have operated even longer than condensing unit.

Naturally, in many cases the TPS life can be extended.

Based on comprehensive research of the metal in power equipment that has seen extensive service, generalization of statistics, and durability predictions using fracture mechanics techniques, it has been established that the normal safe operation time of KhTZ 300-MW steam turbines is 170,000 hrs, and that of the LMZ steam turbines is 220,000 hrs. This is the so-called "fleet" life relating to the entire fleet of equipment.

The scope of work for inspection, repair, and replacement of key power unit component between the design life of 100,000 hrs and the fleet life does not change significantly from that required for the first 100,000 hrs.

After expiration of the fleet life one can forecast (with reference to 300-MW unit) the following scope of work to extend it's life:

- replace 50 percent of the stop and control valves on KhTZ turbines, and 10 percent on LMZ turbines;

- replace 25 percent of the rotors on KhTZ and 8 percent on LMZ turbines;

- repair of 25 percent of the rotors on KhTZ and 10 percent on LMZ turbines;

- repair of 30 percent of KhTZ and LMZ turbine cylinder casings by grinding to remove surface cracks and/or repairing deeper cracks by metal-locking or similar techniques;

- replace about half of the live steam and hot reheat pipes (or rehabilitate by heat treatment);

- replace 30 percent of boiler heating surfaces.

Accomplishing the above scopes of replacement and repair followed by careful periodic inspections can increase the equipment life 50,000 hrs beyond the fleet life. Further operation will demand replacement and repair of a large number of component and more rigid in-service inspections of the metal. In this situation, complete replacement of the turbine unit seems reasonable.

However, it should be considered that many existing TPS constructed 30-40 years ago have obsolete equipment which does not meet the modern requirement for efficiency and environmental impact. Continuation of their operation becomes unreasonable. Frequently, it is very difficult technically, or rather costly, to repower such TPS to improve the performance.

A more attractive way is replacement using new technologies. The adequate economical substantiation of constructing efficient TPS with advanced equipment is next to impossible in Russia now.

1.2. TPS Environmental Impact

TPS, especially coal fired, are large environmental polluters [5].

The sanitary standards currently existing in Russia for regulating the maximum permissible concentrations (MPC) near ground-level of the major pollutant [6] are given below.

Pollutant	MPC mg/m^3	
	maximum	daily average
Fly ash	0.30	0.10
Same, for K-A coals	0.05	0.02
SO_2	0.50	0.05
NO_x	0.60	0.06
NO_2	0.085	0.04
CO	5.0	3.0
Benz(a)pyrene	—	1×10^{-6}

For new TPS, the MPC of the ground-level contaminant have long been met in the U.S.S.R. by emission scattering through tall stacks.

Now, the State Standard has been prepared oriented to today's level of power engineering and gas cleaning equipment (up to 2001) and more stringent requirement after 2001. The norms of the Standard are given in Tables 1, 2, and 3 [7].

The strong position of local authorities and the public often force lower emissions than those specified in the Standards. Sometimes it is justified, i.e., in regions with high background industrial or transport emissions. Sometimes, implementing environment protection measures demands unjustifiable expenditures from the ecological and economical point of view.

The data on actual emissions of Russian thermal power stations in 1994 are given below.

Pollutant	Emissions, 10^6 t
SO_2	2,110
NO_x	1,210
Fly ash	1,500
Total	4,820

Coal TPS are responsible for the major part of the emissions listed above.

Specific emissions, g/kWh are strongly different for different coals.

Pollutant	Coal grade			
	Kuzn	K-A	Donetk AC	Ekib
Fly ash, slag	82.0	29.0	103.0	250.0-420.0
SO_2	3.5	2.6	21.6	9.1 -11.5
NO_x	3.7	1.5	2.8	3.4 - 3.6

Some years ago, a considerable reduction of the TPS environmental impact was felt at the state level. The development of new environmentally friendly energy technologies, conventional boilers with lower or minimum emissions, and gas cleaning equipment and systems have been under way. They were carried out in accordance with the "Ecologically Clean Power Generation" State program, including the "Ecologically Clean Coal Power Stations" section. Much of the work was being done by manufacturers of equipment and energy enterprises at their own initiative. Though at present, the rate of environmental protection work in power engineering is reduced due to the economical difficulties in this country, the development are still under way and many of them have already gained positive result.

2. ELECTRIC POWER EQUIPMENT OF RUSSIA

2.1. General

The electric power manufacturing industry of the former U.S.S.R. produced all kinds of equipment required for electric power stations: steam boilers, steam and hydro-power turbines, associated electric generators, transformers, auxiliary mechanical and electrical equipment, component and materials [1]. Brief characteristics of the thermal power station equipment used in Russia can be found in Section 1 of this report. The equipment in many respect meet the world's standards and ensures high reliability and economic efficiency. Some design data on large Russian TPSs, and a distribution of main equipment by manufacturer and rating can be found in Table 4.

The manufacture and operation of electric power equipment was based on domestic R&Ds, metal, electronics, chemicals, etc. TPSs were constructed by large specialized organizations having all the necessary equipment and facilities. At the same time, there was a certain lag of the Soviet, and later Russian, industry in the development and manufacture of GT, automatic control systems, and gas cleaning systems and equipment.

Given below are some data on Russian TPS equipment and manufacturers.

2.2. Steam Boilers and Associated Equipment

The major utility boiler manufacturers for large power unit are Taganrog Boiler Manufacturing Works (TKZ) and the Podol'sk Boiler Manufacturing Works (ZiO). The scope of their shipment for the Russian large power unit can be seen from Table 4. These two boiler works also produced many subcritical-pressure boilers with steam output up to 670 t/h. Such boilers are likewise manufactured at the Barnaul Boiler Works (BKZ). Utility boilers of smaller capacity and industrial boilers are produced at the Biysk (BIKZ) and Belgorod (BEZM) works.

The domestic works manufacture boilers of various steam output, designed at different steam parameters and adapted to fire different fuels. The boiler fleet was updated continuously due to the use of new fuels, the reduction of harmful emissions, and the export of boilers [8].

All new boilers have been designed with suspended gas-tight waterwalls. The boilers are supplied as large-size transportable assemblies to provide for high quality, rapid erection, and commissioning.

Liquid and gaseous fuel fired utility boilers are produced in the range of 160-3,950 t/h, 14-25 MPa, 560/560 °C and 545/545 °C [9,10].

Despite significant differences in capacity and steam parameters, the domestic fuel oil boilers have much in common. All of them have Π-shaped layouts and have prismatic furnaces with all-welded water walls. The boilers can operate under pressure, are equipped with a gas recirculation system, and regenerative air heaters.

The 3,950- (Figure 4) and 2,650-t/h boilers for 1,200- and 800-MW unit are suspended from the building structures, and the remaining boilers are suspended from their frame.

For gas/oil boilers with prismatic furnaces the opposed, multi-tier swirl burners are used: three-tier burners for 800- and 1,200-MW unit boilers; and two-tier for 300 MW and lower output unit boilers.

With close arrangement, only front burners are applied.

The Π-shaped, 320 t/h and larger boilers have a ledge at the back wall protecting the platens or the vertical bank of the convective superheater from direct furnace radiation.

Regenerative rotary heaters with rotor diameters from 5.4 m (429-, 320-, and 160-t/h boilers) to 14.5 m (2,650- and 3,950-t/h boilers) are used for air preheating. To protect the heater packing against corrosion, the air is preheated and ceramic packing is used in the cold layer.

Boilers for firing coals with significantly different physical-chemical properties and mineral matter behavior are manufactured in a greater number of layout and technical design [9,10].

The maximum capacity of domestic coal unit is 800 MW for which 2,650-t/h boilers had been specially designed to fire Berezovo brown coal (P-67, ZiO, Figure 5) and bituminous Kuznetsk and Donetk coals (TPP-804, TKZ). The P-57R, 1,650-t/h boiler was designed and manufactured by ZiO as 500-MW unit to fire high-ash Ekibastuz coal (Figure 6).

Brown coals, such as the strongly slagging Berezovo coal are fired in tangential furnaces. The square-section furnace used by ZiO in the P-67 boiler ensured low-temperature firing with a dry-bottom, good aerodynamics, and uniform heat flux distribution, thereby providing no-slagging operation. The tangential-fired furnaces allow for staged combustion in the plane of each burner tier where the coal-air mixture and secondary air are directed at a certain angle.

The bituminous coal fired TKZ and ZiO boilers for 800-MW and 500-MW are made with wall-mounted burners.

The solid fuel fired boilers of higher capacity are of the T-type layout.

These coal boilers are mostly of the dry-bottom design, with the exception of some 200- and 300-MW unit dedicated to fire anthracite culm and lean bituminous coals which are of the wet-bottom design. The new boiler project for these coals include both dry- and wet-bottom options.

The technical solutions laid down in the schemes and design of the component of coal boilers reflect the experience and traditions of manufacturers. So, for example, ZiO most widely applies steam-to-steam heat exchangers to control reheat temperature, whereas reheater interim stage bypassing is the practice of BKZ, and gas recirculation and water injection are used by TKZ.

Flat-flame burners are widely employed by TKZ (TPP-804 boiler for 800-MW unit, TPE-215 boiler for 200-MW unit and unified series of 400-500-t/h range boilers).

ZiO and BKZ boilers mostly use tube air heaters. Characteristics of some coal boilers are illustrated in Table 5. To decrease NO_x formation, low-NO_x burners of various designs are used. Two-stage combustion and reburning, flue gas recirculation, high concentrated coal dust supply, to mention but a few, are also applied.

Various methods and devices for cleaning the heating surfaces of slag and deposit are applied. Sliding pressure boiler operation has been mastered allowing for unit flexible operation and deep unloading in a "moderate" mode.

Both sub- and supercritical pressure boilers use low-alloyed perlitic steel (12X1MF) and high-alloyed Cr-Ni austenitic (12X18N12T) steel in addition to carbon steel. The ferrite family steels with high heat-resistance (up to 620 °C), among which the domestic example is EI-756, are also employed for some ZiO boilers, and also at foreign TPSs.

The specific metal weight vary widely for coal boilers for which moderate furnace heat release rates and water wall heat fluxes are typical.

The highest metal weight are for boilers designed for high-moisture brown coals. The metal weight for pressurized part of P-67, P-78 (1,650 t/h) and TPE-216 boilers are 3.02; 3.57 and 4.09 t/(t/h), and the total metal weights are 7.4; 8.48 and 10.0 t/(t/h); the latter boiler is suspended from it own frame.

The design gross efficiency of the currently manufactured domestic gas/oil boilers is 92.5-94.0 percent, and that of coal boilers, 90.5-92.5 percent. The actual efficiency in some cases turned out to be below the design value with the difference reaching 2 percent. The causes are increased fouling and slagging of heating surfaces, their inefficient cleaning, increased suction in the furnace and convective boiler part, increased stack gas temperature, and poorer fuel quality.

To evaluate new furnaces and firing technologies some pilot coal boilers were constructed in the 1980s.

In 1984, a 500-t/h, 14.0 MPa, 560 °C TPE-427 wet-bottom boiler was put into operation equipped with the TKTI vortex furnace to fire Kansk-Achinsk coals. The refractory, horizontal-lined furnace chamber with a diameter of 4.4 m and a width of 16 m was separated by two division walls into 3 compartment. The prismatic cooling chamber is 5.9 m deep. Six straight-flow burners are arranged over the front at an angle of 15 degrees to horizontal. The furnace volume heat release rate (0.203 MW/m^3) is considerably higher than at existing E-500 and P-67 boilers (refer to Table 5). The boiler fires Berezovo and Nazarovo field brown coals. Despite modernization of a number of component and the fuel preparation system, the boiler can only operate continuously at 60-65 percent of the nominal capacity due to superheater fouling.

The St. Petersburg Polytechnical Institute has developed low-temperature swirl combustion technology for crushed coal. The BKZ 420-t/h boiler has been redesigned to use this technology. The brown Irsha-Borodinsk coal in lumps of up to 25-mm size was used. To decrease the carbon loss, wear of water walls, and ensure design steam superheating some modernization was introduced into the boiler. As a result, the average load is 0.7-0.9 of the nominal value, carbon loss is 2 percent, furnace excess air is 1.37-1.41, and NO_x emissions - 470 mg/m^3.

Since the beginning of the 1980s, experiment have been undertaken to fire coal in different versions of fluidized-bed boilers.

These small boilers with low-temperature fluidized beds have been designed by BIKZ in cooperation with TKTI. In 1985, first 10- and then 16-t/h boilers were manufactured and reached nominal output. The carbon loss when firing Kuznetsk gas coal is 3-4 percent maximum.

Work on combined flame and bed combustion were conducted by VTI and VNIIAM. The dry bottom hopper was provided with a nozzle screen whereto the coal ranging from 2-25 mm in size was fed. The fine fraction was directed to be milled and was supplied to the furnace via the PC burners. VTI conducted the work and fired Kuznetsk and Ekibastuz coal in 210- and 160-t/h reconstructed BKZ boilers. Increased output and NO_x reduction were obtained but the work was not finished.

Positive result have been obtained by VNIIAM for flame-bed combustion of shales at the 75-t/h boiler of the "Akhtme" cogeneration plant. However, the attempt to transfer the technology to a 250-t/h boiler was confronted with certain difficulties.

The Irsha-Borodinsk brown coal fired in a 420-t/h bubbling fluidized-bed boiler (Figure 7) manufactured by BKZ in cooperation with TKTI and VTI. The furnace is of the four-section design arranged on two floors. Each section is provided with an air distributing grid which has the evaporative and superheating surfaces arranged in the bed of the granular material. The evaporative bank is located in the freeboard above the bed. Provision is also made for a separation space. The evaporative surfaces above the bed are studded to protect them against wear. The slag from the adjacent boilers is used as inert material.

According to predictions, NO_x emissions will be of the order of 350-400 mg/m^3, sulfur capture, up to 90 percent; and boiler path pressure drop, 20-29 kPa. The boiler test will start this year.

At the end of 1987, a program had been adopted in the U.S.S.R. to create CFB utility boilers, according to which BKZ in cooperation with TKTI and VTI had developed 500-t/h, 14-MPa, 565 °C, non-reheat CFB boilers. A boiler firing anthracite culm and using high-temperature cyclones [11] was designed for the Kurakhovskaya TPS, Ukraine (Figure 8).

A boiler for the Novomoskovsk TPS was designed to fire high-sulfur near-Moscow brown coal and employ cold cyclones. Similar boilers are being designed to fire Ekibastuz and Kuznetsk coals.

The anthracite culm-firing CFB boiler is made up of two furnace modules each of which has two cyclones and four ash heat exchangers. The furnace modules are combined by a single convective section. The furnace module dimensions in the upper and lower portions are 8.0 m long by 5.5 m wide and 7.4 m long by 2.5 m wide, respectively. The 1st and 2nd stages of the superheater, 1st and 2nd stages of the economizer and air heater are located in the convective path. The calculated NO_x and SO_x emissions are at 200 mg/m^3.

Much has been done in the U.S.S.R. to introduce higher supercritical steam parameters. In 1949, at the VTI Experimental cogeneration plant a pilot boiler was constructed, designed for 30 MPa, 600 °C (later 650 °C), which has been in successful operation since that time. At the Kashira TPS, the SKR-100 power unit was put into operation in 1966 employing a ZiO manufactured PK-37 boiler rated for 710 t/h, 31 MPa and 650 °C live steam, and 9.8 MPa, 565 °C reheat parameters. The steam was supplied to the high pressure steam turbine, and after being expanded there was directed to the existing K-60 turbines at 3 MPa, 400 °C. To manufacture boiler outlet component and steam pipes high-alloyed austenitic steels EP-184 and EP-17 were designed wherein the Ni content was increased to 17-18.5 percent.

The unit operated for 30,000.hrs at a boiler outlet temperature of 630-640 °C and a short-term live steam temperature rise of up to 650-655 °C. The residual life of the unit equipment is now about 100,000 hrs.

Along with traditional boilers, Russian manufacturers produce some special-purpose utility equipment. For example, the Russia's Taganrog boiler manufacturing Works (TKZ, Taganrog, Rostov district) has experience in designing and manufacturing the supercharged steam generators (SSG) for combined cycle plant. Such steam generators are located between the compressor and turbine of the GT unit. They all use compressed air and fuel to be fired at excess air rates close to that used in the conventional boilers. The released heat is utilized to generate and superheat the steam fed to the steam turbine. The combustion product are cooled down to the acceptable temperature in a heat exchanger and are expanded in a gas turbine to a pressure close to atmospheric.

A 200-MW natural gas CCP (30-MW GT, 150-MW steam turbine) with a 450-t/h supercharged steam generator (14 MPa, 545/545 °C) was constructed in Russia, and since 1973 has been in operation at the Nevinnomyssk TPS. The gas pressure in the supercharged steam generator is about 6.5 bar, and the turbine operates with inlet gas temperatures up to 770 °C. This CCP has been in operation for more than 130,000 hrs.

Later, supercharged steam generators of 600 and 655-t/h steam capacity were designed and prepared for manufacture for a 250-MW CCP (50-MW GT, 200-MW steam turbine) that would use natural gas and low-calorie gas – the air-blown coal gasification product. The layout of a SSG-650 is illustrated in Figure 9. The 250-MW CCP employs two such unit located symmetrically with respect to the GT axis (see section 6.5).

TKZ also produces HP feedwater heaters for power unit of up to 1,200 MW.

Another large boiler manufacturing works of Russia – ZiO – is located in Podol'sk (near Moscow). About 700 boilers have been produced at that works for more than 140 domestic and foreign (Poland, Rumania, Bulgaria, Germany, Greece, China, etc.) TPSs of total capacity over 64×10^6 kW, including 13×10^6 kW for export.

For CCPs ranging from 16-800 MW, heat recovery boilers of various capacity have been designed at the ZiO works. Such boilers widely employ spiral-finned pipes produced successfully at the ZiO works (8 lines for tube finning of up to 20,000 t/y capacity). The available equipment allows for tube finning of all kinds of steels ranging in diameter from 22-114 mm with rib height up to 35 mm and spacing ranging from 4-24 mm.

Since 1931, ZiO has produced equipment for refineries and allied branches of industry. Now, it annually supplies up to 700 items for column, tank equipment, heat exchangers and tube furnaces for a total volume of up to 20,000 tons. More than 40 refineries are fitted with ZiO equipment. Some items of equipment have been manufactured for foreign companies. Among them are rectification columns, stabilizers, absorbers, desorbers, evaporators of up to 3.4 m in an assembled state (for larger diameters the items are shipped to be assembled at the site), heat exchangers, tanks for various processes, product coils for furnaces, etc.

ZiO has been certified to the ASME standards with reference to boilers and pressure vessels. In 1994 the work was completed to certify ZiO in quality by ISO 9000 Standard (it is carried out by Lloyd Register). Certification by DIN is under way.

The "Belenergomash" (BEZM, Belgorod, Central Russia) can serve as an example of an enterprise producing small boilers. It's specialty is low and medium capacity boilers for TPSs, heat recovery boilers for metallurgy, chemical, wood- pulp and paper industries, and small boilers and boiler houses for residential heating. BEZM produces:

- saturated or superheated steam boilers of 35, 50, 75, 100 and 165 t/h operating on natural gas, fuel oil, bituminous and brown coals, and wood wastes;
- gas- and water-tube boilers from 0.4-15 t/h;
- gas-, water-tube and spiral hot-water boilers from 0.1-10 MW;
- equipment for small boiler houses: deaerators, chemical cleanup plant, heat exchangers;
- water- and gas-tube heat recovery boilers for cooling process gases (converter gas, dry coke quenching, etc.);
- boilers for burning black liquor (soda regeneration), hydrogen sulfide, wastes of soot production, etc.;
- hot-water boilers of up to 106 MWt in capacity; heat-recovery boilers with the spiral-finned tubes utilizing GT waste gases ;
- utility boilers of different types.

Belenergomash is also Europe's largest producer of pipes, shaped part and pipe packages for TPS and NPP. The works has bending machines both conventional and with local induction heating to manufacture bends of up to 630 mm in diameter using carbon and Cr-Mo steels, and up to 325 mm using austenitic steels; machines for tube cutting and welding, press-forging plant for stamping t-pieces and bends, and equipment for casting of shaped component.

The equipment for coal handling and pulverizing (conveyors, crushers, mills of various designs, etc.,) is produced by SZTM Works in Syzran' (Middle Volga).

HP valves (dampers, pressure-reducing unit, etc.) are issued by the ChZEM Works in Chekhov (near Moscow).

2.3. Steam Turbines

Steam turbines for large power unit are mostly manufactured by the Leningrad Metal Works (LMZ, St. Petersburg) and Kharkov Turbine Works (KhTZ, Kharkov), while the turbines for combined heat and power generation are made by the Urals Turbomotor Works (TMZ, Ekaterinburg). These works produce single shaft turbines of 30-1200 MW for driving electric generators.

Basic technical data on the largest Russian-made steam turbines are illustrated in Table 6 [12].

The condensing turbines feature the following peculiarities.

The K-160-130 turbine (KhTZ) is of a two-cylinder design with a combined HP and IP cylinder and one two-flow LP cylinder.

The K-200 turbine (LMZ) is of the three-cylinder design with separate HP and IP cylinders and two-flow 1.5 exhaust LP cylinder.

The K-300 turbine features three exhaust. The IP cylinder is combined with one LP cylinder flow which passes 1/3 of the entire steam.

The modern turbines of larger capacity are made with a single-flow HP cylinder, single or two-flow IP cylinders and one or several (up to 3) two-flow LP cylinders. The typical design of a HP cylinder with loop steam flow applied by LMZ and TMZ is shown in Figure 10, and the typical LP cylinder is illustrated in Figure 11 [13,14].

Unit of 30-185 MW are designed at 3-13 MPa and 430-555 °C without reheat and are mostly used for combined electricity and heat production at industrial enterprises and in utilities [15]. The extraction turbines have regulated steam extractions to supply steam for industrial users and to heat water for heating systems. The heating is done in 2-3 stages for better efficiency. Also, back-pressure turbines operating at pressures up to 3 MPa are available with output up to 100 MWe.

The larger turbines (180 MW) for cogeneration, and (150-200 MW) for condensing TPS are designed with reheat at 13 MPa, 540/540 °C.

The TMZ turbines dedicated for combined electricity and heat generation are made so that the nominal capacity is ensured at a nominal heat rate and a minimum steam flow to the condenser. In this case, the turbine cycle efficiency is maximum. The exception is the supercritical pressure reheat T-250 turbine. It carries it maximum electrical load of 305 MW in the condensing mode, without steam extraction.

The IP part of this T-250 extraction turbine is divided into two cylinders. Large steam pipes are connected to the top and bottom extraction point for IP cylinder No. 2. The steam is used to heat district heating water. In 100-, 180-, and 250-MW turbines steam is extracted for these purposes at 50-60 and 150-200 kPa. The maximum amount of extracted steam is 320, 490 and 600 t/h respectively. In a 250-MW turbine unit, up to 385 MWt of heat is extracted.

The process heat is extracted at 1.3-2.0 MPa.

Condensing steam turbines rated at 300 MW and more are manufactured for operation at supercritical (24 MPa) steam pressure with 540/540 °C reheat.

All Russian-made steam turbines of up to 800 MW inclusive have nozzle steam distribution. The flow path is made up by impulse stages with positive reaction in the root section and aerodynamically perfect blades, as a rule, with variable profiles along it. To increase efficiency and dampen bucket vibration, bucket are made with shrouds. This and blades machined from one piece is the latest design for IP and LP cylinders. Axi-radial seals are provided over the shrouds.

In conventional use are diaphragm-type designs of nozzles and integral-disc types of rotors that are generally supercritical, and for the LP part they mostly use shrunk-on discs. With Russian-made steam turbines there were no difficulties due to rotor stress corrosion cracking because less strong steels having a higher ductility were used.

The bucket in the heavily-loaded stages of the LMZ turbines are fastened by fork root; in the less loaded stages by T-shaped root; and in the last stages the long bucket are fastened by serration type root. Interchannel systems of moisture separation and liquid film removal in the rim gap are used in the LP cylinders.

The turbines manufactured now can operate under loads from 20-115 percent. Some characteristics of existing LMZ supercritical steam turbines are given below.

Parameters	Type of Turbine			
	K-300	K-500	K-800	K-1200
Maximum output, MW	330	540	870	1400
Specific heat consumption, kJ/kWh	7704	7641	7683	7616
Specific weight, kg/kW	2.3	1.9	1.5	1.47
Nonscheduled outage, %	1.5	-	0.7	0.6
Number of unit in operation	55	5	15	1

The efficiency of the HP, IP and LP cylinders of supercritical turbines now in operation are 84-86 percent, 91-92 percent and 82.5 percent, respectively. More efficient turbines have been designed (first with increased efficiency of the LP cylinder) with a specific heat consumption of 7300-7500 kJ/kWh.

The Russian-made steam turbines are reliable in operation. Availability factors of 200-1,200-MW steam turbines are 97-99 percent, and the time between overhauls is 4-5 years with operation of up to 6,000 - 7,000 hrs/y. The time between failure is 10,000 hrs.

To ensure the strength and reliability of the component and increase the efficiency of the turbine flow pass, state-of- the-art computer codes (in recent years 3D codes) are used. The Works, Research Institutes and Universities have test facilities and experimental turbines (at LMZ a full-scale LP cylinder with 960 and 1,200-mm long last stage blades) to investigate the flow path and component of steam turbines.

Some unique technical achievement [13] are:

- 50-MW control stage of LMZ steam turbines made-up of bucket that use design damping were welded in packages by an electron-beam welding technique
- LP cylinder last stage bucket 1,200 mm long made of titanium alloy (the annular area of the stage is 11.3 m^2, circumferential velocity over the periphery is 658 m/s) which have been in successful operation since 1983;
- LMZ turbines for PPNs are using one-piece forged LP turbine rotors weighing 80 t without boring at 3,000 rpm

Russia has successful experiences in the operation of 300- and 800-MW turbine unit without deaerators using direct-contact LP heaters where feedwater deaeration is provided, which is sufficient with a neutral-oxygen water chemistry regime.

The turbine extractions for industrial and heating applications are controlled by adjustable diaphragms.

The turbine manufacturers produce for their turbines' condensers with copper-nickel, titanium alloys, and stainless steel tubes. They produce water heaters for heating systems; condensate and feedwater heaters, both surface-types with tubes made of various materials and direct-contact; deaerators; evaporators; oil coolers and heat exchangers for district-heating systems; and auxiliary heat exchangers.

Synthetic fire-resistant OMTI oil has found application in LMZ turbine lubrication and control systems. Some turbines of 300 and 800 MW have been in operation some tens of thousands hrs using OMTI in the lubrication systems. It is also used on all LMZ 1,000-MW turbines at NPP.

For Russian manufacturers wide standardization of technical solutions is typical in the design and manufacture of steam turbines. Identical blade profiles, nozzle blades and bucket, especially of last stages, valves, seals, bearings and other component and systems are used.

Steam turbines of smaller capacity, up to 25-30 MW, are manufactured by the Kaluga Turbine Works (KTZ, Kaluga) to drive electric generators and feed pumps, and by the Nevsky Works (NZL, St. Petersburg) to drive electric generators and compressors.

High-speed steam back-pressure turbines of about 12 MW and condensing turbines of 11-12 and 17 MW are produced for driving feed pumps. Similar turbines of 6.5 MW are manufactured to drive air blowers (fans) of 800 and 1,200-MW unit boilers.

2.4. Gas-Turbine Unit

The former U.S.S.R. and later Russia has long-term experience in GT operation at TPS and main gas pipelines. In the national economy GT unit developed and constructed by power machine manufacturers, and also aircraft and marine derivatives are used.

The land GT are mostly applied in Russia to pump natural gas at main pipe lines. Currently the total capacity of GT unit used for this purpose amount to about 40 GW with unit capacity ranging from 4-25 MW. The most upgraded unit operate at a turbine inlet temperature of 1,060-1,100 °C and an efficiency of 32-35 percent. However, the majority of these unit belong to the first generation with uncooled bucket and vanes, and they operate at a turbine inlet temperature of 760-920 °C.

Such GT are supplied in packages of works manufacture. As a rule, prior to shipment, GT are tested at the works rig under load or at nominal gas temperature. Most of GT operate in severe climatic conditions, and in low-population areas lacking the required infrastructure, transport communications, and transmission lines. Some of the gas pipeline GT' parameters can be found in Table 7.

GT units are made with a free running power turbine and can be used for electric generator driving applications via reducing gear.

For power generating GT characteristics, refer to the same Table 7.

Large heavy-duty GT unit dedicated for electric power generation were manufactured by LMZ (St. Petersburg) and KhTZ (Kharkov); heavy-duty GT unit for the gas industry were manufactured by NZL (St. Petersburg) and TMZ (Ekaterinburg, Urals). For the layout of a GT rated of 150 MW see Figure 12.

The big suppliers of 10- to 12-MW GT unit for electric generation and the gas industry are "Mashproject" and YuTZ in Nikolaev (Ukraine). Currently the Works (industry) produce(s) GT unit for the next generation of 2.5-25 MW turbines with better characteristics, particularly for the power industry. "Mashproject" has worked out, using it advanced technology, a single-shaft state-of-the-art GT rated at 110 MW [16]. This GT will be manufactured in cooperation with the Russian "Rybinskije motory" Works (Rybinsk, Upper Volga). The first GT of this type will be produced this year.

A large number of aircraft-derivative GT of 6.3 and 16 MW have been manufactured for the main gas pipelines by the "Trud" Aircraft engine enterprise in Samara (on the Volga River). Operation of the latest model, NK-36ST, has started at the gas pipeline. The Utility version [17] of this GT unit, NK-37 (Figure 13), is being tested on-load at the pilot plant. Some GT units of this kind have been ordered to be used in 80-MW CCP (2 GT + ST) which are now under construction. The design and supply of this CCP is performed by the Kirov Works (St. Petersburg).

In recent years, the activity of aircraft engine developers and manufacturers in marketing land (fixed) GT unit in Russia has increased. Based on their GT engines they have developed efficient utility and mechanical driving GT unit rated from 1.5-25 MW. Operation of such GT will be started in the near future. The data for the most promising unit are illustrated in Table 8.

Various gas-turbine manufacturers already have agreement or are conducting negotiations with leading Western firms (LMZ-Siemens, NZL and Saturn-ABB, Kirov Works and Rybinskije Motory-GE, etc.).

Some project using combined cycle unit have been developed in Russia with various types of GT. The data for the most efficient project is presented in Table 9.

The technologies of Russian aircraft engine manufacturers are at the top level. Yet, the heavy-duty GT manufacturers have fallen behind the leading Western firms in parameters and in the number of GT produced, in particular, for power generation. However, Russian manufacturers have designed many samples of high-efficient equipment for their GT.[18,19].

About 20 types of efficient air paths have been perfected for axial compressors ranging by flow from 30-700 kg/s, pressure ratio from 2 to 13, and adiabatic efficiency of 85-90 percent. In many cases, the compressor flow paths are provided by using the group stages of previously developed and operationally proven machines [19].

The development of high-temperature component for turbines are based on experimental investigations, mathematical modelling, and computer programs that allow for the calculation of thermal stress and the evaluation of the durability of component over all of the blades.

The vanes with deflector cooling systems have a long operating history with GTN-16 (TMZ) and GTN-25 (NZL) GT unit.

The first stage bucket with original internal cooling (Figure 14,c) had been used for the GTN-25 (TMZ) turbine some 10 years ago. When using 2.5 percent of the air taken past the compressor, the metal temperature of the bucket was reduced by 250 C at low (70 °C) temperature gradient.

For sufficiently long bucket of large GT unit, use is also made of channel and loop-type cooling systems that are capable of reducing the maximum bucket metal temperature to

800-825 °C with a turbine inlet temperature of 1,100 °C and cooling air flow of 1.7-3 percent.

The properties of Ni-based alloys used for blade manufacture of heavy-duty GT are shown in Table 10 [20]. The mechanical properties have been determined at 20 °C after ageing at 750 °C for 3,000-5,000 hrs. The creep-rupture strength is based on a service life of 20,000 hrs.

The most experience available now with a blade operating at up to 700-750 °C is with the alloy EI-893. At many GT unit, the blades made of this alloy have been in operation for over 60,000 hrs. To increase operability, the blades are protected against corrosion by coatings.

For the GT unit manufactured now, the forged bucket are made of EI-929VD, EP-800VD, and EP-957ID alloys. The cast blades are made of EP-539-LMU, TcNK-7 and ZMI-3 alloys.

Some years ago, casting with directional solidification had been mastered for manufacturing the bucket for GTN-25 unit (NZL) which have been in operation for some tens of thousands of hours. The directional solidification has markedly improved ductility and the creep-rupture strength of bucket [20]. The technology has been adapted to manufacture large cooled bucket.

Various types of combustors are in use for the Russian-made heavy-duty GT unit, viz., silo, can-type and annular. For all of these combustors stable and efficient firing of natural gas, and liquid fuel was obtained in various operating conditions and modes whenever required. The component of the combustors exhibited a long service life.

In designing the existing GT, little attention had been paid to NO_x emissions. Now, the combustors of existing GT have been modified to reduce NO_x emissions. For the new GT unit, low-NO_x combustors have been designed that satisfy the modern standards (NO_x < 50 mg/m^3) without water/steam injection when using natural gas.

The work on direct coal combustion in GT was conducted in the U.S.S.R. as far back as the 60s. Then some 3- and 12-MW GT unit firing gases derived from underground coal gasification were constructed and put into operation. The gas used was similar in composition and properties to the coal-derived gas obtained by the air-blown Lurgi gasification method. Combustion of that gas caused no problems.

Intermediate air coolers, tubular and plate air heaters, heat-recovery boilers and water heaters for heating systems have been designed, tested and operated for long periods with different GT units

3. THE POWER INDUSTRY DEVELOPMENT FORECAST FOR RUSSIA

The essential goals of the Russian energy strategy are to promote social and economic revival of the country and increase the GNP, income, life standard and it quality, and reduce the man-made load on the environment [21].

The priority lies in increasing energy efficiency and conservation.

In 10-15 years a more effective use of natural gas and a larger share for it in domestic consumption are scheduled. The quality of coals will be improved by producing smaller amount of high-ash, high-sulfur coals through washing and benefication.

The development of the regions is planned in a way that will ensure their self-sufficiency in electricity, heat, and wherever possible in fuel, while preserving the United Power Grid of Russia.

If economically justified, smaller sources of electrical energy and heat will be provided as close as possible to the consumer. It will be based on economically efficient and ecologically clean technologies, particularly for coal TPS.

Some forecast made just after the collapse of the U.S.S.R. and at the start of the transmission of Russia to a market economy can be seen in Table 11. The forecast are based on the economical demands of the main regions of Russia and are still reasonable. Of course, the forecast could not take into account the depth and consequences of the economical crisis in today's Russia. However, with an optimistic view to the future and hope in the revival of the Russian economy, the figures of Table 11 are of present interest but are not attainable by the year 2010, as supposed, but by some later year.

One can see from Table 11 that for the addition of considerable new capacity, mostly fossil-fueled TPSs, is required to solve the social and economic problems, while increasing the standard and quality of life.

Coal is and will remain, in the near future, the basic fuel in Siberia and the Far East. It is also a very important fuel in the Urals and in the European part of the country. Coal consumption for power generation should double and constitute over 200×10^6 tfe/y in the future.

The prospect for the evolution of the Russian power industry are now uncertain. In recent years, due to economic difficulties and because of the transition to free market conditions, the consumption of electric energy was reduced and is going to decrease further. By 1995, electric generation is predicted at 850 × 10^9 kWh which is 3 percent lower compared to 1994.

The revival of the Russian economy is predicted in a long period of time. By various estimates, electric generation will reach the 1990 level in the years 2000-2010. In the near future, no high-investment construction of large TPS is planned. In 1994, only 25 hydro-power and steam turbines were put in operation for a total capacity of 2.4 GW, including an 800-MW natural gas fired unit at the Nizne-Vartovsk TPS in the Tumen region.

Currently in Russia, mostly in the Eastern and Central regions of Southern Siberia and the Far East, there are some coal-fired TPSs under construction located near brown coal open-cast deposit. Some of them, for example, the Gusinoozersk and the Kharanorsk condensing TPS are in energy-deficient areas. Both TPSs have been designed to employ 215-MW unit. At the Gusinoozersk TPS, 6 such unit are in operation and two unit are scheduled to be started. At the Kharanorsk TPS, the first unit is being prepared for start-up and 6 unit will be commissioned in all.

At the Berezovo TPS N.1, two 800-MW unit are in operation but the construction is not completed yet. The equipment for unit No. 3 is at the site. The Berezovo coal seam, where coal is the cheapest in Russia, can supply 4 unit now, and after further development can supply two additional TPS of 6.4 GW each.

Several cogeneration plant are under construction or being prepared for construction. They will be equipped with 320-670-t/h boilers and 80- to 185-MW turbines.

The main attention is being paid to the radical reconstruction of the existing TPSs and the preparation for using up-to-date technologies. The worn-out and obsolete equipment, which have an overall capacity of about 90 GW, will be put out of operation.

The analysis of energy use in Russia made by several independent Western and Russian organizations indicates that:

- even without the decommissioning of some NPP and
- provided that existing TPS will expire their service life there will be a considerable power deficit in Russia, if new capacities are not put into operation. The deficit are as

follows:

Calendar year	2000	2010
Power deficit, GW	24-56	149-174

About 80 percent of the deficit is attributed to the European regions and Urals which have insufficient fuel resources.

The deficit can be partially covered by a life extension of the existing equipment together with the replacement of the worn-out component. This approach is economically justifiable mostly for cogeneration plant. It could be implemented for equipment with a total capacity of 10-15 GW by the year 2000 and another 10-15 GW by 2010. With reference what can be done by 2010, it will cover only 20 percent of the overall demand. The remaining deficit will be covered by construction of new power unit instead of decommissioning at existing TPS (in the same main building or at the same site). New construction will include both cogeneration and condensing TPSs. TPS retrofitting/repowering will be implemented along with increasing the efficiency (in particular, by increasing the share of combined heat and electricity generation) and decreasing the environmental impact.

Further growth of electric generation will depend on the rates of restoration of the country's economy. If they will be decelerated, and the energy saving be realized at a large scale and efficiently, a small number of relatively low-capacity new condensing plant will suffice, together with cogeneration plant, including those of low and medium capacity.

At higher rates of energy use, construction of some large condensing K-A and Kuzn coal-fired TPS in Siberia, the Urals, and maybe in the Volga River region will be needed. For such TPS, the use of 300- to 500-MW unit is under consideration.

Along with cogeneration plant, a significant fraction of the heat required for consumers will be generated in the boiler houses (district heating plant). The steam capacity of the boilers installed there will be from 1-2 to 160 t/h, while that of hot-water boilers, up to 200 Gcal/h (230 MW). Now, many of them are of low efficiency and operate with considerable SO_2, NO_x and fly ash emissions. The boiler houses could also be the places, where clean coal technologies could be applied.

The Energy Strategy is based on the fact that the coal industry will play the important role supplying the country with fuel, electricity and heat.

The strategy is to terminate the drop of coal production, stabilizing it at 250-270 × 10^6 t/y level, continue the restructuring of the coal industry with the greater share of the open-cut coal production and the closing of unprofitable enterprises by the year 2000. In so doing, the following options of coal production evolution are considered.

Coal annual production	Calendar year				
	1990	1993	1995	2000	2010
Maximum: 10^6 t	396	306	270	290	340
10^6 tfe	257	196	172	185	210
GJ	7530	5740	5040	5420	6150
Minimum; 10^6 t	—	—	260	250	300
10^6 tfe	—	—	166	160	190
GJ	—	—	4860	4690	5670

In the European part of the country the coal production will tend in general to decrease, while that in the Kuzn and K-A fields will increase to supply the regions of Siberia and the Urals where these coals will be fired at TPS. The remaining regions will, to a greater extent, use local coals. The brown coal production is supposed to be increased in the Eastern region of the country in the Irkutk district, Zabaikalie, Primorsk and Khabarovsk regions from about 50 × 10^6 t/y (17 × 10^6 tfe/y) produced at present to 90 × 10^6 t/y (30 × 10^6 tfe/y).

The problems of transporting the cheap K-A and Kuzn coals to industrialized regions of the Urals and the East of the European part of the country are rather acute. It is clear that the handling of a greater portion of coal to raise it heat value prior to transportation will be required along with possible development of special transport means and systems.

Economical estimates provide evidence about competitiveness of Kuzn and K-A coals as fuel for TPS in the Urals, Volga River region and, may be, in the areas to the East from Moscow. For interregional transportation, mostly Kuzn coal or processed, for example, briquetted, K-A coal will be involved. The demands in solid fuel for the Eastern Siberia and Far East will be covered by local production and shipment of K-A coals. The Peach coals will be used in the Northern regions, and the coals from the Eastern Donbas, in the South of the European part of Russia.

The Energy Strategy of Russia plans to distinguish the central and local energy control functions.

The Federal Governmental Bodies will control the activity of Federal power systems and the nuclear power industry, manage the strategic energy resources, establish the standards and norms of safety and efficiency of energy object, supervise their observance, license economic activity of utilities and regulate the activity of natural monopolies by legislative and normative act and by holding their shares.

The local (regional) authorities will set up functioning of the enterprises that are not part of the Federal power systems, issue licenses for construction of new and expansion of the existing TPS and specify additional environmental requirement for them.

Together with the Federal bodies, they will license the activity of the enterprises belonging to the Federal power systems and responsible for reliable electricity and heat supply to the consumers, and also check the execution of the licenses granted.

The regional authorities will have the right required to provide for stable energy supply to the territories under their jurisdiction, state control of electricity and heat tariffs, establishing the energy market at their territories, including participation of independent producers.

The Energy Strategy of Russia declares the equal opportunities for domestic and foreign organizations and companies in the course of mutually beneficial cooperation and welcomes any forms of participation for foreign capital in the power industry of Russia.

4. CLEAN COAL TECHNOLOGY DEMONSTRATION PROGRAM (CCTP) OF U.S. DEPARTMENT OF ENERGY

4.1. General

In the U.S., the clean coal technology program (CCTP) has been underway since 1985 aimed at:

- environmental protection by elaboration and industrial-scale use of economically effective and environmentally low-impact technologies for coal-based electricity generation;

- ensuring the reliable and safe power supply to the country through the development of processes and equipment for direct, or with some conversion, efficient use of coal instead of oil and natural gas;

- increasing the competitiveness of American industry in the external market through the development and industrial application of the above technologies and equipment.

Within this program R&D and demo project are being developed. The scale of the latter is so selected that the result obtained are sufficient to assess all aspect of designing, constructing, and operating industrial plant [22,23,24].

The program for ecologically clean technologies for coal utilization is financed by the government in cooperation with commercial firms, and other institutions. The program builds demo plant using selected technologies that show the most promise for advancement to the market during the next decade. The capacity of such plant shall be sufficient to get evidence (data) on their commercial potential.

Traditionally, DOE undertakes long-term R&D programs for TPSs that have high risk and the potential to be effective. Since the fulfillment of the program at commercial scale was a high risk, DOE undertook full or almost full financing.

The clean coal technology program is realized on the basis of agreement between the government and commercial firms bearing at least 50 percent financing. The patent right to inventions are the property of all sponsors.

The program was based on five independent competitive solicitations.

The project were selected from the offers by commercial firms that were based on technologies that the given companies thought to be most promising.

The execution of the project is supervised by the Pittburgh and Morgantown Energy Technologies Centers.

Currently 47 project selected in 5 competitions are underway in accordance with the Clean Coal Technology Program that was started in 1985. The total cost of the project is over $\$6.5 \times 10^9$, including $\$2.7 \times 10^9$ out of the Federal budget.

At the initial stages the program was mostly oriented to project that would decrease SO_x and NO_x emissions responsible for acid rains. Various devices and systems to decrease these emissions are being developed within the framework of 19 project at a total cost of $\$688 \times 10^6$. Among them are project of NO_x reduction (Table 12) at power plant with an overall capacity of 1,700 MW, SO_2 reduction at power plant of 770 MW (Table 13) and combined NO_x and SO_2 reduction (Table 14) at power plant with an overall capacity of 765 MW. The technologies have been designed to be adaptable to newly constructed and existing TPSs. With reference to the majority of the project, test result and operating experience are available. Some of the project have already been completed and some of them are being implemented for commercial use. The total data on the efficiency of various gas cleaning technologies can be found in Table 15.

Later, as CCTP progressed, greater attention was being paid to the development of advanced AFBC and PFBC technologies, CCPs with integrated coal gasification (IGCC), and other technologies (Table 16) that offered higher efficiencies, reduced CO_2 and rather low SO_2 and NO_x emissions, and also better performance. 15 project, at a total cost of $\$4.7 \times 10^9$, belong to this group. The project are being realized at new TPS with a total capacity of 1200 MW and existing TPS of total capacity of 800 MW.

The operating result for the majority of the power plant will be available in the second half of the 1990s.

CCTP also includes 5 project for processing coal to clean fuels at a total cost of $\$467 \times 10^6$ and 6 project for industrial power plant that offer increased efficiency and better ecological parameters at a total cost of $\$1.118 \times 10^9$. Also included is an integral facility for coke-free iron production and electricity generation with a CCP firing coal-derived gas at a total cost of $\$825 \times 10^6$.

4.2. Project for Reducing Emissions from Conventional Boilers

To reduce NO_x emissions, low-NO_x burners and staged combustion with overfire air are used. These technical solutions ensure NO_x reduction by 40-60 percent for a small capital investment (< $10/kW), some loss in efficiency (< 0,2 percent), and an operating cost penalty. The implementation of these measures do not require much time as shown in Table 12. (Project 7-46 and 7-48 in Table 12, and 7-66, Table 14 are examples of this technology. The project numbers correspond to pages in the 1993 Program Technology Update where these project are described).

Similar technology is a low-NO_x cell burner retrofit (developed) demonstrated by B&W on one of it own boilers (Project 7-42, Table 12). According to the project description the lower burner fires all fuel while the upper burner is used to supply the secondary air.

More complex but more effective measures are associated with reburning. The technology proves to be simpler and more efficient (60-70 percent of NO_x reduction) when natural gas is used as reduction fuel (Project 7-44, 7-70, Table 12). Micronized coal reburning (Project 7-52, Table 12) and cyclone boiler reburning (Project 7-40, Table 12) are more difficult to realize and are less efficient. NO_x emissions in this case are reduced by 50-60 percent. Application of reburning technology needs a $17-65/kW capital investment, reduces unit efficiency by about 0.25 percent, and increases operating cost by about 0.1 cent/kWh (Table 15).

CCTP includes some project using SCR technology for the control of NO_x emissions (Project 7-50, 7-64, 7-68, Tables 12 and 14) and SNCR technology (Project 7-76, 7-72, Table 14).

In non-catalytic systems that use urea 50-70 percent of the NO_x are reduced with a capital cost of $5-20/kW and a cost of generation increased by 0.11-0.13 cent/kWh (Table 15).

The ammonia-based catalytic system can reduce 80-90 percent of NO_x at a capital cost of $80-90/kW (combined with SO_2 control, $250/kW).

In implementing SCR systems, the technologies of both foreign (Project 7-50, 7-64) and domestic (Project 7-68, Table 14) companies were applied.

The data on various NO_x control technologies are shown in Table 15.

Wet and wet/dry flue gas cleaning systems have been used for many years to reduce SO_x emissions at U.S. TPSs. Limestone and lime are employed as sorbent with the final product (usually a mixture of $CaSO_3$ and $CaSO_4$), after additional oxidizing (neutralization) and mixing with ash, being dumped to disposal areas.

Under the CCTP some simplified SO_x cleaning systems are being designed. Among them Project 7-66, 7-76, 7-70 are technologies that inject limestone and various grades of lime into the upper part of the furnace, and humidify the sorbent-containing flue gases in the gas duct to enhance sulfur capture.

To this group belong technologies of sorbent (lime) solution or slurry injection into the gas duct. In some cases the slurry is injected such that it is dispersed along the duct, as it is done in Project 7-56, Table 13. Besides the CCTP project, U.S.A. companies have developed many other simplified SO_x control systems: E-SO_x featured by using the entrance of the ESP as the location of the wet/dry reactor; LIDS, which inject a slurry of ash enriched with unused sorbent into the gas duct, etc.

Implementation of such systems requires relatively small capital investment ($30-100/kW). At considerable sorbent consumption rates their efficiency is 50-70 percent maximum, while the cost of removed sulfur turns out to be rather high ($350-700/t). The by-product of FGD are not commercial grade.

Realization of wet/dry sulfur removal in special reactors (Project 7-54, 7-58, Table 13) enables increased efficiency of up to 80-90 percent and better sorbent utilization, but, of course, at a higher cost of the system.

Under Project 7-54 the technology of wet/dry SO_x removal in a CFB with high particle concentration (from 460-1830 kg/m^3) has been developed . The concept is based on increased surface contact between the lime slurry and acid gases on the particle surface which becomes commensurable with the contact surface typical for wet SO_x control systems. In this case, heat and mass transfer are enhanced, injection of slurry is simplified, and – because of recirculation – lime utilization increases up to about 80 percent. Reaction in the CFB needs less time; 2-3 seconds at a gas velocity of 6-6.5 m/s as compared to 10-12 seconds at

1.2-2 m/s in conventional wet/dry reactors. It is important that the cleaning action of the fluidized particles in the reactor causes no deposit, and the temperatures can be lower than those in conventional wet/dry reactors. The cost of such a wet/dry sulfur removal system can be about 25 percent less, and the total expenditures – despite more expensive sorbent – 15 percent less than in the case of wet limestone FGD.

More efficient sulfur removal systems are required when using high sulfur coals where even 90 percent SO_2 removal efficiency may be insufficient to meet environmental control requirement. The CCTP project include 2 advanced wet limestone FGD technologies of 95 percent efficiency (Project 7-60 and 7-62, Table 13). They are based on improved processes that employ cheap natural limestone as sorbent in minimum amount, operate close to the stoichiometric value, and produce commercial-grade gypsum. For these reasons, despite the complex nature, the high investment cost ($180-250/kW), and decreasing of unit efficiency by about 1.5 percent, the cost of 1 t of removed sulfur is competitive, and with high sulfur coals may be the cheapest technology.

Under Project 7-60, a wet limestone advanced FGD system with a scrubber suitable to clean gases from several boilers has been designed and installed at the Bailly TPS. It employs an advanced single-stage process based on an increased rate of straight-flow washing and better oxidation in the same scrubber to produce commercial-grade gypsum. It also employs an effluent evaporation system.

A jet-bubbling reactor has been designed for FGD at the Yates Plant Unit No. 1, a 100-MW unit firing high sulfur bituminous coal (Project 7-62).

The reactor with a 12.8-m diameter and height is made of fiberglass-reinforced plastic. The flue gas bubbling through the limestone slurry is accompanied by SO_2 absorption, neutralization, gypsum crystallization and washing from the particulate. Air is also bubbled through the slurry oxidizing $CaSO_3$ to $CaSO_4$. Fiberglass-reinforced plastic is used to manufacture the wet flue gas duct, a 115-m high stack, and 8.54-m diameter by 7.63-m high limestone slurry tank. Fiberglass plastic undergoes no corrosion/erosion, which is the case with the same element manufactured from stainless steel. Therefore, no preheating of wet cleaned gases is required to prevent condensation in the gas duct located downstream. Only 2 stages of the separator (mist eliminator) are installed past the absorber to remove water droplet entrained from the latter. Aerodynamic separation of the condensed moisture is provided in the stack throat.

Several integrated NO_x/SO_2 emission control technologies are being designed in CCTP project.

Project 7-76 most completely utilized simplified technologies of NO_x/SO_2 emission control. The base is a 100-MW unit boiler using down-fired burners with over-fire air port in the bottom of the furnace. The boiler fires low-sulfur (S = 0.4 percent) bituminous coal. To reduce NO_x formation low-NO_x burners and two-stage combustion is applied. For further NO_x reduction urea is injected at the furnace outlet. Sulfur is captured by Ca- and Na-based sorbent injected before economizer (540 °C) and air preheater (315 °C).

The SNOX technology (Project 7-64, Table 14) is well known. It has been used for several years at a commercial 300-MW unit in Denmark. Flue gases are catalytically deeply cleaned of NO_x/SO_2 along with the production of saleable sulfuric acid. No data is available on the system's operational characteristics, cost, or the intention of Denmark electric utilities to apply this technology at any other TPS under construction in that country.

The efficiency and prospects for application of SO_2/NO_x, and, sometimes, ash emission control systems that are undoubtedly technically interesting, under Project 7-68, 7-72 and 7-74 (Table 14) are difficult to assess because only predesign data are available. They indicate only technical feasibility and the terms of implementation of the processes and the determination of the major equipment profile.

4.3. Advanced Power Technologies Project

The CCTP includes two project that use circulating fluidized-bed boiler unit.

At Nucla Station (Project 7-16) a 420-t/h CFB boiler with hot cyclones for fly ash separation has been constructed, tested in detail, and is now in operation. The boiler has been designed to fire 3 types of Western coals with sulfur content of 0.4 -0.8, 1.5, and 0.5 percent. Limestone is in-bed injected for sulfur capture.

The final atmospheric fluidized-bed boiler project under the CCTP is Project 7-18 with a goal to design the largest U.S. boiler, a 227-MW unit capable of delivering 175 t/h of 4.3 MPa process steam. The experience known to date has been accounted for in the project. The sulfur capture is scheduled at 92 percent. In addition to using state-of-the-art combustion measures, ammonia/urea will be injected into the gas duct running from the furnace to cyclones to reduce half of the in-furnace formed NO_x. Much attention has been paid to maintaining optimal boiler modes. The start of test is scheduled for the beginning of 1998.

Under Project 7-32 a system of coal combustion in a slagging cyclone has been designed. Two cyclones with a total capacity of 50 MW are planned to be installed at the Healy station in Alaska. The cyclone is in fact a horizontal water-cooled cylinder slightly inclined in the direction of the gas exit. It employs staged fuel and air feed and pulverized limestone injection to capture SO_2. Further SO_2 capture will be in the wet/dry cleaning system. The CaO-containing fly ash removed in the baghouse is used to prepare the sprayed slurry.

As fuel, a mixture of 50 percent run-of-mine and 50 percent waste coal with high ash content and lower heating value is fired. To facilitate removal of the liquid slag, air fed to the cyclone is preheated by firing 25-40 percent of the coal in the precombustor. Seventy to eighty percent of the fly ash is removed as molten slag. The hot gas containing the incomplete combustion product is directed to the furnace, and additional air is fed to the furnace for complete combustion. In such a system, SO_2 emissions are reduced by more than 90 percent, maximum NO_x emissions are 86 mg/MJ (220 mg/m^3), and maximum particulate emissions are 6.5 mg/MJ (16.5 mg/m^3).

The slagging horizontal cyclone combustor included in Project 7-98 is close in concept to the above design. It specific features are ceramic lining and wall cooling by secondary air, which enables the use of compact cyclones to retrofit various types of boilers while leaving their steam/water path unchanged. The design capacity of the cyclones is 6.74 MWt.

Formation of NO_x in the cyclone combustors is reduced by oxygen-deficient combustion; for SO_2 capture limestone is injected. The molten ash and the sorbent that captures the major amount of the coal sulfur are separated on the cyclone walls. Injection of additional amount of sorbent into the boiler duct increases the sulfur capture efficiency.

Under the CCTP, seven project that demonstrate IGCC plant are being developed. Some data on these project can be found in Tables 16 and 17. The total cost is about \$3 × 10^9, including about \$1 × 10^9 from the Federal budget.

Project 7-28 and 7-30 are based on the technology of coal-water slurry, entrained-flow, oxygen-blown gasification which has been commercially demonstrated.

At the Wabash River TPS (Project 7-30) a two-stage gasification of the slurry prepared from a 2.3 to 5.9 percent S bituminous coal will be realized. The coal consumption will be

2,315 t/d (96.5 t/h). In the first stage, gasification occurs creating molten ash which is removed as liquid slag from the gasifier lower part. No ash melting occurs in the second stage. The raw gas is cooled in heat exchangers and cleaned in the conventional low-temperature system where particulate, NH_3, and sulfur compounds are removed. Ceramic filters capture the fly ash and return it to the gasifier. The cleaned mean-calorie (medium Btu) gas is preheated with steam generated in the raw gas cooling system, and then fired in the GT combustor. Superheated HP steam is generated in the heat-recovery boiler downstream of the GT. Also, HP steam produced in the raw fuel gas cooling system is superheated there. Both steam streams are expanded in the steam turbine available at the existing TPS site.

This single-train gasification system will be the largest in the U.S.A.

The designed sulfur cleaning efficiency will be 98 percent, NO_x reduction will amount to 90 percent, and SO_2 emissions will be < 86 mg/MJ, NO_x < 43 mg/MJ.

The Polk Power Station (Project 7-28) will use single-stage gasification of Illinois 6 and Pittburgh 8 bituminous coals having a sulfur content ranging from 2.5-3.5 percent. Two parallel desulfurization systems will be employed in the project: conventional low-temperature and high-temperature in a moving bed of zinc titanate sorbent. To decrease NO_x formation, the cleaned syngas will be mixed with nitrogen from the air separation plant. The design sulfur removal efficiency will be 96 percent (98 percent, for industrial plant), NO_x will be reduced by 90 percent; and the emissions of SO_2 will be 90 mg/MJ, NO_x 116 mg/MJ.

The third CCP project (Project 7-20) using entrained-flow gasification is underway at the Springfield TPS. There, at 23 t/h (550 t/d) dry dust of Illinois 6 coal will be gasified in a two-stage air-blown gasifier with liquid slag removal at the first stage. The raw coal-derived gas temperature will be 1000 °C before being reduced to 540 °C in the gas cooler. At this temperature, the gas will be cleaned of coke particles; first in a cyclone, and then in a fines filter. The particles will be returned to the gasifier, and the gas will be directed to the desulfurization system with a zinc titanate moving bed. The sulfur removal efficiency will be 99 percent, and the NO_x will be reduced by 90 percent. The SO_2 and NO_x emissions will be less than 43 mg/MJ.

Fluidized-bed air-blown gasification of bituminous coals is underway according to Project 7-24 and 7-26.

At the Piñon Pine Station (Project 7-24), 812 t/d (34 t/h) of the Utah 0.5-0.9 percent S crushed coal will be gasified. The limestone is also in-bed injected to capture the sulfur and to prevent the conversion of fuel nitrogen to NH_3. The temperature of the raw coal-derived gas at the gasifier outlet is 925 °C. The fly ash is separated in a cyclone and returned into the gasifier. The gas is cooled to 595 °C and sulfur is additionally removed in an oxide metal bed. When sulfur is captured in the fluidized bed, CaS is formed which forms after oxidation, together with the fuel ash, agglomerated particles suitable to be disposed. The coal-derived gas is fine cleaned of particulate mater in ceramic filters. To reduce NO_x formation steam is added to the cleaned coal-derived gas.

The design sulfur cleaning efficiency is 94 percent, and NO_x emissions will be reduced by 90 percent. The emissions of SO_2 and NO_x will be 30 mg/MJ.

Test are planned using West Virginia bituminous coal with S = 2-3 percent.

An industrial CCP using the above gasification technology will be 43.7 percent efficient and ensure 98-99 percent cleaning of sulfur when high-sulfur coals are gasified. The emissions of SO_2 will be below 19.5 mg/MJ and those of NO_x below 23 mg/MJ.

At the Toms Creek Station (Project 7-26) a fluidized-bed system that will gasifiy 390-t/d (16.5-t/h) of coal will be realized. Using a calcium base sorbent, 90 percent of the coal sulfur is captured in the bed. The raw coal-derived gas will leave the gasifier at an outlet temperature of 980-1040 °C and be cleaned of the fly ash in two stage cyclones. The gas is cooled to 540 °C and the remaining sulfur is removed in a zinc titanate fluidized-bed reactor. Particulates are removed by a ceramic filter. Sulfur removal efficiency is 99 percent, with emissions of 24 mg/MJ SO_2 and 39 mg/MJ NO_x. The efficiency of the industrial 270-MW CCP will be 44 percent.

Another gasification technology is being designed under Project 7-22 for the Camden TPS. Gasification of high-sulfur (S = 3 percent) bituminous coal from West Virginia will be done in an oxygen-blown, moving-bed reactor with liquid slag removal. The gasifier output will be 1,685 t/d (67.5 t/h). The lump coal will be used and the fines will be briquetted.

The raw gas will be washed to reduce it's temperature and remove tars, oils, ammonia and particulate. Combustibles will be returned to the gasifier. Conventional low-temperature cleaning will remove 99 percent of the S. The cold-gas gasification efficiency will be 89 percent and the carbon conversion will be 99 percent.

The clean syngas is mixed with nitrogen from the air separation plant and is preheated prior to being fed to the GT.

SO_2 and NO_x emissions will be less then 43 and 65 mg/MJ respectively (NO_x reduction will be 90 percent).

Part of the syngas, after additional cleaning and saturation with steam, will be used to feed a 2.5-MW electrochemical generator, based on the molten carbonate fuel cell, that will be integrated into the CCP circuit.

One more gasification project, Project 7-96, will be realized within CCTP. There the 2,910 t/d (121 t/h) plant for direct reduction of iron ore without using coke will be integrated with the CCP circuit of 150 MWe. The process system includes an iron ore reduction furnace and the melter gasifier arranged below it. The capacity of gasifier is 2,550 t of coal/d (106 t/h). It's purpose is gasifying coal and melting iron. A reducing gas is generated in the gasifier and the heat required for iron melting is released. The excess of coal-derived reduction gas exiting the furnace is cooled, cleaned, and compressed before firing in a GT.

Reduction of emissions by more than 85 percent is achieved through the capture of ore and coal sulfur in the reducing furnace with limestone injection under effective control of the process. Since no coke is required for iron production there is no environmental pollution resulting from it's production.

The combined process energy efficiency is 35 percent higher, compared with alternative processes, due to the better utilization of the coal's sensible heat, volatiles, and integration with CCP for production of electricity.

It is expected that the final SO_2 and NO_x cleaning efficiency will be above 90 percent and at least 97 percent, respectively; SO_2 emissions will be 10.5 mg/MJ, and NO_x emissions will be 5.2 mg/MJ.

The general requirement for IGCC is the possible use of various kinds of coal. The gasification modules are being designed to provide flexibility when the CCP unit capacity is changed.

Project of CCP with various coal gasification and combustible gas cleaning technologies are at different stages of commercialization.

Testing demo IGCC plants will start in 1995-1996. Oxygen-blown gasification systems with low-temperature gas cleaning are at a higher stage of development (Project 7-28, 7-30, 7-22) than other technologies under development. The specific cost of such systems will be \$1500-2000/kW with LHV coal combustion efficiency at 40-42 percent.

It is thought that the development and use of high-temperature gas cleaning systems will enable a future increase in the IGCC efficiency to 47 percent and create (the opportunity for) large commercial-size unit.

Along with higher efficiency typical for CCP with coal combustion in PFBC it is possible to exclude special de-SO_x systems by adding limestone or dolomite to the coal. At moderate combustion temperature in the bed a small amount of NO_x is formed. The by-product in this case is dry ash which can be utilized. A CCP using first generation bubbling PFBC has been realized at the Tidd Station in the U.S. (Project 7-14) and has operated for a long time. The 110-MW, 9 MPa, 495 °C steam unit was redesigned by replacing the conventional boiler with a PFBC boiler fed with 1.3 MPa air from a 16-MW GT. The PFBC temperature is 860 °C, and the gas turbine inlet temperature is 830 °C. The steam turbine integrated with CCP operates at a reduced load of 55.9 MW. The CCP net capacity is 70.5 MW at 34.5 percent efficiency.

According to the DOE CCTP, the same technology is being designed for the New Haven Station (Project 7-8), a 340-MW (net) PFBC. A GT of 75 MW and a steam turbine with reheat are used there. The PFBC furnace pressure is increased to 1.6 MPa, the bed temperature is 870 °C, and the CCP efficiency is 42.2 percent. The design SO_2 capture and NO_x reduction are 95 percent and 80 percent respectively.

Also under the CCTP, a 70-MW CCP using a PCFB is being designed (Project 7-10) with a bed temperature and pressure of 870 °C and 1.2 MPa. The gas will be cleaned in a cyclone and a ceramic filter. The steam generated in the PCFB boiler will be expanded in an existing steam turbine. After redesigning, CCP efficiency will be 34.5 percent. Considering the parameters of the steam turbine, the efficiency will be increased by 15 percent.

With a 90 percent sulfur capture, SO_2 emissions will be 300 mg/MJ. Fly ash emissions will be 13 mg/MJ, and NO_x emissions will be reduced by 70 percent. The CCP start-up is scheduled for 1996. The project development (preliminary design) has been made for a 45 percent efficient commercial CCP with a PCFB boiler and additional topping combustor.

Work is under way to design a second generation CCP with PFBC. To this end, the following is planned:

(1) replacement of the GT with a U.S.-made unit;

(2) incorporation of a pyrolyzer and gas hot filter;

(3) increasing the GT inlet temperature.

The pyrolyzer ensures partial coal gasification producing a 925 °C combustible gas. The remaining carbon is removed as coke (char) and is fired in the PFBC combustor at 870 °C. The gases after the pyrolyzer and PFBC combustor are cleaned in high temperature filters. The GT inlet temperature is increased due to firing the combustible gas formed in the pyrolyzer in the top (topping) combustor.

The design validating test will be carried out at the Wilsonville, Alabama plant to be started in 1995. The test modules of the plant will be used to investigate heat transfer and refine the conditions for removing the total heat released in the PCFB. The bubbling-bed system is supposed to be used in the pyrolyzer. The demo plant employs a 4-MW GT. The top (topping) combustor is designed for an outlet temperature of 1290 °C. Before the GT, the gases will be air cooled to 1080 °C.

The plant is intended to play an important role in speeding up and simplifying the development and test of integrated GT clean coal technologies. After construction is completed, it will employ 5 modules. Apart from the advanced PFB combustor and GT, the system will use gasification in a transport reactor, several hot gas cleaning rigs, a fuel cell, and the associated gas treatment systems.

Within the framework of CCTP (Project 7-12), a 95-MW equivalent capacity, demo, CCP using a second generation PFBC is being designed and will be constructed at the Calvert City Station. It will employ a 38-MW GT, model W251B12, a 35-MW steam turbine, and produce 141 t/h of process steam.

In the GT with external, indirect coal combustion, the compressed air is preheated in the boiler to be further expanded in the GT. Coal combustion and flue gas cleaning are made close to atmospheric pressure as in conventional utility boilers.

Predesign works dealt with this technology for 280-320-MW CCP proved a possible efficiency of 49.5-51 percent with a simple GT operating at a firing temperature of 1260-1370 °C, and steam parameters of 16.4 MPa, 593/593 °C. In the boiler path in ceramic heat exchangers the air is heated up to 1090 °C. Further temperature rise is obtained by fuel combustion in the additional combustor. The boiler furnace in the active burning zone is screened by wall superheaters.

Under the CCTP (Project 7-36) an externally fired combined-cycle demo system with a ceramic heat exchanger and hot-air operated GT will be constructed at Warren Station in Pennsylvania.

Work has been conducted in the U.S. on direct P.C. or coal-water slurry (CWS) combustion in the GT combustors for a long time. Some result are illustrated in Table 18. In all project, two-stage external combustion systems were used. At the first stage under fuel rich conditions carbon was gasified accompanied by the formation of low-calorie combustible gas which was cleaned between the first and second stages of fly ash, and – in the Allison and Westinghouse technologies – sulfur that was captured by sorbent injected at the first stage. According to the Solar technology, sorbent was injected at the second stage. In all cases at the second stage high amount of excess fresh air was added for full burnup of combustibles contained in the gas. Shown in the third column of Table 18 are the result of test conducted by the Allison with a full-size 4-MW GT. In large utility CCP with a coal-fired GT predesign, a net efficiency of 42 percent was calculated. Despite the promising result of the research, no construction of a demo plant is now planned.

4.4. Result Obtained in CCTP Project

Many project using low-NO_x burners and reburning are either close to completion or are already completed with good result.

Under Project 7-46 with wall-fired burners and over-fire air at a nominal 500-MWe load, NO_x emissions were reduced to 172 mg/MJ (440 mg/m^3). The emissions were found to vary insignificantly when the load dropped to 200 MW. When compared to the initial level of 546 mg/MJ (1400 mg/m^3), NO_x emissions were reduced by 68 percent, including 43 percent due to burner retrofit and 25 percent because of staged combustion (over-fire). The test were conducted with bituminous coal of 28.6 MJ/kg (LHV) and 30.0 MJ/kg (HHV). The coal contained 10 percent ash, 33 percent volatiles, 72 percent carbon, 1.7 percent sulfur and 1.4 percent nitrogen.

The amount of combustibles in the fly ash at 500-MW load increased from 5.5-8.0 percent despite considerably more fine coal dust.

	Mesh 200 undersize,%	Mesh 50 oversize,%
Initial state	63	2.8
Advanced burners and over-fire air	74	0.6

This fact caused boiler efficiency to decrease by 0.25 percent. By increasing excess air, carbon loss can be decreased to the initial level. In this case, however, NO_x emissions increase to 228 mg/MJ (589 mg/m^3).

Under project 7-42 cell burners were redesigned (see above). When firing different bituminous coals with S = 1.1 percent, the average NO_x concentration at boiler full load was found to drop from 500 mg/MJ (1280 mg/m^3) to 205-240 mg/MJ (530-615 mg/m^3), 55 percent on average. The fly ash combustibles content was 1.1 percent and the carbon loss was 0.2 percent. The unit efficiency was not changed and no boiler corrosion rate change was observed.

Reduction of NO_x formation by 37-48 percent at full-load was attained under Project 7-48 when testing a low-NO_x burner in a tangential-fired furnace with various combinations of burner rows, an additional air feed just above the row and separately above the burner area. The test were carried out firing various Eastern bituminous coals with S = 2.5-3.0 percent.

The reconstruction and testing of boilers with the new low-NO_x burners and reburning, using natural gas as a reducing fuel was made at 3 coal TPS employing different firing systems (Project 7-44, Table 12).

Basic result of test can be seen from the Table below:

Quantity	Location of test, furnace specifics		
	Hanneping, tangential-fired	Lake Side, cyclone	Denver, wall-fired burners
Unit output, MWe	71	33	172
NO_x initial emission,			
mg/MJ	320	435	310
mg/m^3	820	1115	795
NO_x attained level,			
mg/MJ	105	150	110
mg/m^3	270	330	285
NO_x reduction, %	67	66	64
Share of natural gas, %	18	22.5 (20-26)	12.6 (5-19)
Reduction of boiler efficiency, %	0.3-1.1	0.59	0.45
Over-fire air, %	—	28.7	19.3

Reburning, using coal dust as a reducing fuel, was implemented on a 100-MW unit cyclone boiler (Project 7-40) with the result that follow.

Quantity	Coal Grade	
	Lamar bituminous, S = 1.8%	Powder River Basin subbituminous coal, S = 0.6%
NO_x initial emissions,		
mg/MJ	505	445
mg/m^3	1290	1140
NO_x attained level,		
mg/MJ	230	165
mg/m^3	590	420
NO_x reduction, %	55	63
Carbon loss, %	1.5	0.3
Increase of carbon loss, %	0.1	0.0

In Project 7-56, 50 percent SO_2 capture was attained on 73.5-MW unit boiler firing bituminous coal with S = 1.5-2.5 percent when sorbent – slurry of hydrated calcite and pressurized hydrated dolomite limes – were sprayed in the gas duct.

The evaporation of droplet and the absorption of SO_2 were completed in 2 s. No deposit were observed in the duct. The system operated reliably and it is easily automated.

When testing a simplified wet/dry SO_2 control system under Project 7-66, LIMB-Coolside, 61 percent of SO_2 capture was reached in LIMB system on a 105-MW unit firing 3.8 percent S coal using lignolime as sorbent. In the Coolside process using hydrated lime at a Ca/S = 2.0 and a Na/Ca = 0.2, 70 percent SO_2 capture was reached at 11 °C of the approach-to-saturation temperature.

In SO_2 control system testing with LIFAC technology (Project 7-58) 20-30 percent SO_2 was captured using limestone injection into the top of a 60-MW boiler furnace. Another 40-55 percent SO_2 was captured in the activation reactor where flue gas containing CaO – the limestone calcination product – was humidified with injected water. Thus, the overall SO_2 cleaning efficiency reached 80-85 percent. To recover the flume opacity above the stack, the leaving gas temperature, which was reduced since SO_2 control installation, was increased to

93 °C by mixing the leaving gas with a small amount of hot gas.

Using technological methods in Project 7-76, NO_x emissions were reduced from 665 mg/MJ (1700 mg/m^3) to 240 mg/MJ (615 mg/m^3), i.e., by 63-69 percent without increased carbon losses. With in-furnace urea injection, NO_x emissions were further decreased to 128 mg/MJ (330 mg/m^3), that is another 40 percent with an $NH_3/NO_x = 0.85$. The overall NO_x reduction was greater than 80 percent. Urea injection causes N_2O formation in the amount of 20-35 percent of the total reduced NO_x. With the injection of pretreated urea to yield NH_3 only 3-10 percent N_2O was formed.

With in-duct injection of dry calcium hydroxide (Ca/S = 1.75-2.0) followed by gas humidification to 16.5 °C of the approach-to-saturation temperature not more than 25 percent S was captured. Even in this case hard to remove deposit were formed in the fabric filter.

Injection of dry sodium sesquicarbonate and bicarbonate before the air heater in the ratio of Na/S = 1.2-1.5 enables an 80-89 percent SO_2 capture to be obtained. Despite formation of 20-35 ppm of NO_2 a colored plume above the stack was not observed.

As for Project 7-54, good result were reported in testing wet/dry SO_2 removal in a CFB reactor with a high concentration of particles.

The reactor with an equivalent capacity of 10 MWe was constructed on the gas duct bypass of the 150-MW unit boiler. In demonstration test on 2.7 percent S (in some periods up to 3.5 percent S) and 0.12 percent Cl coal the system operated with an average SO_2 reduction of 90-91 percent at a molar ratio of $Ca(OH)_2/SO_2 = 1.40 - 1.45$ and an approach-to-saturation temperature of 10 °C. Previously the system operated normally without deposit formation at an approach-to-saturation temperature of 2.8 °C using coal with low Cl content, and at 10.0-12.8 °C of the approach-to-saturation temperature with Cl content no more than 0.3 percent. With such approach-to-saturation temperature values and $Ca(OH)_2/SO_2 = 1.4$, SO_2 capture was 98-100 percent in preliminary test. The effect of operating conditions on SO_2 reduction can be seen below.

Approach-to-saturation temperature, °C	4.4	10.0	10.0
Coal Cl content, %	0.004	0.04	0.12
SO_2 removal efficiency, %:			
at $Ca(OH)_2/SO_2 = 1.0$	79.5(72-92)	70(67-77)	84(78-95)
at $Ca(OH)_2/SO_2 = 1.3$	94.0(88-99)	85(78-92)	93(90-95)

The advanced wet SO_2 control systems have been in operation for years (Project 7-60, 7-62).

The average system efficiency at the Baily TPS 500-MW unit (Project 7-60) firing bituminous coal with 2.0-4.5 percent S content was 94 percent. During special test over 98 percent efficiency was attained. With regular unit operation SO_2 emissions were 165 mg/MJ (420 mg/m^3). Auxiliary power requirement were 5.3 MW (< 0.9 percent), and the gas path pressure drop was about 800 Pa. The SO_2 control system operated reliably. The 2-year average availability factor of the whole complex was close to unity (99.996 percent). During that period, 121,300 t of SO_2 was removed, 198,800 t of limestone was consumed, and 356, 000 t of 97.2 percent quality gypsum was produced.

The average water flow rate was 355 m^3/h with an average effluent discharged at 18.4 m^3/h. Waste waters contained 4,560 ppm chlorides, < 2,500 ppm sulfates, 19 ppm fluorides, 14.1 g/m^3 dissolved solids and had a pH = 8-9.

The SO_2 control system using a bubbling reactor (Project 7-62) was put into operation in March 1993. It enabled 98.7 percent S capture, collected 90 percent of particles > 1 micron and up to 50 percent, of particles < 1 micron that were left after cleaning by a 99 percent efficiency ESP, and utilization of over 97 percent of the limestone when operating at low pH value. The SO_2 removal system final product is saleable gypsum produced at rate of 7 t/h. The power consumed by the SO_2 control system constitutes about 1.5 percent of the unit output with a possible reduction by process optimization. No liquid deposition from the flume above the stack was observed even at 100 percent air humidity. During the first 5,000 operating hours the system availability was 98 percent.

The 35-MW equivalent capacity system of flue gas cleaning was installed as a bypass (slipstream) on a boiler firing coal with S = 3.4 percent. The system used a baghouse to remove particulate matter and SNOX technology to catalytically remove SO_2 and NO_x. The flue gas cleaning efficiency of SO_2, NO_x, and particulate matter was 96 percent, 94 percent and 99.9 percent respectively. The system produced 25.5 t/d of 93 percent sulfuric acid with no solid wastes. The majority (99 percent) of flue gas toxics were removed in the SNOX process itelf, with or without the baghouse The system has been in operation for 5,700 hrs.

When testing a 5-MW equivalent capacity SNRB system (Project 7-68) the following result were obtained using real combustion gases of bituminous coal with S = 3.4 percent.

Sorbent	Ratio	Temperature, °C	Sulfur Capture,%
Commercial hydrated lime	Ca/S = 2.0	430-470	80
Sugar hydrated lime	Ca/S = 2.0	430-470	90
Sodium bicarbonate	Na/S = 1.0	220	80

At 430-470 °C, 90 percent NO_x reduction was attained with zeolite catalyst and ammonia injection providing an NH_3/NO_x = 0.9. Particulate removal by the baghouse was 99.89 percent.

Out of the advanced electric power generation technologies, the PFB coal combustion CCP project is the most mature (Project 7-14, Table 16).

The CCP test began at the end of 1990. Since that time comprehensive investigations have been conducted. Problems were detected and eliminated with preparation, feed, and distribution of the coal-water paste used as fuel; uniform in-bed coal combustion without impermissible ash agglomeration; ensuring nominal steam capacity by increasing the surface of in-bed tube bundles; and cleaning combustion product of fly ash in cyclones and removal of separated ash. The modifications and repairs to restore operability after damages took time. Ultimately the CCP total operating time by mid-1994 was 7,880 hrs.

When assessing CCP availability one should take into account that the plant had been designed without backup systems and component which were the practice with industrial (commercial) unit. It is also important to note that CCP availability increased constantly with operational and test experience.

CCP featured good ecological characteristics. At full load and a 3.2 m high bed a 90 percent S capture was obtained at a Ca/S = 1.15-1.35, and 95 percent S capture at a

Ca/S = 1.5-1.8. NO_x emissions were 65-77 mg/MJ.

Considering the experience obtained in mastering similar plant in Sweden and Spain, the PFBC technology can be considered ready for commercial application.

Project 7-16 is less complicated and also relates to the same group. The Nucla Station CFB boiler designed under this project was tested during 15,700 hrs firing various coals with S = 0.4-0.8 and 1.4-1.8 percent. At bed temperature of 880 °C, the following result were obtained:

Ca/S Ratio	1.5	4.0
Sulfur Capture, %	70.0	95.0

NO_x emissions were < 145 mg/MJ (375 mg/m^3) with 77 mg/MJ (200 mg/m^3) on the average, and coal burnup was between 96.9-98.9 percent. The presence of combustibles in the fly ash was evidence of incomplete combustion: only a small fraction of it is attributed to combustibles in the bottom ash and the flue gas CO. The boiler efficiency was 85.6-88.6 percent.

The new development for power generation are advanced cyclone combustors enabling radical reduction of SO_2 and NO_x. Such a cyclone (Project 7-98) operated on an industrial boiler under heat loads from 5.57-1.76 MW. It was tested during 900 hrs firing 8 various bituminous coals containing 19-37 percent volatiles and 1.0-3.3 percent sulfur. When limestone was used in the cyclone as sorbent in the ratio of Ca/S = 2.0, up to 58 percent S capture was observed. It increased reaching 80 percent with sorbent addition in the boiler furnace. NO_x emissions were 160-184 ppm (130-150 mg/MJ, 330-380 mg/m^3). Removed from the cyclone combustor as liquid slag were 55-90 percent of the ash and sorbent. The inert slag is a waste product. The combustion efficiency was > 99 percent.

5. REDUCTION OF COAL TPS ENVIRONMENTAL IMPACT IN RUSSIA

5.1. Coal used at Russian TPS

5.1.1. General

Russia possesses rich coal resources. The largest and most economically important of these are the Kuznetsk (Kuzn.) and Kansk-Achinsk (K-A) coal fields located in the southern part of Central Siberia. The production of coal now amount to about 270 × 10^6 t/y.

In the European part of the country much coal is produced in the south, in the Eastern Donbass (Donb.) and to the north, in the Pechora (Pech.) coal fields. Production of the expensive and low-grade brown coals found near Moscow is rapidly decreasing.

There are many coal fields covering the (rather high) demands of the nearby regions.

A large amount of Ekibastuz (Ekib) coal produced in Kazakhstan is fired in Russian TPS.

The quantities and properties of coal fired in Russian TPS are illustrated in Table 19 [3].

Coal production conditions are most favorable in the K-A field, where large, horizontal seams, tens of ms thick, are located near the surface. The field is in an easily-accessible area with acceptable climatic conditions. The coal is produced by the open-cast (strip-mining) method at rather low cost.

The geological conditions in the highly-developed Kuzn field are now rather complex. The industry environmental impact here is high in many areas and the infrastructure is inadequate.

In the European part of the country the coal is mined underground which makes it cost very high. The geological conditions of the heavily mined areas (Eastern Donb and the Moscow area fields) are unfavorable. The Pechora coal field is located in a severe climatic area.

The Eastern regions of the country supply mostly low-grade, high-moisture, and high-ash local coals to be fired at power stations. Many old coal fields are exhausted and vast territories are energy-deficient. Coal will continue to plat an important role for the Russian power industry in the near future. The direction and specifics of the evolution of the coal industry in Russia are briefly discussed in Section 3.

5.1.2. Characteristics of Bituminous Coals

Russia mostly uses the Kuzn bituminous coals from the Southern Part of Central Siberia. These high-grade, low-sulfur coals are adaptable for transport over large distances. Coals of various petrographic composition and degrees of carbonization are used to fire utility boilers. The properties of these coals are given in Table 20 wherein LF stands for long-flame, G denotes gas-coals, WS designates weakly sintering, L means lean and A – anthracite. Wider limit of variation of some properties – maximum moisture content up to 18-21 percent, lean coal volatile matter content of 5.5-14 percent, heating value of 16.5-27.7 MJ/kg are characteristic of open-cut produced coals of respective grades [26].

Besides the graded coals, TPS are supplied with various by-product and slurries from coal-beneficiation operations. The properties of such materials vary widely (refer to the last column of Table 20).

In terms of geology and available transportation asset, production of these superior coals could be significantly increased. However, the region in which they occur is saturated with various large, basic industries such as coal, metallurgy, chemicals and others. This has strained the local infrastructure to the point that increasing coal output substantially would require large capital investment.

Despite all this, the Kuzn coal field is still a major coal base of Russia and the coals from this field are used at many existing TPS, including those in the European part of the country. This coal is fired at a great number of cogeneration and condensing power plant employing 150- and 200-MW subcritical unit, and also at TPS with 300-MW supercritical unit. 800-MW unit Installed at the Perm, and designed to fire Kuzn coal are also operated on natural gas.

Characteristics of bituminous coals from other fields in Russia are shown in Table 21.

Only a small area of the Donetk coal field remains in the Rostov region (the south of the European part of the country) of Russia. The power industry uses mostly the high-sulfur lean coals and anthracite culm (AC) produced there.

The Pechora coal field is located in the northern part of European Russia. Inta coals, produced there, have a high sulfur and high ash content which is difficult to reduce by beneficiation.

In both coal fields the coal is mined underground at high cost.

The coal from the Ekib field in northern Kazakhstan, widely used at Russian TPS, is weakly sintering mostly because of the high content of mineral matter. In view of seam peculiarities, the Ekib coal is mostly produced in bulk where the ash content reaches 55 percent.

Twenty to thirty percent of the ash of the Kuzn, Donetk, Pechora and Neryungri coals consist of the basic oxides: Fe_2O_3, CaO, mgO, K_2O, Na_2O with the major share of Fe_2O_3. Because of that, the ash fusion temperature for Kuzn coals is in the range of 975-1,050 °C. It was found to decrease with increasing concentration of alkali element Na and K in the ash [27].

In firing most Kuzn coals, no substances are formed or selectively released that form stubborn deposit on heating surfaces because the coals are weakly sintering.

Donetk coals have characteristically high sulfur content, up to 70 percent of which is in the form of pyrites.

Low-reaction Donetsk coals are usually fired in wet-bottom furnaces and at high temperatures which cause the melting out and averaging of the entire fly ash. That is why the heating surface deposit are friable; even at the slagging temperatures given above self-removal of deposit is observed.

In rare cases, when firing Donetsk coals in dry-bottom furnaces, a dense layer of primary deposit with a concentration of Fe_2O_3 up to 40 percent is formed on tubes of platens and on the first rows of the convective superheater.

5.1.3. Characteristics of Brown Coals

The brown coals play a rather important role in the structure of fuel supply to Russian TPS. Out of about 150×10^6 t of coals fired at TPS in 1993, the share of brown coals was about 50 percent (Table 19). The brown-coal fields are mostly located in Siberia and the Far East. The largest is the K-A field located in the southern Part of the Krasnoyarsk region. It is a unique natural phenomenon due to the size of the coal deposit and structure of it's coal seams. Of the 19 fields in the K-A basin that have been explored, three seams are currently being developed; Nazarovo, Berezovo and Borodinsk with a total production capacity of 58×10^6 t/y.

K-A coals have good firing and ecological characteristics: ash content 4.0-16 percent, sulfur content 0.3-0.4 percent, heating value 11.8-15.6 MJ/kg, and volatile yield 47-48 percent.

The K-A coal ash chemical composition is illustrated in Table 22 showing high (up to 42 percent) CaO content, and an increased content of Na and K oxides [27].

Brown coals used for power generation in eastern Siberia and the Far East differ from K-A coals both in firing properties (Table 19) and coal ash characteristics (Table 22).

In the European part of Russia, brown coals are mostly produced in the near-Moscow coal field. However, because of the high cost of mining and the low quality of these coals ($S = 2.3$-2.5 percent, $A = 35$-38 percent, $W = 30$ percent, $LHV = 7$-9 MJ/kg) their use for power generation is decreasing.

The open-cut produced K-A coals are the cheapest and their increased use for power generation is an important economic goal. Production of these coals can be increased up to $80\text{-}130 \times 10^6$ t/y as long as the country's economy will improve.

Despite the available positive experience of transporting considerable amount of K-A coals by rail (up to 1.5×10^6 t) to TPS and storing it in open piles for a year and longer, more efficient long-distance transport of K-A coal-derived product are under consideration in order to reduce transportation cost on-site processing.

Among such possibilities are:

- preparation of the required coal dust at central pulverizing plant;
- preparation of crushed coal to be used in CFB boilers;
- production of coal briquettes;
- preparation of coal-water slurries;
- various kinds of pyrolysis to obtain semi-coke and liquid fuel.

Based on performance characteristics and feasibility by the year 2005, the first priority is the production of coal briquettes. It will enable reduction of cost for transport and services for coal storage, increase the reliability of fuel handling and pulverizing systems, and reduce environmental impact.

5.2. Power and Environment Protection Technologies in Use

Conventional bituminous coal-fired dry- and wet-bottom boilers are available.

Kuzn, Pech, and Yuzhno-Yakutk coals are close in their physical/chemical characteristics and are almost consistent with bituminous steam coal standards adopted for the World Market.

Ekib coals have a high ash content, are highly abrasive, non-slagging, and explosion-proof.

Donetsk AC are characteristically of very low reactivity (volatile yield of 4 percent); and are difficult to fire even with liquid slag removal.

The peculiarities of firing brown K-A coals and cleaning the flue gases formed result from the properties of these coals, which feature a high volatile yield, high reactivity, and a tendency to intensively slag boiler heating surfaces. They also readily self-ignite in storage, and the dust is explosive.

The history of using K-A coals goes back to firing Nazarovo and Irsha-Borodinsk coals in 320-500 t/h dry- and wet-bottom boilers.

The basic problems when firing the above coals are the accelerated slagging of furnace waterwalls and the impaired removal of liquid slag due to varying coal properties (when various-seam coals are supplied) and ash content. To overcome these problems, pilot boilers have been designed using special firing systems. These are briefly described in Section 2. Though they have been investigated in detail and numerous modifications of their component have taken place, the boilers have not found further application.

In view of the available commercial experience and the result of testing K-A and other brown coals from the eastern fields, the most suitable combustion is a low-temperature one (below 1,200-1,300 °C) combined with gas drying and ballasting of the flame with combustion product. This has been implemented with the simultaneous modification of the modes and design of the tangential-fired furnaces with straight-flow burners on the new E-500 and P-67 boilers (see Section 2).

The experience with firing the most slagging Berezovo coal in the E-500 and P-67 boilers showed that the furnace temperature level should not exceed 1,300 °C to prevent quick slagging [28,29,37].

The firing process can be improved by using more uniform coal dust, uniform flow of air and recirculated gases over burner tiers and channels, intensifying the fuel ignition, reducing the active burning zone temperature by increasing swirl in the upper part of the furnace chamber, and increasing to 40-45 percent the amount of recirculated gas to these zones.

When bituminous coal ash contacts water no hard deposit are formed. This makes possible the wide application of wet ash collectors and hydraulic ash removal systems at old TPS firing Kuzn coals in boilers producing up to 670 t steam/h (186 kg/s). The above systems are also installed at AC and Ekib coal-fired boilers, with reference to the latter up to 500-MW unit. However, these systems are not sufficiently effective on ash separation and provide problems with further ash utilization. At newly installed bituminous coal-fired boilers of up to 1,000 t/h and more of fly ash is caught by ESP. When these power unit were designed ESP efficiency at 90-96 percent had been thought quite sufficient and an ESP of limited size with up to 3 m/s gas velocity – economically reasonable.

The Ekib coal-fired 500-MW unit employ two-stage ash removal systems with a wet venturi scrubber being installed as the first stage and an ESP as the second stage, with an overall efficiency of 99.5 percent [28].

The K-A coal-fired TPS are now equipped with two types of ash collectors – multicyclones (66 percent) and ESP (34 percent). The fly ash removal in multicyclones is 92 percent maximum, while that in an ESP is 94-97.5 percent and depends on their type and size (generally, they fail to provide for the required residence time) and the boiler outlet temperature (often at 160-180 °C). These figures cannot be considered satisfactory.

In retrofitting/repowering existing and constructing new TPS upgraded ESP and baghouse filters will be applied to ensure the particulate matter emissions at 50-100 mg/m^3 or below. Now in Russia a new type of ESP with a 460 mm electrode spacing has been mastered. It will be equipped with a variable current supply, automatic control and monitoring, and a pneumatic fly ash discharge from the hoppers.

The fly ash of low-sulfur Kuzn and Neryungri coals, and, particularly, of Ekib coals is of increased electrical resistivity. This may impair ESP operation and reduce the collection efficiency. In many cases, especially in retrofitting/repowering of existing TPS which lack space to install additional ESP fields or to extend the ESP area, flue gas conditioning at the ESP inlet is advantageous. Conditioning includes temperature reduction (which may also increase fuel utilization), using chemical additives (for example, SO_3) or electromagnetic radiation which transforms lower SO_x and NO_x to higher oxides.

At some TPS by using simple flue gas conditioning before ESP (for example, reducing the temperature by injection of water-treatment plant salted effluent) fly ash emissions were decreased by 2-3 times.

Fabric filters are attractive as a means of fly ash collection, but there is practically no operating experience with them in Russia. In this connection, the risk exist that with the high ash content (up to 25-35 percent) of many steam bituminous coals, the use of the fabric filter may entail difficulties or be inefficient.

Small-capacity demonstration fabric filters have been in successful operation with a K-A coal-fired boiler for some years. Baghouse filters in sizes of 110,000, 280,000, and 940,000 m^3/h have been made commercially available. They are employed in the metallurgical industry. A project is under way to install baghouse filters on the 500-t/h K-A coal-fired industrial boiler at the Minusinsk cogeneration plant.

In cases where it is profitable to keep a wet ash collection system and increase scrubber efficiency by using a higher spray rate, or by applying emulsifiers with a high rate of ash removal, it seems reasonable to use them to collect part of the SO_2 contained in the flue gases. Experience indicates that SO_2 reduction in these cases can be 50-70 percent.

The increased ash collection efficiency and reduction of particulate matter emissions up to < 50 mg/m^3, which is technically feasible, also solves the problem of heavy metals and toxic product of incomplete combustion, which emissions are not regulated now.

Kuzn and Pech coals contain of 2.1-2.7 percent fixed nitrogen. High flame temperatures are required to ensure the complete combustion of the above and other bituminous coals with a moderate volatile yield. These circumstances facilitate NO_x formation in firing bituminous coals and make it difficult to attain the environmental requirement through technological methods only. Nevertheless, application at existing boilers (including wet-bottom boilers) of various methods capable of improving combustion (feed of coal dust of high concentrations, use of special burners, stage combustion) enabled NO_x reduction of up to

450-600 mg/m^3 [28-32].

At low-temperature, combustion of brown coals, and K-A coals in particular, NO_x are primarily formed from the fuel nitrogen compounds. Theses compounds during volatile yield and firing can be converted to NO or N_2 depending on the conditions.

In firing slagging coals, care is needed in the application of known firing methods for NO_x suppression.

The boiler test showed that NO_x concentrations could be reduced to 200-350 mg/m^3 simply by decreasing excess air (SR). However, in this case, starting from a certain SR value, slagging of waterwalls was found to be accelerated. Boiler operation at minimum excess air is an urgent problem. The solution of the problem could be facilitated by mode optimizing with respect to the slagging and NO_x formation, automatic control of furnace processes (flows of coal dust, air, recirculation gases), use of finer coal dust particles, and better waterwall cleaning.

Work is under way to modernize burners through the optimization of velocities of coal-air mixtures, secondary air and recirculation gases, stream outlet angles in horizontal and vertical planes, etc. Of interest is the application of bottom burners to fire high-reactivity, low-ash, strongly-slagging coals that make the flame longer (burning start at the furnace bottom) and move the flame from the furnace walls.

Simplified reburning of brown coals was implemented at 270-t/h and 420-t/h boilers at the Irkutk cogeneration plant. Both boilers have tangential-fired, dry-bottom furnaces with a two-tier arrangement of straight-flow burners. The upper-tier burners operated at SR<1.0, where the air required for complete combustion was fed via overfire nozzles. The result obtained on the 420-t/h boiler are illustrated in Figure 15: NO_x concentration was reduced by 35-45 percent [25,29].

Reburning will be more extensively tested in the near future in a 500-t/h boiler.

To decrease NO_x formation, a scheme with brown coal dust preheating in a direct fired system has been designed. When firing the coal dust preheated to 600-950 °C at the pilot facility, NO_x formation was reduced 2.5 times, and in the case of reburning, more than 3 times. At the pilot 35-t/h boiler, NO_x concentration was reduced from 400-500 mg/m^3 to 220-300 mg/m^3. Further NO_x reduction could be predicted to 200-250 mg/m^3 [28]. Technical solutions for coal dust preheating and staged combustion have been designed for a P-67 800-MW unit and 500-t/h boilers.

As mentioned above, there are possibilities of long-distance transport of K-A coals. As briquettes, for example. In this case, the firing conditions will be different but not new to the Russian industry. For example, there are many years of experience with the combustion of dry, centrally-treated Nazarovo field K-A coal dust in wet-bottom boilers. NO_x emissions were reduced under such conditions by using a highly concentrated coal-air mixture: 50 kg of coal dust per 1 kg of air. The typical dependence of the furnace outlet NO_x concentration upon excess air is shown in Figure 16 with reference to a 680-700-t/h boiler [31,7].

All of the low-NO_x burners and reburning technologies (7-40, 7-42, 7-44, 7-52) demonstrated under the DOE Clean Coal Technology Program (CCTP) for bituminous coal-fired boilers can be implemented when firing the Russian coals discussed above. The U.S. technical solutions will compete with those available in Russia. Joint development using, for example, U.S.A. burners, mills for superfine grinding of coal for coal reburning, measurement and control devices, etc., could be attractive.

Where primary technological measures fail to attain the required NO_x emissions, noncatalytic and catalytic de-NO_x systems will be used.

Russia has experience with the noncatalytic system of NO_x reduction by injection of ammonia water into the high-temperature (about 1000 °C) boiler path. Test were conducted at two 420-t/h natural gas and Kuzn coal-fired boilers. When firing coal, NO_x concentrations with ammonia water injection were decreased by almost 2 times [28]. Now the system is automated, based on U.S. measurement devices.

Projects have been designed for catalytic de-NO_x systems for 500-MW Ekib coal unit (see below) where the catalytic reactor is located before and after the particulate matter and the SO_x gas cleaning devices in the dust-laden flue gas boiler duct. Pilot and industrial test are being carried out on Russian- and foreign-developed catalyst for de-NO_x systems using real dust-laden flue gases.

The flue gas SO_2 concentrations when Kuzn coals are fired are generally within 300-350 mg/MJ (800-1,100 mg/m^3). For the Neryungri coals the figures are half as high. As specified in the prepared National Standard, such emissions allow for boiler operation with no special flue gas SO_2 cleaning measures.

Wherever required in firing Kuzn, Neryungri and Ekib coals, use may be made of simple de-SO_x technologies employing wet ash collectors (see above) and wet/dry devices, in particular, those that are integrated into the gas duct. Their efficiency will be at 50-70 percent. Among the CCTP DOE technologies that can be used are those demonstrated in project 7-54, 7-56, 7-58, 7-60, and 7-62.

In ecologically dangerous locations when Ekib, and to a lesser extent Kuzn and Neryungri coals, and as a rule Pech and Donetk coals are fired, the use of wet/dry technologies in special apparatus for about 90 percent sulfur capture can be required. Such technologies are being developed, in particular, under CCTP DOE project.

As mentioned previously, low-sulfur, low-ash K-A coals feature high-calcium-content ash (CaO = 26-42 percent for different coal fields, including 17-32 percent of free CaO; CaO/SO_2 = 2.5-5.3; free CaO/SO_2 = 1.1-3.5). With low-temperature, dry-bottom furnace combustion of such coals, up to 40-60 percent of the sulfur (Figure 17) is captured in the furnace volume [33]. Injection of activated ash containing much unused active CaO into the gas duct adds to the degree of sulfur capture by about 20 percent. The jet-mill, crushed ash is better if injected into the furnace top; and that which is processed in the digester is better if injected into the convective section where gas temperature is 500-600 °C.

If a baghouse is used to clean the gases of particulate matter, additional sulfur is captured in the ash layer that forms on the filter material. Ultimately, with additional injection of activated ash, the overall sulfur capture in the dry system without external sorbent may reach 80-90 percent [37].

To clean combustion product resulting from the combustion of near-Moscow field 3 percent S brown coal, a demo plant of 400,000 m^3/h capacity, based on the ammonia-cyclic-technology has been constructed at one of the utility boilers of the Dorogobuzh TPS. This method is based on the SO_2 absorption by ammonia sulphite and the formation of hydrosulfite and sulphate. The final product are 10 percent liquid SO_2, crystalline ammonia sulphate and colloidal sulfur. Basic characteristics of the plant are given below.

Flow of flue gases to be cleaned, m^3/h	400,000
Flue gas temperature, °C:	
Before de-SO_x system	150
Past de-SO_x system	45-55
Flue gas SO_2 concentration, mg/m^3:	
Before de-SO_x system	5500
Past de-SO_x system	300-350
Flue gas NO_x concentration, mg/m^3:	
before de-SO_x system	350-400
past de-SO_x system	200-250
Yield of de-SO_x system by-product with 7,000-hour operation, t/y:	
Liquid SO_2	18,000
Ammonia Sulphate	14,200
Colloidal Sulfur	214,500
Annual ammonia consumption, t/y	1,830

The plant efficiency and the consumption of the reagent required for operation are being refined.

The lowest emissions, sometimes below those specified in the Standards, and the highest flue gas cleaning efficiency will be required for cogeneration plant located in towns, sometimes in residential areas, and also for industrial cogeneration plant in highly contaminated areas.

In all cases of conventional bituminous coal combustion, the washing of raw coals would be reasonable to decrease the ash content. This would facilitate the ash collection and removal and also facilitate the use of the various technologies for emission reduction and flue gas cleaning.

6. BASE OPTIONS OF ADVANCED COAL THERMAL POWER PLANT

The following base-option project were deemed to be winners of the competition by their inclusion in the "Clean Coal Technology" section of the State Program "Ecologically Clean Power Generation." [35, 36]

Basic parameters of the TPS employing various technologies are shown in Table 23.

It is difficult to compare the technologies on the basis of economic parameters for the following reasons: They have been designed around coals of differing properties and cost. The TPS have been sited in differing geographic locations. Different operating modes have been employed. Finally, equipment and construction cost have been unstable and not always fully justifiable.

The lowest specific cost relate to TPS with low-cost 500-MW unit firing Ekib bituminous coal. TPS with brown K-A coal fired 800-MW unit are higher in cost because the lower combustion temperatures necessary to prevent ash slagging dictate larger physical dimensions for the furnace (see Section 2). The lack of Russian experience with direct flue-gas removal of SO_x and NO_x has led to conservative cost estimates for such equipment and TPS utilizing it. By contrast, the specific cost for CFB boilers seems optimistic for the very same reason.

6.1. 6.4-GW TPS Project with 800-MW, Brown K-A Coal-Fired Unit

The 6.4-GW TPS featuring 8 800-MW supercritical boilers firing brown coal from the Berezovz field is a base option.

Principal features of the P-67 boiler (Figure 5) at the Berezovo TPS-1 are: Dry-bottom, tangential-fired furnace. Low active combustion zone heat-release rate. Low flame temperatures, i.e., 1,300-1,400 °C maximum. Early ignition and intensively pulverized coal (PC) burnup at the initial point.

Specific coal composition as regards mineral and organics content allowed SO_x and NO_x reduction and attainment of ecologically-required levels of SO_x and NO_x of 200-300 mg/m^3 without special de-SO_x and de-NO_x systems [7, 28, 37].

The following methods will be employed for NO_x reduction: fuel preheated to 650-850 °C, staged low excess air combustion and combustion gases used for fuel drying in the pulverizing mill fans system. A schematic drawing of the coal preparation and firing systems for the P-67 boiler is illustrated in Figure 18. The raw coal from the hopper enters the drying section at 33 percent moisture. This is reduced to 13 percent by the 590-650 °C combustion gases. Also, the fuel is classified by the mill fan into high and low solids concentration streams. A portion of the coal-air mixture is fed to the muffle burner where it is used for heating the main stream in the PC preheater. To ensure complete combustion and minimize slagging of the boiler's heat-exchange surfaces, simultaneous coal particle size reduction from R_{90} = 40-60 percent to R_{90} = 20-30 percent and R_{1000} < 1.5 percent is required.

Low-temperature combustion allows for sulfur capture within the furnace of up to 50 percent by the calcium in the ash. Fabric filters are used to clean the flue gases and additional sulfur is captured in the fly-ash layer on the filter bags. Also, feed of activated ash into the furnace and the convective path is provided.

Firing Berezovo coal with 0.4-0.5 percent sulfur in pilot test showed that the 200 mg/m^3 maximum requirement can be assured by the above methods of sulfur capture in the furnace and on the flue gas filter bags. The cleaning efficiency of the fly-ash layer on the filter bags is sufficient to meet the specified ecological maximum of 50 mg/m^3.

Technical data for the FRO-12000 baghouse module is shown in Table 24. Figure 19 illustrates the two-storey layout of the baghouse bay adopted for the TPS.

Operation on coal with 7 percent average ash content will yield 1.5×10^6 t/y of ash and slag wastes.

Because the K-A coal ash contains CaO, provision is made for its granulation (as $CaSO_4$) by treating with acid waste water from the make up treatment system to improve salability properties and prevent environmental impact when land filling.

The 6.4-GW TPS is constructed within two main buildings. Each contains 4 of the 800-MW unit. Each unit has it own 84 m wide bay. Overall, each main building is 434 ms wide and 177 ms deep. The baghouses and the induced-draft fans are located in separate buildings. Two 250 m-high stacks are provided, each serving four unit (Figure 20).

The proposed new technologies for the project are being perfected in the 35 t/h pilot boiler: The influence upon NO_x of the high temperature preheating of the PC and staged combustion, SO_x capture in the boiler gas path and in the baghouse, and injection of ash activated in the jet mill or digester at various point in the gas path are being quantified.

These techniques will be further tested in a 500 t/h boiler presently under construction and due to be started up in 1996.

The result of experiment aimed at validating this project were considered briefly in Section 5.2.

Basic parameters of the TPS employing 800 MW unit designed under this project are shown in Table 23. It is compared with alternative TPS based on the same coal technology below:

	Existing unit w/o de-SO_x/de-NO_x systems	Existing unit with de-SO_x / de-NO_x systems	Base option
Efficiency at nominal output, %	38.50	37.50	39.20
Mean annual efficiency, %	38.07	37.28	38.85
Mean annual specific standard fuel consumption, g/kWh	323.10	329.90	316.60
Relative specific investment	0.978	1.24	1.00
Relative averaged electricity cost	0.996	1.23	1.00
Specific emissions, mg/m_3			
NO_x	600	200	200
SO_x	600	300	300
Particulate matter	150	50	50

6.2. Yuzhno-Ural Ekib Bituminous Coal-fired 4-GW TPS with 500-MW Unit Project

The base option is a 500-MW supercritical unit with conventional PC firing [38]. Some parameters of the unit and TPS are shown in Table 23.

The P-57, 1,650 t/h, 24 MPa, 545/545 °C boiler manufactured by the Podol'sk Machine

Building works in 1986 was adopted as the prototype.

Conventional firing of Ekib coal in the P-57 boiler generates rather high NO_x – in the order of 800-1,300 mg/m^3. Two versions of the furnace have been specifically designed with technologies intended to reduce NO_x emissions.

The furnace is equipped with two tiers of wall swirl burners (Figure 21), and has additional straight-flow burners arranged 3-4 m above the second tier. These burners, operating with SR = 0.7, handle 20 percent of the fuel. Above them, at 26-30 m elevation, nozzles are arranged to feed 10-24 percent of the total air.

The tangentially-fired furnace (Figure 22) has 24 straight-flow burners arranged in three tiers of eight burners (two set of four) each on the side walls with the coal/air channels of each set aimed at the perim of a 1,200 millim diameter circle situated in the space between them so as to generate a counter-clockwise "swirl." Burners of the first and second tiers operate at excess air of SR = 1.1 and those of the third tier with SR = 0.7. About 15 percent of the secondary air is fed through the tertiary air nozzles located about 8 ms above the third tier of burners.

The result of pilot and industrial-scale tests at the Ekib TPS-2 indicate that this technique can reduce the NO_x emissions in the P-57R boilers to 500-550 mg/m^3.

Further reduction of NO_x will be effected by application of selective catalytic reduction (SCR) using ammonia. The specific location for the SCR catalyst has been analyzed in view of the high dust content and dust abrasivity of the Ekib coal. A line drawing showing the de-NO_x system after the hot electrostatic precipitator and before the air heater, and another showing it after both the de-SO_x unit and the air heater appear as Figures 23 and 24, respectively. Operating conditions and some characteristics of the catalyst for these schemes are illustrated in Table 25. The de-NO_x system located in the flue ahead of the air heater is more efficient.

Reduction of SO_x will be accomplished in a wet lime scrubber with gypsum produced as a by-product. A schematic of the process appears as Figure 25 with basic process parameters presented in Table 26.

Fly ash production is one of the most serious problems with Ekib coal combustion. Ash removal efficiency of 99.9 percent is required to reduce the dust content from the reference value of 90 g/m^3 to 100 mg/m^3. This is difficult with Ekib coal because of increased electrical resistivity of the fly ash. Within the temperature range of 140-180 °C, this causes back corona in the electrostatic precipitator which impairs ash separation.

The required efficiency can be reached by maintaining the stack gas at 95-100 °C along with adequate gas velocity and residence time within the ESP active zone. Utilizing four 8-pole ESPs, each with 12 m high electrodes and an active cross-section of 197.5 m^2, the cleaned gas velocity will be about 1 m/s and the residence time within the ESP more than 30 s. These conditions ensure a 100 mg/m^3 maximum fly ash content in the cleaned gas stream. The elecrostatic precipitators are equipped with variable voltage supply sources which prevent back corona and increase operational reliability.

Reduced power output and efficiency caused by the use of the gas cleaning systems is to some extent compensated by extra syngas production as a result of steam condensed instead of being extracted. This is because some condensate and, in some cases, feedwater, are heated by boiler flue gases as a result of less steam flow to preheating. The temperature of the flue gas is reduced from 160 °C to 90-100 °C to meet ESP operating conditions. For this temperature reduction, low-temperature economizers or heating of excess air have been designed. In the latter case, a larger amount of air than required for combustion is passed via the air heater, while part of the air preheated to 300-330 °C recirculates, heating feedwater and condensate (Figure 26, and mean SR). The requirement of low gas velocities for the ESP greatly influences the system layout.

The plant configuration with included de-NO_x system and an 84 m wide bay housing the electrostatic precipitators is shown in Figures 27 and 28.

Table 27 compares the performance of the existing Ekib TPS-2 power plant without gas cleaning equipment, a 500 MW unit with the de-NO_x system located in the furnace flue-gas stream, and a 500 MW unit with the de-NO_x system located after the ESP and the de-SO_x system.

Different combustion systems have been tested to validate this project. A tangential-fired furnace has been implemented at the Ekib TPS-2 500 MW plant. This has resulted in a reduction in NO_x emissions to 500-650 mg/m^3, i.e., almost 50 percent, compared with emission of 1,100-1,200 mg/m^3 from other boilers.

The swirl burner with simplified reburning has been tested on a 210 t/h Ekib coal fired boiler. In this case, NO_x emissions were reduced 47 percent, from 1,100 mg/m^3 to 520-570 mg/m^3.

Long-term test of the de-NO_x system catalyst have begun on heavily dust-laden Ekib coal fired combustion product. The catalyst are installed in a bypass duct of the existing 500 MW boiler flue, and see about 5,000 m^3/hour of gas flow.

A low temperature economizer reducing flue gas temperature to 90-100 °C, is installed on a 420 t/h boiler. The resulting change in the electrophysical properties of the fly ash improved ESP efficiency and reduced fly ash emissions by factors of 3.

Pilot tests were conducted of the simplified de-SO_x system which is close in concept to the LIFAC system. Sulfur capture and the effect upon the system of lime injection into the high temperature (800-1,000 °C) flue gas stream were tested, as well as sulfur capture with this system using various methods of humidification of the CaO-laden flue gas stream.

Effort are under way to develop heat exchangers for de-SO_x and de-NO_x systems.

6.3. 2,400MW TPS with CFB Boilers Firing Poor-Quality Anthracite Culm (AC)

Circulating Fluidized Bed (CFB) combustion is a promising approach to firing poor fuels [8, 11, 39]. A project utilizing this technology has been developed featuring a 2,400 MW TPS with 300MW unit located in the Eastern Donbass.

The TPS employs once-through, two-furnace, 2,500 t/h, 24.5 MPa, 545/545 °C CFB boiler and K-300-240 steam turbine. The fuel is poor quality anthracite culm with 36 percent ash, 1.4 percent sulfur, 10 percent moisture and 4-6 percent volatiles. The boiler features a high recirculation ratio, external "hot" (900-940 °C) cyclones and special external heat exchangers for cooling a portion of the cyclone ash before it is returned to the furnace. For boiler start-up and for operation at loads less than 30 percent of nominal design, each combustion chamber has 6 gas/oil burners arranged on the front and rear walls and is equipped with primary air preheating up to 650-700 °C.

The coal and limestone preparation system uses common hoppers and cyclones and the crushed coal and limestone are combined as feed to the boiler. The coal and limestone mean particle size are 0-4 mm and 0.55 mm, respectively.

Reduction of the stack gas temperature to 100 °C while heating ambient air (see Figures 26 and 29) for use as combustion air serves to increase ESP efficiency and result in particulates emissions below 50 mg/m^3.

Figure 29 is a schematic drawing of the unit. Layout and operation are simplified, and capital investment reduced, by elimination of the deaerator in favor of two, direct-contact, low-pressure heaters. Air preheating is used to prevent boiler cooling during hot startup of the unit operating in a shifting mode. The boiler is provided with a full-flow separator, and the waterwall hydraulics are designed to start the unit at sliding pressure across the entire boiler system. The two-bypass starting scheme is provided to improve temperatures when the turbine is placed in operation.

The once-through CFB boiler design is illustrated in Figures 30 and 31. The firing system consist of 2 modules. Each module has it own furnace, two cyclones and two external heat exchangers located under the cyclones. The combustion product from both modules are directed through a common convective section.

The primary air fed through the fluidizing screen is about 50 percent of the total required for complete combustion. The velocity of the combustion gases at the outlet of the dense bed is 6.4 m/s. Fuel is fired in the combustor freeboard (the upper part) using secondary air supplied by special nozzles.

The combination of two-stage air feed, high fly ash recirculation ratio, 900 °C furnace temperature and limestone injection insures low concentrations of SO_x and NO_x in the flue gas. Complete combustion, i.e., 94-97 percent, of the anthracite culm fuel and possible reduction of boiler loads to 30-50 percent of nominal design rates are attained without firing fuel oil or gas. The external heat exchangers, along with the last stages of the primary superheater and reheater, are designed for 60 percent heat recovery from the CFB firing circuit.

The design and thermo-hydraulic boiler parameters can be seen in Tables 28 and 29.

The ash will be landfilled on site and/or, depending upon it properties, used for water treatment, to reduce effluent volumes and the requirement for treatment chemicals.

The layout of the CFB boiler in the main building and of the TPS as a whole are shown in Figures 32 and 33.

The performance of the TPS with CFB boilers is illustrated in Table 23, which also compares the TPS with pc-fired boilers both with and without de-SO_x and de-NO_x systems. Given identical environmental impact, construction of a 300-MW TPS with CFB boilers under this project will be 20-25 percent cheaper than a pc-fired unit with de-SO_x and de-NO_x systems.

Comprehensive testing was done in order to validate the engineering assumptions used in designing the above boilers. Conditions tested were: Kuzn coal and anthracite culm firing, NO_x and SO_x suppression, hydrodynamics of dust-laden flows under typical CFB duct conditions, and boiler startups and shutdowns. The result obtained made possible the determination of the main characteristics of the processes; kinetic constant necessary for calculations; measures necessary to ensure complete combustion of the anthracite culm; sulfur capture and suppression of NO_x formation in the furnace, e.g., temperature conditions, air feed staging, sorbent dosing; and also pointed to the improvement of CFB boiler critical component, e.g., cyclones, fly ash reintrainment path lockhoppers and others.

The highest anthracite culm firing efficiency – 96 percent – was obtained by supplying 60 percent of the total air to the primary zone. At conditions of equal flow between primary and secondary air, i.e., 50-50 percent, and overall furnace excess air of SR = 1.15-1.25 the flue gas NO_x concentration was 200 mg/m^3 maximum. Also, NO_x formation is perceptably influenced by both sorbent feed rate to the boiler and Ca/S ratio. At furnace temperatures of 740-940 °C, 90-95 percent of the sulfur is captured at Ca/S = 1.7-2.0. With further increase of the Ca/S ratio, sulfur capture remains essentially constant at about 95 percent (see Figure 34).

Investigations were done on the quality of the ash from CFB coal combustion with limestone addition. As a result, technical solutions were found that ensure ESP performance with increased electrical resistivity of the fly ash

Fuel and limestone preparation equipment for CFB boilers has been tested and coal and limestone crushers have been designed which provide for the proper size composition.

CFB combustion technology also holds promise for brown coals. Some result of work in this area were illustrated in Section 2. The largest and most interesting systems for firing brown coals are the 420 t/h bubbling-bed and the 500 t/h CFB boilers.

In the 420 t/h boiler fuel preparation system, K-A coal is separated into fractions. The 1-25 mm sized coal is fed beyond the bed, while the 0-1 mm sized material is injected directly into the bed by pneumatic-screw type pumps. The fly ash reentrainment system includes the louvre-type ash collector, 8 cyclones and ejectors to feed the collected fly ash to the lower section of the bed.

K-A coal properties are rather attractive for CFB combustion technology: up to 95 percent sulfur capture by the CaO in the ash can be expected at 850-900 °C, no slagging of heating surfaces, NO_x reduction, lower sensitivity of the system to the quality of fuel fired, and better ash properties for further utilization.

Investigation of Irsha-Borodino brown coal combustion in the pilot plant and foreign operating experience with CFB boilers indicate that with K-A coals, emissions of NO_x and SO_x will be 200 mg/m^3 maximum.

The good ecological characteristics of the CFB boilers give them an initial advantage for both new and reconstructed city cogeneration plant.

The Barnaul Boiler Manufacturing Works designed 500 t/h boilers based on "cold" cyclones [40] for combustion of high-sulfur brown coal from the Moscow area (Novomoscovskaya TPS) and K-A coal (Omsk cogeneration plant No. 6). The drum boiler with heating surfaces in a tower arrangement has a furnace plan section with dimensions of 19.3 × 8.0 m (Figure 35). The furnace is the key element in solids circulation. It has an all-welded, gas-tight waterwall design. At the bottom of the furnace is a cap-type, perforated-screen air distributor with directed blasting, through which about 50 percent of the total air passes as primary air. The remaining air is fed through secondary air nozzles arranged in three tiers on the side walls. Provision is also made to feed recirculation gases into the primary air stream. The construction of such boilers is presently delayed by economic problems within the country.

6.4. IGCC TPS Project with Entrained-Flow and Moving-Bed Coal Gasification

A large-capacity (4.0-6.5-GW) Integrated Gasification Combined-Cycle (IGCC) TPS has been designed to use Kuzn and K-A (Berezovo) coals.

The 600-700-MW Combined-Cycle (CC) plant includes two gas turbine/generators (GT) of 200-MW each, two heat recovery boilers and a single 240MW steam turbine/generator (ST). Some of the characteristics of this equipment can be seen in the Appendix (pages 67-71).

The CCP designs are based on two different gasification technologies: moving bed and entrained flow. Each system was designed with both air blown and (95 percent pure) oxygen-blown options. The technical considerations and the equipment are to a great extent universal and, therefore, various grades of coal can be used including those with high sulfur content.

Gasification proceeds at about 3MPa pressure. In both systems, slagging gasifiers are fed dry coal through lockhoppers.

As feed for the moving-bed gasifier, coal is first dried and crushed to <50 mm size. This coal is screened. Material <50 mm and >5 mm is stored in a hopper and fed into the top of the gasifier vessel via a lockhopper system. The coal fines (<5 mm) are milled and fed via a second lockhopper system to the tuyeres through which they are blown into the gasifier. Technology also was tested whereby excess fines are pressed into pellet of 6-10 mm size. These are fed into the gasifier with the screened coal.

As feed for the entrained-flow gasifiers, the coal is milled, passed through lockhoppers and conveyed into the gasifier as highly concentrated dust (0.015 kg of nitrogen per 1 kg of coal).

Coal-derived gas (syngas) is used for sealing purposes and as a transport agent in the air-blown systems. In oxygen-blown systems, nitrogen, coproduced with the oxygen, is used for these purposes.

The composition of the syngas produced by gasification of dried coal depends largely upon the process conditions, e.g., kind and temperature of the blast, steam consumption, temperature, pressure, etc. Syngas composition is only very sleghtly influenced by the elementary composition of the coal.

The temperature of the syngas at the reactor outlet is dependent upon the process: moving bed, oxygen-blown = 500-559 °C; moving bed, air-blown = 900-960 °C and entrained-flow = 1,300-1,600 °C.

Preliminary cooling of the entrained-flow gasifier syngas to 900-950 °C is done either in a radiant gas cooler featuring platen-type heat exchange surfaces, or by quenching with recirculated, cooled gas to the reactor outlet. Further cooling of the gas stream to 500-550 °C, at which temperature it can be cleaned, is done in convective coolers.

As much as 30 percent of the steam consumed in the steam turbine/generator is produced in the gasifier waterwall and the radiant and convective syngas coolers.

The raw syngas is cleaned of sulfur at 500 °C by passing the gas stream through a fluidized bed of oxidized metal, e.g., iron. The sorbent is regenerated and the regeneration gases used to produce sulfuric acid (see Appendix).

For the oxygen-blown cases, standalone air separation facilities are required (see Appendix).

Air-blown gasification systems feature two trains of gasification for each gas turbine/generator. In oxygen-blown cases this is one-to-one.

Figure 36 is a flow sheet of an IGCC with moving-bed, air-blown gasification. An IGCC featuring entrained-flow, oxygen-blown gasification is shown in Figure 37. Both of these are considered principal technologies and have received detailed study.

The layout for a moving-bed, slagging gasifier is illustrated in Figure 38, and it associated convective gas cooler shown in Figure 39.

The design of one version of an entrained-flow gasifier is shown in Figure 40.

Figure 41 is a schematic drawing of a syngas cleaning system. Figure 42 is a flow sheet for the generation part. Parameters and descriptions for the gas turbine, the heat-recovery boilers and the steam turbine are in the associated appendix. Figure 43 is a sectional view of the heat-recovery boiler.

The exhaust gas flow from the gas turbine is greatly dependent upon ambient air temperature, and ranges from 560-580 kg/s at +30 °C to 830-850 kg/s at -30 °C. At the average ambient air temperature of -5 °C, the gas flow is 700-730 kg/s.

For the air-blown gasification case, approximately 100 kg/s of air is extracted from the gas turbine compressor for gasification air. After extraction, this air stream is cooled and fed to a 15-MW booster compressor whose outlet temperature is held at 500-540 °C maximum. The booster compressor is driven by a condensing steam turbine consuming about 50 t/h of steam. The resulting air pressure is 3.2 MPa. The gasifier also is fed superheated steam.

The heat recovery boilers are dual-pressure, wherein 13.8 MPa/520 °C and 0.4 MPa/240-250 °C steam is generated by the heat from the turbine exhaust. Given 2 turbines and 2 heat recovery boilers, 2 × 205 = 410 t/h of high pressure steam is generated. Additionally, about 170 t/h of high pressure steam is supplied to the steam turbine by the gasification plant. This steam is expanded in the high pressure cylinder of the steam turbine and then reheated in heat-recovery boilers. The steam flowing to the steam turbine's intermediate-pressure cylinder is at 2.2 MPa/460 °C.

A portion of the low-pressure steam produced in the heat-recovery boilers is used for coal drying. This amount to 85-130 t/h out of the total make of 185-210 t/h. The remaining low-pressure steam is fed to the low pressure cylinder of the steam turbine.

For the oxygen-blown gasification, a KT-70, 66,000 m^3/hr air separation plant is used to produce the required oxygen. Specifications for this plant can be found in the Appendix.

More steam is produced in the entrained-flow, oxygen-blown integrated gasification combined-cycle than in the air-blown plant. This amount to 607 t/h, as compared with 580 t/h in the air-blown case.

The layout of the main building for the commercial TPS with 10 IGCC unit is shown in Figure 44. A cross-section of the building along the gas turbines and heat recovery boilers and a cross-section of the ST building is shown in Figure 45. The section of the gasifier plant with a moving-bed and air-blown design is shown in Figure 46. Figure 47 illustrates the general layout of a TPS with 10 gasification combined cycle units using K-A coals.

Basic parameters of the IGCC plant at standard ISO conditions are given below:

Param	Type of Gasifier and Oxidizer			
	Moving bed		Entrained Flow	
	Oxygen	Air	Oxygen	Air
Two GT Output, MW	418	413	414	372
ST Output, MW	188	220	233	227
CCP Output (gross), MW	606	633	647	600
Auxiliary Power, MW	68	32	94	31
CCP Output (net), MW	538	601	553	569
CCP Efficiency (net), Percent	43.4	44.2	43.8	44.1
Live Steam HP Flow, t/h	454	532	574	551
Live Steam HP Temperature, °C	535	540	540	540
Fuel Saving, Percent	10.1	11.8	11.0	11.6

The fuel saving compares IGCC with that of a conventional steam supercritical unit operating at 39 percent efficiency. The data are shown in more detail in Table 30.

During commercial operation the average IGCC output and efficiency will be lower by 30-35MW and by 1.0-1.5 percent respectively.

The efficiency of CCP utilizing various gasification technologies is almost the same. With the oxygen-blown option, efficiency is 1.7-2.5 percent lower than with the air-blown configuration.

Combined-cycle plant capital investment, percent:

Portion of IGCC Plant	Type of Blowing	
	Oxygen	Air
Power Generation	38.75	40.25
Oxygen Plant	15.85	—
Gasifiers	5.80	11.60
Syngas Cooling	3.30	6.55
Fuel Preparation and Feed	5.65	5.65
Desulfurization	5.95	11.50
Particulate Removal	5.35	7.45
Other Expenditures	19.30	19.40
Total	100.00	102.40

Basic characteristics of IGCC TPS with 600-700-MW CC unit using Kansk-Achinsk coal are shown in Table 23. The comparison with alternative PC TPS is given below:

Param	Commercial PC 800MW		IGCC	
	Without De-SO_x De-NO_x	With De-SO_x De-NO_x	Oxygen-Blown (Base)	Air Blown
Nominal Efficiency, Percent	38.50	37.60	42.50	43.50
Mean Annual Efficiency, Percent	38.07	37.28	42.17	43.23
Mean Annual Specific Standard Fuel Consumption, g/KwH	323.10	329.90	291.70	284.50
Relative Specific Investment Cost	0.925	1.118	1.000	1.024
Relative Average Electricity Cost	0.962	1.159	1.000	0.962
Specific Emissions, mg/MJ:				
NO_x	600 (325)	200 (80)	40* (30)	30* (25)
SO_x	600 (235	300 (120)	3.5* (2.5)	10* (8)
Particulate Matter	150 (60)	50 (20)	0.7* (0.6)	0.7* (0.6)

* at O_2 = 15 percent as it is adopted for GT.

As a prototype for a full-scale oxygen-blown IGCC plant, a demonstration plant has been designed with K-A coal gasification based on a 100-130MW gas turbine/generator combined with heat generation of 230-280MWt [35].

Conceptual designs have been made for the gasification plant including the PC feed system; the air separation plant; the gasifier; convective syngas coolers; gas/gas heat exchanger and desulfurization equipment, e.g., Selexol, Klaus, etc.

To validate the technical solutions, pilot test were made of the kinetics of entrained-flow PC gasification, industrial test of fines filters and pilot project for testing the lockhopper equipment to feed PC to the gasifier and coal-derived syngas firing in the gas turbine combustor.

Appendix

IGCC Equipment

Gas Turbine

The GTE-200 gas turbine was designed some years ago by LMZ. This is a simple-cycle, single-shaft unit.

The GT as a unit includes an axial compressor, a turbine and a combustion section consisting of 14 combustor cans. It layout is like that depicted in Figure 11. The overall dimensions of the machine – 16.6 m × 5.0 m × 5.1 m, and it weight is 210 t – allow it to be transported by railroad car as a single assembled unit. The compressor flow path is identical to that of the GTE-150 GT which is now on line. Adding two compression stages increases the compression ratio from 13.0 to 15.6 at the same air flow rate of 630 kg/s.

The GTE-200 is designed to operate on clean liquid fuel and natural gas. Operation on low-calorie syngas will require redesign of the combustors.

At the time the GTE-200 was designed, LMZ had no experience with large, high-temperature GT. Because of this, the design was a conservative one, and the possibilities of upgrading it performance have been considered in designing the IGCC plant. The machine data at ISO conditions using liquid fuel are shown below:

GT type	GTE-200
Designer	LMZ
Output, MW	198
Efficiency, Percent	34.6
Pressure Ratio	16.2
Turbine Inlet Temperature, °C	1,250
Turbine Outlet Temperature, °C	557
Overall Dimensions, m:	
length:	15.6
width:	5.0
height:	5.1
Weight of GT, t	350.0

The table below present basic characteristics of the GTE-200 GT unit using syngas produced in a steam-air blown gasifier. Gasifier air is obtained by extraction from the GT compressor in an amount equal to 75 percent of the fuel gas supplied to the combustor:

Ambient Temperature, °C	-5	+15
Turbine Inlet temperature, °C	1,250	1,250
Pressure Ratio	19.0	16.9
Compressor Air Flow, kg/s	692.2	608.4
GT Output, MW	250.0	206.3
Fuel Gas Consumption, kg/s	174.2	150.9
GT Efficiency, Percent	33.7	32.1
Turbine Outlet temperature, °C	547.6	568.3
Exhaust gas Flow, kg/s	730.8	641.1

Heat-Recovery Boiler (HRSG)

The design of the HRSG is illustrated in Figure 43. It is of the drum type, with multiple forced circulation. The heating surfaces are layed out in a tower configuration with countercurrent flow in the economizer and superheating sections and cocurrent flow in the evaporative section. The GT exhaust enters the boiler at the botton. The element are arranged in the order of: HP superheater, reheater, HP evaporator, HP economizer, LP superheater, LP evaporator and LP economizer. The feedwater is supplied to the LP circuit and the HP circuit is fed from the LP drum.

Part of the LP steam is directed to steam dryers located in the fuel preparation section, with the condensate returned to the ST condenser.

The HRSG working dimensions are: gas duct size 11,900 × 11,900 mm, the tube axis height is 25,100 mm. The outide dimensions are: 13,500 × 13,500 mm in plan, 34,110 mm overall height.

All of the heating surfaces feature tubes with cross-band fins. The weight is about 1,700 t. The gas path pressure drop at design conditions and -5 °C ambient temperature is 2.5 kPa. The stack gas temperature is 95-100 °C.

Steam Turbine

The steam turbine was selected to compliment the two HP and LP circuit and live steam flows varying with ambient temperature as follows: within -30 °C to +30 °C the mass flow rate of the live steams varies by 20 percent, from 640 t/h to 520 t/h. As a consequence of simultaneous change in the live steam temperature, the change in volumetric flow is only 12 percent.

At a design ambient temperature of -5 °C, the ST has the following characteristics:

HP Live Steam Flow, t/h	580
HP Live Steam Temperature, °C	515
HP Live Steam Pressure, MPa	12.75
Steam Pressure after Reheater, MPa	2.20
Steam Temperature after Reheater, °C	460
LP Steam Flow, t/h	120
LP Steam Temperature, °C	240
Condenser Pressure, kPa	5
Condenser Flow, t/h	550
ST Output, MW	240

With 355-MW heat delivery for heating purposes, the output of the turbine drops to 167 MW. The ST has two cylinders: a combined HP and IP cylinder and a two-stream LP cylinder.

To ensure the maintenance of adequate flows with changing ambient temperatures, sliding pressure operation is anticipated with fully-opened live steam valves: at -30 °C the pressure increases to 13.8 MPa, at +30 °C it drops to 12.1 MPa. The design cooling water temperature is 20 °C.

Gasifiers

The characteristic data of the selected coals is depicted in Table 31. The design of the moving-bed gasifier appears in Figure 38, and that of the entrained-flow gasifier with cooling by back-mixing syngas in Figure 40. The convective gas cooler is shown in Figure 39.

The composition and some parameters of the coal-derived combustible gas (syngas) are given in Table 32.

Over 70 percent of the ash is removed from the gasifiers as liquid slag. The dust content of the raw syngas is 400 g/m^3 with the air-blown configuration (11.5 kg/m^3 density at operating conditions), and 765 g/m^3 in the oxygen-blown configuration.

The removal of particulates in the gas path is done by cyclones (2 for the air-blown and 1 for the oxygen-blown). Polishing is done in filters with 0.3 m diameter × 4 m longceramic element. The gas dust content at the filter outlet is 2.5-6.5 mg/m^3.

The syngas desulfurization is carried out in fluidized-bed reactors using 4 screens located at different levels of the 18 m high and 4 m diameter column. The IGCC with air-blown gasification requires 8 while only 4 are required for the oxygen-blown application. The sorbent is regenerated in the fluidized-bed furnace at temperatures below 800 °C. The bed where heat is released during regeneration is water-cooled. The heat exchange surfaces arrabged in the bed are switched between steam and water as required. The regeneration gases contain 4-6 percent SO_2. The spent regeneration gases are used in the production of sulfuric acid. A schematic of the cleaning system is shown in Figure 41.

Some parameters of a 600 to 700 MW unit desulfurization system designed with 100 percent H_2S margin in the raw syngas are illustrated below:

	Air-Blown	Oxygen-Blown
Syngas Flow, kg/s	300	132
Flow at Operating Conditions, m^3/s	26.2	13.7
H_2S Content, Percent (Volume)	0.1	0.2
H_2S Amount, kg/s	2.16	2.26
Reactor Cross Section Area, m^2	100.0	52.8
Number of reactors	8	4
Mass of Circulating Sorbent, t	80	44

Air Separation Plant

Oxygen is produced in the air-separation plant by distillation of liquified air. The IGCC employs the Kt-70 plant designed and manufactured on a special order by the NPO "Kriogenmash." This plant has the following characteristics:

Inlet Air Pressure, Bar	6.56
Inlet Air Temperature, °C	60
Air Flow, m^3/h (normal)	350,000
Production 95 Percent O_2 at 1.03 Bar (Absolute), m^3/h	66,000

The turndown capability of this plant is to 70-80 Percent of nominal design value. Startup from cold condition takes 4-5 hours. The plant is designed for 1-2 year continuous operation with time between overhauls of 8 years.

The energy requirement are 0.35 kWh/m^3 of produced oxygen. Other gases are co-produced with the oxygen in this plant, as follows: 30,000 m^3/h of Nitrogen at 1.0 Bar absolute, 9.57 m^3/h of 40 percent concentration Neon-Helium mixture at 0.5 Bar absolute and 130 m^3/h of 0.2 percent concentration Krypton-Xenon mixture.

The overall size of the air separation plant are:

Air Separation Unit: 20 m × 13.6 m × 44.45 m.
Regenerator Unit: 22.65 m × 16 m × 16 m
Weight of the Plant: 1,210 t

6.5. TPS with Fluidized-Bed Gasification CCP Project

The Central Boiler/Turbine Institute (TsKTI, St. Petersburg) and VNIPIEnergoprom Design Institute (Moscow) have developed a TPS project with a 250 MW CCP and gasification of Kuzn coal in a fluidized-bed, steam/air-blown gasifier.

The flow sheet for the highly-integrated CCP is illustrated in Figure 48. The air for the gasifier is extracted from the GT compressor and boosted to gasifier pressure of 2.0 MPa by an auxiliary compressor arranged on a common shaft with the expansion turbine which operates on clean syngas and the auxiliary steam turbine balancing the output of the CC block. Steam for the gasifier is extracted from the HP section of the ST. Prior to entering the gasifier, it is superheated in one of the sections of the convective raw syngas cooler. Cooling of the raw syngas ahead of low-temperature gas cleanup, and it subsequent reheating after sulfur removal are done with minimal wastage of sensible heat along with production of HP saturated steam.

The design of the gasifier is illustrated in Figure 49. The octogon-shaped reaction chamber is formed by the waterwall tube membranes transitioning into the the steam generator multiple forced-circulation loop. To make the gasifier path leak-tight and protect the gasifier external shell from the effect of the reaction heat, the steam extracted from the HP side of the ST is fed through the space between the gasifier shell and the waterwall membrane. Some gasifier parameters and characteristics are shown in Table 33.

The power island on a CC with supercharged steam generator (SSG) includes a GTE-45-2 GT unit of KhTZ manufacture (See section 2.3), T-180 extraction ST made by LMZ and two SSGs of TKZ design. It sectional view is shown in Figure 9. The GT is connected with the SSGs, arranged symmetrically at both sides, by double-walled duct. The air extracted from the GT compressor is directed to the SSG through the annular space between the walls of the duct. The outer wall is cold and the inner wall contains the combustion product returning to the GT. Each SSG is fed by the syngas from it own gasification train which consist of the fuel lockhopper system, gasifier, gas coolers, gas cleaning and preheating system and turboexpander. Natural gas can be fired in the SSG, which ensures operability of the TPS when the gasifiers are down.

The schematic of the coal preparation system for a fluidized-bed gasifier is shown in Figure 50.

The fuel is fed by the station-wide fuel handling system to the raw coal hoppers after coal crushing. For the fluidized-bed gasifier, coal lumps shall not exceed 20 mm in size and the amount of the <1 mm-sized fines shall be 15 percent maximum. For this reason, the coal is again crushed in a special crusher which produces minimum fines. After crushing, the coal is dried to 10-12 percent moisture content. The GT exhaust gas is used as a drying agent. Fine fractions are entrained out of the fluidized-bed drier with the drying agent and are separated in the cyclone, with final removal in an ESP. The dust is combined with binding agent and granulated to the 3-10 mm size. The granules are then predried and strengthened. The crushed coal and the granules are fed to the gasifier through a lockhopper system, driven by syngas taken from before the gas heater, additionally cooled and compressed [42].

The syngas is cooled and heated in several exchangers. Some of the operating data for these exchangers is given below:

No. of Cooler/Heater	Gas Duct	1	2	3	4
Gas Temperature, °C					
Inlet	950	971	522	410	160
Outlet	917	522	410	220	335

The 16 MPa, 346 °C boiler water from the forced-circulation loop of the SSG is used as a cooling agent. The temperature of the tubes in this case is 400-410 °C maximum. They can be fabricated of low-alloy steel.

The gasifier shell is protected from the effect of high temperatures and the aggressive attack of the syngas by the water-wall membrane. The gas duct and the walls of gas cooler No.1 are protected in the same fashion. The gas cooling path includes 3 additional convective cooling sections operating at gas velocities of 6-7 m/s which ensures self-cleaning of the surfaces withour tube erosion. The 3rd Section incorporates a tube bundle whose purpose is to superheat the gasifier steam to 450 °C. It has austenitic tubes. The walls of the other gas coolers, operating at syngas temperatures no greater than 522 °C, are unprotected. For wet cleaning, the temperature of the syngas is reduced to 160 °C, and after cleaning increases to 330-350 °C, at which point it is fed to the expansion turbine and thence to the SSG burners. All gas coolers have 3.8 m diameter outer shells assuring transportation by normal means as assembled unit. The shell length is 17-33 m.

The coarse cleaning of the syngas is done by cyclones in two stages. The first stage is after gas cooler number 1 and occurs at 500-550 °C. The cleaning efficiency of the first stage is 65-70 percent. The second stage is located after gas cooler number three at 210 °C. The efficiency of this stage is 90 percent.

The fine cleaning of the syngas to a particle content of less than 10 mg/m^3 (under normal conditions) is by washing in a venturi scrubber followed by a cyclone mist eliminator.

The greater part, i.e., 70-80 percent, of sulfur removal occurs in the fluidized bed where limestone or dolomite sorbent is injected along with the coal feed. The test trains, which account for about 5-7 percent of total capacity, are incorporated in the system for dry, fine cleaning of the syngas particulates at 410 °C; dry removal of SO_2 by iron ore at the same temperature; and mid-temperature, i.e., 140-160 °C, catalytic SO_2 removal using activated coal. When these technologies are mastered, total sulfur capture will increase to 95 percent and above.

Low No_x emissions are ensured by:

- a considerable percentage of the nitrogen contained in the fuel is converted to ammonia in the gasifier. The ammonia is removed from the syngas by later washing.

- lower combustion temperatures of the syngas in the SSG.

One possible layout for the CCP-250 and gasification plant is shown in Figure 51.

The separate processing sections are each housed in a separate building: turbine hall (the entire CCP including SSG), fuel preparation equipment, gasification plant, additional compressor-expansion turbine, and the balance of plant equipment.

The combined cycle is arranged in a single-bay building 180 m long and 42 m wide. The building houses the steam turbine, GT, SSG and gas-water heater (HRSG) in the GT exhaust path. The deaerator and condensate feed equipment are located between the steam turbine and the GT. The maintenance sites and the through railroad track also are located in this building.

An open bay building, 39 m wide and 72 m long, shelters the two gasifiers, gas coolers and heaters, and the gas cleaning equipment.

Basic parameters of the IGCC-250 TPS and coal gasification system are shown in Tables 22 and 23. Here also are the parameters of the CCP "industrial unit" designed by TsKTI to the same process scheme but a larger and more efficient GT with an inlet gas temperature of 1,100 °C.

Test and validations for the project were conducted on the 250 kg/h coal capacity pilot plant operating at up to 3 MPa [43] and at the large-scale TsKTI test facility at up to 0.6 MPa [44].

The model for the CCP-250 gasification system was reproduced at the TsKTI test facility. Gasification test were conducted on Kuzn bituminous coals of WS grade at flow rates from 600 to 1,100 kg/h, as well as on brown K-A coals. The facility's gasifier vessel is 2.2 m in diameter and 10 m high. The actual reactor diameter is 800 mm and the syngas output is 4,500 m^3/min. The gasification was conducted with steam/air blast at 900-1,000 °C. This plant facilitated the discovery and elimination of many "children's diseases" in such areas as fuel preparation and handling, startup and maintaining gasifier operation, removal of gasifier bottom ash, ensuring maintenance of non-slagging conditions, etc.

The test were conducted at the following conditions:

Coal Characteristics:	
Heating Value, MJ/kg	16.9-27.4
Moisture Content, Percent	23.1
Ash Content, Percent	10.6-15.1
Mean Particle Size, mm	0.95-3.5
Fines Content, Percent	28-48
Coal Consumption, kg/h	600-1,100
Air Flow, kg/h	1,220-3,100
Steam Flow, kg/h	400-800
Gasifier Pressure, Bar	2-3
Steam-Air Mixture Temperature, °C	200-350
Fluidized-Bed Temperature, °C	800-950
Gas Heat Value, MJ/m^3	3.45-4.9
Unburned Carbon, Percent	2.7-10.0

At design velocities of 1.7-2.0 m/s and with moderate amounts of coal fines, the syngas was of normal quality and fly ash removal was acceptable.

Fuel preparation devices, such as the cutting 10 t/h crusher, fluidized-bed dryer/feeder, etc., as well as fines granulation technology were mastered on special pilot rigs. Fluidized-bed gasification of granules has been successfully conducted.

CONCLUSIONS

TERMS OF APPLICATION OF CLEAN COAL TECHNOLOGIES AT RUSSIAN TPS

Wide use of as-mined, high-ash coals at TPS is a characteristic of Russian power generation.

Large amounts of brown coals are produced and fired at TPS. The cheapest and most promising of these in terms of future use are strongly-slagging K-A coals.

The positive feature of the worth-while Russian coals is low sulfur content, leading to SO_2 emission standard compliance. Nevertheless, the production and use of some amounts of high-sulfur coals (from the near-Moscow, Inta and Donetsk coal fields) will continue for a long period of time.

In practice, fuel standards are not strictly met. There are cases where the ash content and heating value of a coal are beyond specified limits. Many times it has been necessary to change the grade of coal supplied to some TPS or units.

No steam coal market exists in Russia and the possibility that one might eventually materialize is not generally accepted.

<u>These conditions demand testing of the applicability of clean coal technologies for high ash fuels, brown coals with specific ash properties and the adaptability of these technologies to coals of varying properties.</u>

The Russian climate is more severe than that in the U.S. It is traditional to employ centralized heating systems for residential and industrial premises. Over half of all fossil-fueled TPS are cogeneration facilities. In terms of generation capacity, this percentage is even higher. Many of the cogeneration plants are therefore of necessity located within city areas and so the requirements for them to be reliable sources of heating as well as producing reduced emissions are foremost. The cogeneration plants employ boilers of relatively small size and capacity, e.g., 170-670 tph.

<u>Low ambient temperatures must be taken into account in the design and installation of equipment; the opportunity to locate equipment out-of-doors is relative limited; and the technologies designed for large power units need to be tested with reference to smaller applications.</u>

The most important task for the Russian power industry will be life extension for older TPS in line with increased efficiency and reduced adverse environmental impact. Such TPS represent the largest market for the environmentally benign technologies.

Russian TPS typically locate 6-12 units of the same type within a common main building. While this carries certain economic advantages, e.g., ease of construction, erection and operation, such TPS layout complicates the arrangement of additional equipment during modernization to improve performance or for gas cleaning because of lack of space.

For this reason, location of pollution control equipment and the necessary additional air, fuel and gas ducting can differ greatly from the U.S. CCTP practice. Similar difficulties appear when replacing coal-fired boilers requiring more space due to things such as large-sized, external cyclones. For this reason, the CFB boilers with in-duct ash separators developed by B&W seem more attractive.

Russia has well-equipped manufacturing facilities for power-industry equipment, and organizations with highly-qualified personnel capable of accomplishing the engineering and design, construction and operation of pollution-control equipment and systems. These assets are under-utilized at present. The Russian power industry has relied upon domestic equipment meeting high standards and providing for reliable TPS operation up until now. Russia uses its own norms and standards. Even though, in some areas Russian engineering fell behind current practice, e.g., GT, CCP, environmental protection and I&C systems, the decision makers – managers of power systems and TPS – are mostly oriented toward Russian equipment and materials.

With this in mind, the most fruitful route toward transferring the CCTP-based U.S. technologies to Russia is joint production, with Russia, of the equipment and employment of Russian personnel to solve possible technical problems. This may require revision of the U.S. technical documentation to comply with Russian standards, materials and manufacturing technologies, and prove Russian sorbents, catalysts and other materials in the technological processes, and etc.

Finally, in transferring the technologies, it is useful to take into account today's difficult economic situation in Russia. Electricity consumption has dropped, only a small percentage of the necessary investment capital is available for retrofitting/repowering of existing capacity and construction of new TPS. Financial difficulties are a major cause of long construction times in Russia.

Under these conditions, <u>lower-cost technologies become more attractive, especially if they can be implemented in stages. Design and supply of shop-fabricated, modular equipment is desirable. Careful planning and organization of the construction process should be the rule.</u>

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ACRONYMS AND ABBREVIATIONS

A	anthracite; air (table 17)
ABBCE	ABB Combustion Engineering Inc.
AC	Anthracite Culm
AFBC	Atmospheric Fluidized-bed Combustion
AOFA	Advanced Over-Fire Air
ASME	American Society of Mechanical Engineers
B&W	Babcock & Wilcox Company
BGL	British-Gas-Lurgi (technology)
BEZM	Belgorod Boiler Works
BIKZ	Biysk Boiler Works
Bit., bitum.	bituminous (kind of coal)
BKZ	Barnaul Boiler Works
Br.	brown (kind of coal)
CCP	Combined Cycle Plant
CCTP	Clean Coal Technology Demonstration Program of U.S. Department of Energy
CE	Combustion Engineering Inc.
CFBC	Circulating Fluidized-Bed (technology)
ChZEM	Chekhov Power Engineering Works (near-Moscow)
COREX©	a registered trademark of Deutsche Voest-Alpine Industrieanlagenbau GmBH
CWS	Coal-Water Slurry
CZD/FGD	Confined Zone Dispersion/Flue Gas Desulfurization process
DCh	Dow Chemical
de-NO_x	NO_x removal technology
de-SO_x	SO_x removal technology
DOE	U.S. Department of Energy
EAS	Electrosila Works (St.Petersburg)
EERC (E&ER Corp)	Energy and Environmental Research Corporation
EF	Entrained-Flow
Ekib	Ekibastuz coal field
EPA	U.S. Environmental Protection Agency
E-SO_x	SO_x Semidry Removal Technology in the Inlet of ESP
ESP	Electrostatic Precipitator
ETM	Electrotyajmash Works (Kharkov)
FB	Fluidized Bed (table 17)
FBC	Fluidized-Bed Combustion (technology)

FGD	Flue Gas Desulfurization
FLS	Parent Company of AirPol, Inc.
FRO-12000	Trademark of Russian fabric filter
F-W	Foster Wheeler Energy Corp.
G	gaseous coals (kind of coal)
GE	General Electric Co.
GR-LNB	Gas Reburning and Low-NO_x Burner
GSA	Gas Suspension Absorption
GT	Gas Turbine
HD	High Dust
HHV	High Heating Value
HP	High Pressure
I&C	Instrumentation and Control System
IGCC	Integrated Gasification Combined Cycle
IP	Intermediate Pressure
ISO	International Standards Organization
K-A	Kansk-Achinsk coals
KhTZ	Kharkov Turbine Works (The Ukraine)
KRW	U.S. Company
KTZ	Kaluga Turbine Works
Kuzn	Kuznetsk coal field
L	Lean coals (kind of coal); Liquid (table 17)
LD	Low Dust
LHV	Low Heating Value
LIDS	Type of de-SO_x System, developed by B&W
LIFAC	Type of de-SO_x System
LF	Long-Flame coals (kind of coal)
Lig., Lign.	Lignites (kind of coal)
LIMB	Type of SO_2 and NO_x Reduction System (Limestone Injection Multistage Burner)
LMZ	Leningrad Metal Works (St. Petersburg)
LNB	Low-NO_x Burner
LNCB	Low-NO_x cell burner
LNCFS	Low-NO_x Concentric Firing System
LP	Low Pressure
MB	Moving-Bed (table 17)
MPC	Maximum Permissible Concentration
N. Caucasus	Northern Caucasus

N-W	North-West (regions of Russia)
NZL	Nevsky Works (St. Petersburg)
OMTI	Trademark of the Synthetic Fire-Resistant Oil
P.C., pc	Pulverized Coal combustion
PCFB	Pressurized Circulating Fluidized Bed (technology)
Pech	Pechora coal field
PermTPS	Permskaya Thermal Power Station
PFBC	Pressurized Fluidized-Bed Combustion
R&D	Research and Development
SCR	Selective Catalytic Reduction
SETM	Sibelektrotyajmash, (Novosibirsk)
SNCR	Selective Non-Catalytic Reduction
SNOX™	Type of combined NO_x, and SO_x Reduction System
SNRB™ SO_x-NO_x-R_{ox}-B_{ox}	Combined NO_x, SO_x and particulate Reduction System of B&W
SR ( )	Excess Air
SSG	Supercharged Steam Generator
ST	Steam Turbine
Subbitum.	subbituminous coals (kind of coal)
SZTM	Power Station Equipment Manufacturing Works (Syzran', Middle Volga)
T	Tampella and Gas Research Institute (only for table 17)
TKZ	Taganrog Boiler Manufacturing Works
™	Trademark
TMZ	The Urals Turbomotor Works (Ekaterinburg)
TPS	Thermal Power Station
TsKTI	Central Boiler/Turbine Institute (St. Petersburg)
TWR	U.S. Company
U-GAS©	Registered Trademark of the Institute of Gas Technology (gasification technology)
VA	Voest-Alpine
VNIIAM	Research Institute (Moscow)
VNIPIEnergoprom	Designing Institute (Moscow)
VTI	All-Russia Thermal Engineering Institute (Moscow)
WS, WS1, WS2	weakly sintering coals (kinds of coal)
YuTZ	Gas Turbine Manufacturing Works in Nikolaev (The Ukraine)
ZIO, ZiO	Podol'sk Boiler Manufacturing Works

Abbreviations

A,%	ash content
Al_2O_3	aluminum oxide
bar	unit of pressure
10^9	billion
BTu	British Thermal unit
°C	degrees centigrade
C	carbon; cold (table 17)
CO	carbon monoxide
CO_2	carbon dioxide
Ca	calcium
ca.	circa, approximately
$CaCO_3$	calcium carbonate, calcitic limestone
cal	calorie,unit of heat
CaO	calcium oxide, lime
$Ca(OH)_2$	calcium hydroxide, hydrated lime
CH_4	methane
CaS	calcium sulphide
Ca/S	molar ratio of calcium to sulphur
$CaSO_3$	calcium sulphite
$CaSO_4$	calcium sulphate
CaO/SO_2	molar ratio of calcium oxide to sulphur dioxide
Cl	chlorine
Cr	chromium
d	dry
daf	dry ash free
$/kW	dollars per kilowatt
$/t	dollars per ton
Fe_2O_3	ferric dioxide
g/kWh	gram per kilowatt-hour
g/m^3	gram per cubic meter
Gcal	gigacalorie, 10^9 calories
GW	gigawatt, 10^9 watts
H, (H_2)	hydrogen; hot (table 17)
H_2O	water
H_2S	hydrogen sulphide
H_2SO_4	sulphuric acid
h, hr(s)	hour(s) - unit of time

h/y	hours per year
He	helium
J	Joule
K	potassium
K_2O	potassium oxide
kcal/kg	kilocalorie per kilogram
kg/s	kilogram per second
kilo	1,000
kJ/kWh	kilojoule per kilowatt-hour
km	kilometer
kPa	kilopascale; unit of pressure
Kr	krypton
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
kWh/y	kilowatt-hour per year
M	mixture
m, m^2, m^3	meter, square meter, cubic meter
m^3/h	cubic meter per hour
m^3/s	cubic meter per second
mega	million, 10^6
mg/m^3	milligram per cubic meter
mg/MJ	milligram per megajoule
MgO	magnesium oxide
$MgSO_3$	magnesium sulphite
$MgSO_4$	magnesium sulphate
MJ	megajoule
MJ/kg	megajoule per kilogram
10^6	million
m	micrometer, micron
mm	millimeter
MnO	manganese oxide
MPa	megapascale; unit of pressure
MW	megawatt
MWe	megawatt electric
MWt	megawatt thermal
MW/m^3	megawatt per cubic meter

N, N_2	nitrogen
NH_3	ammonia
N_2O	nitrous oxide
NO	nitrogen monoxide, nitrogen oxide
No(s)	number(s)
NO2	nitrogen dioxide
NO_x	nitrogen oxides
nom	nominal
norm.	normal conditions
Na	sodium
Na/S	molar ratio of sodium to sulphur
Ne	neon
Ni	nickel
O, O_2	oxygen
P_2O_5	lead pentoxide
Pa	pascale; unit of pressure
pH	measure of acidity, basicity; inverse of the hydrogen ion concentration
ppm	parts per million
R_{90}, R_{1000}	coal particle size less than 90 m and 1000 m respectively
rpm	revolutions per minute
S, S,%	sulphur, sulphur content
S	solid (table 17)
Sn	normatired sulphur content
s	second (unit of time)
SiO_2	silicon dioxide
SO_2	sulphur dioxide
SO_x	oxides of sulphur
SO_3	sulphur trioxide
Ta, Tb, Tc, °C	typical temperatures of ash softening
t(s)	tonne(s), unit of mass
t °C	difference of temperatures
tfe	ton of standard fuel
tfe/y	ton of standard fuel per year
t/d	ton per day
t/h	ton per hour
t/y	ton per year
Tnj, °C	temperature of the beginning of normal liquid slag removal

TiO_2	titanium dioxide
thou m^3/h (min)	thousand cubic meter per hour (minute)
thou hrs	thousand of hours
thou hrs/yr	thousand hours per year
W,%	moisture
w/o	without
Xe	xenon
Y, yr, yrs	year, years
(SR)	excess air efficiency

Types of Russian PC Boilers

E-500	type of BKS's boiler (natural circulation, steam output 500 t/h)
P-57, P-67	trademarks of ZIO's boilers
TPE-214A, TPE-216, TPP-312A, TPP-804	trademarks of TKZ's boilers

Types of Russian Large Steam Turbines

K-1200-240, K-800-240, K-300-240, K-210-130, PT-80/100-130/13	types of LMZ's steam turbines
K-500-240, K-160-130	types of KhTZ's steam turbines
T-250-240, T-185-130, T-100-130	types of TMZ's steam turbines

Types of Russian Gas Turbine Units

GTE-200, GTE-150	manufactured by LMZ
GTG-110	manufactured by Mashproject
GTE-45	manufactured by KhTZ
GTN-25	manufactured by NZL output 30.0 MW)
GTN-25, GTN-16	manufactured by TMZ

Types of CIS marine and aeroderivative GT Units

GT-15, GT-16, GT-25	manufactured by Mashproject and YuTZ
RD-29-300	manufactured by Tushino
AL-31STE	manufactured by "Saturn"

NK-37	manufactured by "Trud"

Types of Russian CCPs

CCP-450T (V94.2 GT type)	GT manufactured by Siemens-LMZ
CCP-325 (GTG-110 GT type)	GT manufactured by Mashproject
CCP-80 (NK-37)	GT manufactured by "Trud"

Marks of Russian Boiler-Turbine Steels and Alloys

12X18N12T	high-alloyed Cr-Ni austenitic steel
12X1MF	low-alloyed perlitic steel
EI607A, EI893, EI765, TsD-1, TsJ-24, EP783, EP800, EI-929, EP-220, EP-927	deformed GT alloys
EI893L, EP539LMU, TsL-2, Ts-4 (ZMI-4U), TsL5(7), ZMI-3, TsNK-7NK, JSBK-RS, JSBK-NK	casting GT alloys

TABLES

Table 1

NOx Specific Emission Norms for Boilers to be Installed at TPS before 01.01.2001

Boiler thermal output,MW	Fuel fired	Units of measurement		
		g/MJ	kg/tfe	mg/m³ of dry gas (= 1.4)
100-299	Gas	0.05	1.46	150
	Fuel oil	0.10	2.93	290
	Brown coal:			
	dry-bottom	0.12	3.50	320
	wet-bottom	0.13	3.81	350
	Bituminous coal:			
	dry-bottom	0.17	4.98	470
	wet-bottom	0.23	6.75	640
>300	Gas	0.05	1.46	150
	Fuel oil	0.103	3.03	300
	Brown coal	0.14	3.95	370
	Bituminous coal:			
	dry-bottom	0.2	5.86	540
	wet-bottom	0.25	7.33	700

NOx Specific Emission Norms for Boilers to be Installed at TPS since 01.01.2001

Boiler thermal output, MWFuel fired	Units of measurement			
		g/MJ	kg/tfe	mg/m³ of dry gas (= 1.4)
100-299	Gas	0.043	1.26	125
	Fuel oil	0.086	2.52	250
	Brown coal	0.11	3.2	300
	Bituminous coal:			
	dry-bottom	0.17	4.98	470
	wet-bottom	0.23	6.75	640
>300	Gas	00.043	1.26	125
	Fuel oil	0.086	2.52	250
	Brown coal	0.11	2.52	250
	Bituminous coal:			
	dry-bottom	0.13	3.81	350
	wet-bottom	0.21	5.97	570

Table 2

SOx Emission Norms for Boilers to be Installed before 01.01.2001

Boiler thermal output, MW	Unit of measurement	g/MJ		kg/tfe		mg/m^3 (= 1.4)	
	Fuel	Normatired S content, % kg/MJ					
		S_n0.045	S_n >0.045	S_n 0.045	S_n >0.045	S_n 0.045	S_n >0.045
100-299	All solid and oil fuels	0.875	1.5	25.7	44.0	2000	3400
300	All solid and oil fuels	0.875	1.5	25.7	38.0	2000	3000

SOx Emission Norms for Boilers to be Installed since 01.01.2001

Boiler thermal output, MW	Unit of measurement	g/MJ		kg//tfe		mg/m^3 (= 1.4)	
	Fuel	Normatired S content, % kg/MJ					
		Sn 0.054	Sn>0.045	Sn0.045	Sn>0.045	Sn0.045	Sn>0.045
100-199	All solid and oil fuels	0.5	0.6	14.77	17.6	1200	1400
200-249		0.4	0.45	11.7	13.1	950	1050
250-299		0.3	0.3	8.8	8.8	700	700
300		0.3		8.8		700	

Table 3

Particular Matter Specific Emission Norms for Boilers to be Installed before 01.01.2001

Boiler thermal output, MW	Unit of measurement	g/MJ			kg/tfe			mg/m^3 (= 1.4)		
	Fuel	Normatired ash content, % kg/MJ								
		below 0.6	0.6-2.5	above 2.5	below 0.6	0.6-2.5	above 2.5	below 0.6	0.6-2.5	above 2.5
100-299	All solid fuels	0.06	0.06-0.2	0.2	0.176	1.76-5.85	5.86	150	150-500	500
300	All solid fuels	0.04	0.04-0.16	0.16	1.175	1.175-4.7	4.7	100	100-400	400

Particulate Matter Specific Emission Norms for Boilers to be Installed since 01.01.2001

Boiler thermal output, MW	Units of measurement	g/MJ			kg/tfe			mg/m^3 (= 1.4)		
	Fuel	Normatired ash content, % kg/MJ								
		below 0.6	0.6-2.5	above 2.5	below 0.6	0.6-2.5	above 2.5	below 0.6	0.6-2.5	above 2.5
100-299	All solid fuels	0.6	0.06-0.1	0.1	1.76	1.76-2.93	2.93	150	50-250	250
300	All solid fuels	0.02	0.02-0.06	0.06	0.586	0.586-1.76	1.76	50	50-150	150

Table 4

Some Data on Steam Turbine Units of Russia

Quantity	Unit rating, MW					
	150	200	300	500	800	1200
Total number of units	37	89	101	7	14	1
Including coal-fired units	27	47	31	7	2(5)	
Number of monoblock	14	57	50	6	14	1
Number of two-boilers single-turbine units	23	32	51	1		
Number of TKZ boilers	22	58	91		12	1
Number of ZIO boilers	38	56	65	8	2	
Number of BKZ boilers		9				
Number of LMZ turbines	4	89	53		14	1
Number of KhTZ turbines	33		26	7		
Number of TMZ turbines			22			
Number of EAS alternators	37	31	71		14	1
Number of ETM alternators		58	26	5		
Number of SETM alternators			4	2		
Live steam pressure, MPa	14.0	14.0	25.5	25.5	25.5	25.5
Live and reheat steam temperature, C	545	545	545	545	545	545
Steam Flow, t/h	500	640-670	950-1000	1650	2650	3950
kg/s	139	178-186	264-278	458	736	1097
Nom.gas flow, thou.m^3/h	500	660	1060	1700	2700	4000
kg/s	172	227	364.5	585	929	1376

Table 5

Data on some pulverized coal boilers

Name	Type and Manufacturers of Boilers						
	E-500 BKZ	TPE-214A TKZ	TPE-216 TKZ	TPP-312A TKZ	P-57R ZIO	TPP-804 TKZ	P-67 ZIO
Delivery of first boiler	1981	1988	1984	1976	1986	1982	1983
Grade of Coal	Brown	Bitumin.	Brown	Bitumin.	Bitumin.	Bitumin.	Brown
Coal Field	Berezovo	Kuznetsk	Berezovo Kharanor	Donbas	Ekibastuz	Kuznetsk	Berezovo
Steam capacity, t/h	500	670	670	1000	1650	2650	2650
kg/s	139	186	186	278	458	736	736
Live steam pressure, MPa	14.0	14.0	14.0	25.5	25.5	25.5	25.5
temperature, C	545	545	545	545	545	545	545
Reheat temperature, C	–	545	545	545	542	542	542
Furnace section (depth width), m	10.311.3	12.513.5	13.512.5	8.717.4	9.821.8	15.530.9	23.123.1
Heat release rate:							
volume, MW/m³	0.1	0.072	0.084	0.135	0.134	0.075	0.061
section. MW/m²	3.22	3.38	3.39	5.33	6.04	4.29	3.95
Boiler efficiency, %	90.0	92.0	90.5	89.5	90.5	92.4	92.6
Exhaust gas temperature, C	167	131	158	165	157	132	140

Table 6

Basic Parameters of Large Steam Turbines Operating in Russia

Parameters	Turbine type and manufacturer									
	LMZ					KhTZ		TMZ		
	K-1200-240	K-800-240	K-300-240	K-210-130	PT-80/100-130/13	K-500-240	K-160-130	T-250-240	T-185-130	T-100-130
1. Nominal capacity, MW	1200	800	300	210	80	500	160	250	185	100
2. Max.output, MW	1400	870	330	215	100	535	165	300	220	120
3. Live steam pressure, MPa	23.5	23.5	23.5	12.8	12.8	23.5	12.8	23.5	12.8	12.8
4. Live steam temperature, C	540	540	565*	565*	555	540	565	540	555	555
5. Reheat pressure, MPa	3.5	3.24	3.53	2.31		3.65	2.8	3.68		
6. Reheat temperature, C	540	540	565*	565*		540	565	540		
7. HP cylinder max. steam flow: t/h	3950	2650	930	670	470	1650	516	980	760	485
kg/s	1097.2	736.1	258.3	186.1	130.6	458.3	143.3	272.5	225	135
8. Condenser pressure, kPa	3.58	3.43	3.43	3.45		3.5	3.43	5.8	5.0	5.6
9. Cooling water temperature, C	12	12	12	10	20	12	12	20	20	20
10. Cooling water flow, thou.m^3/h	103	73	33.5	25.0	8.0	53.5	20.8	28.0	24.8	16.0
11. Number of steam extraction for regeneration9	8	8	7	7	9	7	8	7	7	
12. Feedwater temperature, C	274	274	265	240	249	265	229	263	232	232
13. Designed specific heat consumption, kJ/kW.h	7660	7720	7720	8065	9610	7720	8260	8170	8760	9080
14. Same at present, kJ/kW.h	7616	7683	7704			7640		8145		
15. Number of cylinders	5	5	3	3	2	4	2	4	3	3
16. Number of stages, including	21	26	29	27	30	26	21	31	25	25
HP**	8	1R+11	1R+11	1R+11	1R+16	16+9	7	1R+11	1R+12	2R+8
IP**	28	29	12	11	1R+8	11	8	10+26	9	14
LP**	25	25	25	24	1R+3	45	26	23	2(1R+2)	2(1R+1)
17. Number of exhausts	6	6	3	2x1.5	1	4	2	2	2	2
18. Last stage average dia, mm	3000	2480	2480	2100	2000	2550	2125	2390	2280	1915
19. Last stage blade length, mm	1200	960	960	765	665	1030	1030	940	830	550

* — operated at 540 C; ** — 1R, 2R - single and twin control stage.

Table 7

Parameters of heavy-duty GT units

Name	Type, manufacturer and purpose							
	TMZ		NZL	KhTZ	Mashproject	LMZ		
	GTN-16	GTN-25	GTN-25	GTE-45	GTG-110	GTE-150	GTE-150	GTE-200
	mechanical drive			utility				
1. Output, MW	16.8	25.5	30.0	54.0	110.0	131.0	161.0	190.0
2. Efficiency, %	29.5	32.3	29.0	28.0	36.0	31.0	31.5	33.1
3. Number of shafts	2	2	3	1	1	1	1	1
4. Turbine inlet gas temperature, C	920	1060	900	900	1210	950	1100	1250
5. Turbine outlet gas temperature, Ñ	430	460	400	475	517	423	530	545
6. Pressure ratio	11.5	13.0	12.5	7.8	14.7	13.0	13.0	15.6
7. Air flow, kg/s	89	103	170	271	357	636	630	630
8. Possible heating load, MJ/s	28.5	37.9	51.1	98.8	157	220	296.5	302
9. Turbine unit weight, t	60	60	97	180	50	320	320	320

Table 8

Parameters of CIS marine and aeroderivative GT units

Name	Manufacturer, type, year of production					
	Mashproject		YuTZ	Tushino	"Saturn"	"Trud"
	GT-15	GT-16	GT-25	RD29-300	AL-31STE	NK-37
	1990	1993	1994	1996	1996	1994
1. GT output, MW	15.8	17.0	25.7	20.0	20.0	25.0
2. GT efficiency, %	30.0	35.5	36.8	30.0	35.5	36.4
3. Pressure ratio	12.8	20.0	21.8	10.7	21.0	23.4
4. Turbine inlet gas temperature, C				957	1252	1147
5. Gas flow, kg/s	98.5	71.0	85.0	98.0	62.0	101.0
6. Turbine outlet gas temperature, C	365	420	497	457	518	425
7. Possible heating load, MW	23.4	22.6	33.3	34.4	25.9	23.1

Table 9

Parameters of Domestic CCPs

Designation	CCP-450T	CCP-325	CCP-80
1. GT type/manufacturer	V94.2, Siemens-LMZ	GTG-110, Mashproject	NK-37, TRUD
2. Number of GTs	2	2	2
3. Heat recovery boiler (HRSG) manufacturer	ZIO	ZIO	BZEM
4. ST manufacturer	LMZ	LMZ	KTZ
5. GT gross output, MW	143.6	110.0	24.2
6. ST gross output, MW162.8	115.0	19.8	
7. CCP gross output, MW	450.0	325.0	68.2
8. Auxiliary consumption, MW	13.5	8.1	3.4
9. CCP net output, MW	436.5	316.9	64.8
10. CCP efficiency, %	50.0	52.5	45.5
11. Gas flow, kg/s	499.4	358.5	104.2
12. Gas turbine outlet temperature, C	545	524	429
13. Exhaust gas temperature, C	110	100	130
HP Circuit			
14. Steam flow, t/h	472	305	71
15. Steam pressure past HRSG/before ST, MPa	8.0/7.6	7.0/6.5	40.8/37.0
16. Steam temperature past HRSG/before ST, C	515/510	495/490	430/427
LP Circuit			
17. Steam flow, t/h	114.0	75.0	18.5
18. Steam pressure past HRSG/before ST, MPa	0.65/0.6	0.65/0.6	0.765/0.6
19. Steam temperature past HRBG/before ST, C	200/195	210/205	205/203

Table 10

Gas Turbine Blade Alloy characteristics

Name	Deformed alloys									
	EI607A	EI893	EI765	TsD-1	TsJ-24	EP783	EP800	EI-929	EP-220	EP-957
1. Ultimate strength, MPa	930	1050	1100	1050	1150	1100	1150	1150	1165	1260
2. Yield point, MPa	485	560	620	630	660	710	750	730	845	940
3. Relative elongation, %	39	30	25	25	20	15	10	15	15	8
4. Impact viscosity, kJ/m^2	1350	500	400	400	350	200	200	200	230	110
5. Stress rupture, MPa: 650C	275	390	390	430	480					650
750C		180	180	190	210	275	280	300		350
850C							95	110	130	135
6. Corrosion loss, mg/cm^2	9	10				11	320	320	660	

Name	Casting alloys									
	EI893L	EP539LMU	TsL-2	TsL-4 (ZMI-4U)	TsL5(7)	ZMI-3	TsNK-7RS	TsNK-7NK	JSBK-RS	JSBK-NK
1. Ultimate strength, MPa	700	750	740	750	700	800	800	750	950	750
	750	850	800	850	850	860	900	1100	1000	1100
2. Yield point, MPa	440	650	600	600	500	700	700	700	850	700
	480	700	700	650	600	750	770	1050	900	1100
3. Relative elongation, %	10–25	2–4	2.2–3.6	2.5–6.0	2.5–5.0	2.5–5.0	2.5–7.0	1.5–2.5	1–3	1–20
4. Stress rupture, MPa: 650C		580				615	645	665		
750C	180	320				335	360	380		
850C		120	120	115	120	125	145	155	170	190
5. Corrosion loss, mg/cm^2	10	8	30		6	13	6	6	650	650

Table 11

Forecast of Electric Energy Generation in Regions of Russia

Parameter	Calendar year	Main regions							
		Center	N-W	Middle Volga	N.Caucasus	Urals, Tumen	Siberia	Far East	Total
Electricity production, bln kWh	1990	305.9	77.0	111.1	58.8	260.4	199.6	44.6	1057.0
	2010	457.8	131.4	162.0	112.0	401.6	344.0	102.1	1711.0
Heat consumption, bln GJ	1990	3.546	0.754	1.242	0.502	2.140	2.001	0.175	10.363
	2010	4.112	0.892	1.708	0.586	2.483	3.538	0.837	14.156
Installed capacity, GW	1990	55.3	14.5	22.5	10.8	41.2	45.2	11.1	200.7
	2010	84.3	24.7	34.5	25.3	71.6	73.2	26.5	340.
including TPS, GW	1990	39.2	6.0	13.2	8.6	38.8	22.0	8.3	136.2
	2010	59.3	14.9	23.9	17.7	69.8	43.3	15.7	244.6
Max.Load, GW	1990	47.8	11.8	16.7	11.3	38.4	31.8	7.9	165.7
	2010	74.0	19.0	22.6	18.6	59.8	47.0	18.6	259.6
Fuel demand, mln. tfe	1990	106.7	17.2	44.2	21.5	103.8	57.8	17.9	351.2
	2010	150.0	35.0	64.5	45.4	174.0	114.0	40.3	582
Including coal, mln. tfe	1990	13.8	1.9	1.0	3.7	21.9	55.0	12.3	97.3
2010	27.2	6.0	9.8	10.4	67.2	99.0	27.7	219.6	

Table 12

NOx Control Technologies

Data \ Project Technology Develope Sponsor p.p. of CCTDF	The Babcock & Wilcox coal-reburning system Babcock & Wilcox Company 7-40	ABB CE LNCFS with AOFA Southern Co Services, Inc. 7-48	Foster Wheeler's LNB with AOFA Southern Co Servisec, Inc. 7-46	The Babcock & Wilcox Low-NO_x Cell burner system The Babcock & Wilcox Company 7-42	EERC's gas-reburning and Low-NO_x burner system (GR-LNB) Energy & Envir.Res. Corp. 7-44	Fuller's micronized coal reburning technology Tennessee Valley Authority 7-52	SCR Technology for the Control of NOx Emission Southern Co Serv. Inc. 7-50
1. Power Unit Output, MW	100 – 300	200 – 800	50 – 800	300 – 800	50 – 800	50 – 800	200 – 800
2. Status (development stage):	commercial	commercial	commercial	commercial	commercial	demo	pilot
Pilot, demo, commercial.							
Date of commercial implementation	1995	1995	1995	1995	1995	1998	1998
3. Reasonable operating time, ths.hrs/yr	> 6	> 4	> 4	> 4	> 4	> 4	> 4
4. Emissions reduction, %	50	40	65	55	70	50 – 60	>80
5. Construction period, years	1.0	0.5	0.2	0.2	1.0	0.5	0.92
6. Availability, %	–	–	–	90,0	–	–	–
7. Kinds of fuel** À, Bit, Lign	Bit, Lign	Bit	Bit	Bit	Bit	Bit	
8. Reagents: type	–	–	–	–	natural gas	–	ammonia
comsumption, g/MJ	–	–	–	–	< 20%	–	–
9. Capital investment, doll/kW	40 – 65	30 – 40	30 – 40	5.5 – 8.0	17 – 42	32	80 – 90
10. Maintenance costs, cents/kW.h	0.21 – 0.29	0.067 – 0.17	0.067 – 0.17	0.03 – 0.04	0.2 – 0.7	0.1	0.4 – 0.5
11. Cost of 1 t of NO_x removed, $	260	420 – 1590	420 – 1590	160 – 450	400 – 2000	–	700 – 5000
12. Reference Unit Capacity, MW	200	500	500	500	300	300	300

* – Clean Coal Technology Demonstration Program; Program Update 1993

** – A (anthracite), Bit (bituminous coals), Lign (Lignites)

Service life is about 20 years

Table 13

SO_2 Control Technologies

Project / Technology Developer / Sponsor / p.p. of CCTDP* — Data	(CT-121) advanced FGD process (wet) South.Co Serv., Inc. 7-62	AFGD-process (wet) Pure Air on the Lake, L.P. 7-60	FLS milio a/s's (GSA) system for FGD (semidry) AirPol, Inc. 7-54	Bechtel Corp.'s (CZD/FGD) process (semidry) Bechtel Corp. 7-56	LIFAC's sorbent injection process (semidry) LIFAC-North America 7-58
1. Power Unit Output, MW	100	200 — 800	50 — 300	50 — 800	50 — 300
2. Status (development stage): pilot, demo, commercial.	demo	commercial	pilot	demo	commercial
Date of commercial implementation	1995	1995	2000	1995	1995
3. Reasonable operating time, ths.hrs/yr	> 6	> 6	> 4	> 4	> 4
4. Emission reduction, %					
- of SO_2	95	95	90	50	80
- of NOx	~20	—	—	—	—
- of particulate matter	~50	—	—	—	—
5. Construction period, years	2.0	2.5	0.4	0.3	1.1
6. Availability, %	—	99.9	—	—	—
7. Kinds of fuel**	Bit; S > 2% Lign; S > 1.5%	Bit; S > 2% Lign; S > 1.5%	Bit; 1 < S < 2% Lign; 0.6 < S < 1.5%	Bit; S < 0.4% Lign; S < 0.3%	Bit; S < 1% Lign; S < 0.6%
8. Water requirement, 1/MJ	—	0.1	—	—	—
9. Reagents: type	$CaCO_3$	$CaCO_3$	$Ca(OH)_2$, $Mg(OH)_2$	$Ca(OH)_2$	$CaCO_3$
Ca/S ratio	~1	~1	~1.0 — 1.5	~2	~2
consumption, g/MJ	< 5	< 5	< 2.8	0.7	<2.5
10. Wastewater, ml/MJ	—	5.0***	—	—	—
11. By-Products type	$CaSO_4$	$CaSO_4$	$CaSO_4$, $CaSO_3$, $CaCO_3$	$CaSO_4$, $CaSO_3$, $MgSO_4$, $MgSO_3$	$CaCO_3$
yield, g/MJ	< 6.5	< 6.5	< 5 + fly ash	< 1 + fly ash	< 3 + fly ash
application	sale	sale	ash disposal	ash disposal	ash disposal
12. Capital investment, doll/kW	180 — 250		(160)	30 — 60	50 — 60
13. Maintenance costs, cents/kW.h	0.5 — 1.3		(0.551)	—	—
14. Cost of sulfur removed, doll/t	470 — 630		420 — 680	500 — 650	650
15. Reference Unit Capacity, MW	100	500	300	200	—

* CCTDP - Clean Coal Technology Demonstration Program; Program Update 1993

** — Bit (bituminious coals), Lign (lignites)

*** — Wastewater Dissolved Solids: pH = 8–9; content of chloride - 4560 ppm; sulphate - < 2500 ppm; fluoride - 19 ppm; tot al dissolved solids - 1.41 g/m³
Service life is about 20 years.

Table 14

Combined SO2/NOx Control Technologies

Data \ Project / Technology Developer / Sponsor / p.p. of CCTDP*	SNOX Flue Gas Cleaning Technology ABB Environ. System 7-64	SNRB Flue Gas Cleaning Technology The Babcock & Wilcox Co 7-68	NOXSO SO_2/NO_x Flue Gas Cleanup System NOXSO Corp. 7-74	Integrated Dry NO_x/SO_2 Emission Control System B&W Technology Public Service Co of Colorado 7-76	Millicen Clean Coal Technology Demonstrat. Project New York State E & G Corp 7-72	Technology: LIMB B&W Babcock & Wilcox Co 7-66	Technology: Coolside Consolid. Coal Co	E & E Research Corp.'s Gas Reburning and sorbent injection process Energy & Envir. Research Corp. 7-70	TWR-technology Healy Clean Coal Project Alaska Industr. 7-32
1. Power Unit Output, MW	200 – 800	50 – 200	100 – 300	50 – 250	300	50 – 500	50 – 250	50 – 500	50 – 300
2. Status (development stage): Pilot, demo, commercial	commercial	pilot	demo (no results)	demo	demo (no results)	commercial	commercial	commercial	pilot
Date of commercial implementation	1998	2000	after 2000	1998	after 2000	1995	1995	1995	after 2000
3. Reasonable operating time, ths. hrs/yr	> 6	> 6	> 6	> 4	> 6	> 4	> 6	> 5	> 6
4. Emission reduction, %									
- of SO_x	95	80	97	70	98	20 – 30	70	> 50	> 90
- of NO_x	90	90	70	70	50	40 – 50		> 60	80
- particulate matter	> 99	99.8	-	-	20	-	-	-	99.9
5. Construction period, years	1.0	0.8	1.0	1.3	1.1	2	2	2.3	2.3
6. Kinds of fuel**	Bit; S > 2% Lign; S > 1.5%	Bit; S < 1% Lign; S < 0.6%	Bit; S > 2% Lign; S > 1.5%	Bit; S < 0.7% Lign; S < 0.4%	Bit; S > 2% Lign; S > 1.5%	Bit; S < 0.3% Lign; S < 0.2%	S < 0.7% S < 0.4%	Bit; S < 0.4 Lign; S < 0.3	Bit; 1 < S < 2% Lign; 0.7 < S < 1.5
7. Reagents, type	NH_3, catalysis	$Ca(OH)_2 + NH_3$ $NaHCO_3 + NH_3$	sorbent natural gas	Ña + Na + urea	$CaCO_3$ urea	$CaCO_3$	$Ca(OH)_2$	$CaCO_3$, $Ca(OH)_2$	$CaCO_3$
Ca/S ratio	-	1.5 - 2.0 (Ca/S) 1.0 - 1.5 (Na_2/S)	-	-	~1	2	2***	1.7	
NH_3/NO_x ratio	0.9	0.9			-	-	-	-	-
consumption, g/MJ	NH_3 - 0.2	$Ca(OH)_2$ - 1.4 NH_3 - 0.2	-	-	$CaCO_3$ < 5	ÑaCO_3 < 5	-	0.65	-
8. Wastewater					neutralized				
9. By-Products, type	H_2SO_4, Na_2CO_3 $NaNO_3$, NaCl	$CaSO_4$, $CaSO_3$, $CaCO_3$, $CaCl_2$, CaO, Na_2SO_4, Na_2SO_3	sulfur	$CaSO_4$, $CaSO_3$ Na_2SO_4, Na_2SO_3 fly ash	$CaSO_4$, $CaCl_2$	$CaSO_4$, $CaSO_3$, $CaCO_3$	Na_2SO_4	$CaSO_4$, $CaSO_3$, $CaCO_3$	slag, $CaSO_4$ $CaCO_4$, fly ash
yield, g/MJ	< 4.7	1.4 + fly ash	< 1.5	-	< 6.5	-	1.9 + fly ash	0.9 + fly ash	-
application	sale	ash disposal	sale	ash disposal	sale	ash disposal		ash disposal	ash disposal
10. Capital investment, doll/kW	-	260	250	-	180	31–102	69 – 160	40	-
11. Maintenance costs, cents/kW.h	-	1.5	0.4	-	-	0.54	-	-	-
12. Cost of sulfur removed, doll/t	-	510	210	-	450	370 – 620	-	-	-
NO_x removed, doll/t	-	510	800	-	-	-	-	-	-
13. Reference Unit Capacity, MW	300	200	200	100	300	200		300	200

* – CCTDP - Clean Coal Technology Demonstration Program. Program Update 1993

** – Bit (bituminous coals), Lign (Lignites)

*** – With addition NaOH or Na_2CO_3 of Na/Ca = 0.2 ratio
Service life is about 20 years

Table 15

Basic Characteristics of Coal TPS Emission Reduction Technologies

Contaminant	Technology		Coal grade and combustion technology	Maximum cleaning efficiency %	Enlarged specific heat consumption Btu/kW.h (%)***	Specific cost, $/kW		Enlarged costs for repair and service c/kW.h	Enlarged electricity cost, c/kW.h	
						new plants	modified plants		new plants	modified plants
Sulfur Dioxide	FGD	Wet Limestone/ Forced Oxidation	High Sulfur Coals	95 - 98	120 (1.34)	130 - 300	150 - 250	0.28	0.48 - 0.61	0.53 - 0.66
		Lime Slurry Wet/Dry	Low Sulfur Coals	80 - 90	60 (0.67)	100 - 150	130 - 200	0.16	0.35 - 0.40	0.37 - 0.48
		Simplified Wet/Dry	Low Sulfur Coals	60 - 70	54 (0.6)	30	70	0.15	0.30	0.35
		Dry	Low Sulfur Coals	30 - 50	9 (0.1)	30	40	0.10	0.10	0.10
Nitrogen Oxides	Low-NO_x burners + overfire air supply		reconstruction of dry-bottom boilers	40	20 (0.22)	<10	10 - 20	0.01	<0.03	0.03 - 0.04
	reburning and additional measures (burners. etc.)		FBC, PC and cyclon boilers	50 - 70	22(0.25)			0.10	0.04	0.05
	SCR on hot side at high dust content		rigid standards for PC, FBC and cyclon boilers	60 - 80	75 (0.84)	70 - 90	80 - 100	0.26	0.40 - 0.43	0.41 - 0.45
	SNCR with ammonia or urea injection		rigid standards for PC,CFB,FBC	40 - 80	0	5-10	10 - 20	0.10	0.11 - 0.12	0.12 - 0.13
Fly ash	ESP		High Sulfur Coals	4.3-8.6* 11 - 22**	5 - 20 (0.06 - 0.22)	85	85	0.15	0.25	0.20
	baghouses	reverse air cleaning	All grades of coals	4.3*/11**	<10 (<0.11)	70	90	0.17	0.28	0.31
		pulse jet cleaning	All grades of coals	4.3*/11**	20 (0.22)	50	60	0.20	0.28	0.30

* mg/MJ;

** mg/m^3 at SR =1.4;

*** at b_e = 8980 BTu/kW.h, which corresponds to =38%

Table 16

Advanced Electric Power Generation Projects

Project Technology Develo Sponsor p.p. of CCTDF Data	Pressurized Fluidized-bed Combustion (PFBC) Systems				Atmospheric circulating FB Combustion Systems		Integrated Gasification Combined Cycle (IGCC)						
	Tidd PFBC The Ohio Power Co 7-14	The Appalachian Power Co PFBC 7-8	DMEC-1 Limited Partnership PYROFLOW PCFB 7-10	Four Rivers Energy Partners PCFB 7-12	ACFB York County Energy Partners 7-18	ACFB Nucla Tri-State Generation & Trasmis. 7-16	ABB CE Inc. 7-20	Texaco's technology Tampa Electric Co 7-28	Tampella U-GAS system TAMCO Partn.Co 7-26	Pinon Pine Sierra Pacific Power Co KRW 7-24	Wabash River Coal Gasific Repowering Project JV Destec 7-30	Duke Energy Corp. BGL 7-22	Centerior Energy Corp. COREX 7-96
1.Power Unit Output, MW	80	300 – 500	50 – 200	300-500	100 – 300	50 – 200	200 – 400	200 – 600	200 – 600	200 – 600	200 – 600	200 – 600	200 – 400
2.Status (development stage):	commercial	demo	demo	pilot	demo	commercial	demo	demo	demo	demo	demo	demo	demo
Pilot, demo, commercial													
Date of commercial implementation	1998	2000	after 2000	after 2000	2000	1995	after 2000	1998	2000	2000	1998	2000	after 2000
3.Reasonable operating time, ths.hrs/yr	>6	>6	>6	>6	>4	>4	>4	>6	>6	>6	>6	>6	>6
4.Emissions reduction, %													
of SO_2	90	95	90	95	90	70 – 95	99	96	99	98 – 99	98	99	90
of NO_x	80	80	70	70	60(80)	60	90	90	90	94	80	90	97
5.Construction period, yrs	3.0	3.2	2.0	—	1.5		—	2.7	—	2.2	—	—	—
6.Kinds of fuel**	Bit;1<S<2.5%	Bit;S >2%	Bit;1<S<2%	Bit; S >2%	Bit; S <2%	Bit;S <1.5%	Bit; S <3%	Bit; S >3%	Bit;S >3%	Bit;S >3%	Bit;S >3%	Bit;S >3%	Bit;1<S <2%
	Lig;0.6<S<2%	Lig;S>1.5%	Lig;0.6<S<1.5%		Lig;S <1.5%	Lig;S <1.0%	Lig; S >2%	Lig; S >2%	Lig;S >2%				Lig;0.6<S<1.5%
7.Water requirement,	no	no	no	no	no	no	no	yes	no	no	yes	yes	yes
8.Reagents type	$CaCO_3$	$CaCO_3$	$CaCO_3$	$CaCO_3$	$CaCO_3$	$CaCO_3$	regenerated		$CaCO_3$	$CaCO_3$	regenerated		$CaCO_3$
Ca/S ratio	—	—	—	—	—	1.5/4.0	—	—	—	—	—	—	—
9.By-products type	M	M	M	M	M	M	slag	H_2SO_4, slag	M	M	sulfur, slag	sulfur, sl.	M
application	ash disposal	ash dispos	ash disposal	ash dispos.	ash dispos.	ash dispos.	sale	sale	ash disposal		sale	sale	—
10. Reference Unit Capacity, MW	80	340	100	300	250	150	200	250	300	300	300	300	200
11. Reference Unit Efficiency,%	40.0	42.2	40.0	47.0	39.5	—	45.0	42.0	46.2	45.9	40.0	44.6	47.2
12. Emissions Particulate matter, mg/MJ	—	—	—	—	—	—	—	—	—	4.3	—	—	—
SO_2, mg/MJ	—	—	—	—	100	—	45	90	25	20	85	45	100
NO_x, mg/MJ	—	—	130	130	—	80	45	115	40	30	45	65	50
mg/m³	165 – 200	110	330	330	—	200	115	300	100	75	85	105	130
13. Year of Unit Start-up —	2002	1997	—	1997	—	1998	1996	1998	1997	1995	1998	1999	
14. Cleaning	—	—	—	—	—	—	dry clean.	wet clean.	dry clean.	dry clean.	wet clean.	wet clean.	wet cleaning
15. Oxidizer	—	—	—	—	—	—	air	oxygen	air	air	oxygen	oxygen	oxygen

* CCTDP - Clean Coal Technology Demonstration Program, Program Update 1993

** Bit(bituminous coals); Lig(Lignites)

M mixture of utilized ($CaSO_4$, $CaSO_3$) and nonutilized ($CaCO_3$) sorbent with fly ash

Service life is about 20 years

Table 17

IGCC Demo Projects developed in USA in accordance with CCTP

Name	Location						
	Wabash River	Springfield	Pinon Pine	Cleveland	Camden	Tampa	Tom Creek
1. Gasification technology	EF	EF	FB	FB	MB	EF	FB
2. Developer	DCh	CE	KRW	VA	BGL	Texaco	T
3. Gasifier output, t/h	95	23	30	111	435	72	16.5
4. Coal grade	bituminous						
5. CCP output, MW	269	60	100	150	480	260	55
6. Type of GT, MW	M7F	M6B	M6FA	–	M7F	M7F	M6B
7. GT output, MW	191	40	61	–	2192	192	–
8. ST output, MW	111	25	46	–	–	(124)	–
9. CCP efficiency, %	39.0	–	–	–	–	40.6	39.1
10. Blown by	O	A	A	O	O	O	A
11. Ash removal in gasifier	L	S	S	–	L	L	S
12. Clean up of particulates	H	H	H	–	–	H	H
13. Desulfurisation of gas	C	H	H	–	C	H	H
14. New (n)/retrofit (r)	r	r	r	n	n	n	n
15. Start of tests	1995	1996	1997	–	–	1996	1998
16. Completion of tests	1998	2001	2000	–	–	1997	2000
17. Project cost, mln.USD	398	271	270	825	780	241	197
18. DOE share, %	50	48	50	18	25	50	47

EF - entrained-flow; FB - in fluidized bed; MB - in moving (fixed) bed; DCh - Dow Chemical;
CE - Combustion Engineering; VA - Voest Alpine; BGL - British- Gas-Lurgi; KRW - Kellog;
T - Tampella & Gas Research Institute; O - oxygen; A - air; L - liquid; S -solid; H - hot; C - cold.

Table 18

Test Results of Direct Coal Combustion for GT

Name	Company				
	Solar	Allison		Westinghouse	
1. GT capacity, MW	4.0	4.6		104	
2. Fuel supplied	CWS	CWS		dust	CWS
3. Max. particle size, mm	75	15		200	110
4. Mean particle size, mm	11	5		44	40
5. Ash content (dry), %	3.0	0.8		6.5	
6. S (dry), %	0.6	0.7		1.0	
7. Gas outlet temperature, C	1054	1127		1054	1010
8. Combuster pressure, MPa	0.55	1.07		0.59	0.60
9. Air flow, kg/s	1.60	1.86	15.0	3.18	
10. Carbon burnout, %	99.9	99.6	94 – 99	99	
11. Type of slag removal liquid	dry	liquid			
12. Type of precipitator	inertial + filter			inertial	
13. Ash slag removal, %	98	—	89	90	89
14. Emissions of NO_x, ppm	29	25	25	90	80
15. Capture of SO_2, %	55	50	-	40	22
16. Type of sorbent	dolomite			limestone	
17. Ca/S molar ratio	1.2 – 1.6	3.7	—	2 – 4	3

CWS coal-water-slurry

Table 19

Quality of Russian Coals Fired at TPS in 1993

Coal Field/Type	Used at TPS, mln.t	Content as per working mass						Volatiles
		W, %	A, %	LHV, MJ/kg	C, %	S, %	N, %	V, %
Kuznetsk, bit.	22.3	10.7	20.4	21.8	40.5 - 66.0	0.4	1.3 - 1.8	12 - 41
Kansk-Achinsk, br.	27.5	33.1	6.8	15.4	37.4 - 44.3	0.3	0.5	48.0
Eastern Donbas, AC	5.8	8.2	25.1	21.5	62.5	1.7	0.5	5.0
Pechora.,bit. (Inta)	2.2	11.6	29.1	17.0	43.9	2.4	1.5	40.0
Neryungrinsk, bit.(Yakutia)	4.2	8.3	15.8	24.85	64.8	0.2	0.7	20.0
Chelyabinsk, br. (Urals)	6.4	15.2	37.2	12.6	33.8	0.8	0.9	44.0
Near-Moscow, br.	6.0	29.6	36.2	7.9	22.2	2.35	0.4	48.0
Azeisk,.br. (East)	8.0	23.5	17.4	16.3	43.1	0.5	0.9	48.0
Kharanorsk, br. (East)	8.2	38.6	13.6	11.8	34.3	0.3	0.5	44.0
Bikinsk, br. (Far East)	5.5	38.0	28.8	7.0	22.0	0.3	0.6	53.0
Ekibastuz, subbitum. (Kazakhstan)	25.6	6.1	39.9	16.4	41.9	0.7	0.8	25.0
Gusinoozersk, br. (Buryatia)	2.5	24.7	21.3	13.1	38.3	0.4	0.6	43.0

Bit bituminous; br. brown; AC anthracite culm.

Table 20

Some Characteristics of Kuznetsk Coals and their Ash

Name	Coal Grade					
	LF	G	WS1	WS2	L&A	Wastes
Moisture content, W,.%	11.5 - 13(18)	8.5 - 11(19)	9 - 12(21)	8.5 - 12(19)	710(13)	6 - 25
Ash content, A^d ,%	18(25)	18.5 - 25	20 - 30	18 - 30	20 - 25	13 - 45
Volatiles, V^{daf} ,%	40.5	39.5	31	20	12.5	16 - 41.5
Sulfur content, S^{daf}, %	0.4	0.5	0.5	0.4	0.5	0.3 - 0.9
LHV, Q, MJ/kg	21.9(18 - 23)	23.6 (16 - 27)	23.4 (17 - 25)	25.3 (16 - 26)	25.1(27.7)	17.4 - 22.3
Fixed nitrogen, N^{daf}, %	2.6	2.7	2.1	2.1	2.2	1.7 - 3.1
SO_2 concentration in combustion gases: mg/MJ	365	425	430	315	400	345 - 810
mg/m³*	935	1080	1090	810	1020	880 - 2060
Ash composition, %: SiO_2	59.5	55.7	56.0	59.7	55.4	41.4 - 64.2
Al_2O_3	20.6	21.6	23.6	22.4	25.4	17.4 - 26.8
Fe_2O_3	6.7	7.8	10.1	8.5	77.2	4.1 - 10.8
CaO	3.9	6.0	4.0	2.7	4.6	2.4 - 7.6
MgO	2.7	2.8	1.8	1.6	1.9	1.4 - 3.4
K_2O	3.0	2.3	2.0	2.6	1.9	0.8 - 3.9
Na_2O	2.0	2.0	0.7	0.9	0.7	0.4 - 3.7
TiO_2	0.9	0.8	1.0	0.9	0.8	0.8 - 1.2
P_2O_5	0.5	0.8	0.5	0.5	1.6	0.2 - 1.6
MnO	0.2	0.2	0.2	0.3	0.3	0.4
Temperature of normal liquid slag removal, C	1600	1500	1550	1700	–	1430 - 1580

* Here and hereinbelow, the emissions are related to m³ in standard conditions with excess air of 1.4 or O_2 = 6%.
The bracketed values are limiting for open-cast produced coals.

Table 21

Some Characteristics of Bituminous Coals and their Ash

Name	Field/Coal Grade							
	Pechora		East Donbass		S.-Yakutia. Neryungri	Ekibastuz		
	Inta	Vorkuta						
	LF	G	L	AC	WS	group 1	group 2	middle
Moisture content, W, %	11.5	8.0	6.0	9.0	10.0	6.0	5.0	6.0
Ash content, A^d,%	32.5	32.0	34.0	35.0	22.0	43.0	48.0	45.0
Volatiles, V^{daf}, %	40.0	33.0	12.0	4.0	20.0	25.0	25.0	25.0
Sulfur content, S^{daf}, %	3.2	1.1	2.7	1.9	0.2	0.6	0.6	0.6
LHV, Q, MJ/kg	16.9	20.8	20.6	19.1	22.5	16.1	14.6	15.5
Fixed nitrogen, N^{daf}, %	2.6	2.4	0.8	0.8	0.8	1.7	1.7	1.7
SO_2 concentration in combustion gases, mg/MJ	3790	1060	2620	1990	180			770
mg/m^3	9680	2700	6700	5080	460			1970
Ash composition, %: SiO_2	54.6	62.6	49.9	54.1	53.6	62.6	59.2	60.6
Al_2O_3	18.6	19.4	22.3	23.9	27.5	28.2	29.6	28.6
Fe_2O_3	14.1	8.6	17.5	11.1	8.0	5.0	6.0	5.4
CaO	6.9	3.0	4.0	2.9	4.9	1.0	1.6	
MgO	2.3	2.3	1.6	1.7	2.4	0.7	0.6	
K_2O	1.3	2.1	2.8	3.5	0.7	0.6	0.5	
Na_2O	1.4	1.0	1.2	1.5	0.7	0.2	0.2	0.2
TiO_2	0.8	1.0	0.7	1.3	1.2	1.1	1.3	
P_2O_5					0.8	0.6	0.7	
MnO					0.2	0.1	0.2	
Temperature of normal liquid slag removal, C	1450	1550	1400	1550	1600	1650	1580	1600

Table 22

Brown Coal Ash Chemical Composition and Fusibility

Field	Ash Chemical Composition, %								Ash Fusibility, C			Tnj, C
	SiO_2	TiO_2	Al_2O_3	Fe_2O_3	CaO	MgO	K_2O	Na_2O	Ta	Tb	Tc	
1. Kansk-Achinsk coals:												
Irsha-Borodinsk 46.8	0.6	12.9	7.9	25.8	5.0	0.5	0.5	1180	1210	1230	1300	
Nazarovo	30.5	0.6	10.0	19.0	35.0	4.0	0.4	0.4	1200	1220	1240	1300
Berezovo	30.0	–	11.0	9.0	42.0	6.0	1.2	0.8	1270	1290	1310	1400
2. Azeisk	52.8	0.4	28.8	7.2	7.9	2.1	0.6	0.2	1200	1340	1420	1550
3. Gusinioozersk	51.5	1.3	23.6	12.1	5.6	2.8	1.9	1.2	1150	1260	1330	1460
4. Kharanorsk	57.9	0.7	23.3	5.5	7.4	2.8	1.6	0.8	1170	1270	1360	1450
5. Raichikhinsk	55.7	0.8	25.5	7.8	7.0	1.4	1.2	0.6	1150	1240	1340	1400
6. Bikinsk	58.2	0.7	26.8	5.3	3.5	2.3	1.7	1.5	1240	1450	1500	–
7. Near-Moscow	47.5	0.5	38.5	8.5	3.5	0.5	0.7	0.3	1350	1500	1500	1750

Ta, Tb, Tc, C typical temperatures of ash softening;

Tnj, C temperature of beginning of normal liquid slag removal.

Table 23

Base-Case Options of Russian Advanced Coal TPS

Parameters	Supercritical Pulverized Coal Units			IGCC Plant		Supercritical Pulverized Coal Units			Supercritical Pulverized Coal Units		CFB Unit	Subcritical Pulverized Coal Units	IGCC Plant	
	existing	$De\text{-}SO_x$-$De\text{-}NO_x$ systems	Ecologically clean	oxygen blowing	air blowing	existing	with $De\text{-}SO_x$-$De\text{-}NO_x$ systems LD	HD	existing	with De-SOx-De-NOx clean				
TPS capacity, MW	6400			6000		4000			2400			360	500	640
Utilization period, h/yr	6500			6500		6190			4000			6000		
Unit capacity, MW	800			650		500			300			180	250	320
Fuel characteristics:														
Coal field	KANSK-ACHINSK					EKIBASTUZ			DONETSK			KUZNETSK		
Coal grade	BROWN COAL					BITUMINOUS			AC			BITUMINOUS		
Heat value, MJ/kg	15.07					14.45			17.25			22.25		
Ash content, %	7.00					45.60			36.00			21.60		
Moisture content, %	38 (33 – 38)					5.00			10.00			10(12 – 20)		
Sulfur content, %	0.3 (0.2 – 0.5)					0.60			1.40			0.4		
Nitrogen content, % 0.3	0.80					0.50			1.50					
Efficiency in nominal output, %	38.50	37.60	38.70	42.50	43.50	38.15	35.90	37.20	37.60	36.80	37.30	36.30	38.50	41.90
Relative specific investment cost	1.227	1.483	1.193	1.326	1.358	1.000	1.577	1.470	1.043	1.673	1.071	1.375	1.534	1.399
Specific emissions														
NO_x, mg/m³	600	200	200	40*	30*	900	200	200	800–1200	200	200	900	80*	80*
mg/MJ	220	75	75	30	25	320	70	70	280–420	70	70	320	65	65
SO_x, mg/m³	600	300	300	3.5	10	2100	200	200	2800	200	200	1000	60*	60*
mg/MJ	220	110	110	2.5	8	750	70	70	1000	70	70	350	48	48
Particulate matter, mg/m³	150	50	50	0.7	0.7	500	100	100	500	50	50	250	2*	2*
mg/MJ	55	18	18	0.6	0.6	180	35	35	180	18	18	90	1.6	1.6

* For IGCC Plants the emissions are related to m³ in standard conditions with excess air of 3.0 or O_2 = 15%

Table 24

Technical Characteristics of modular type FRO-12000 fabric filter

Filtering surface area, m^2	1200
Specific gas loading at filtering surface, $m^3/(m^2 min)$	not more than 47
Number of sections	24
Number of filtering bags per section	54
Total number of filtering bags	1296
Bag length, mm	10000
Bag diameter, mm	300
Temperature of gases to be cleaned, C	not more than 180
Rarefaction in the filter, Pa	not more than 8000
Pressure drop, Pa	not more than 2000
Dimensions, mm: length	40200
width	9810
height	19000
Filter weight, kg	420000

Table 25

Characteristics of catalysts for different De-NO_x locations

Name	De-NO_x location	
	before air heater	past De-SO_x
Flue gases dust content, g/m^3	70 – 100	not more than 0.15
SO_2 concentration, mg/m^3	2000-2200	200 – 300
Temperature, Ñ	300 – 320	320 – 350
Catalyst:		
channel size, mm	6.1 – 6.3	3.4 – 3.6
surface, m^2/m^3	430 – 470	750
relative activity	1.0	1.0 – 1.2
relative volume	1.0	0.4 – 0.5
service life, thou.h	12 – 15	24
Relative pressure drop	1.0	1.0 – 2.5

Table 26

Some Data of Limestone $DeSO_x$ Plant

Cleaned gas flow, m^3/h	2.110^{6}
Gas temperature: before $DeSO_x$ plant, C	100
past absorber, C	50
past $DeSO_x$ plant, C	55
SO_2 Concentration: before $DeSO_x$ plant, mg/m^3	2100
past $DeSO_x$ plant, mg/m^3	300
SO_2 discharge after cleaning, g/s	175
Pressure drop, kPa	3.5
Limestone consumption (95% of calcite), kg/h	6860
Amount of gypsum produced, kg/h	10860
Service water consumption, m^3/h	60
Gas dust content: before $DeSO_x$ plant, mg/m^3	150
past $DeSO_x$ plant, mg/m^3	100

Table 27

Performance of 500 MW Unit with differ De-NO_x Plant Location

Parameter	500 MW Unit		
		Ecologicaly clean TPS	
	Ekibastuz TPS-2	DeNO_x past DeSO_x	in-build DeNO_x
Additional capacity*, MW	0	4.8	1.1
Heating surface, thou.m^2			
air heater	163	252	252
economizer	12.4	12.4	17.3
heat exchangers: air-water	–	3.42	6.12
in-build air-water	–	23.10	7.50
gas-gas	–	230.00	–
Design power of draft machines. MW	10.22	20.48	13.70
ESP power, MW	2.05	3.80	3.80
Power consumed for DeSO_x plant, MW	–	5.53	5.68
Increased auxiliary power, MW	–	17.54	13.15
Total fuel consumption, t/h	327.3	339.0	327.2
Boiler efficiency, %	91.09	94.37	94.07
Exhaust gas temperature, C	159	99	100
Annual specific fuel consumption, g/kW.h	322.4	342.7	330.3
Annual efficiency, %	38.15	35.89	37.20
Relative specific investment cost	1.0	1.58	1.50

* Power, produced by steam which was not used for feedwater preheating

Table 28

Design Characteristics of CFB Boiler for 300 MW Units

FURNACE	
Number per boilers	2
Plan dimensions, mm	108008600
Outer diameter and wall thickness of waterwall tubes, mm	326
Heat absorption surface of furnace waterwalls, m²	1144
CYCLONES	
Number per boiler	4
Inner diameter, mm	10000
Inlet port size, mm	25005715
Letdown inner diameter, mm	1500
Total height, mm	25000
EXTERNAL HEAT EXCHANGERS	
Number per boiler	4
Number of main superheater sections	2
Number of reheater sections	1
Outer diameter and wall thickness of tube, mm	386
Heat transfer surface, m²	1250+480
Exchanger dimensions, mm: length14200	
width	6000
height	6000
CONVECTIVE SECTION	
Superheater: number of banks	1
tube dia, mm	32 ŏ 6
heat transfer surface, m²	2750
Reheater: number of banks	2
tube dia, mm	424
heat transfer surface, m²	6230
Economiser: number of banks	2
tube dia., mm	383
heat transfer surface, m²	8200
Air heater: number of banks	3
number of passes	4
tube dia, mm	401.5
heat transfer surface, m²	67500
Boiler dimensions, m: width	39.0
depth	43.5
height	52.5

Table 29

Some Data of CFB 300 MW AC-fired Boilers

Boiler capacity, t/h	1000
Flow of reheated steam, t/h	800
Temperature of superheated steam, C	545
Temperature of reheated steam, C	545
Pressure of live steam, MPa	25.0
Pressure of reheated steam, MPa	3.8
Feedwater temperature, C	270
Boiler efficiency, %	86.4
Heat losses, %: exhaust gases	5.5
unburned gases (CO,CH, etc.)	0
carbon loss	6.0
external	0.2
slag	0.4
limestone decomposition	1.5
Total fuel consumption, t/h	176.6
Limestone consumption, t/h	16.8
Exhaust gas temperature, C	140 (100)
Furnace thermal characteristics:	
outlet temperature, C	900
mean gas velocity, m/s	6.4
volume heat release rate, kW/m^3	169.3
Furnace ash balance:	
flue gas fly ash concentration at furnace outlet, kg/m^3	10.4
fly ash circulation ratio	180
ash fed to furnace, t/h	5300
Air distribution:	
furnace air excess	1.02
same,past air heater	1.28
share of primary air of total air flow, %	50
share of secondary air, %	50
share of recirculation air past air heater,%	9.5
Temperature, N:	
economizer inlet water	270
furnace chamber wall outlet steam	394
convective superheater outlet steam	402
external heat exchanger superheater outlet steam	545
convective reheater inlet steam	287
same, outlet steam	446
external heat exchanger reheater outlet steam	545
cold air	30
air heater inlet	50
air heater outlet	300
Convective section gas velocity, m/s:	
superheater	10.0
reheater	10.0
economizer	6.5
air heater	13.3
Air heater air velocity, m/s	6.9

Table 30

IGCC Plant Performance

Name	Types of gasifiers								Natural gas CCP	
	moving bed				entrained flow					
	oxygen blast		air blast		oxygen blast		air blast			
Ambient temperature, C	-5	+15	-5	+15	-5	+15	-5	+15	-5	+15
HP live steam flow to ST, t/h	472	454	577	532	607	574	585	551	495	480
LP steam flow past boiler, t/h	228	185	268	209	244	190	232	184	244	195
Steam consumed for drying, t/h	99	86	129	112	124	106	111	97	0	0
Superheated steam temperature, C	515	535	520	540	520	540	520	540	505	525
Reheat temperature, C	460	470	455	465	460	475	465	475	455	460
LP steam temperature, C	240	232	256	243	248	236	247	234	248	237
Reheat steam pressure past boiler, MPa	2.25	2.16	2.30	2.16	2.30	2.16	2.30	2.16	2.20	2.16
GT output, MW	509	418	500	413	510	414	445	372	487	405
ST output, MW	196	188	240	220	246	233	242	227	222	210
CCP gross output, MW	705	.606	740	633	756	647	687	600	709	615
Auxiliary power, MW	74	68	38	32	110	94	36	31	13	11
IGCC net efficiency (on coal basis), %	43.6	43.4	44.9	44.2	43.9	43.8	44.8	44.1	52.1	52.0
Fuel saving as compared with p.c.										
800 MW unit (39% efficiency), %	10.6	10.1	13.1	11.8	11.2	11.0	12.9	11.6	25.1	25.0

Table 31

Coal characteristics adopted in CCP design

Parameter	Coal grade			
	Berezovo		Kuznetsk WS2	
	raw	dried	raw	dried
Heat value, Q, MJ/kg	15.66	21.97	20.51	
Ash content, %	4.70	6.60	24.00	
Moisture, %	33.00	6.00	11.50	
Sulfur content, %	0.20	0.28	0.40	
Elementary composition on fired basis, %: C	44.63	62.62	56.80	63.20
H	3.06	4.29	3.01	3.35
N	0.61	0.86	1.38	1.53
O	13.8	19.35	3.01	3.35
Volatiles per combustibles, %	48.00		20.00	

Table 32

Composition and properties of coal-derived gas

Parameters	Gasification technology and type of blast			
	moving-bed		entrained-flow	
	air		oxygen (95%)	
	raw	cleaned	raw	cleaned
Gas composition, %				
including: CO	19.52	19.53	54.60	54.70
CO_2	5.92	5.93	9.70	9.72
H_2	10.17	10.18	20.40	20.44
H_2S	0.06		0.175	
CH_4	1.39	1.39		
H_2O	14.96	14.97	14.10	14.10
N_2	47.98	48.00	1.00	1.00
Density, kg/m^3	1.120	1.001	1.005	
Low heat value, MJ/m^3	4.07	4.06	9.09	9.07
Consumption per 1 kg of dried coal, kg				
oxydant		2.69	0.74	
steam		0.40		
Combustible gas yield, kg/kg		4.454	1.590	
Raw gas temperature at reaction zone outlet, C	1280		1530	

With entrained-flow oxygen-blown gasification of Kuznetsk coal featuring lower ash melt temperature, the gasifier outlet temperature is adopted at 1300C. The raw syngas contains 65% CO, 2.7% CO_2, 29.7% H_2; its LHV = 11.43 MJ/m^3, density 0.925 kg/m^3.

Table 33

Characteristics of fluidized bed gasification system

Reaction chamber pressure, MPa	2.0 - 2.1
Fluidized bed area, m^2	8.7
Fluidized bed height, m	3.0
Combustible gas LHV, MJ/kg	4.07
Flows for one gasifier, t/h (kg/s):	
coal	60 (16.7)
steam and air	230 (63.9)
ash from bed	8 (2.2)
Consumption of oxydizers per kg of coal, kg:	
air	3.15
steam	0.67
Gas yield, kg/kg of coal	4.3
Temperature, C:	
in reaction volume	1100
steam-air	450
gas past reactor	950
gas before cleaning	210
gas past cleaning	160
gas before expansion turbine	310
Coal characteristics: LHV, MJ/kg	23.65
Moisture, %	10 - 12
Ash content, %	13 - 21.5
Sulfur content, %	0.35 - 0.40

FIGURES

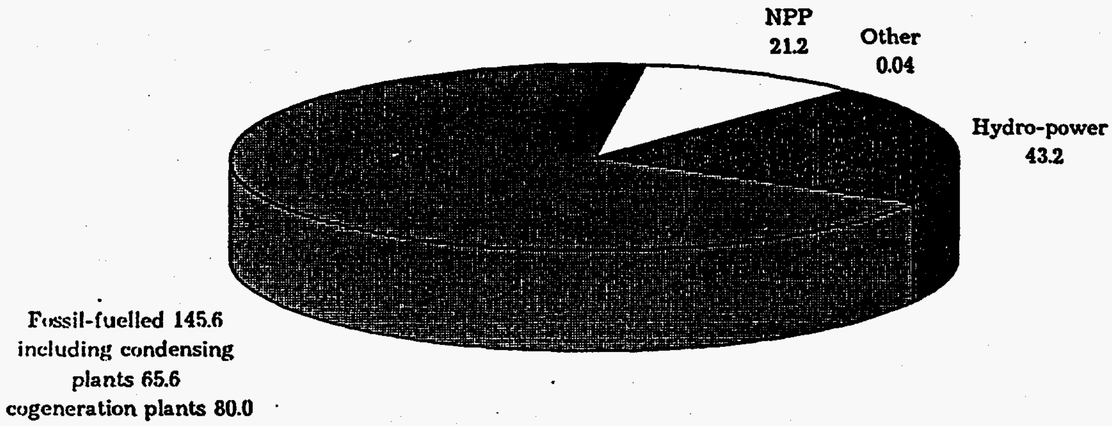


Fig.1. Russian electric power generation mix, GW

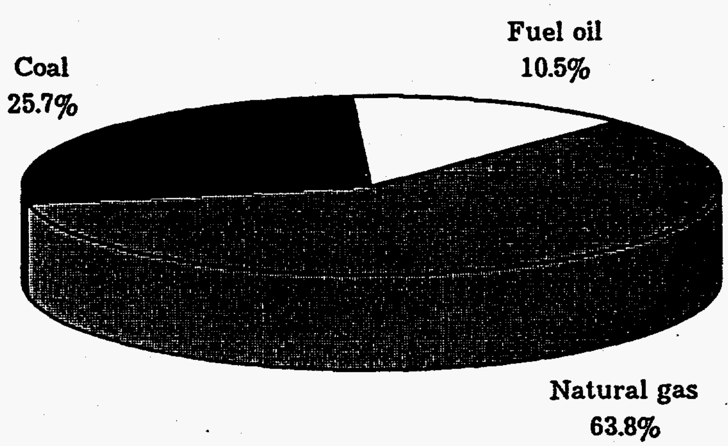


Fig. 2. Russian fuel mix for fossil power plants

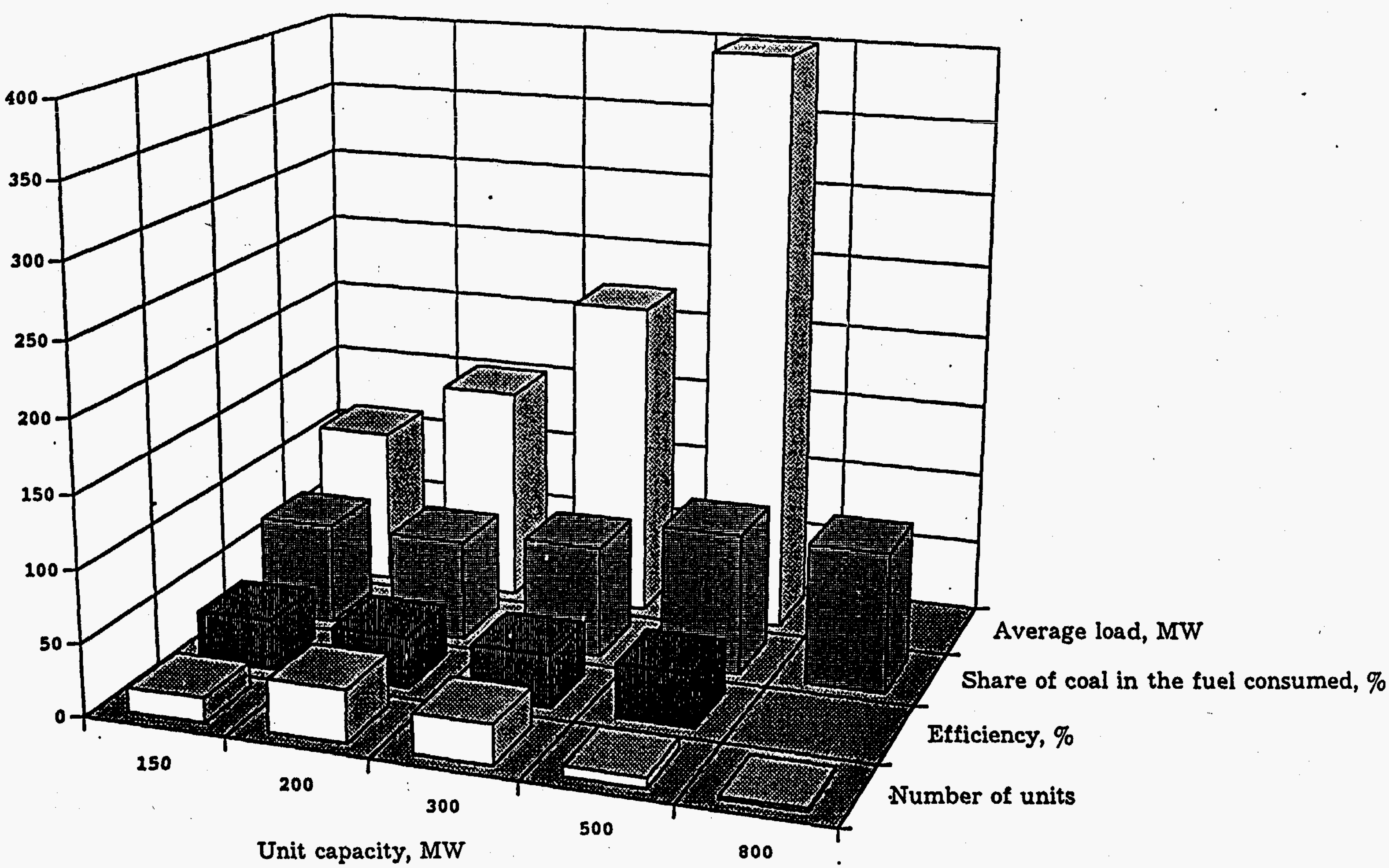


Fig.3. Some data on coal condensing power units (TPS)

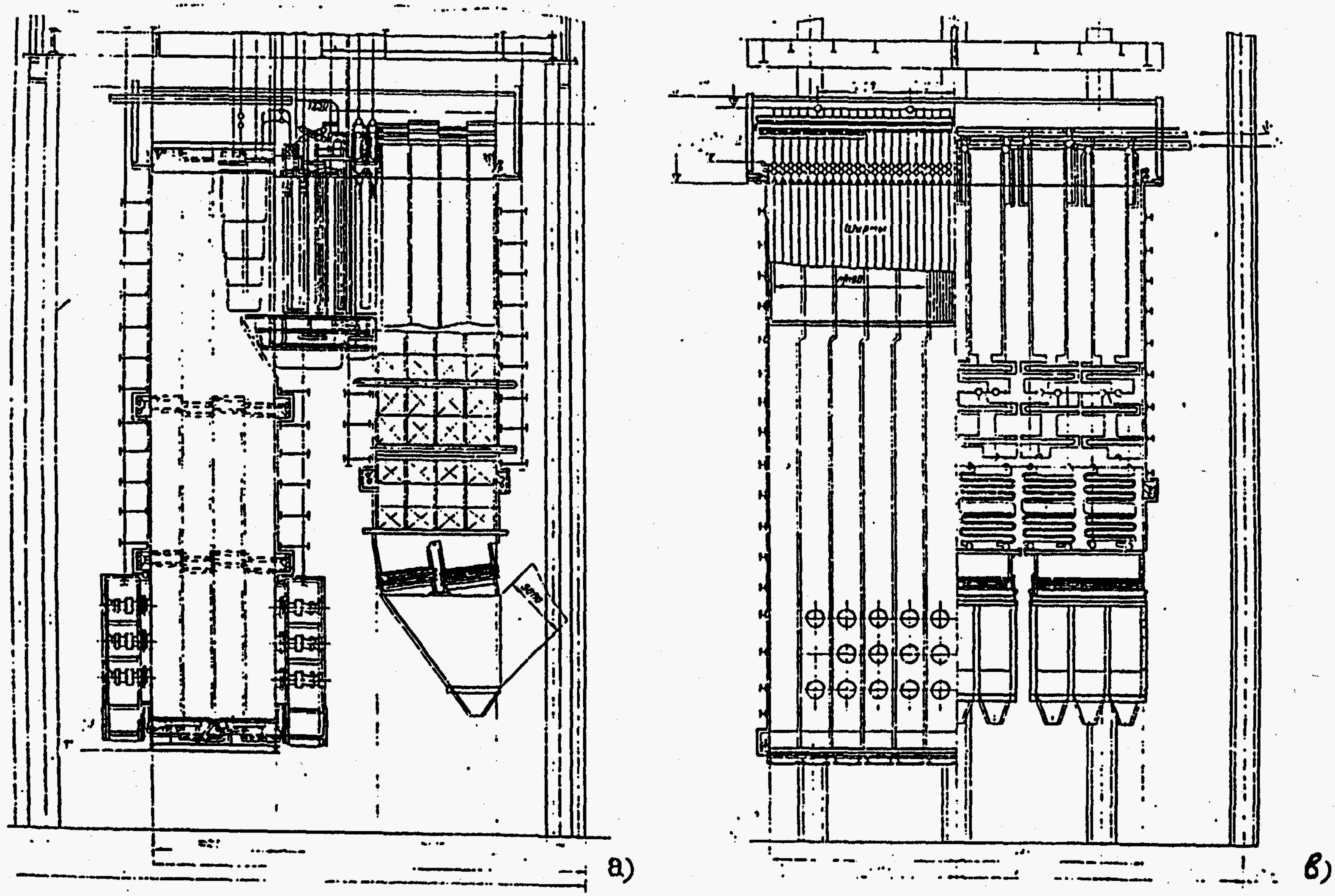


Fig. 4. Pp-3950-25-545/542 GMN (TGMP-1202) Boiler: a,b) - longitudinal and cross sections respectively

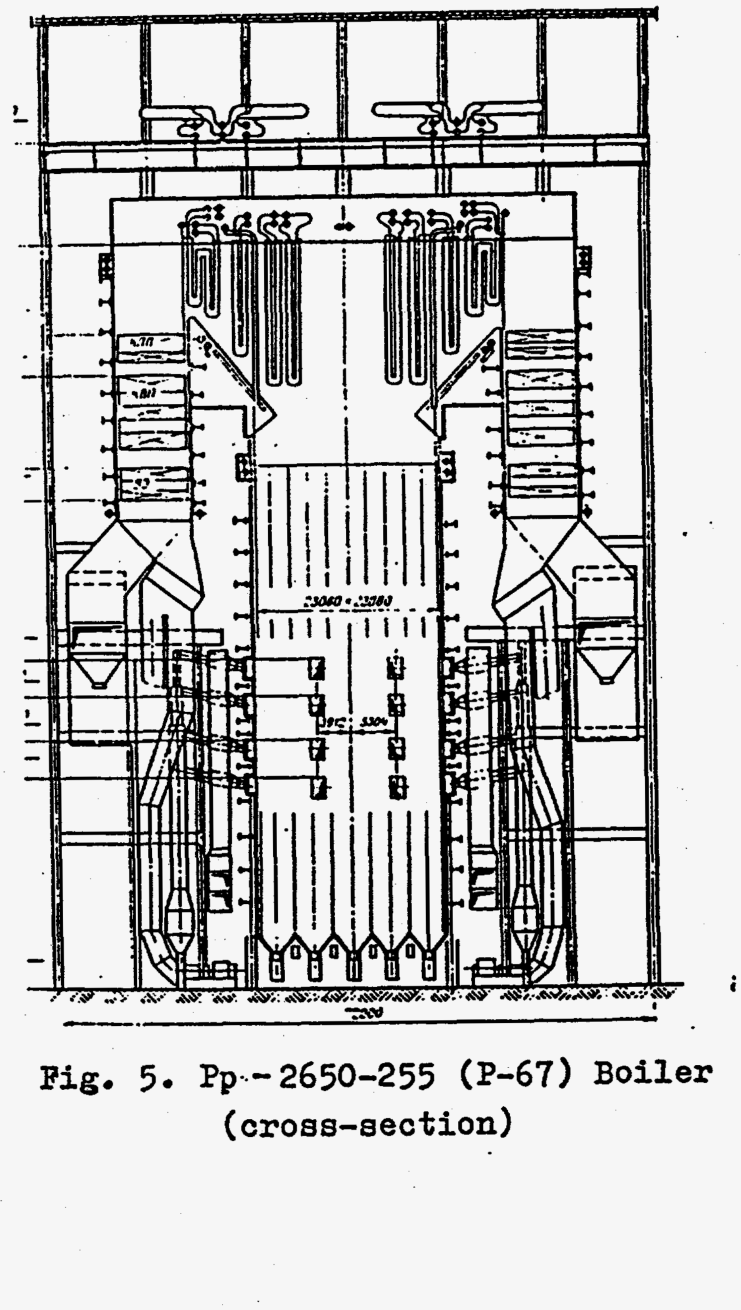
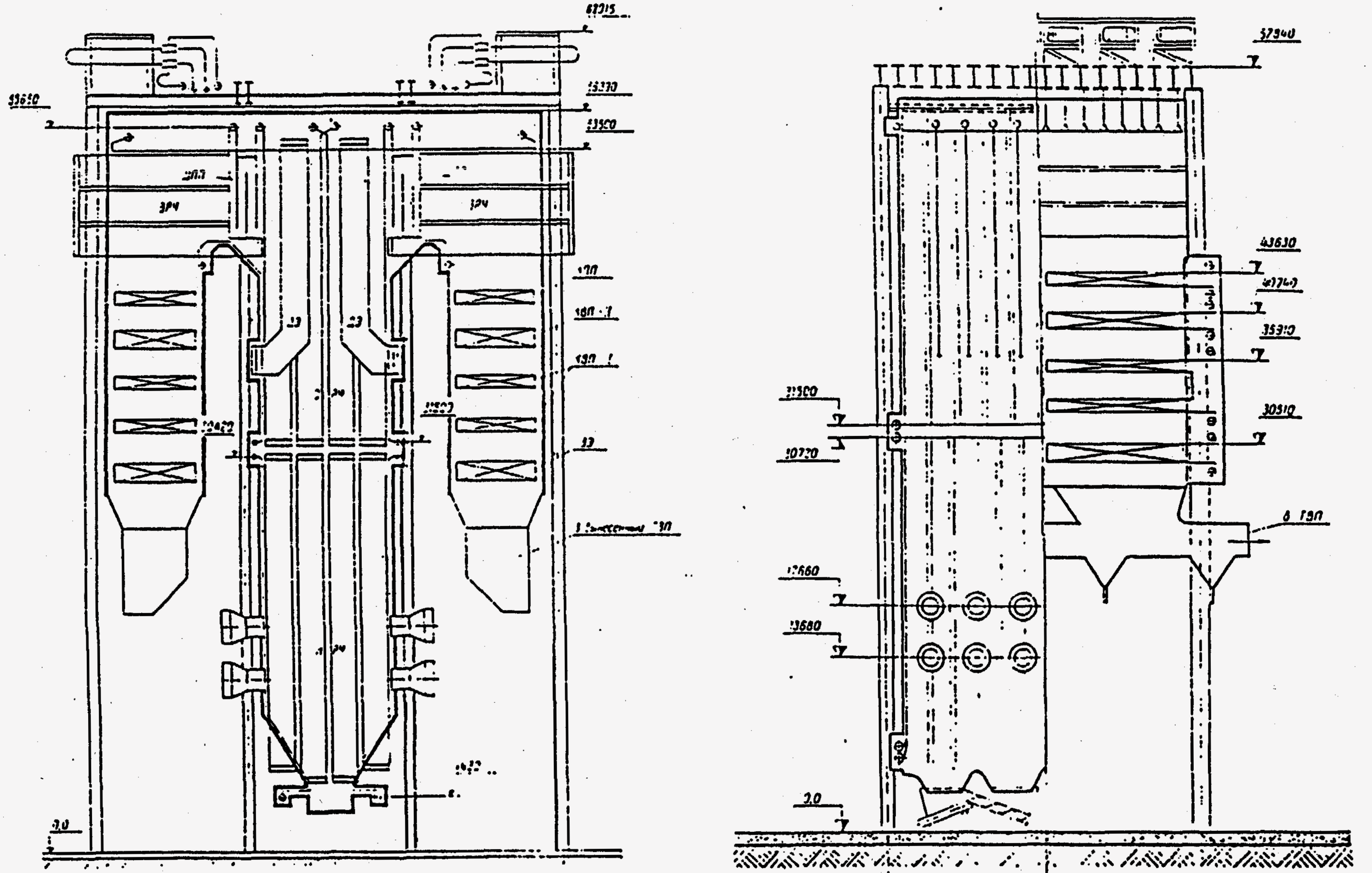


Fig. 5. Pp--2650-255 (P-67) Boiler
(cross-section)



a)

b)

Fig.6. Boiler P-1650-255 (P-57R):

a - longitudinal section view

b - cross section view

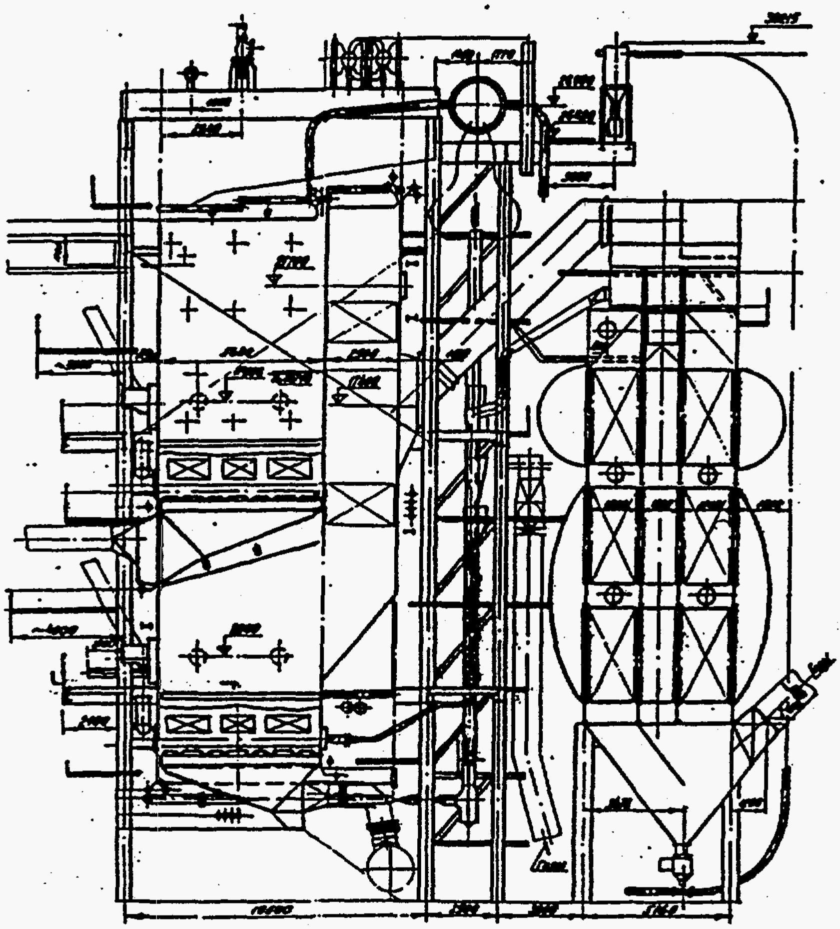


Fig. 7. The 420 t/h bubbling fluidized bed boiler (E-420-140 KS); steam pressure 13,8 MPa, temperature 560°C

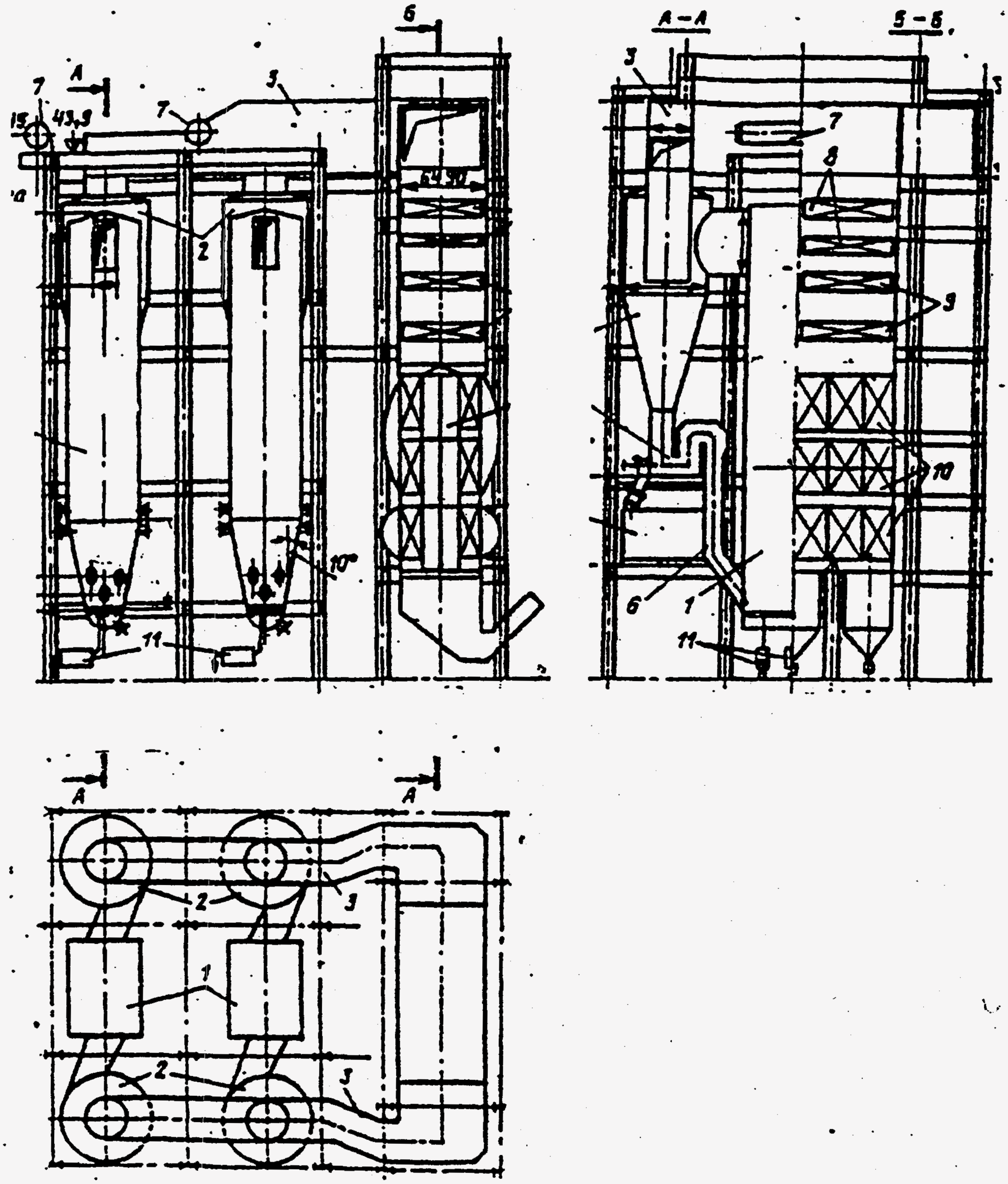


Fig. 8. Demo 500 t/h CFB boiler

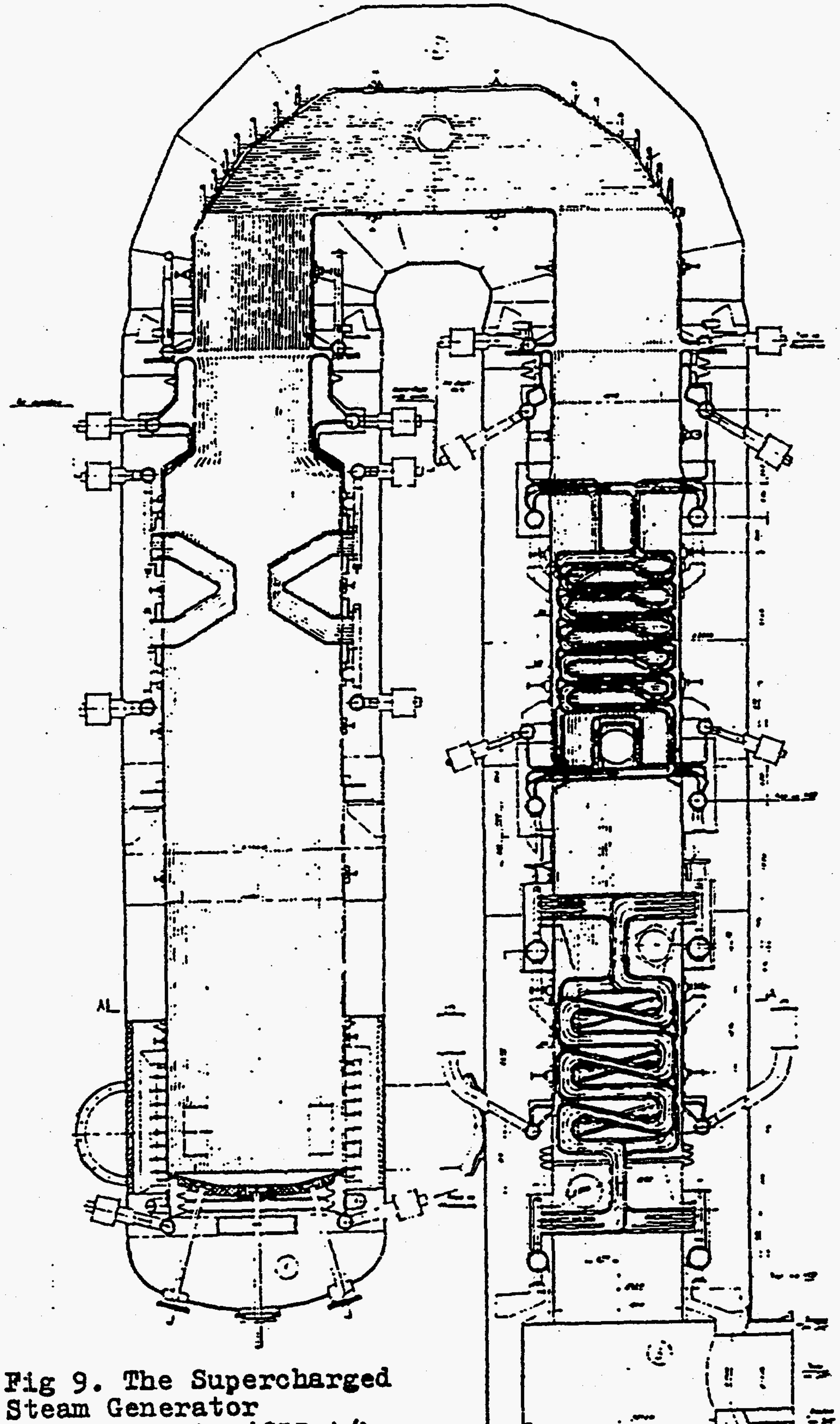


Fig 9. The Supercharged Steam Generator
Steam output - 655 t/h; live steam pressure-14 MPa; superheated steam temperature - 545/545°C; gas pressure - 0,9 MPa

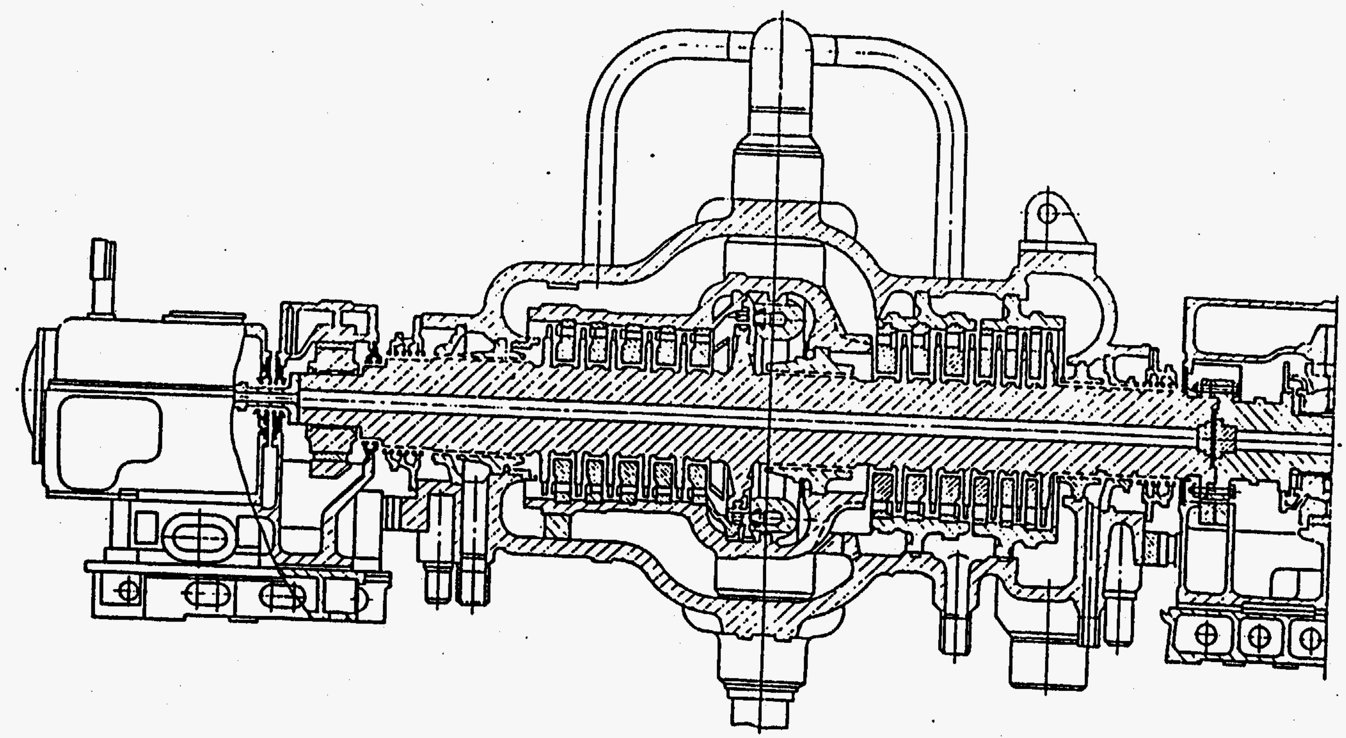


Fig. 10. The typical design of HP cylinder with loop steam flow

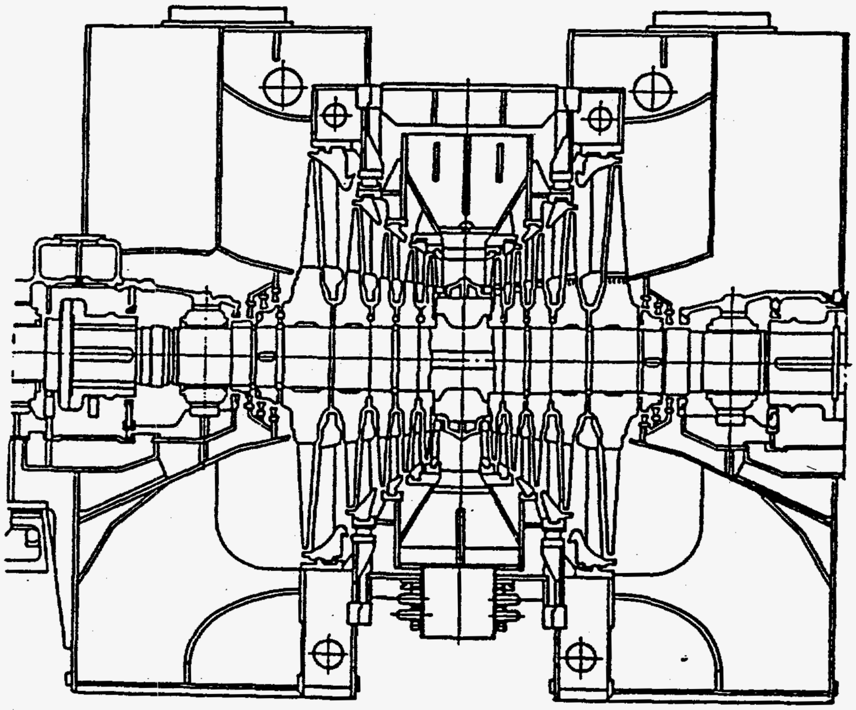


Fig. 11. The typical LP cylinder

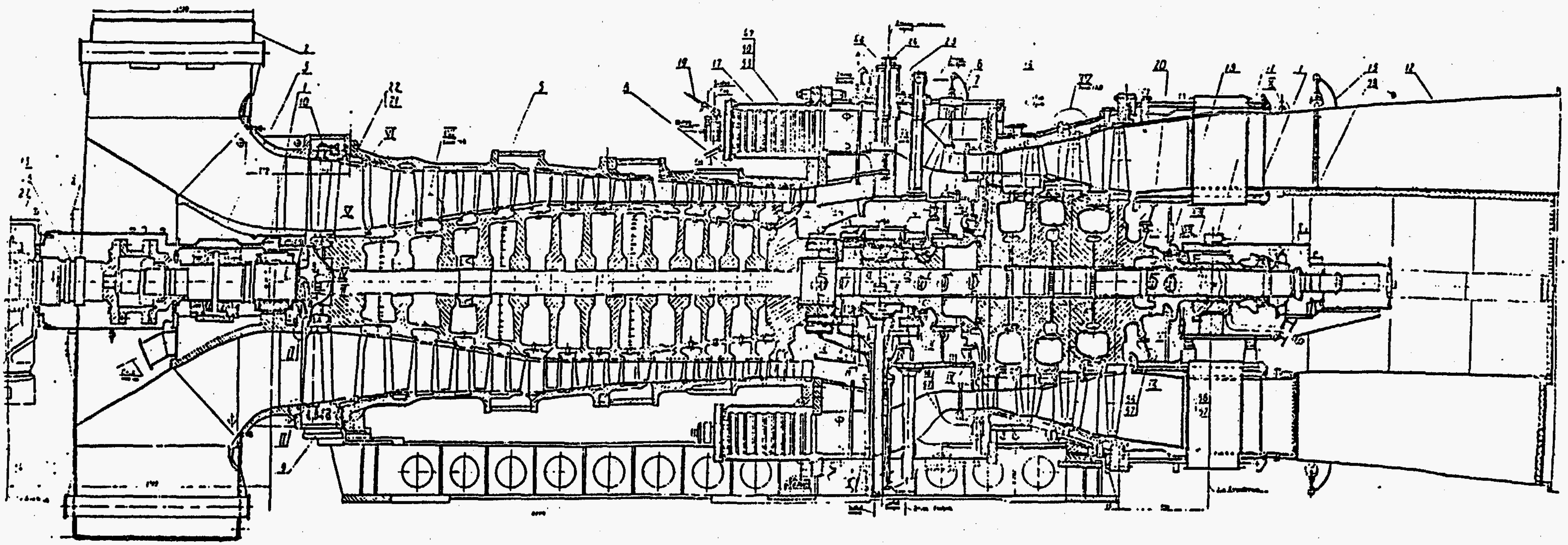
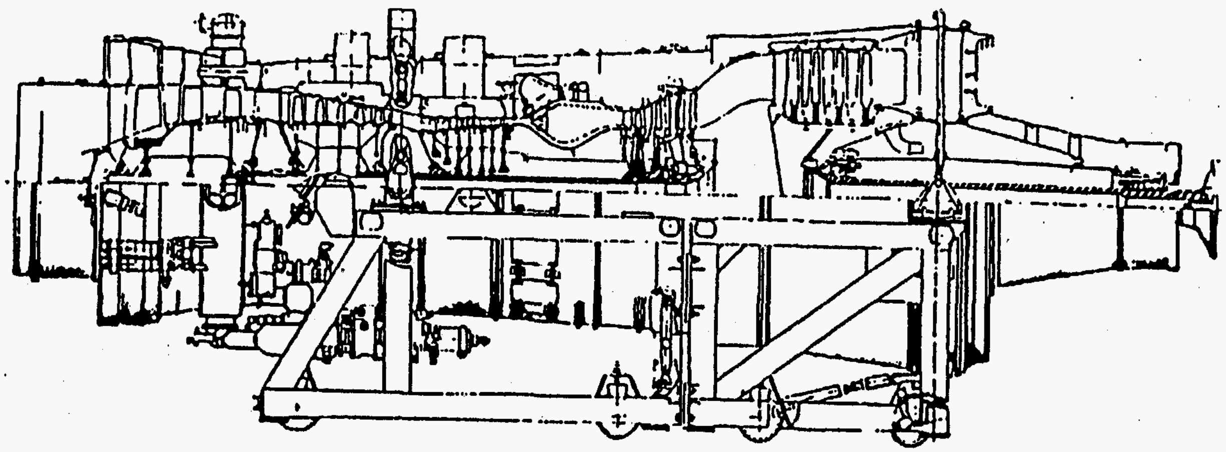


Fig. 12. Longitudinal section through GTE-150 unit



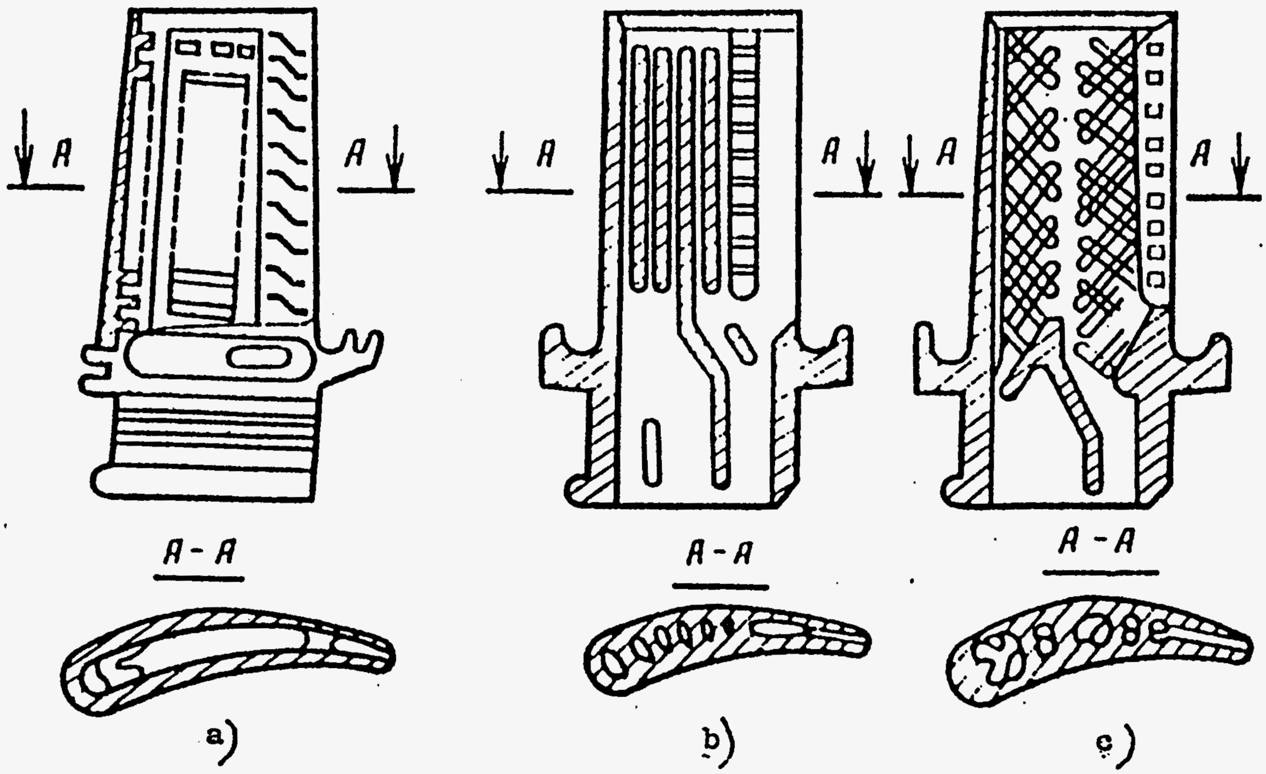


Fig. 14. The first stage buckets with various internal cooling

a - air deflector b - serpentine c - vortex

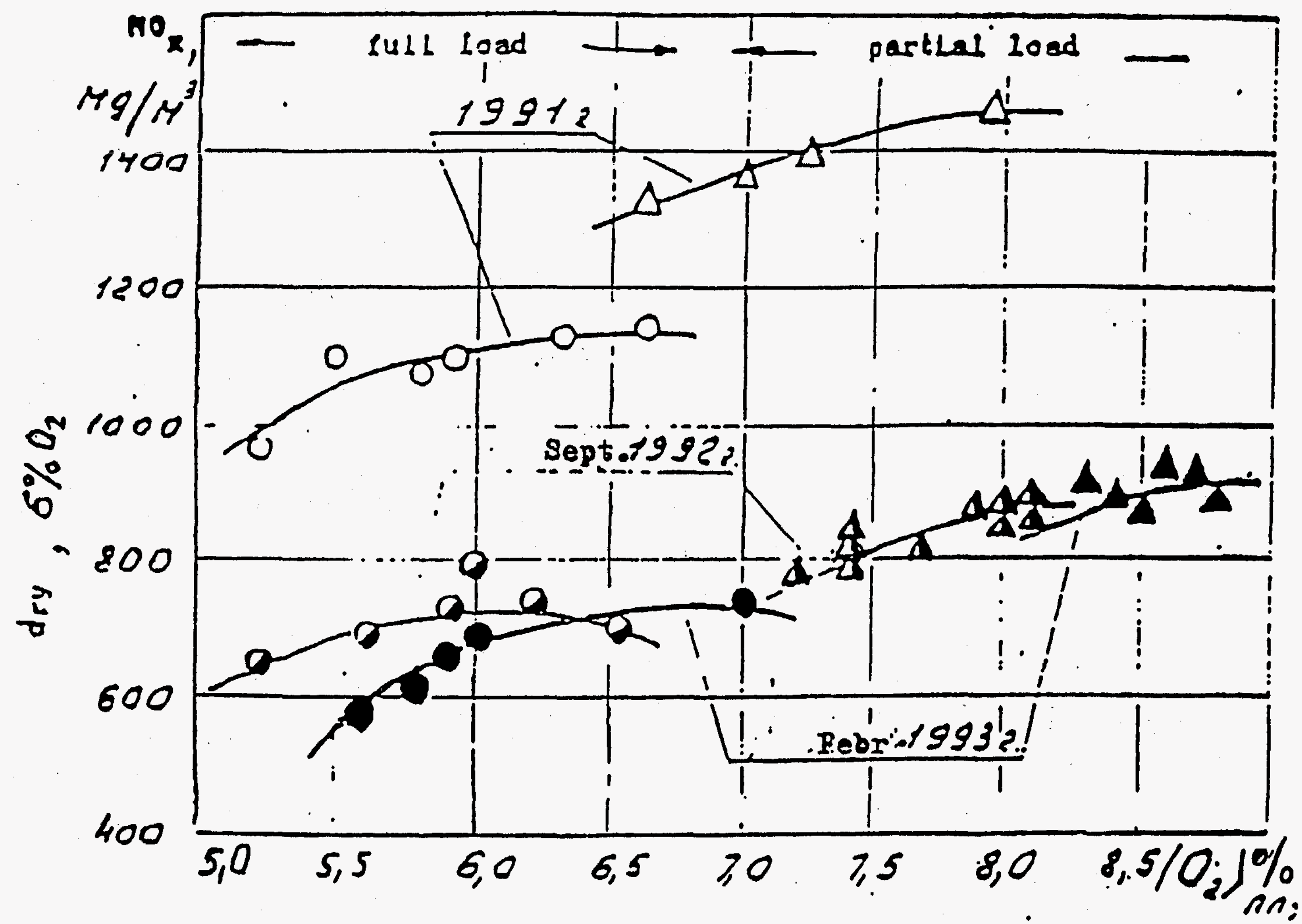


Fig. 15. NOx emission versus O_2 after superheater before (1991) and after (1992-93) reconstruction. Boiler 420 t/h; brown coal

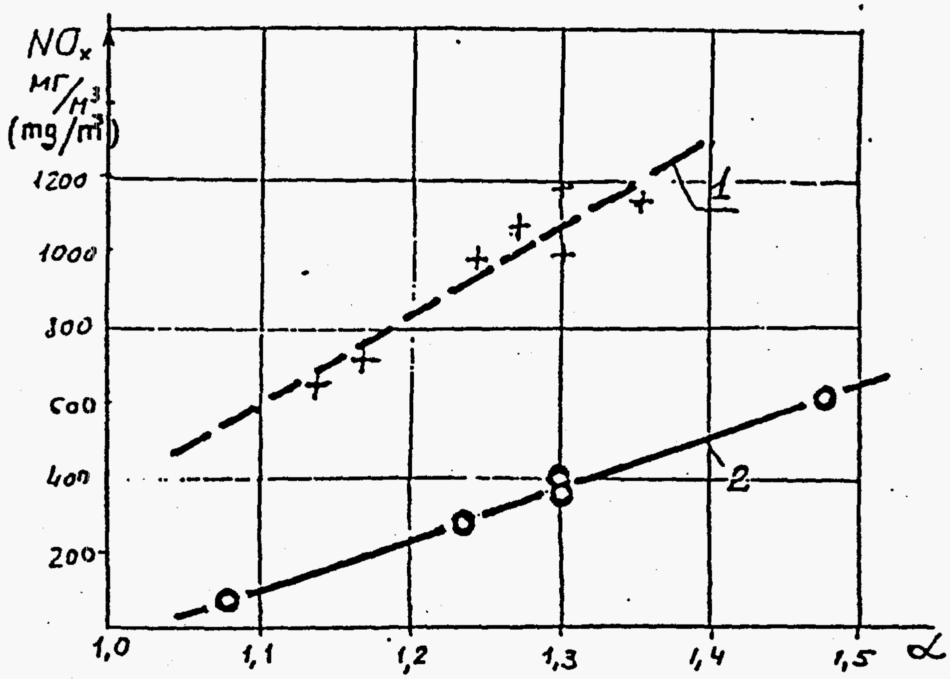


Fig. 16. NOx emissions when high concentrated pulverized coal mixture is fired

1 - coal entrance before burner;
2 - coal entrance in burner throat; α — furnace outlet excess air coefficient

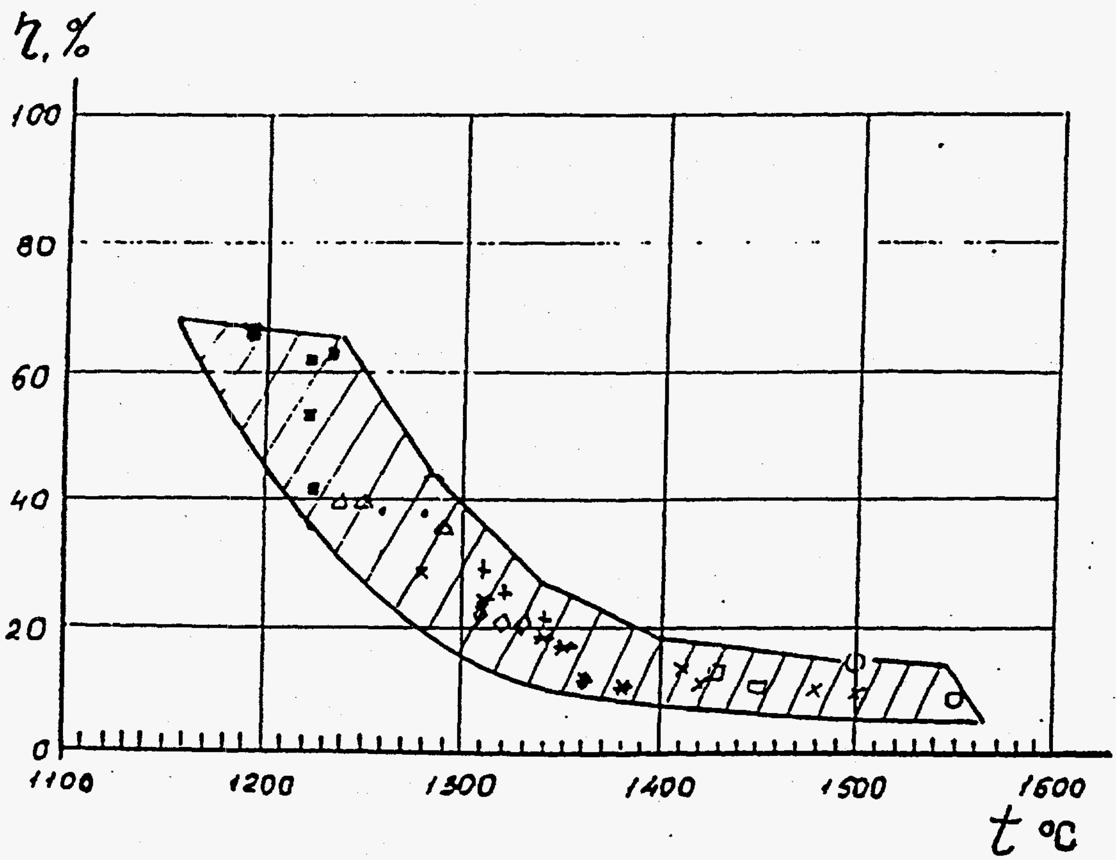


Fig.I7.Sulfur fixation by fly ash in
boilers firing K-A coals

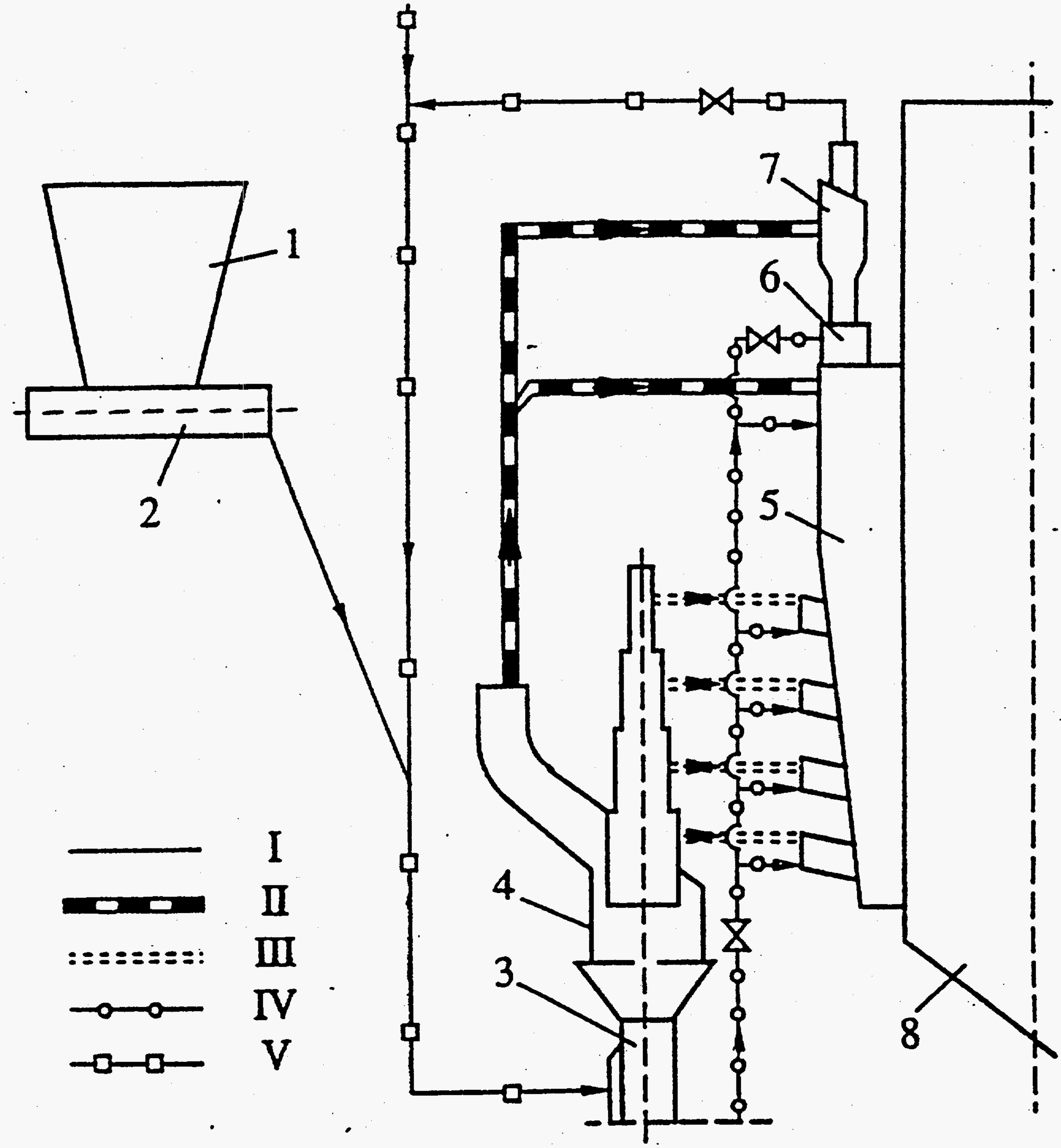


Fig. 18. The coal pulverizing system with an installation for high-temperature powder heating (for a P-67 boiler). (1) Raw coal hopper; (2) raw coal feeder; (3) MV 3400 fan-pulverizer; (4) coal-powder concentrator; (5) coal-powder heater; (6) muffle burner; (7) cyclone; (8) furnace; (I) fuel; (II) coal-powder-air mixture (concentrated stream); (III) coal-powder-air mixture (low-powdery stream); (IV) hot air; (V) flue gases

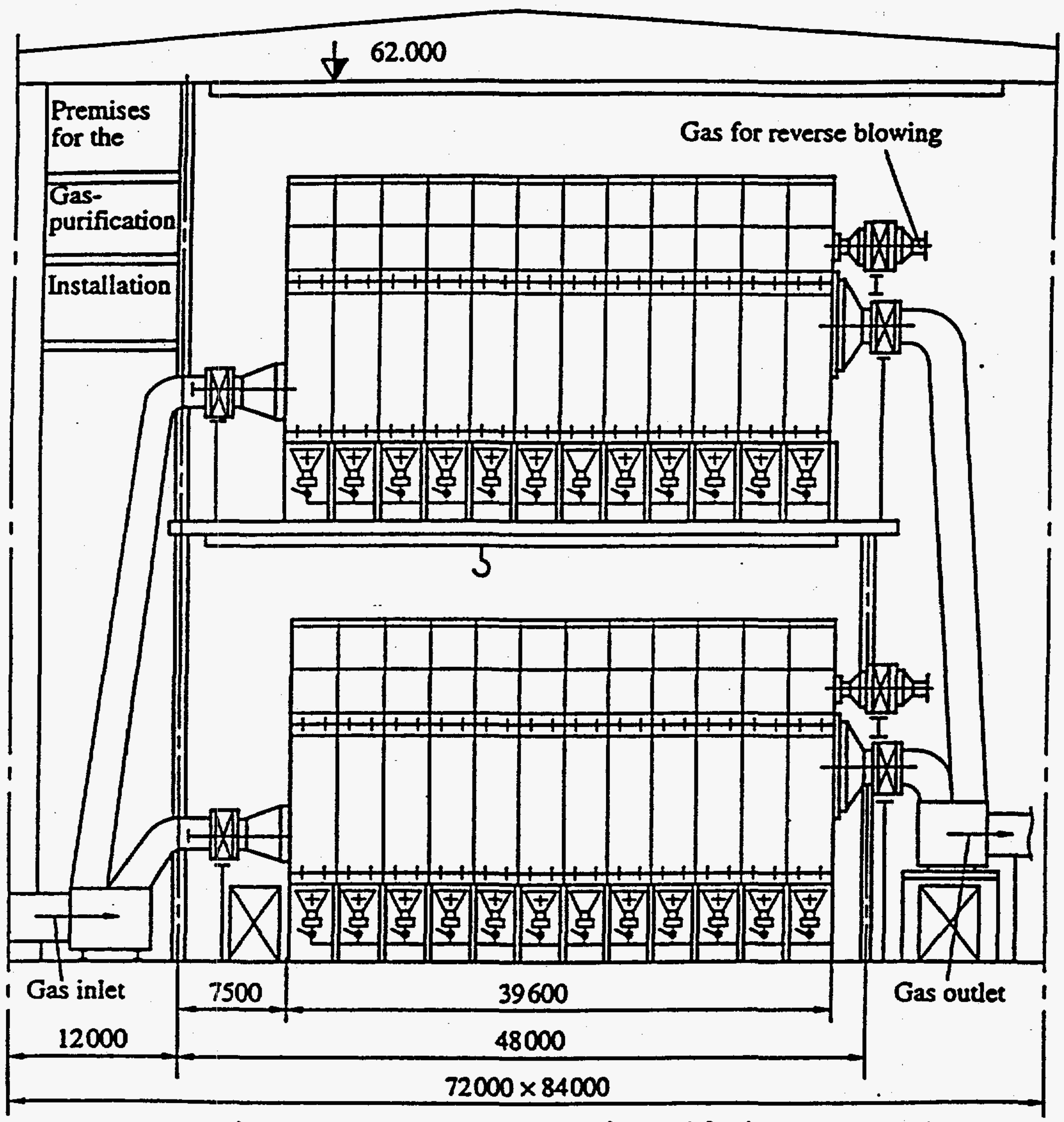


Fig. 19. Two-storey baghouse with FRO-12000 filter

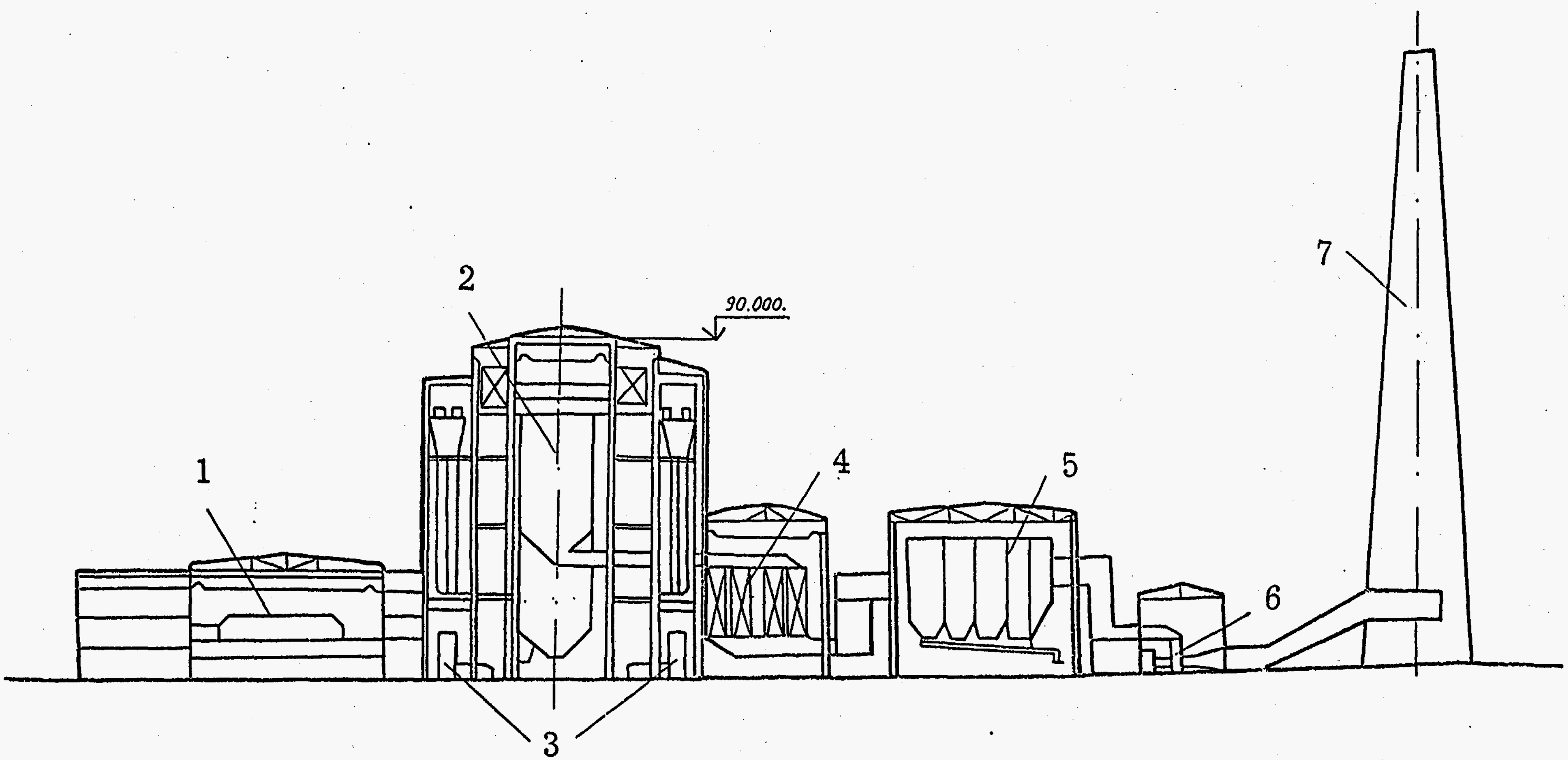


Fig. 20. Cross-section of 800 MW Unit

1-ST; 2-boiler; 3-mills; 4-air heater; 5-baghouse; 6-induced draught fan; 7-stack

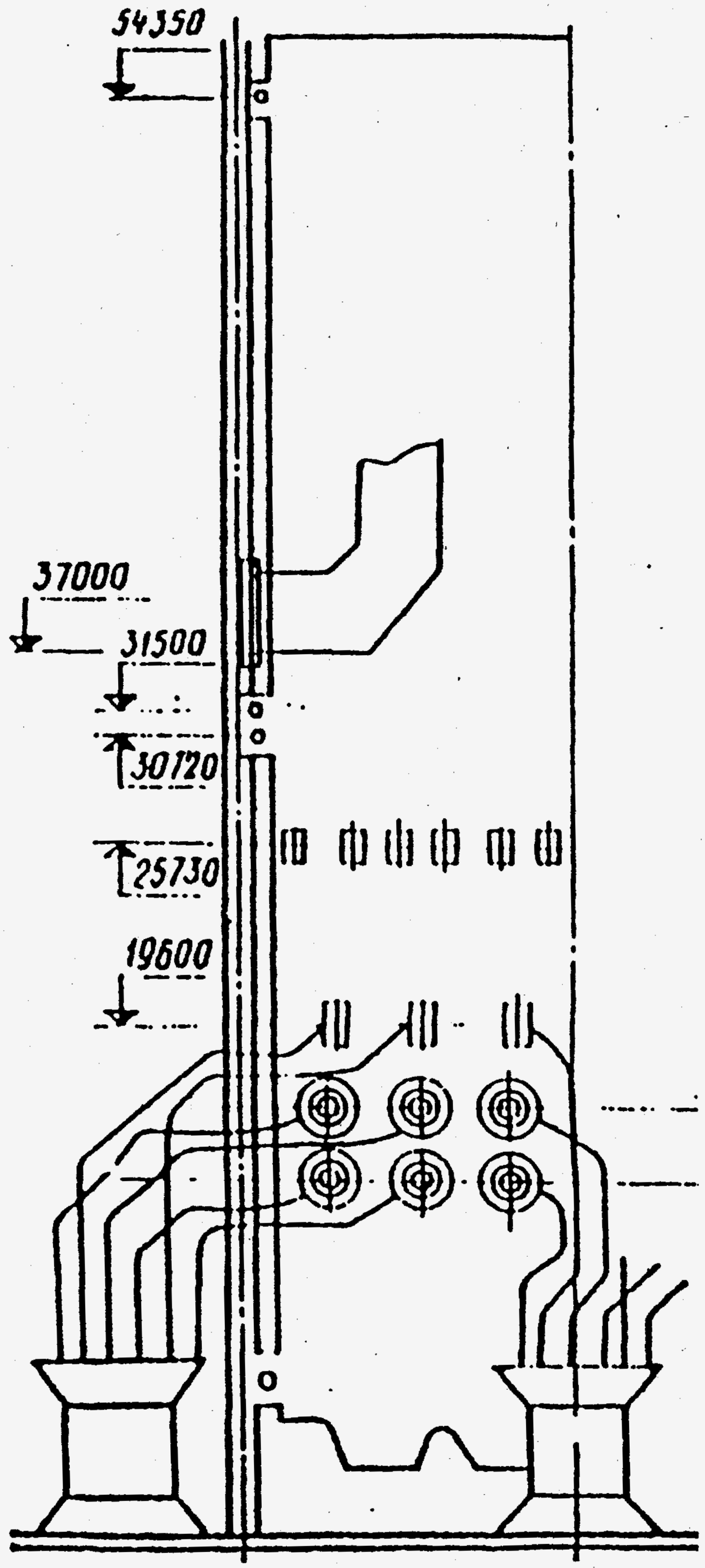


Fig. 21. The layout of the furnace with in-wall vortex burners

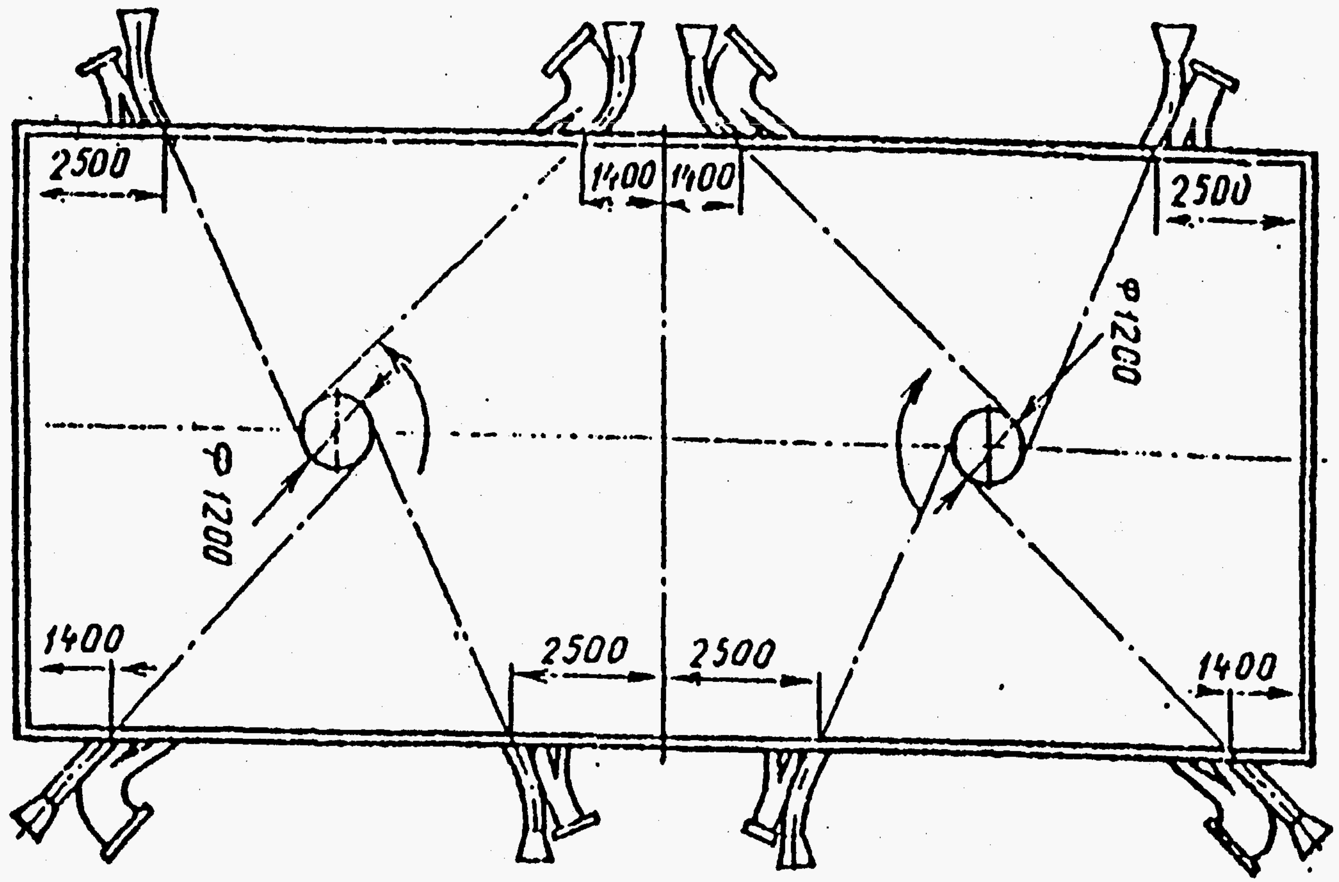


Fig. 22. The furnace with tangential scheme of fuel combustion

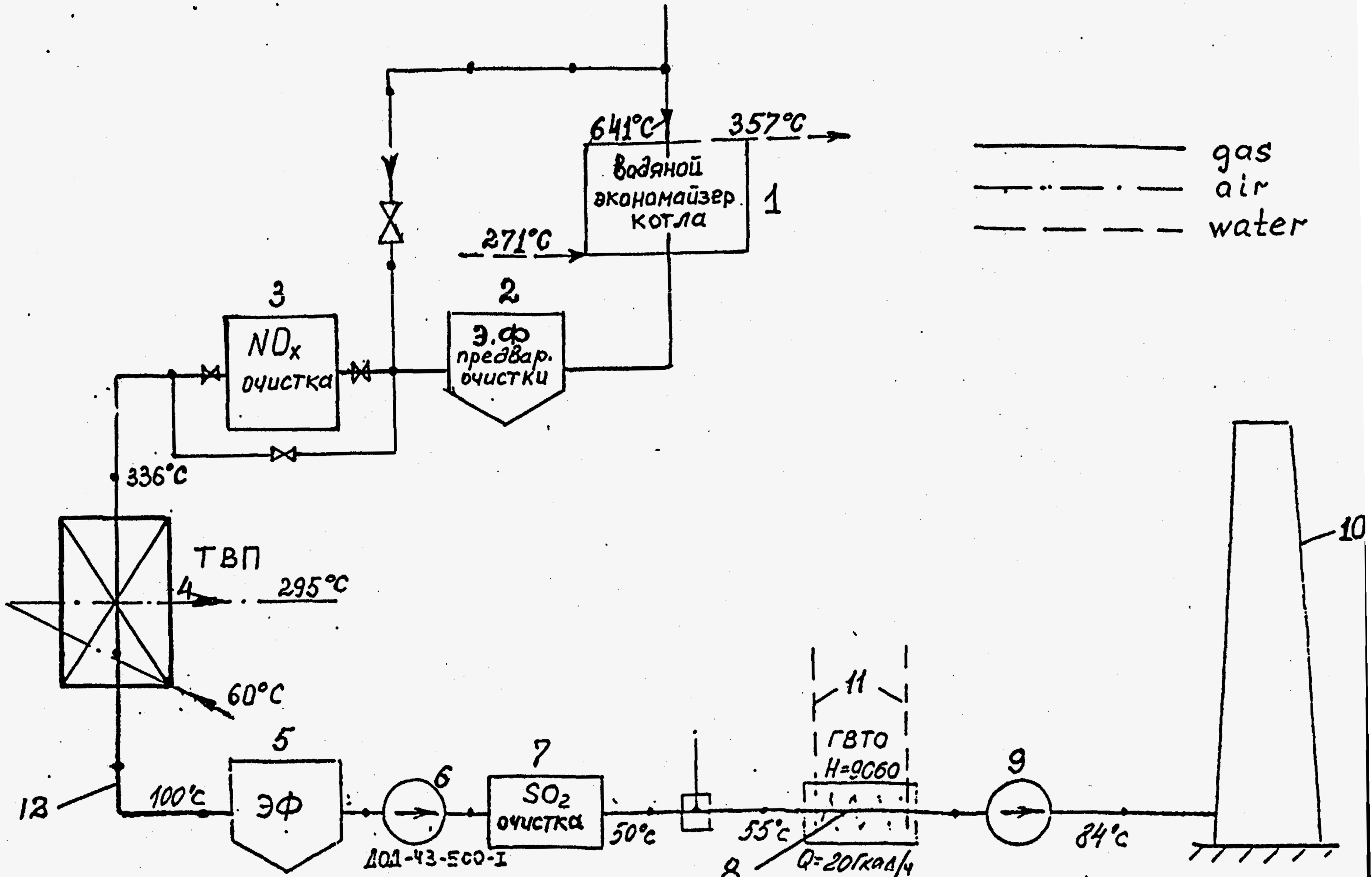


Fig. 23. Low Temperature 500 MW Unit's Boiler Path with High Dust DeNOx

1-economiser; 2-hot ESP; 3-DeNOx; 4-air heater; 5-main ESP; 6-main induced draught fan; 7-DeSOx; 8-gas heater; 9-auxiliary induced draught fan; 10-stack; 11-hot water for gas heating; 12-flue gases

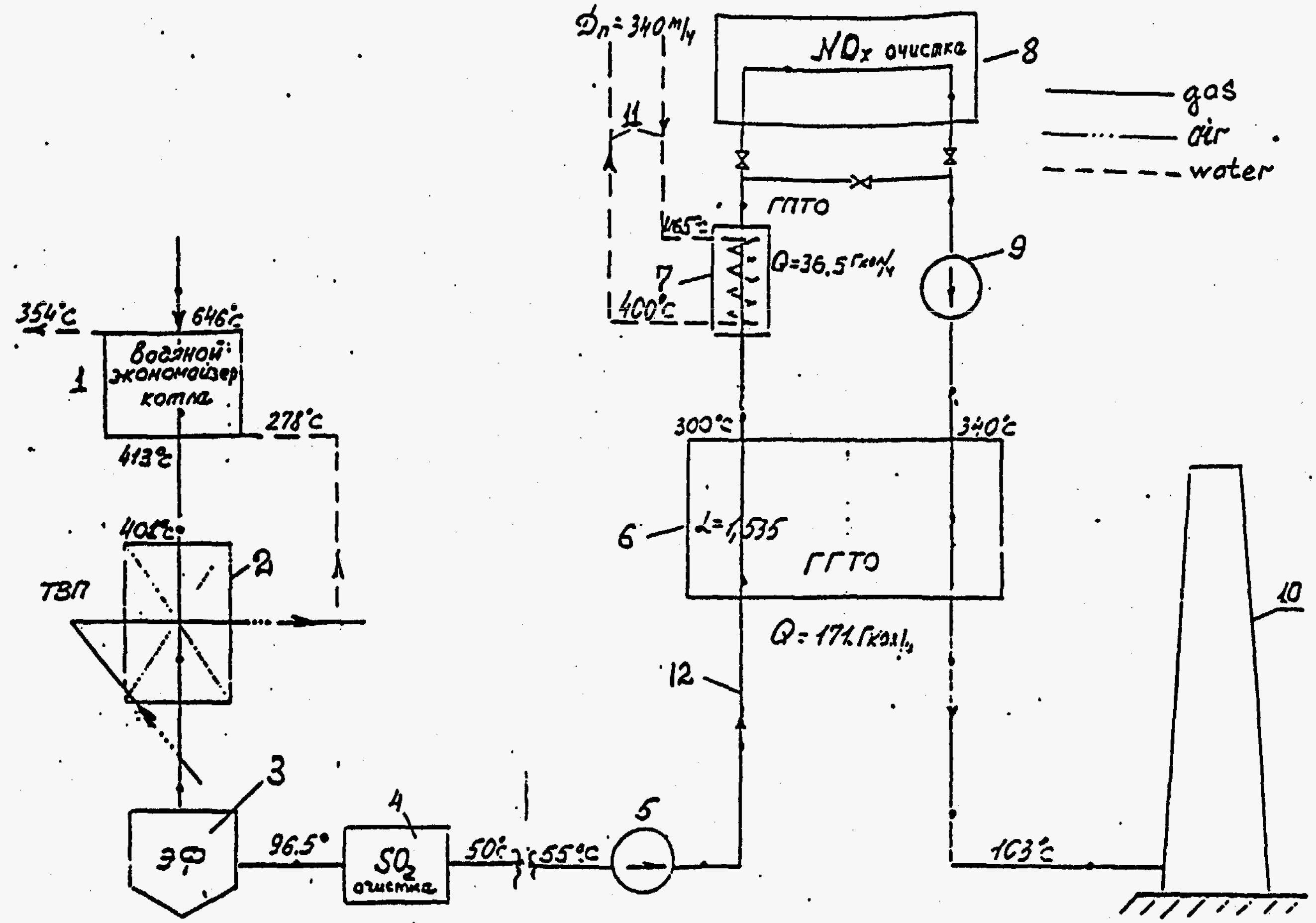


Fig. 24. Low Temperature 500 MW Unit's Boiler Path with Low Dust DeNOx

1-economiser; 2-air heater; 3-main ESP; 4-DeSOx system; 5-main induced draught fan; 6-convective gas heater-cooler; 7-high temperature gas heater; 8-DeNOx; 9-auxiliary induced draught fan; 10-stack; 11-superheated steam for gas heating; 12-flue gases

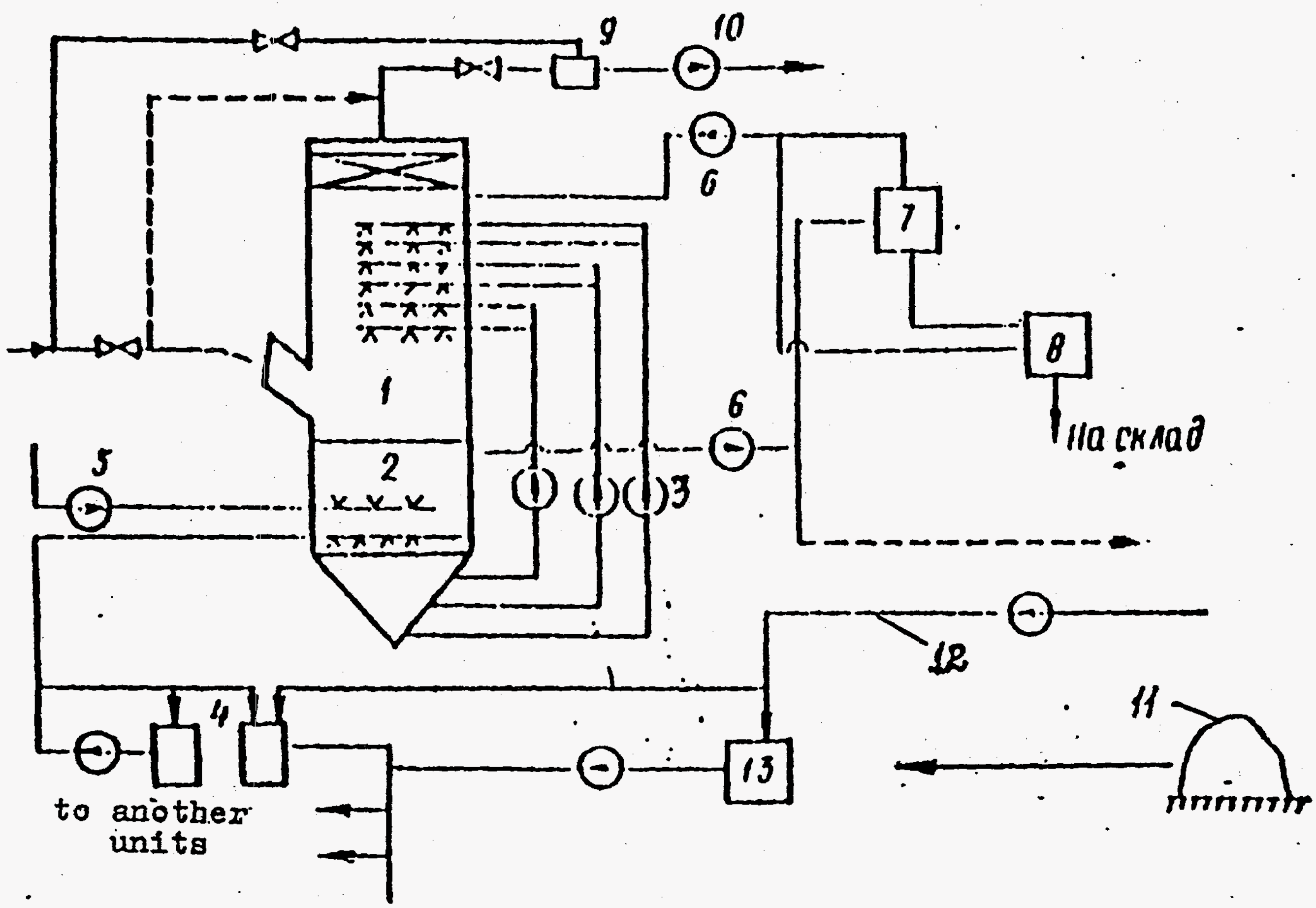


Fig. 25. Wet DeSOx System

1 - scrubber; 2 - water collected part; 3 - slurry recirculating pump; 4 - slurry tanks; 5 - oxydizing air blower; 6 - waste slurry and sludge pump; 7 - hydrocyclone; 8 - centrifuge; 9 - gas heater; 10 - induced-draught fan; 11 - limestone; 12 - water; 13 - slurry preparation

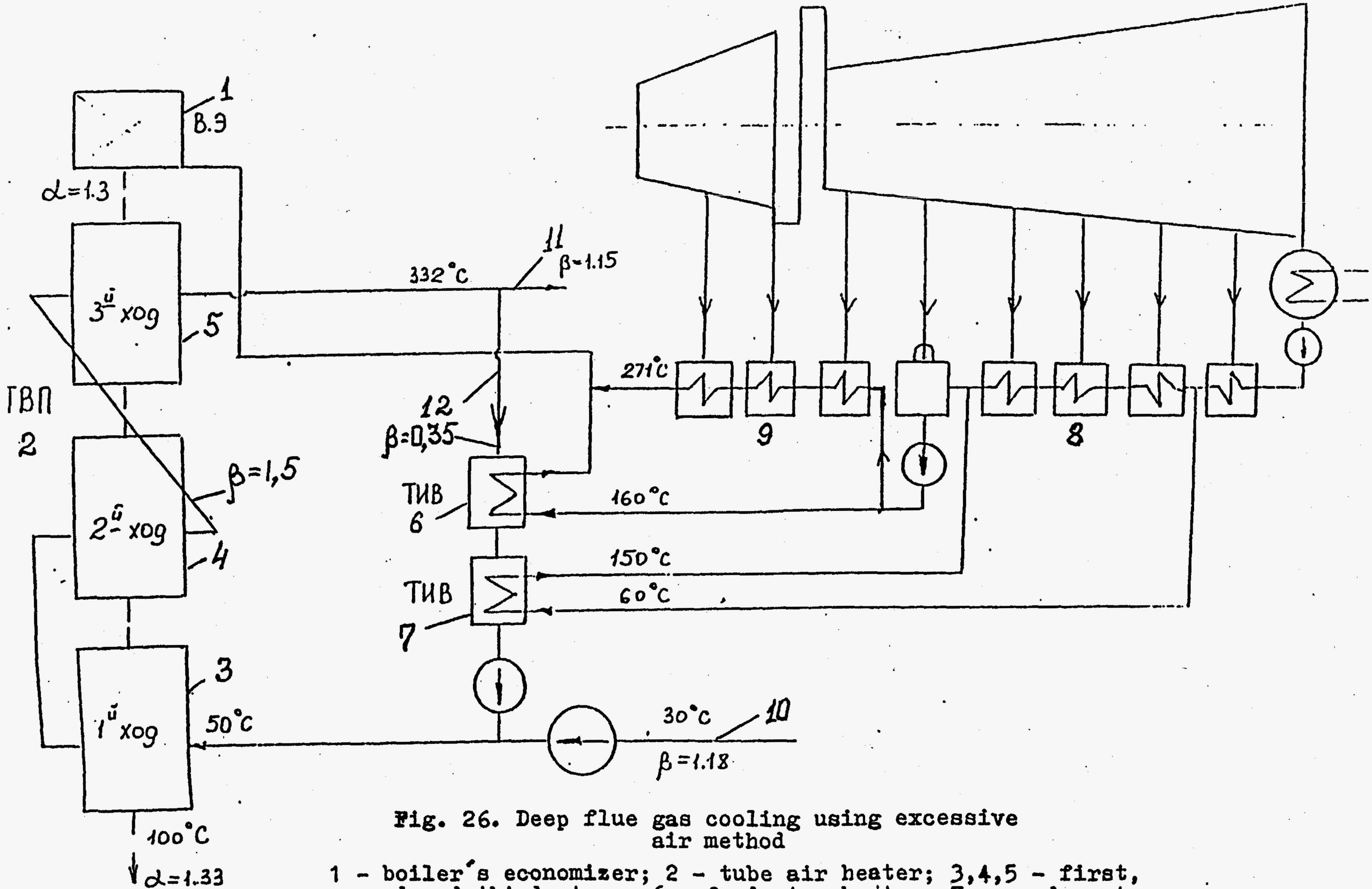


Fig. 26. Deep flue gas cooling using excessive air method

1 - boiler's economizer; 2 - tube air heater; 3,4,5 - first, second and third stage; 6 - feedwater heater; 7 - condencate heater; 8 - LP preheaters; 9 - HP preheaters; 10 - ambient air; 11 - to-furnace air; 12 - recirculated air

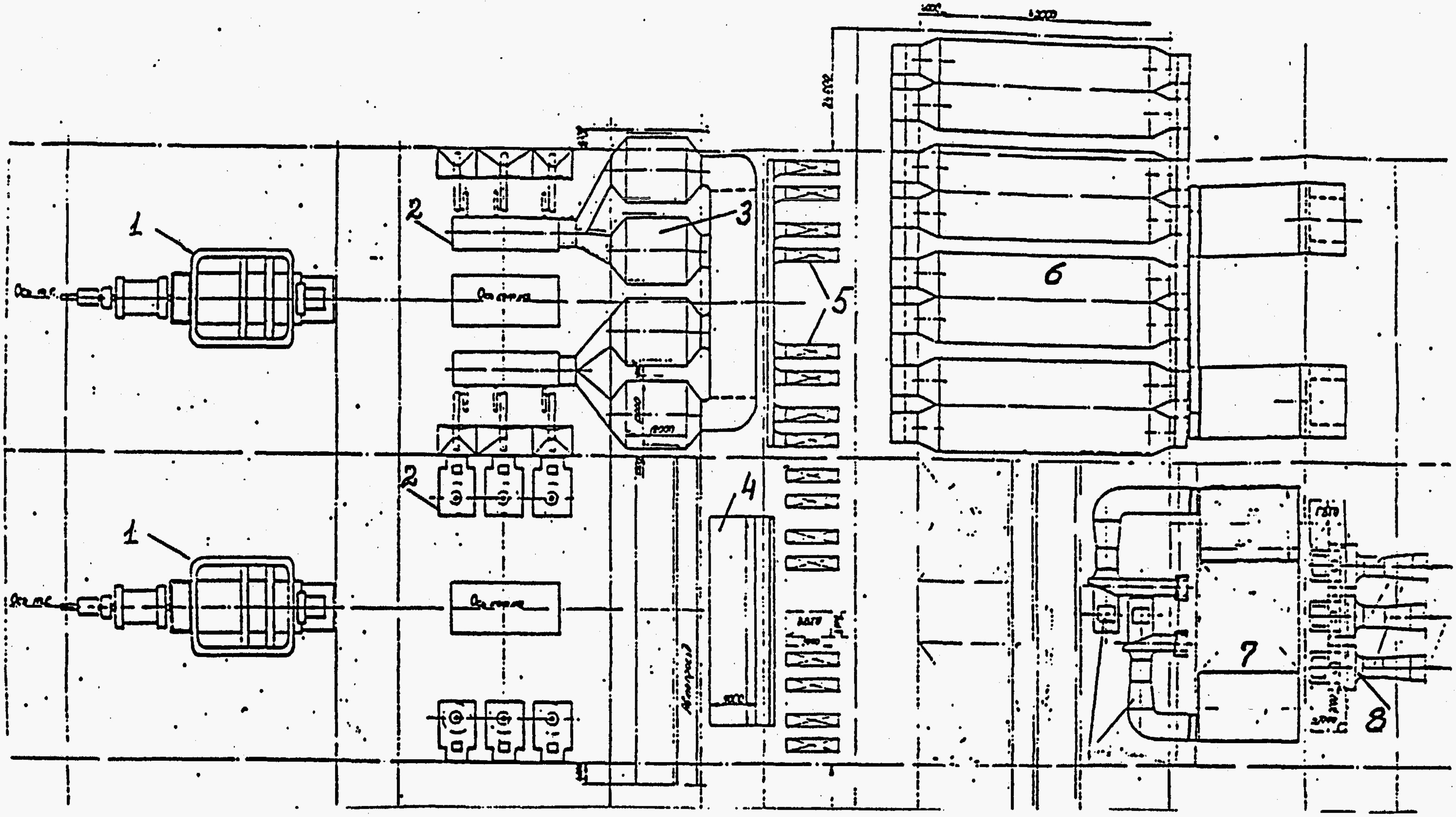


Fig. 27. Layout of p.c.500 MW Unit

1 - ST; 2 - boiler; 3 - hot ESP; 4 - DeNOx system; 5 - air heater;
6 - main ESP; 7 - DeSOx system; 8 - induced draught fan

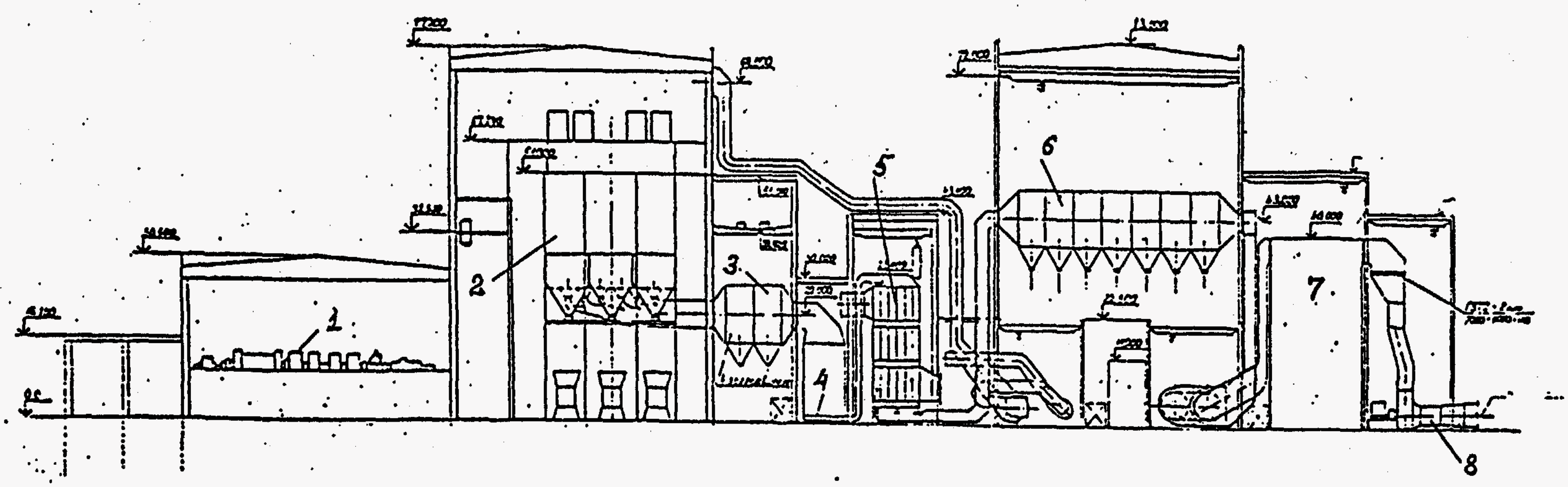
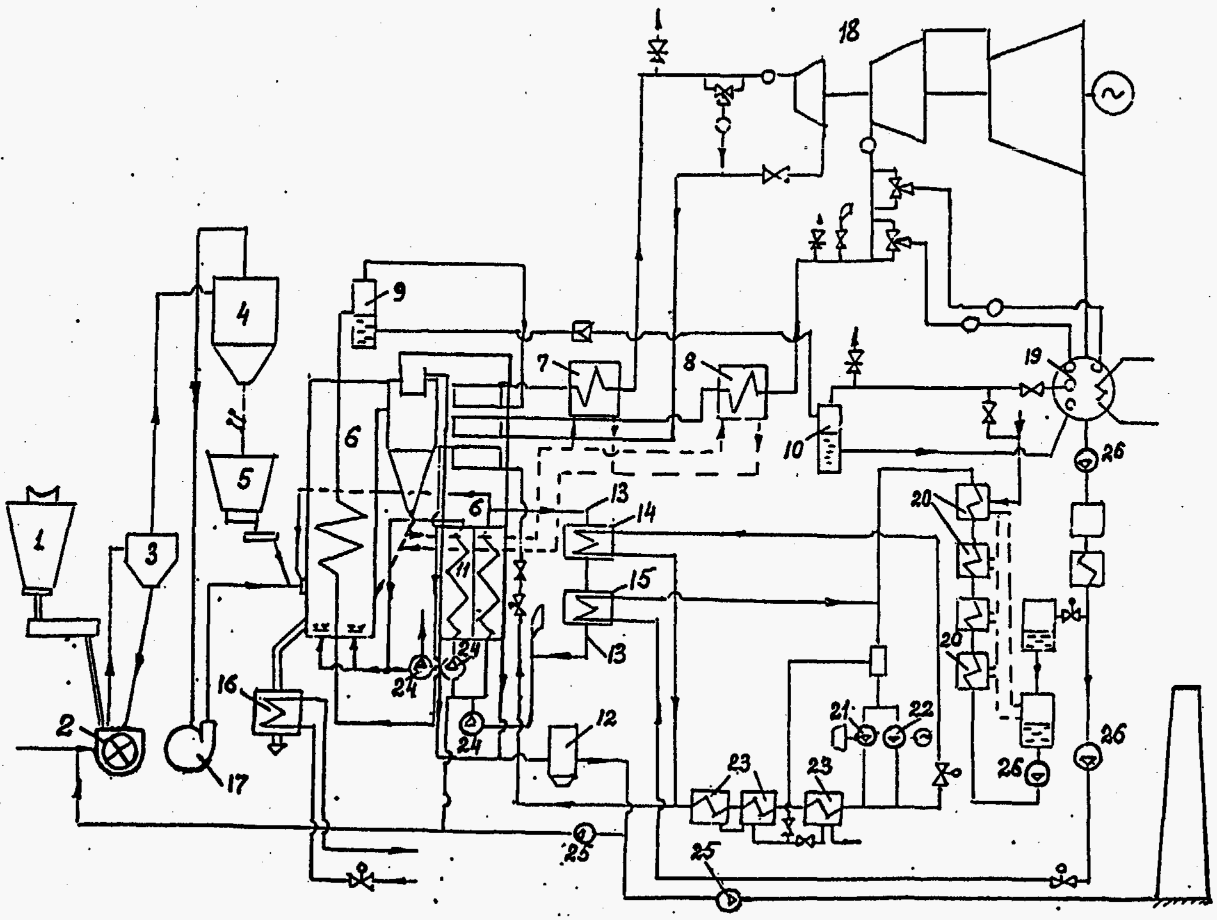


Fig. 28. Cross-section of p.c.500 MW Unit

1 - ST; 2 - boiler; 3 - hot ESP; 4 - DeNOx system; 5 - air heater;
6 - main ESP; 7 - DeSOx system; 8 - induced draught fan



1. raw coal hopper
2. hammer mill
3. separator
4. cyclon
5. day hopper
6. furnace and gas path
7. live steam-ash heat exchanger
8. reheat steam-ash heat exchanger
9. full flow separator
10. starting separator
11. air preheater
12. ESP
13. overflow air
14. HP air-water heater
15. LP air-water heater
16. discharged bed ash cooler
17. for mill air fan
18. steam turbine
19. condenser
20. LP steam-water preheaters
21. feed water turbo pump
22. feed water electrical pump
23. HP steam-water preheaters
24. forced draft fans
25. induced draft fans
26. condensate pumps

Fig. 29. Schematic of a CFB boiler with K-300-240 Turbine

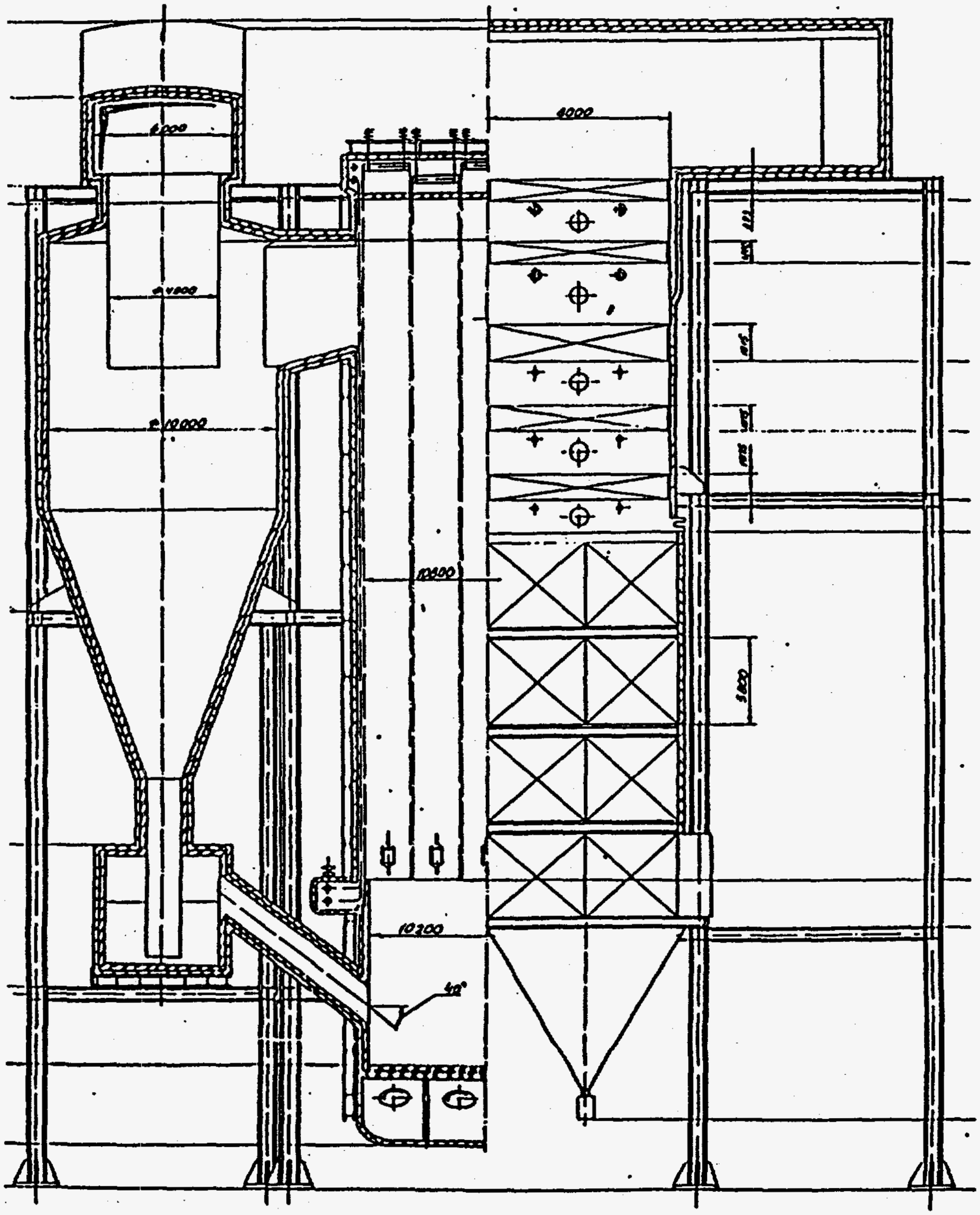


Fig. 30. Cross-section of the 1000 t/h CFB boiler

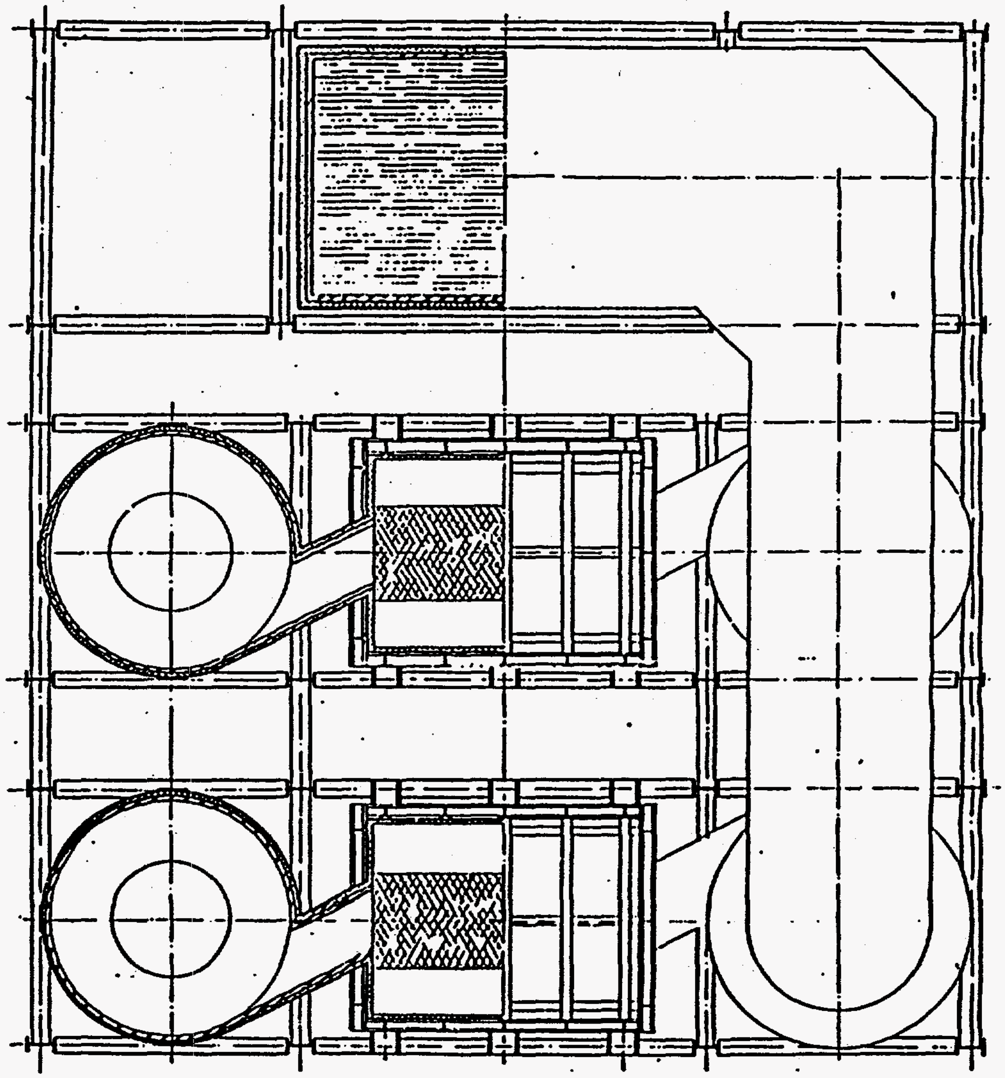


Fig. 31 . The layout of the 1000 t/h CFB boiler

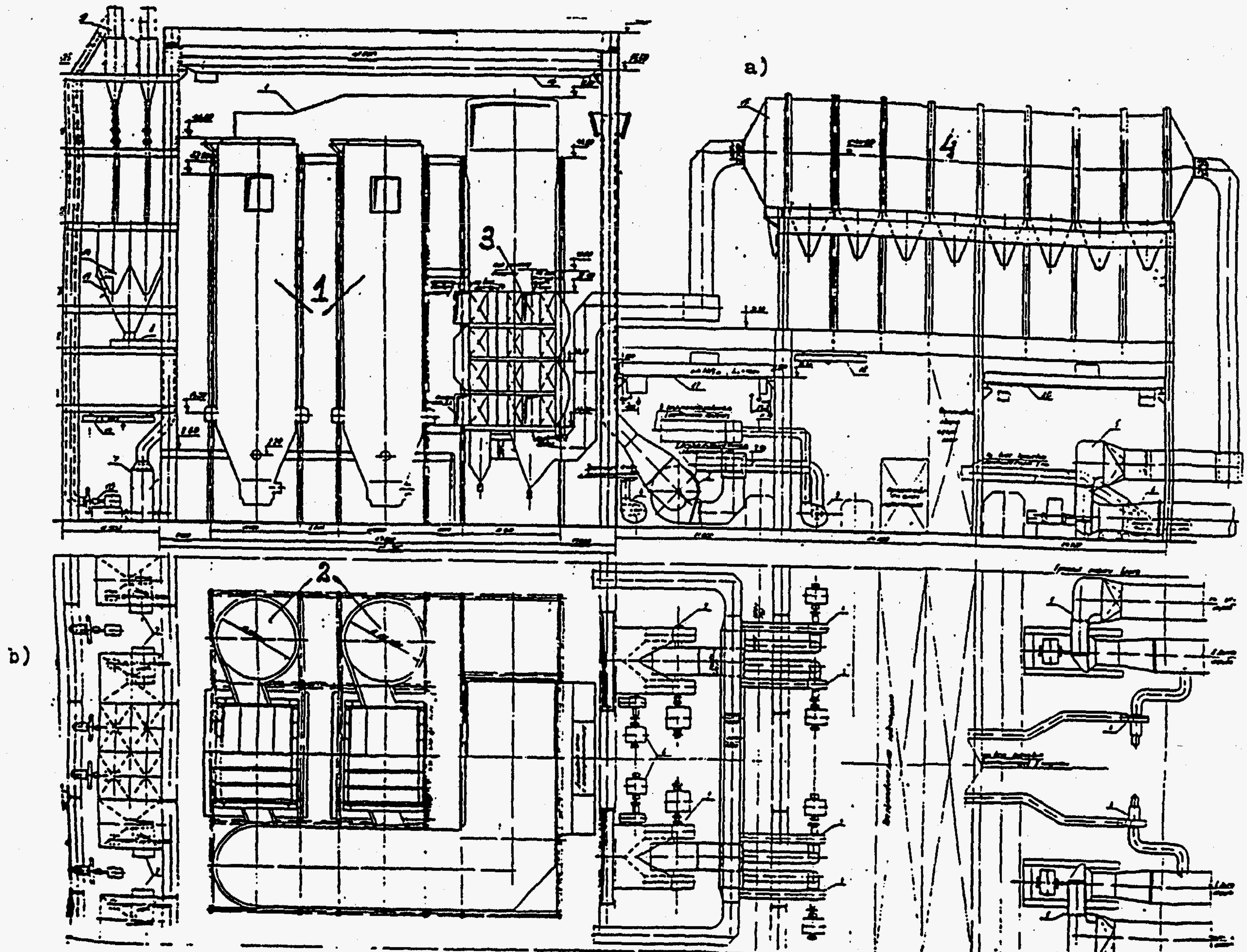


Fig. 32. CFB boiler installation: a) cross-section, b) layout
1 - furnace; 2 - hot cyclones; 3 - air heater; 4 - ESP

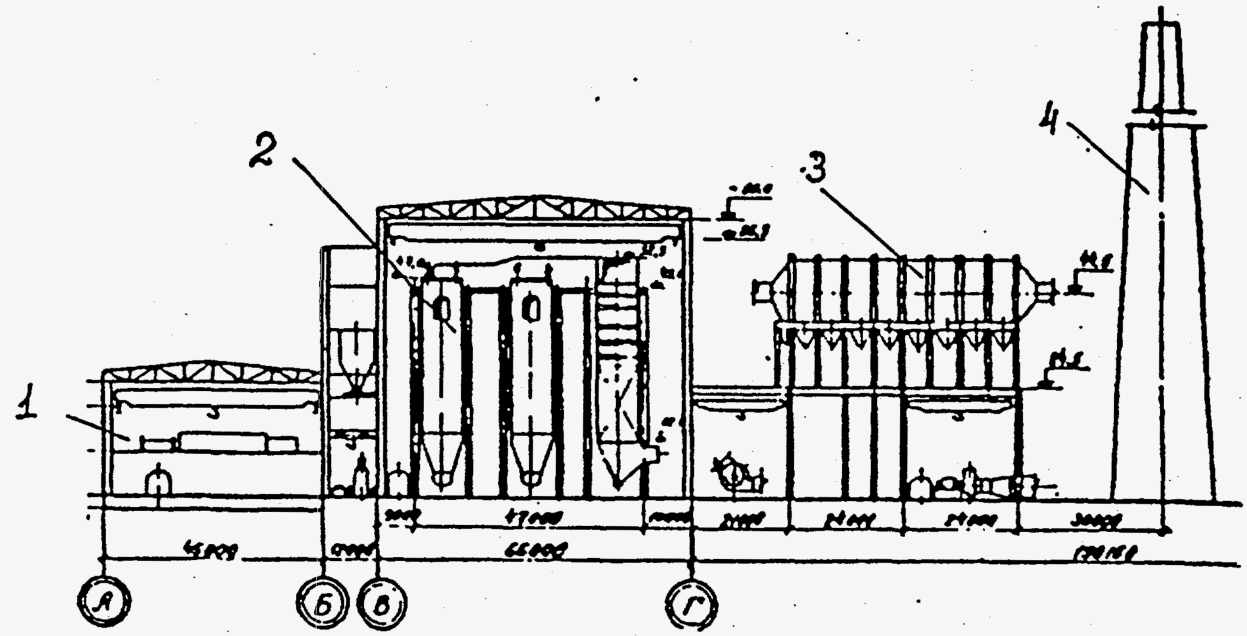


Fig. 33. Cross-section of 300 MW CFB unit

1 - ST; 2 - CFB boiler; 3 - ESP;
4 - stack

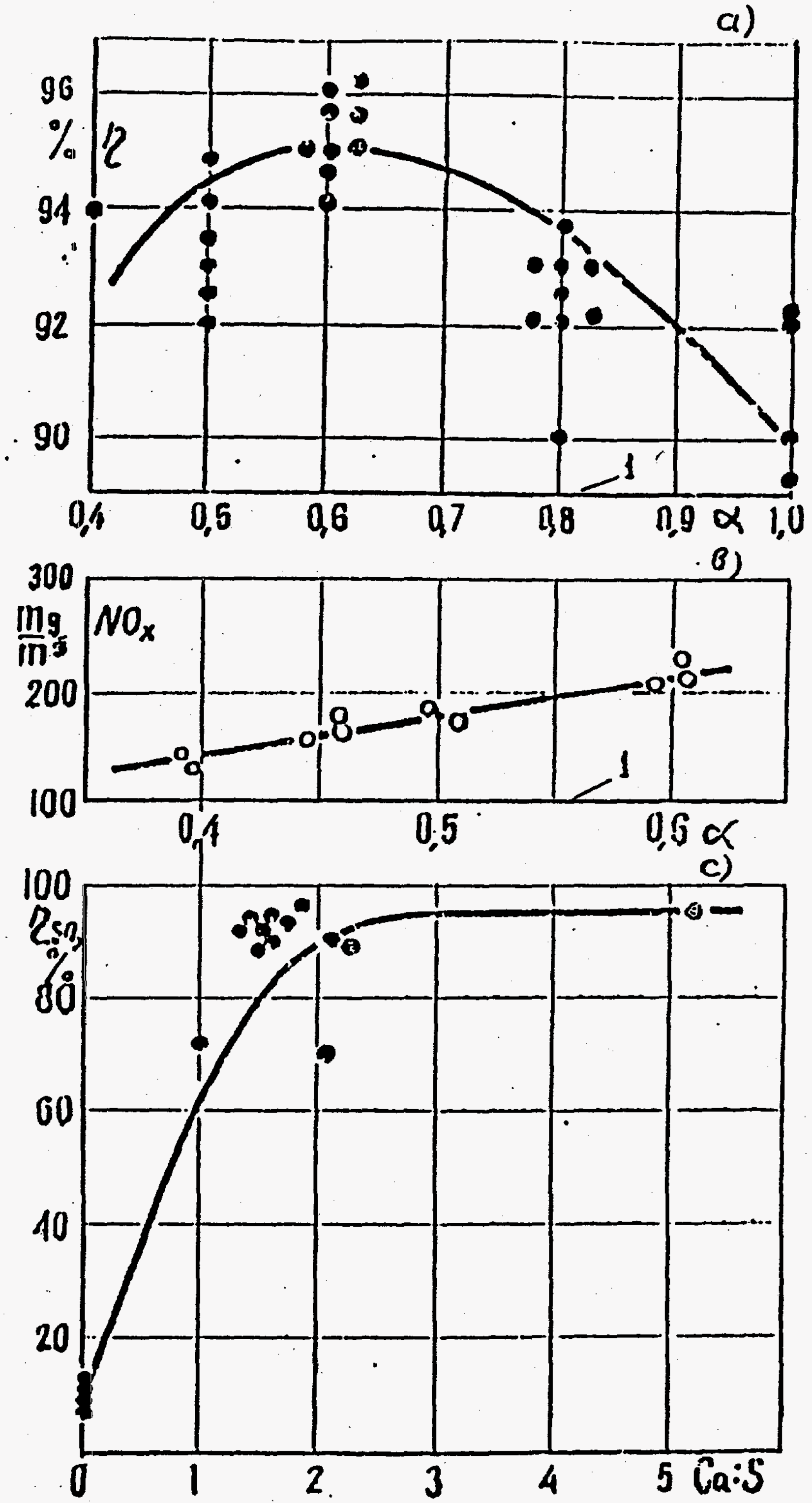


Fig. 34. Anthracite culm firing efficiency with CFB

(a) anthracite culm conversion; (b) NOx formation (Ca/S=2.5 - 4.0, t = 860-900°C, α = 1.15-1.25); (c) SO_2 fixation. 1- primary air to fuel stoichiometry

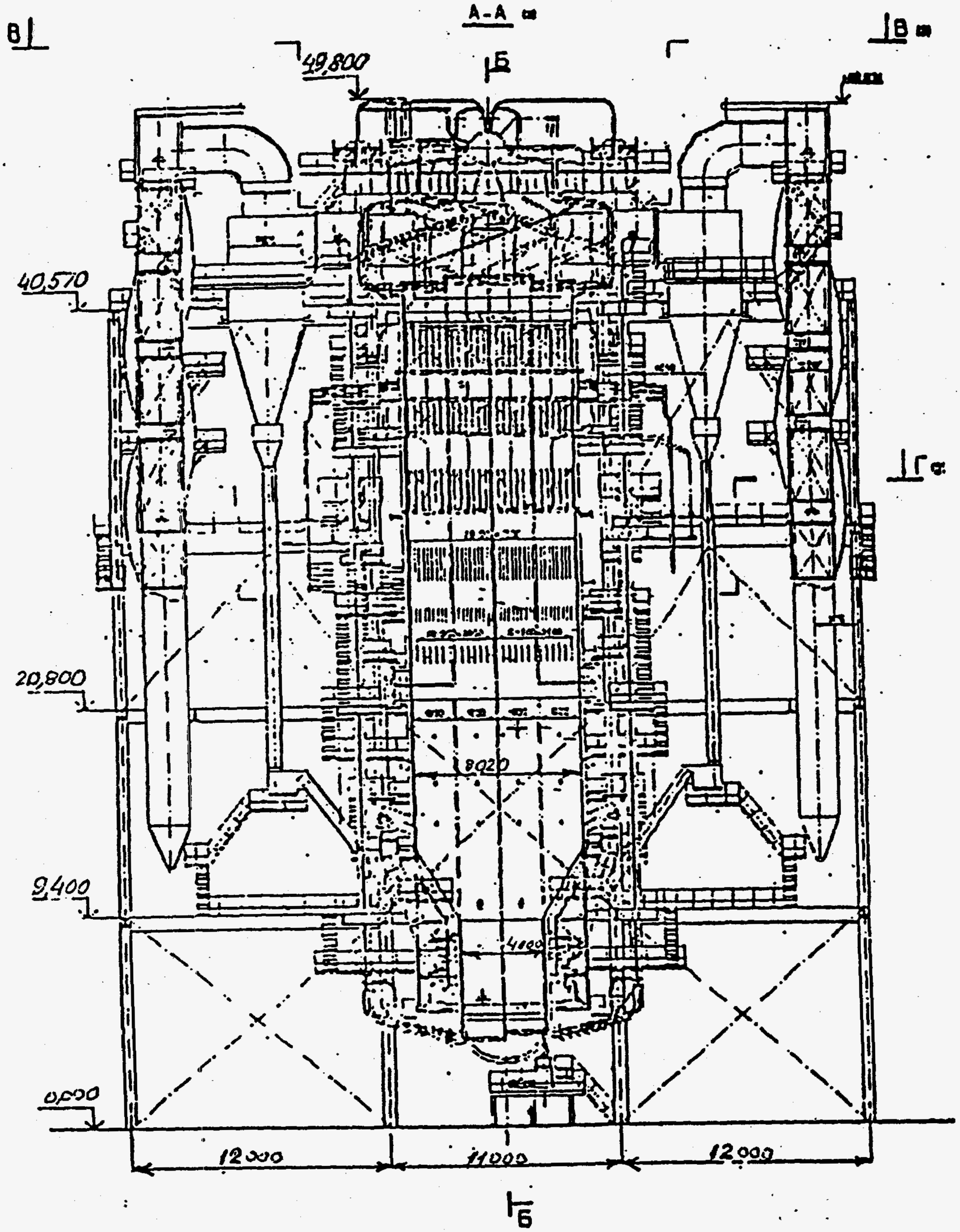


Fig.35.Demo 500t/h CFB boiler with "cold" cyclones.

1 - coal treatment; 2 - gasifier; 3 - waterwall cooling system; 4 - gas cooler; 5 - gas cleaning; 6 - GT; 7 - HRSG; 8 - ST; 9 - condenser; 10 - direct contact preheater; 11 - alternator; 12 - additional compressor; 13 - combustible gas auxiliary compressor

a - coal; b - raw combustible gas; c - clean combustible gas; d - GT exhausted gases; e - to stack; f - air; g - compressed air; h - steam

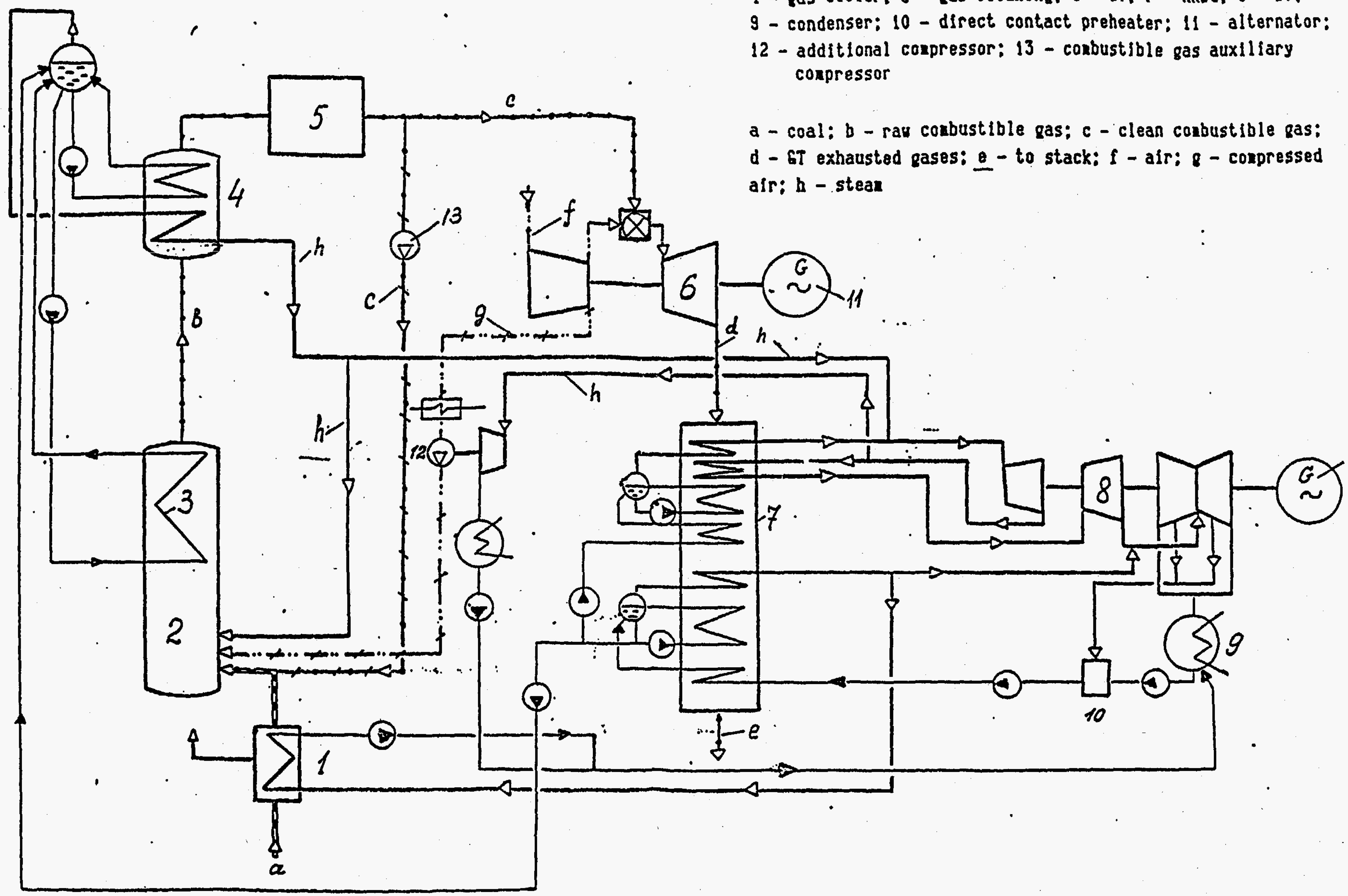
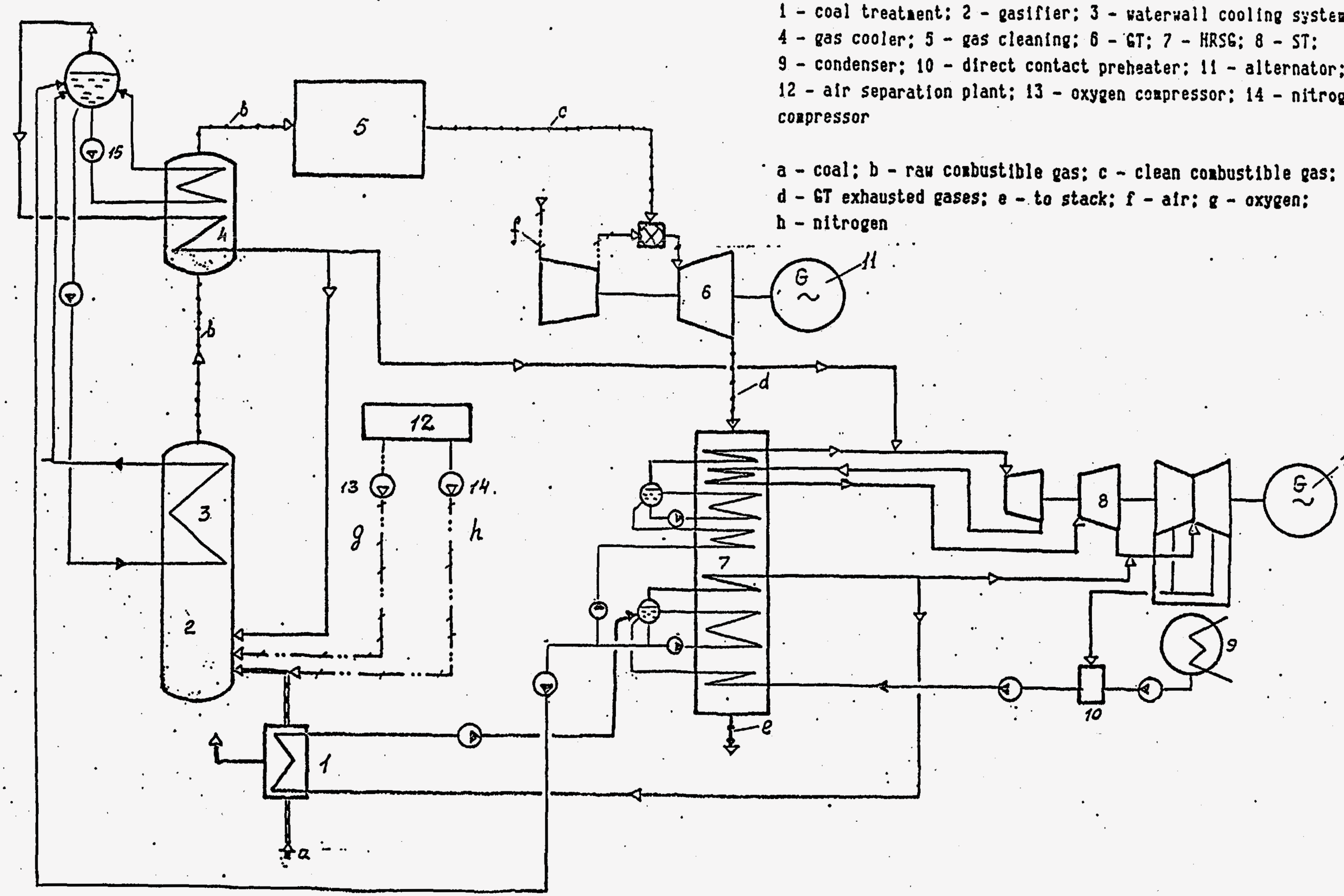


Fig. 36. Flow Sheet of Air Blown IGCC-600



1 - coal treatment; 2 - gasifier; 3 - waterwall cooling system;
4 - gas cooler; 5 - gas cleaning; 6 - GT; 7 - HRSG; 8 - ST;
9 - condenser; 10 - direct contact preheater; 11 - alternator;
12 - air separation plant; 13 - oxygen compressor; 14 - nitrogen compressor

a - coal; b - raw combustible gas; c - clean combustible gas;
d - GT exhausted gases; e - to stack; f - air; g - oxygen;
h - nitrogen

Fig. 37. Flow Sheet of Oxygen Blown IGCC-600

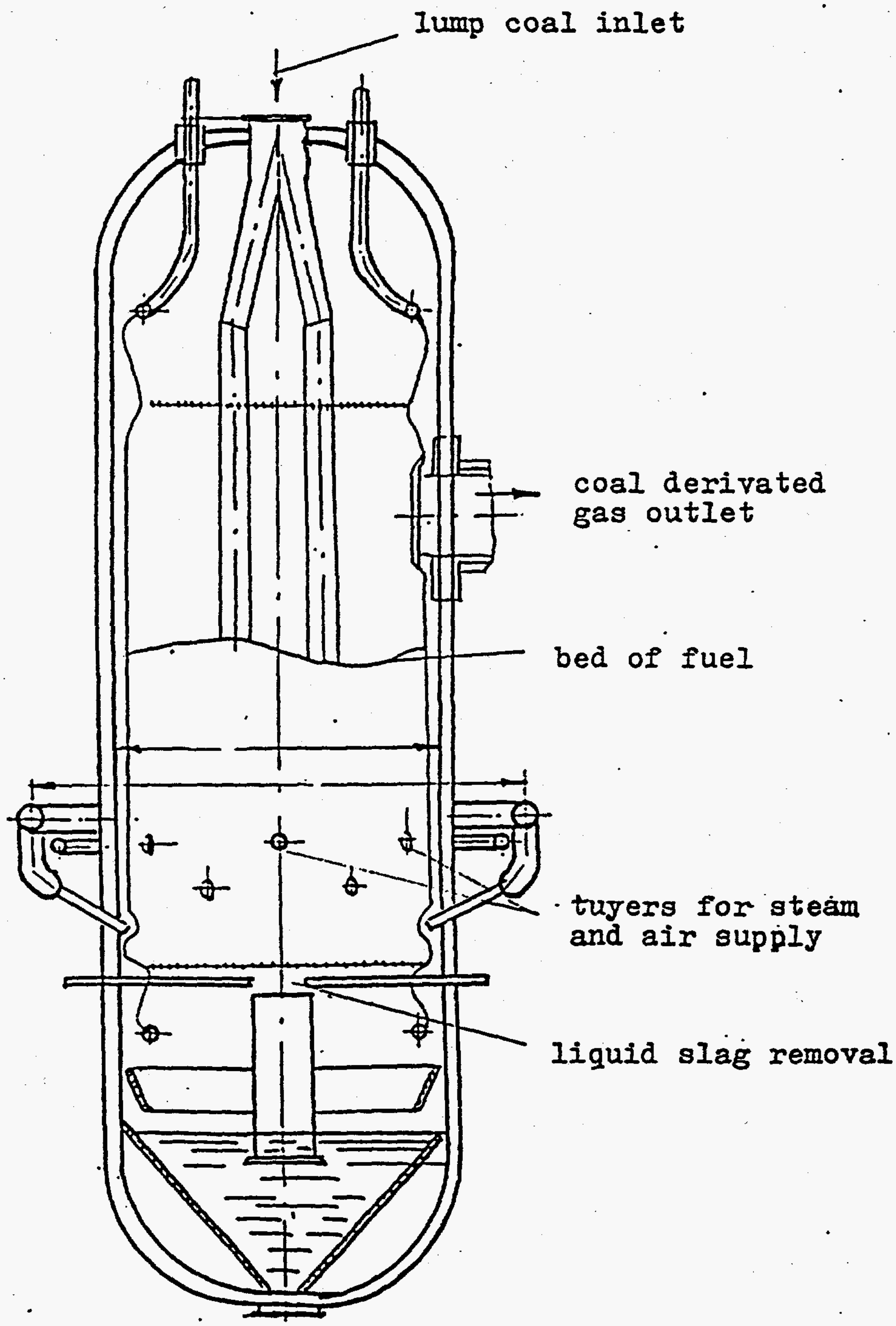


Fig. 38. Moving-bed gasifier

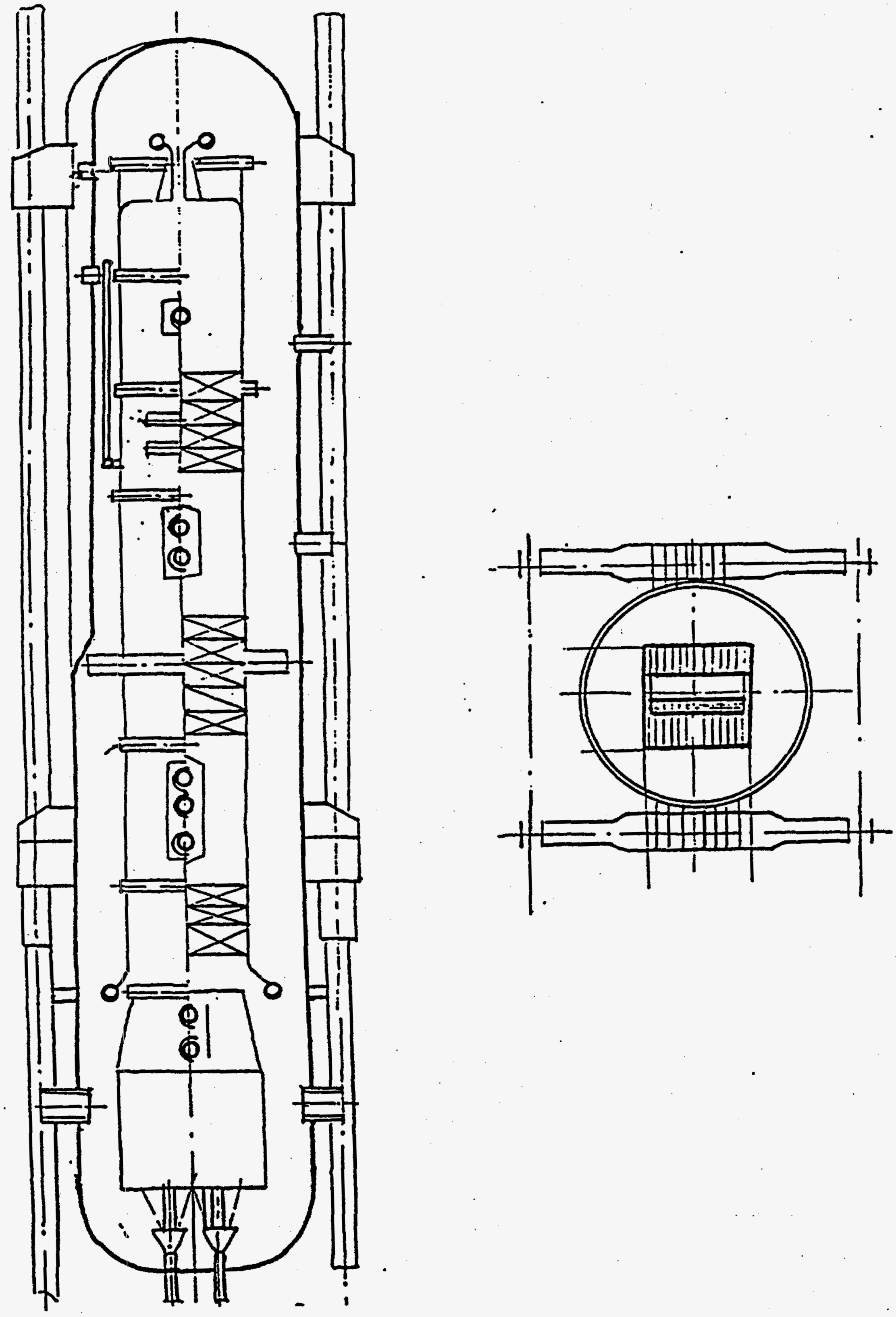


Fig. 39. Convective gas cooler for moving-bed gasifier

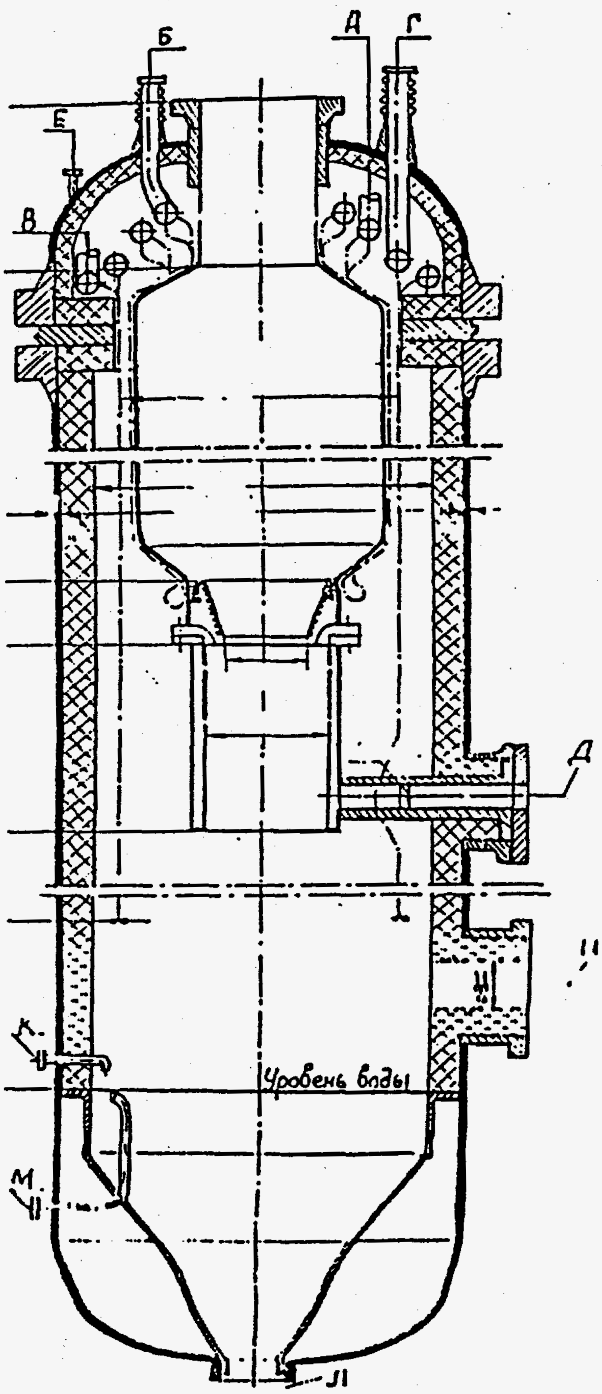


Fig. 40. Entrained-flow oxygen blown gasifier

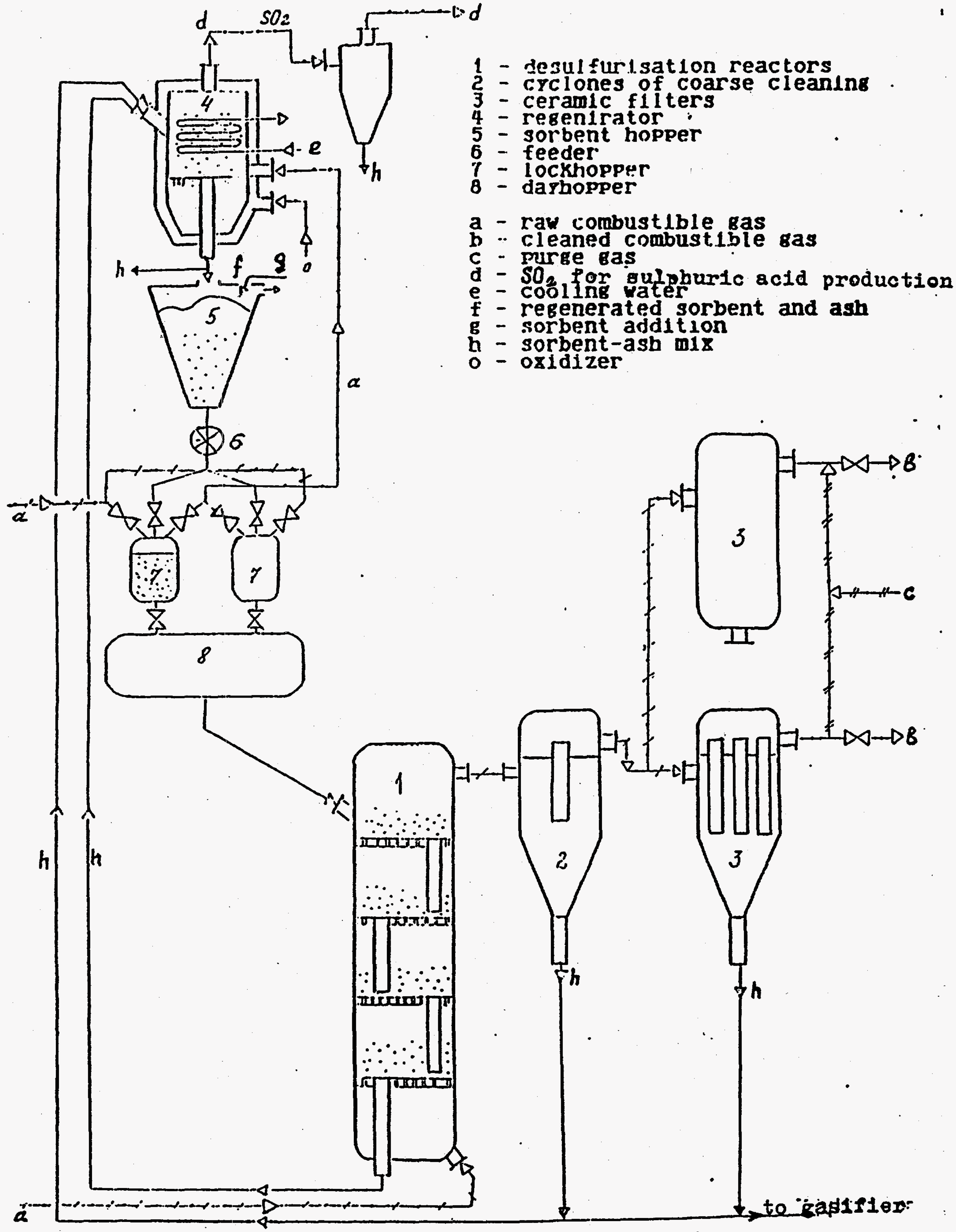


Fig.41. The cleaning system of raw coal derivative gases

1 - GT; 2 - HRSG; 3 - ST; 4 - condenser; 5 - direct contact preheater; 6 - additional compressor; 7 - auxiliary turbine; 8 - condensate pump; 9 - feed pump; 10 - air to gasifier (for air blown options); 11 - feedwater to gas cooler; 12 - steam for coal drying; 13 - steam to gasifier; 14 - steam of gasification system; 15 - condensate return from dryers

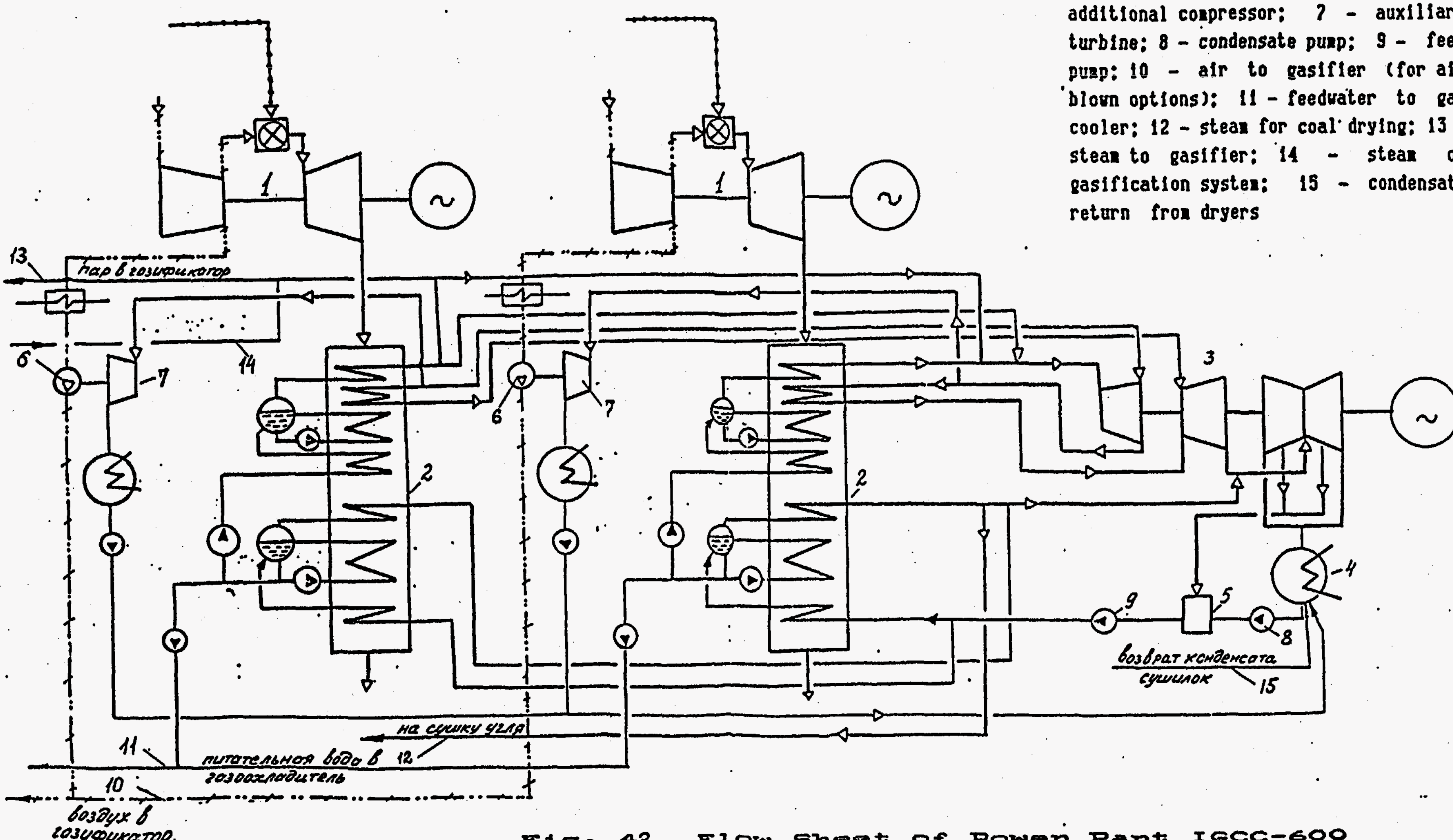


Fig. 42. Flow Sheet of Power Part IGCC-600

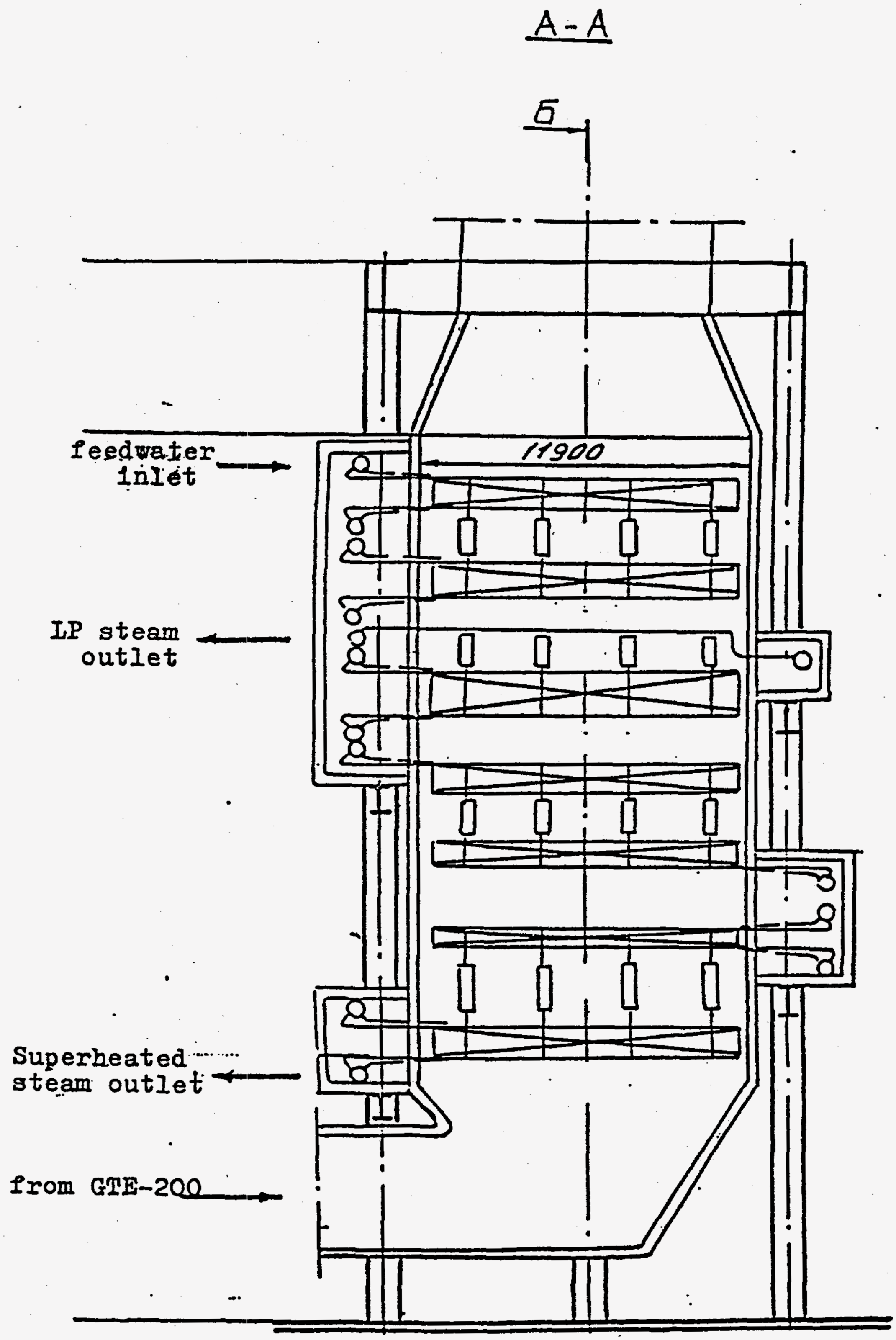


Fig. 43. Heat-Recovery Boiler

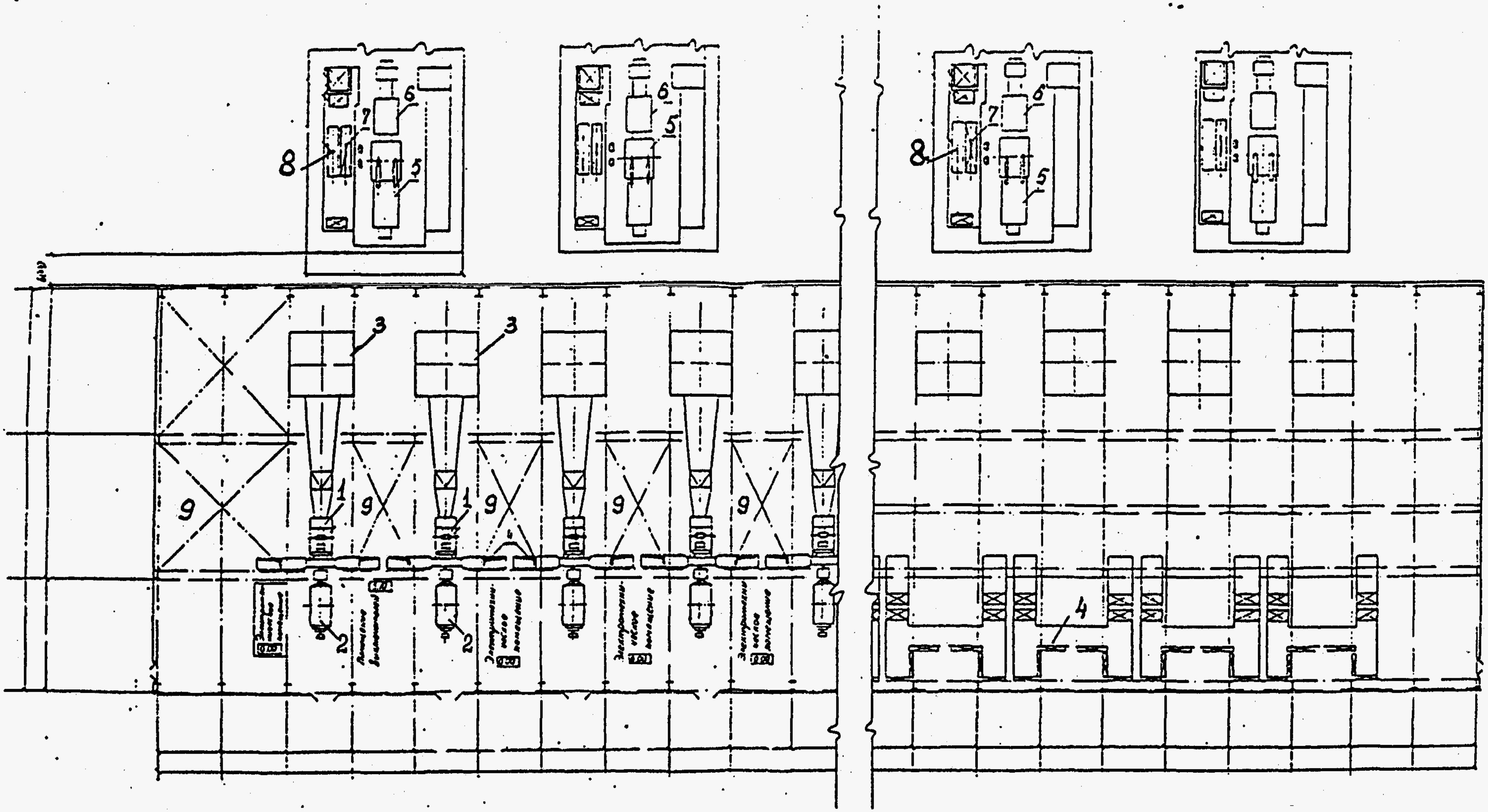


Fig. 44. Layout of the Main Building for Power Part of IGCC Plant

1 - GT; 2 - alternator; 3 - HRSG; 4 - air suction; 5 - ST;
6 - ST alternator; 7 - electrical drived feed pump; 8 - stand
by feed pump; 9 - place for maintenance

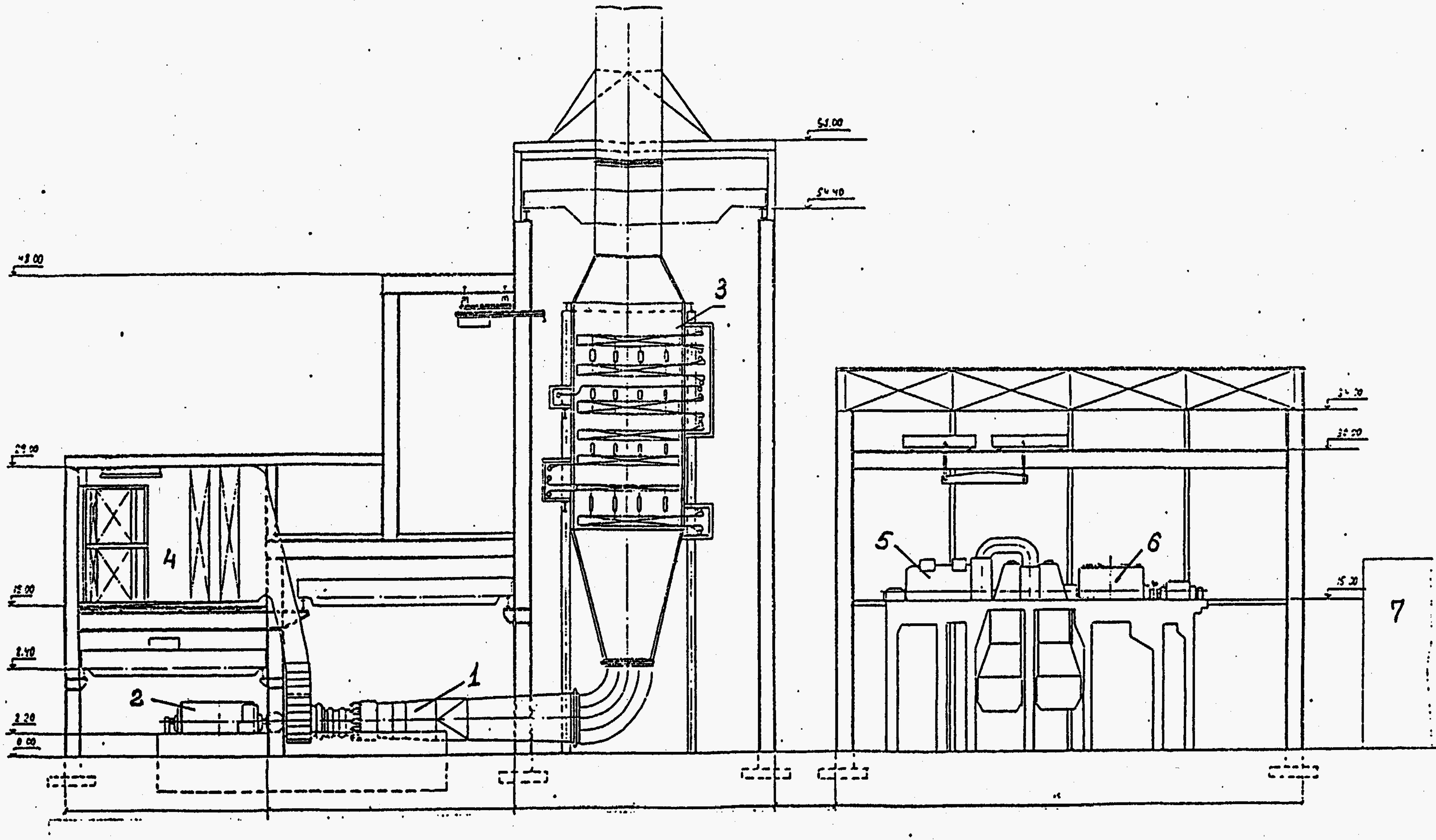


Fig. 45. Cross-section of the Main Building for Power Part of IGCC Plant

1 - GT; 2 - alternator; 3 - HRSG; 4 - air suction;5 - ST; 6 - ST alternator; 7 - main control room

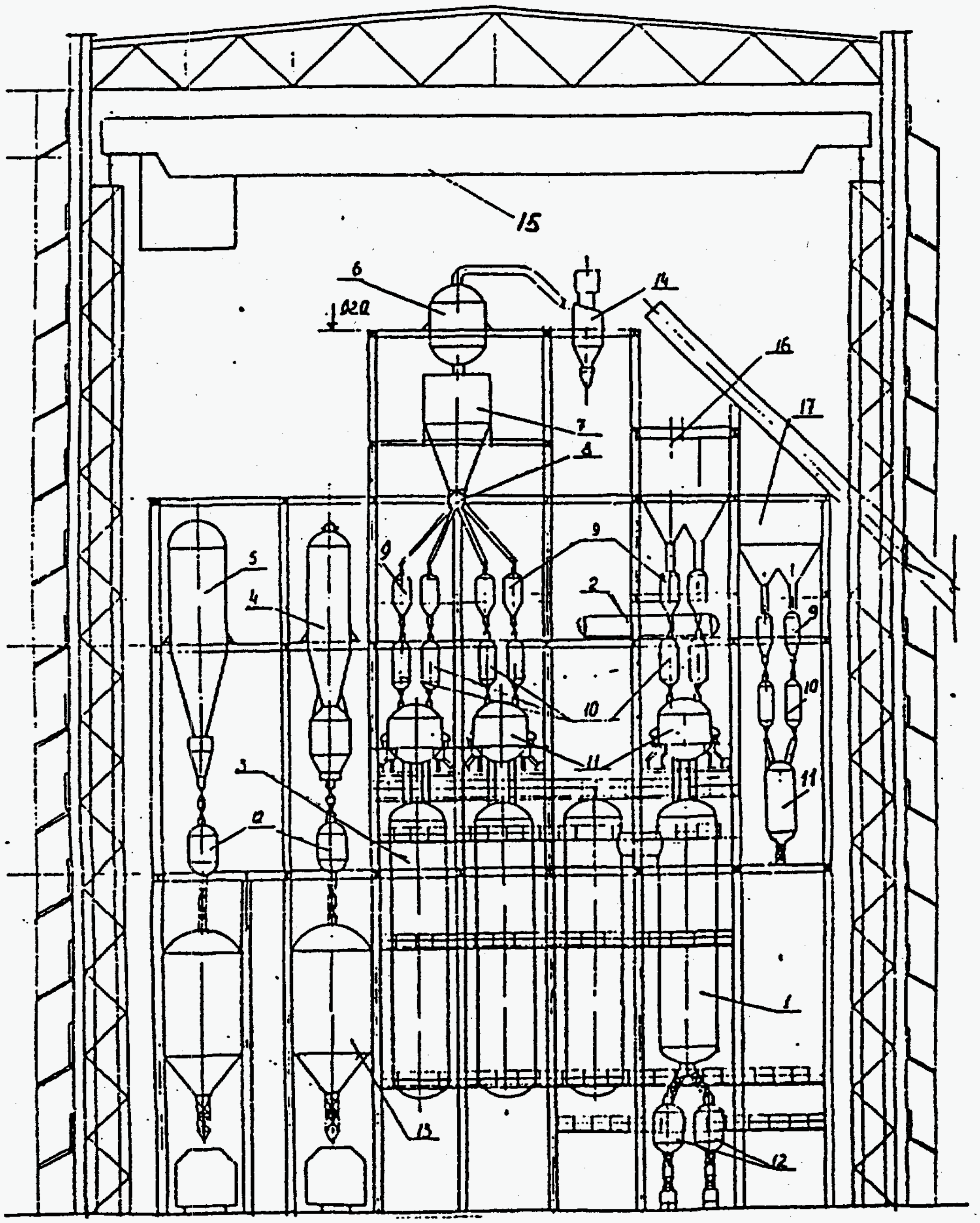


Fig. 46. Cross-section of gasification system
using air blown moving-bed gasifier

1 - gasifier; 2 - steam drum of gasifier cooling; 3 - reactor of desulfurisation system; 4 - cyclone of coarse cleaning; 5 - ceramic filters; 6 - regenerator; 7 - sorbent hopper; 8 - feeder; 9-10 - lockhopper system; 11 - day hopper; 12 - slag removing lockhopper; 13 - hopper; 14 - cyclone; 15 - bridge crane; 16 - lump coal hopper; 17 - fines hopper; 18 - convective gas cooler

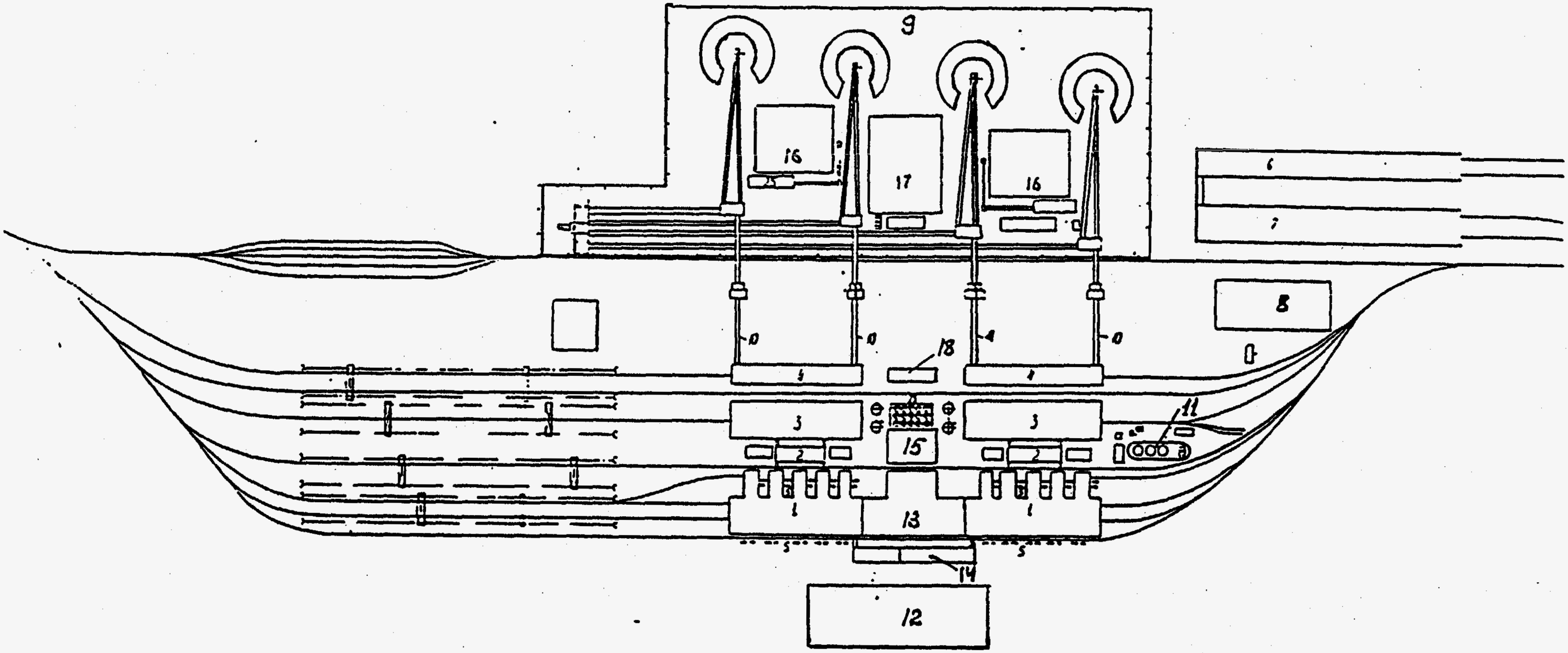


Fig. 47. The Layout of TPS with 10 IGCC 600 MW Units

1 - main building; 2 - main control room; 3 - gasification systems; 4 - fuel treatment; 5 - transformers; 6 - air separation plant (ASP); 7 - ASP compressor's building; 8 - sulphuric acid plant; 9 - coal yard; 10 - conveyors galeries; 11 - fuel oil tank; 12 - open switchgear; 13 - auxiliary building; 14 - officies; 15 - water treatment; 16 - ash disposal place; 17 - sladge pond; 18 - auxiliary boilerhouse

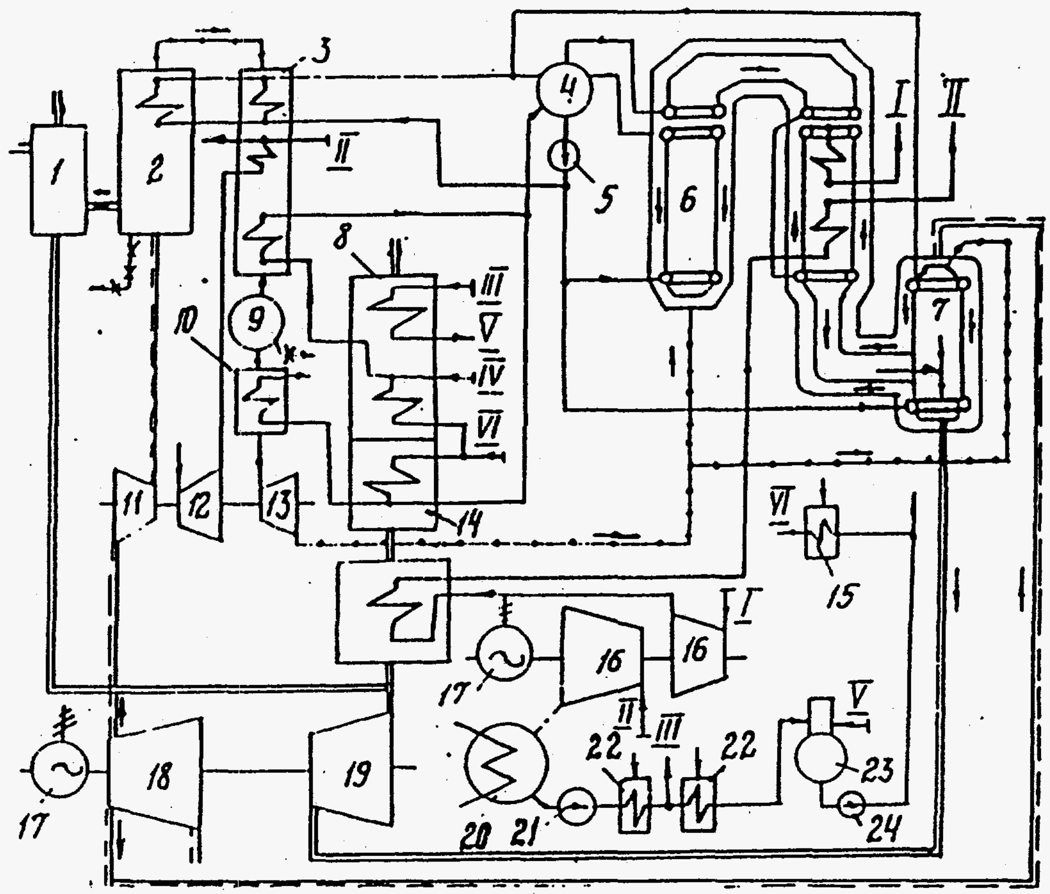


Fig. 48. Flow Sheet of IGCC Unit rated 250 MW

1 - coal drying; 2 - fluidized-bed gasifier;
3 - gas cooler; 4 - drum of SSG; 5 - internal circulating pump SSG; 6 - furnace of SSG;
7 - top combuster; 8 - gas-water heater (GWH);
9 - scrubber; 10 - gas heater; 11 - additional compressor; 12 - auxiliary steam turbine;
13 - turboexpander; 14 - economizer; 15 - HP preheaters; 16 - main steam turbine; 17 - alternators; 18 - GT compressor; 19 - GT turbine;
20 - steam condenser; 21 -condencate pump;
22 - LP preheaters; 23 - deaerator; 24 - feed pump; I,II - steam to HP and LP sections of ST;
III - condencate to GWH; IV - feedwater to GWH;
V - condencate to deaerator; VI - feedwater to economizer

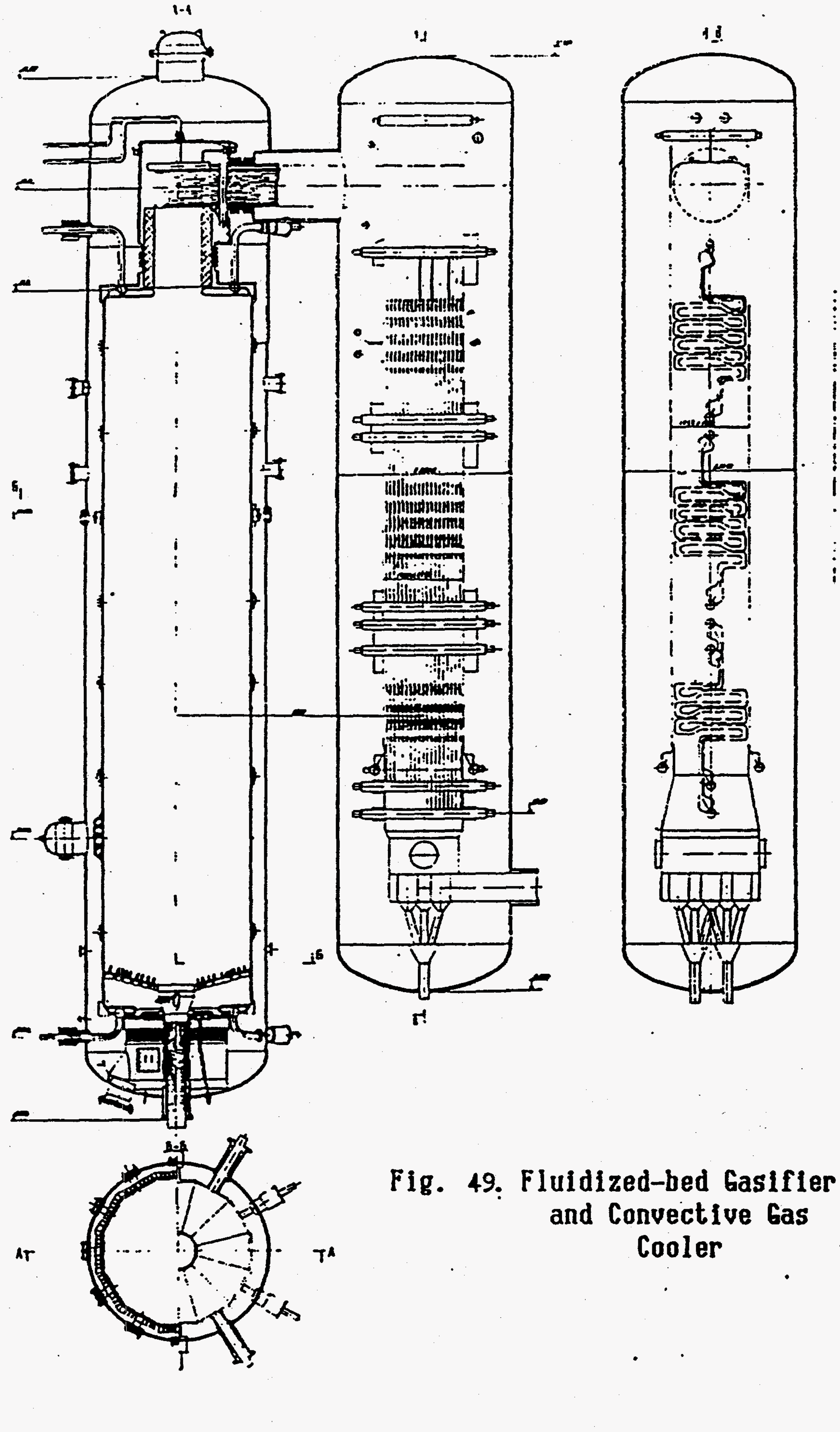


Fig. 49. Fluidized-bed Gasifier and Convective Gas Cooler

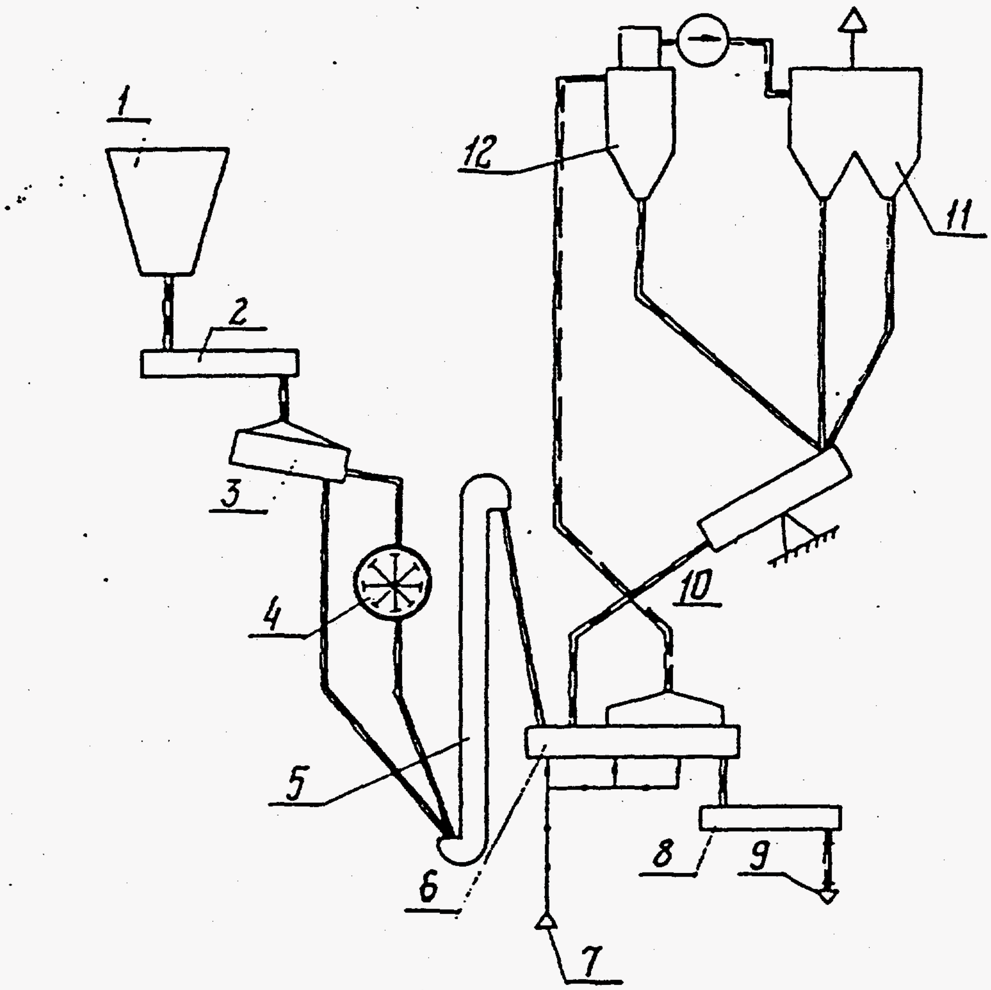


Fig. 50. Fuel Treatment for Fluidized-bed Gasifier

1 - raw coal hopper; 2 - feeder; 3 - screen
4 - crusher; 5 - elevator; 6 - fluidized-bed dryer;
7 - combustion gases; 8 - treated fuel feeder;
9 - to lockhopper; 10 - dust granulator; 11 - ESP;
12 - cyclone

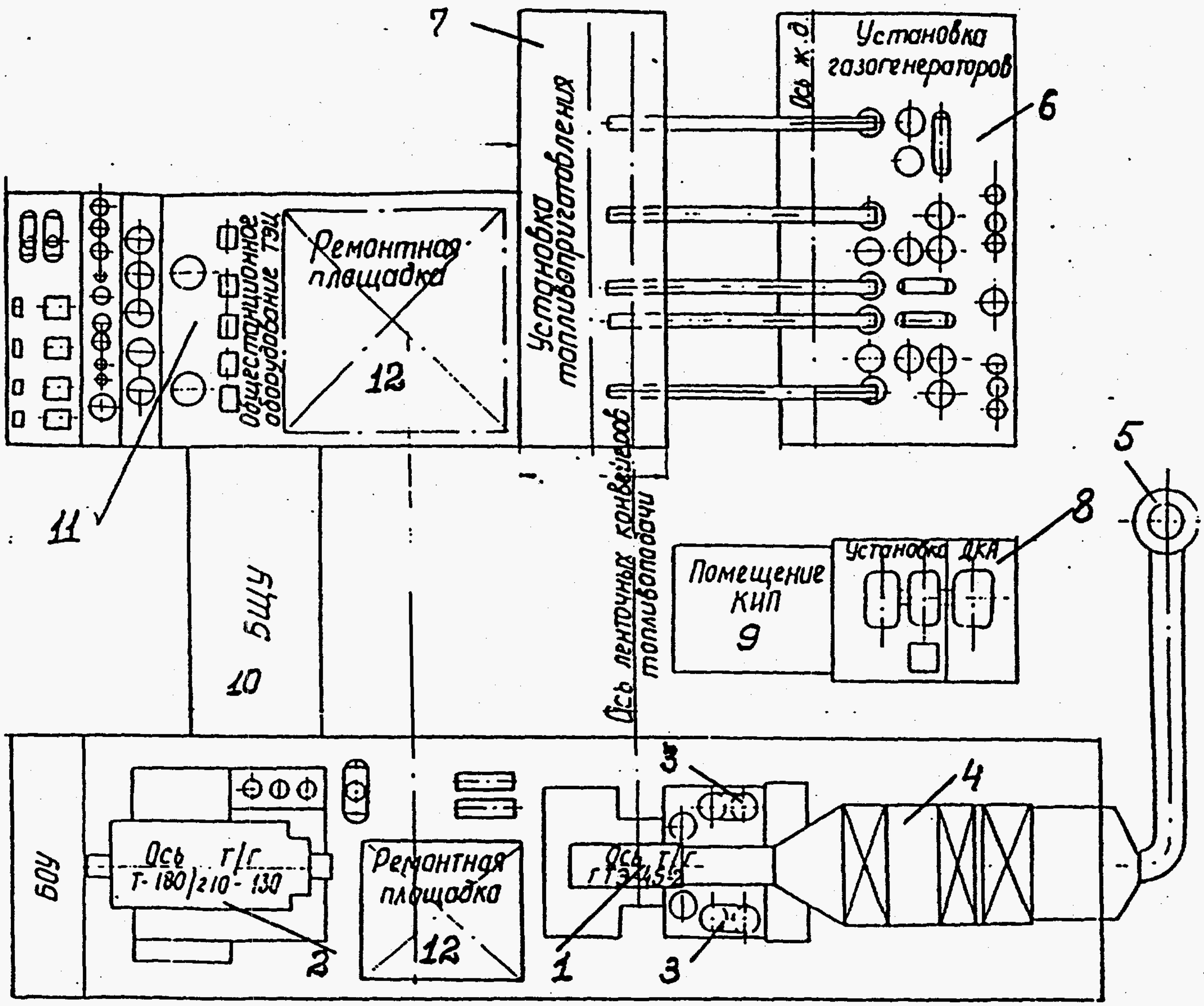


Fig. 51. The Layout of IGCC Plant rated 250 MW

1 - GT; 2 - ST; 3 - supercharged boiler; 4 - gas- water heat exchanger; 5 - stack; 6 - gasifier's building; 7 - fuel treatment; 8 - auxiliary compressor-turbo-detander; 9 - I&C room; 10 - main control room; 11 - balance of plant equipment; 12 - place for maintenance