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On the issue of modernization of steam-gas power units

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Abstract. Combined cycle power plants are an efficient solution for combined heat and power generation; however, during the summer period, their electrical output decreases due to the high ambient air temperature at the gas turbine compressor inlet. This study examines an alternative approach – increasing the thermal output of a combined cycle plant by installing a block-type supplementary firing unit in the heat recovery steam generator. Using a 450 MW combined cycle power unit as an example, it is shown that the application of the supplementary firing unit allows increasing the thermal output from 237 to 320 Gcal/h (a 35% increase), the electrical output by 6% in district heating mode and by up to 11% in condensing mode, with a slight increase (3%) in the specific equivalent fuel consumption for electricity generation. Firing additional fuel between the high-pressure superheater and the evaporator ensures stabilization of steam parameters and eliminates the need to activate additional district heating equipment (steam turbines or hot water boilers) during the transitional months (April, October). An analysis of climatic conditions is performed, confirming the feasibility of using the supplementary firing unit to cover heat loads in the ambient temperature range from –5 to +10 °C. The proposed retrofit improves the flexibility and economic efficiency of the combined heat and power plant, eliminating the need to purchase new generating equipment.

1 Introduction

Gas turbine units are one of the key elements of modern power engineering, ensuring the reliability of distributed generation, covering peak loads, and enabling the operation of autonomous power nodes [1]. The share of gas turbine technologies in the structure of newly

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commissioned capacity is steadily increasing: according to the International Energy Agency (IEA), over the past ten years, the total installed capacity of gas turbine units worldwide has grown by nearly 30%, and this trend continues due to their high flexibility, relatively low capital costs, and the ability to operate in a cogeneration cycle [2]. However, the efficiency of gas turbine units depends significantly on ambient conditions, and this issue is most pronounced during the summer period [3]. The operational paradox lies in the fact that precisely during the hot months, when annual peak electricity demand is recorded due to the operation of air conditioning and cooling systems, gas turbine units exhibit a sustained decrease in output power and efficiency. Figure 1 shows the power reduction of the GE 6fa gas turbine.

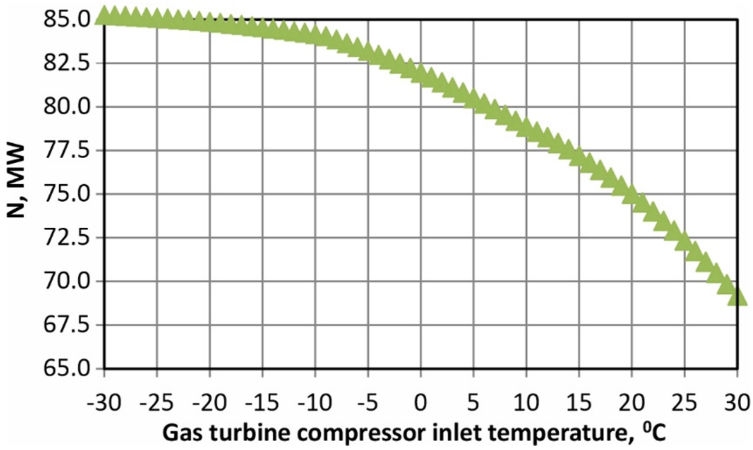

Fig. 1. Gas turbine GE 6FA power versus compressor inlet temperature

Losses can reach 15–25% of the rated values when the ambient temperature rises from +15 °C to +35…+40 °C, which creates serious imbalances in the power generation balance. For the power systems of southern regions (the Mediterranean, the Middle East, southern Russia, US states), this problem takes the form of a seasonal systemic risk, requiring the activation of expensive reserves or consumer load shedding [4–6]. The decrease in gas turbine unit power with increasing ambient temperature is due to fundamental properties of the working fluid – air. The mass flow rate of air through the axial compressor is given by the expression:

$$G_v = \rho v S_k, \tag{1}$$

where ρ – is the density, v – is the axial velocity at the inlet,S_k – s the flow cross-sectional area. Air density is inversely proportional to the absolute temperature; therefore, when the temperature rises from the ISO standard conditions (+15 °C, 101.3 kPa, 60% humidity) to +30 °C... The reduction in mass flow rate leads to a proportional decrease in the work produced by the turbine and also impairs the cooling of the hot blades, which may further limit the turbine inlet gas temperature due to service life considerations [7–9]. In addition, the specific work of the compressor increases:

$$T_c = T_0 \pi_k^{\frac{k-1}{k}} \tag{2}$$

As a result, the specific useful work of the gas turbine unit decreases more rapidly than the mass flow rate:

$$l_{\kappa} = c_p \cdot T_0^{\kappa} \left(\pi_{\kappa}^{\frac{k-1}{k}} - 1 \right) \cdot \frac{1}{\eta_{\mathrm{oi}}^{\kappa}} \tag{3}$$

where c_p – is the isobaric specific heat capacity of air, kJ/(kg·°C); $T_{0\kappa}$ – is the inlet air temperature, ^{0}C; k – s the isentropic exponent; π_k – is the pressure ratio; η_{oik} – is the compressor efficiency. The combined effect is a reduction in electrical power of 0.5–1.2% for each degree Celsius above the rated temperature.

According to operating company estimates, the loss of electricity generation due to summer power reduction of a gas turbine unit can reach 5–7 GWh per hot month for a single 100 MW unit. On a power system scale, the losses amount to tens and hundreds of gigawatt-hours, which, at market prices, is equivalent to millions of dollars in lost revenue. In addition to direct financial losses, indirect effects arise increased wear of auxiliary equipment (frequent starting of reserve capacity), increased specific fuel consumption (3–8% in the summer period), and increased CO_2 emissions per unit of energy supplied [10].

To combat the summer performance degradation of gas turbine units, technical solutions aimed at reducing the air temperature at the compressor inlet are employed. The main ones are:

• Evaporative cooling – water injection upstream of the compressor; effective in dry climates, reduces the temperature to the dew point, but is inoperable at high relative humidity (>60%);

• Absorption lithium bromide chillers (absorption chillers) using exhaust gas heat; they can cool the air to +10…+15 °C, but require high capital costs and free space;

• Ejection and compression coolers (trigeneration); provide deep cooling but are energy-intensive, reducing the overall plant efficiency;

• Periodic compressor washing – removes fouling that degrades the flow path but does not solve the thermodynamic problem.

• Despite the variety of technologies, their application is often empirical, and a universal methodology for selecting the optimal cooling method for specific climatic conditions and gas turbine unit operating modes is lacking.

The aim of this work is to modernize a combined cycle power plant by increasing its thermal output while maintaining the certified electrical output using a block-type supplementary firing unit installed in the heat recovery steam generator. The relevance of the work lies in covering peak heat demands without bringing additional district heating equipment into operation. To address this task, a retrofitting option for the heat recovery steam generator with the installation of a block-type supplementary firing unit is considered. The issue of supplementary firing in heat recovery steam generators is relevant for the power industry when retrofitting existing capacities using combined cycle plant superstructures.

2 Retrofit of the power unit

The application of a supplementary firing unit (SFU) makes it possible to increase the main steam parameters to their maximum values, thereby increasing the installed thermal output without bringing additional district heating equipment into operation. Thus, an important issue is to consider the possibility of increasing the thermal output of the combined cycle plant while maintaining the design (declared) electrical output, which would allow the steam turbine equipment to be taken out of service during periods of minimum heat loads and, as a consequence, improve the economic efficiency of the entire CHP plant [11].

For power plants operating on gaseous fuel, the most effective retrofit method is the superstructure (repowering) of the existing steam turbine part, which provides a significant increase in heat output with minimal capital investment.

Over the past two decades, the central focus in the retrofitting of Russian CHP plants has been the implementation of binary-type combined cycle power plants with heat recovery steam generators. The efficiency of a supplementary firing unit is most evident in large power units. Currently, several 450 MW combined cycle double-units (PGU-450) are in operation, as well as a number of smaller-capacity cogeneration combined cycle plants. At present, large energy companies operating in the wholesale electricity and capacity market are interested in achieving optimal and efficient loading of their existing equipment.

The object of the study is CHP-22 of the "Nevsky" branch of PJSC "TGC-1", which has the following equipment composition: three T-250-240 steam turbines, three power boilers (TGMP), six hot water boilers, and two steam boilers for auxiliary needs.

The PGU-450 power unit consists of:

• two LMZ-produced GTE-160 gas turbines;

• two Podolsk ZiO-produced heat recovery steam generators (HRSGs);

• one T-150 steam turbine (UTZ production) with an electrical output of 145 MW and a thermal output of 163 Gcal/h.

The use of a supplementary firing unit (SFU) in a combined cycle plant allows flexible provision of required capacities and additional heat supply during periods of higher demand. The SFU is applicable in the gas turbine cycle, where combustion products are obtained at the gas turbine combustor outlet; then the thermal energy of the combustion products is converted into electrical energy in the steam turbine cycle (as part of the combined cycle power unit). The additional fuel supply increases the steam output of the HRSG.

The heat recovery steam generator is one of the most important elements of combined cycle plants. The purpose of HRSGs is to recover the heat of the exhaust gases from the gas turbine unit.

The PR-228/47 HRSG, manufactured by the Podolsk Machine-Building Plant, is designed to produce superheated steam at high and low pressures and to preheat the condensate from the steam turbine by utilizing the heat of the hot exhaust gases from the gas turbine. The PR-228/47-7.86/0.62-515/230 HRSGs are of vertical design, two-drum, with forced circulation in the high-pressure and low-pressure evaporator circuits, gas-tight, with a self-supporting frame. Arranged sequentially along the gas path are: a superheater, an evaporator, an economizer, a superheater, an evaporator, and a gas-fired condensate preheater for the steam turbine.

There are two options for installing the SFU in the HRSG:

• At the HRSG inlet, before the high-pressure superheater;

• Between the high-pressure superheater and the high-pressure evaporator.

The second option has the following advantages:

• reduced costs for external cooling and thermal protection of the high-pressure superheater and the HRSG walls;

• installing the SFU before the high-pressure superheater at the HRSG inlet leads to an increase in the boiler dimensions.

In condensing-type combined cycle plant schemes, supplementary firing can be used to increase the electrical output of the steam turbine part of the CCGT, stabilize the parameters of the generated steam, and effectively integrate existing and newly installed equipment during the retrofitting of existing power facilities.

In a CCGT with supplementary firing in the HRSG, an additional amount of fuel is combusted. Burner elements for supplementary firing are typically placed in the HRSG gas duct (Figure 2).

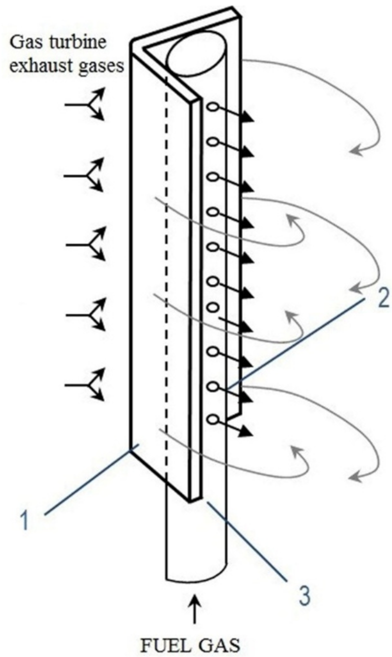

Fig. 2. Diffusion – stabilizer burner of the afterburning chamber: 1 – Stabilizer; 2 – axis of the gas jet; 3 – gas collector

Figure 2 shows a diffusion-stabilizer burner of a supplementary firing chamber used in practice. Such burners can be installed between the HP superheater and the HP evaporator. In this method, natural gas is combusted in supplementary firing chambers. For this purpose, natural gas is introduced into the recirculation zone by a jet system through a special tubular manifold on the rear side of the stabilizer. The exhaust gases from the gas turbine enter the combustion zone from the flow around the stabilizer. A certain amount of combustion products is also supplied here by recirculation counterflow, which helps stabilize the combustion process. This method of supplementary firing is characterized by a high intensity of the mixing process with a short flame length along the flow (despite the separate supply of exhaust gases and fuel) [12–14]. When the afterburning unit is turned on, CO_2 emissions increase by 15% (in proportion to the increase in gas consumption), and NOx emissions increase by about 50% due to higher local temperatures in the diffusion-stabilization burner. It is important to note that this disadvantage is partially compensated by preventing the start-up of less efficient equipment (T-250 turbines), as well as the possibility of using stepwise combustion or steam injection, which will be the subject of further research.

When additional fuel is combusted in the block-type supplementary firing unit, the high-pressure steam temperature increases by 3%, and its flow rate increases by 35%. Supplementary firing takes place in the environment of the gas turbine exhaust gases, which makes it possible to increase their temperature, stabilize the parameters of the steam generated in the HRSG, and increase the power of the combined cycle plant.

3 Results of simulation of equipment operation

Table 1 presents the changes in the main characteristics of the PGU-450 combined cycle power unit before and after the installation of the supplementary firing unit in the heat recovery steam generators. The data are given for the district heating mode of the unit**.**

Table 1. Comparative characteristics of the CCGT – 450 without a BDU and with an installed BDU

Parameter	Without SFU	With SFU	Change (%)
HP steam temperature at HRSG outlet (°C)	515	530	+3
HP steam pressure at HRSG outlet (MPa)	7.86	8.09	+0,3
Average electrical load in district heating mode (MW)	450	477	+6
Thermal load (Gal/h)	237	320	+35
Specific equivalent fuel consumption for electricity (g/kWh)	184	190	+3
Specific equivalent fuel consumption for heat (kg/Gcal)	146.2	145.4	- 0.5
Electrical efficiency of the unit (%)	38.15	36.3	-5

SFU — supplementary firing unit, HRSG — heat recovery steam generator, HP — high pressure.

As can be seen from Table 1, when using the supplementary firing unit (SFU):
• The high-pressure steam temperature increases by 3%;
• The pressure in the high-pressure circuit increases by 42%;
• The thermal output of the unit increases by 35%, and the electrical output increases by 6%.

It should be noted that the specific equivalent fuel consumption for electricity generation increases, while the specific equivalent fuel consumption for heat generation decreases slightly due to the large increase in thermal output. In condensing mode (summer operation), the increase in electrical output will be greater – up to 11%. Thus, the task of increasing the thermal output of the PGU-450 combined cycle unit without reducing its electrical output is accomplished.

Figure 3 shows the change in the high-pressure steam temperature at the HRSG outlet as a function of the heat input from the gas turbine exhaust gases.

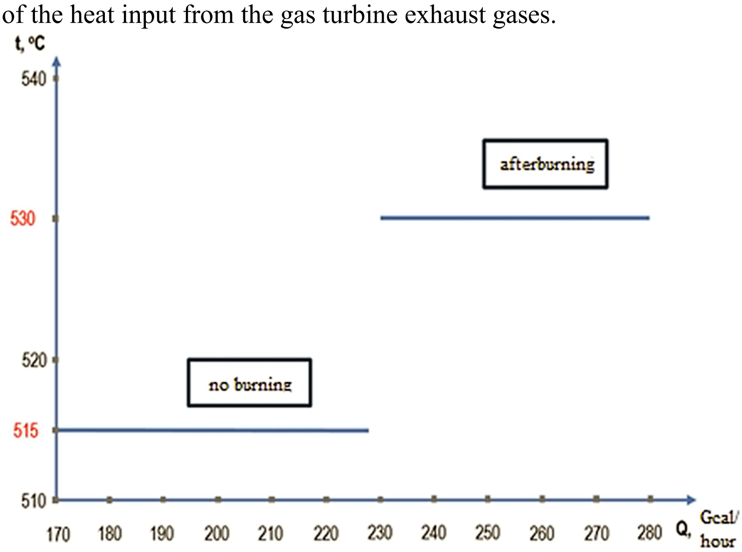

Fig. 3. Dependence of the steam temperature on the heat consumption of gases per GTU

As can be clearly seen from the diagram, when the supplementary firing unit is switched on, the steam temperature increases by 3% – up to 530 °C.

Figure 4 shows the change in the HP steam flow rate from the HRSG without the SFU and with the SFU in operation. As can be seen from the graph, the HP steam generation increases by 35%, and at the same time the thermal output of the combined cycle unit increases by 35% when the supplementary firing unit is switched on.

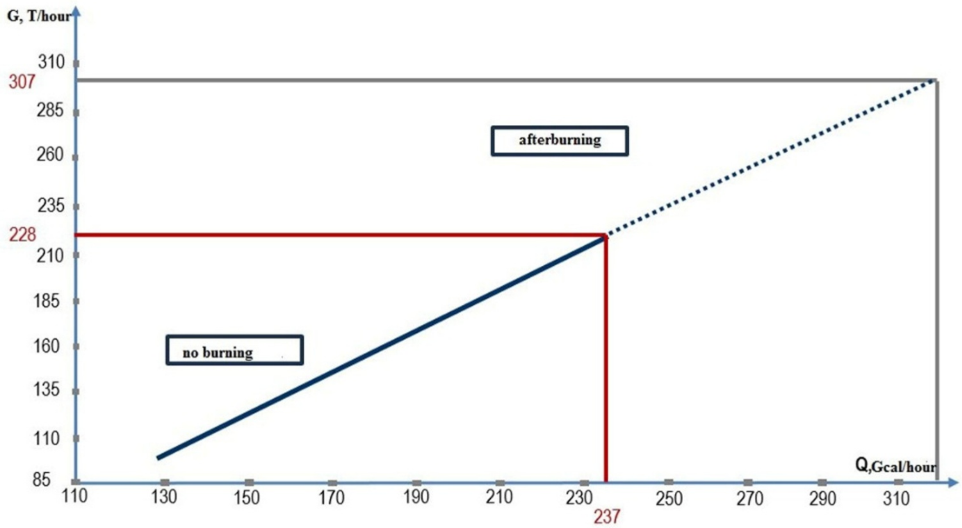

Fig. 4. Dependence of high-pressure steam consumption on heat consumption per GTU

When the SFU is in operation (Figure 5), the electrical output increases due to the activation of the T-150 steam turbine. In district heating mode, the electrical output increases by 6% (+27 MW), while in condensing mode, the output increase is 8.5% (+39 MW).

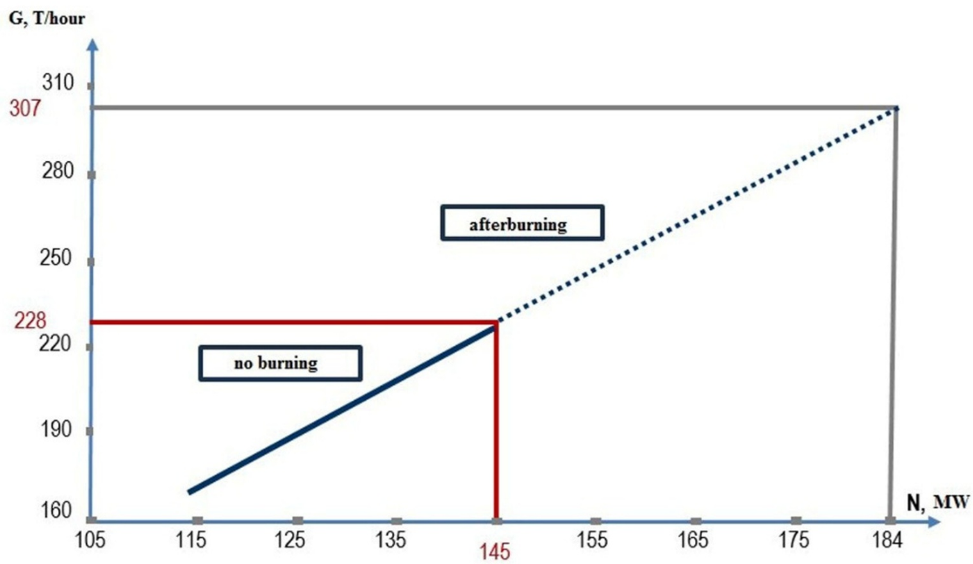

Fig. 5. Dependence of the electric power of the T-150 turbine on the consumption of high-pressure steam in the condensation mode

As a result, the balance between the thermal output and the consumers' heat load will change (Table 2).

Table 2. The balance of thermal power and thermal load of consumers

Month	Heat supply (Gcal/h)	CCGT thermal output without SFU (Gcal/h)	Imbalance without SFU	CCGT thermal output with SFU (Gcal/h)	Imbalance with SFU
April	347.6	237	-110.6	320	-27.6
May	183	237	54	320	+137
September	201	237	36	320	+119
October	356.5	237	-119	320	-36.5

It should be noted that the loads presented in Table 2 are monthly average reduced consumer loads. Moreover, the second half of April, early May, the last ten days of September, and early October are characterized by slightly positive temperatures and relatively high heat loads (compared to summer months) in the range of 250–300 Gcal/h. The use of the supplementary firing unit can increase the steam flow rate and pressure to their maximum values, thereby improving the flexibility characteristics of the CCGT and increasing the installed thermal output without bringing the T-250 steam turbine or hot water boilers into operation. Another advantage of the block-type supplementary firing unit is the ability for smooth regulation of thermal output. A thermal output imbalance of 8–10% occurs briefly during nighttime hours. During these hours, it is possible to switch from qualitative to quantitative regulation of the district heating network parameters instead of starting up the KVGM-180 hot water boiler.

Additional justification for the necessity of using the supplementary firing unit in the HRSG of the PGU-450 combined cycle unit is provided by the climatic parameters of the St. Petersburg region (Table 3).

Table 3. Climatic parameters of St. Petersburg

Period with daily average air temperature	Average air temperature (°C)	Duration (days)
$\leq 0°C$	-5.1	139
$\leq 8°C$	-1.8	220
$\leq 10°C$	-0.9	239

As can be seen from Table 3, the maximum number of days occurs at temperatures close to zero and, accordingly, at minimum heat loads, and a significant number of days in this period can be covered by the thermal output of the PGU-450 combined cycle unit using the SFU. The actual heat load of consumers at an outdoor temperature of +3 °C does not exceed 315 Gcal/h, which allows it to be covered by the operation of the PGU-450 unit without bringing the T-250 steam turbine or KVGM hot water boilers into operation. Among the disadvantages, the following should be noted: an increase in the specific equivalent fuel consumption for electricity by 3%; an increase in gas consumption by 15%; a decrease in the efficiency of the PGU-450 combined cycle unit by 5%. However, these disadvantages are fully offset by the overall economic effect from avoiding the startup of additional district heating equipment at the CHP plant (Table 4).

Table 4. The balance of thermal capacities in April and October during operation PSU-450 with BDU.

Month	Heat supply (Gcal/h)	Heat supply with SFU (Gcal/h)	Imbalance	Average outdoor temperature (°C)
April	347.6	320	-27.6	+9
October	356.5	320	-36.5	+8

The outdoor air temperatures presented in Table 5 are monthly average values. The actual temperatures in April and October differ significantly between the first and second halves of each of these months.

Table 5. Average temperatures in October 2025 and April 2025 (St. Petersburg).

Period	Day (°C)	Night (°C)	Average (°C)
October 1–15	+8.46	+5.26	+6.9
October 16–31	+4.9	-0.76	+2.07
April 1–15	+4.3	-0.5	+1.9
April 16–30	+9.3	+3.53	+6.4

From Table 5, it can be seen that the temperature variation ranges within 30–31%. Accordingly, the consumer load will also vary: 240.6–249 Gcal/h. Thus, the maximum output of the PGU-450-unit (237 Gcal/h) does not cover the actual (daily average) consumer load, and to maintain normal heat supply conditions, it becomes necessary to bring the T-250 steam turbine or a hot water boiler into operation.

When the supplementary firing unit is activated, the thermal output of the PGU-450 unit increases to 320 Gcal/h, which makes it possible to cover the missing thermal output. Consequently, the operation of the T-250 turbine in a mode close to condensing (with a specific equivalent fuel consumption for electricity of 350 g/kWh) is avoided, and the entire heat load is covered by the PGU-450 unit, albeit with a slightly worse specific fuel consumption for electricity of 190 g/kWh. With high gas prices, modernization remains economically feasible due to additional revenue from the sale of electricity (about 101 million rubles/year). The project becomes unprofitable only if the gas price exceeds 9,000 rubles/1,000 m3 and there is no demand for additional electricity, which confirms the sufficient stability of the proposed solution to fuel price volatility.

This configuration of the CHP equipment provides a significant increase in the economic efficiency of the plant's operation compared to the baseline scenario (without the BDU). Any short-term imbalance in the thermal output of the CCGT unit with the SFU in operation can be covered by switching from qualitative to quantitative regulation of the district heating network.

4 Conclusion

The installation of a block-type supplementary firing unit between the high-pressure superheater and the evaporator in the heat recovery steam generator of the PGU-450 combined cycle unit makes it possible to increase the thermal output of the unit by 35% (from

237 to 320 Gcal/h) with a slight decrease in electrical efficiency (by 5%) and an increase in the specific equivalent fuel consumption for electricity by 3%. The electrical output of the PGU-450 unit increases by 6% (27 MW) in district heating mode and by up to 11% (39 MW) in condensing mode, which is achieved due to the increased steam generation of the HRSG and more efficient operation of the T-150 steam turbine.

The use of the SFU ensures coverage of heat loads during the transitional months (April, October) without bringing the T-250 steam turbine units or hot water boilers into operation. For the climatic conditions of St. Petersburg, this allows replacement of up to 220 days per year with outdoor temperatures ≤8 °C.

The economic effect is achieved by eliminating the costly operation of additional district heating equipment (whose specific equivalent fuel consumption for electricity is 350 g/kWh compared to 190 g/kWh when operating the CCGT with the SFU) and reducing start-up operations. Short-term thermal output imbalances (up to 10%) are compensated by switching to quantitative regulation of the district heating network.

The proposed modernization does not require changing the certified electrical capacity of the plant and can be recommended for CHP plants with similar equipment configurations, especially in regions with long heating seasons and moderate winter temperatures.

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