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Repowering a Coal Power Plant Steam Cycle Using Modular Light-Water Reactor Technology

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Abstract: This article presents the results of a techno-economic analysis of repowering a coal-fired power plant's steam turbine system to instead accept heat produced by a pressurized water reactor-type small modular nuclear system (PWR SMR). This type of repowering presents a challenge due to the significantly lower steam pressure and temperature produced by the nuclear system. A 460 MW supercritical power unit with steam parameters of 28 MPa/560 °C/580 °C, operated in the Łagisza Power Plant in Poland, was selected for the analysis. After repowering, the turbine system would be fed with saturated steam from the steam generators of the SMRs at a pressure of 7 MPa and a temperature of 285 °C. In total, four options for repowering were analyzed. In all cases, the existing high-pressure section of the turbine was disconnected, and the existing low-pressure stages of the turbine, as well as all auxiliary and outward components (feedwater heaters, pumps, generator, condenser, condenser cooling, etc.), are re-used in their existing configurations, except for a feedwater-heater pump that needs to be replaced. In three cases, the existing intermediate pressure turbine section acts as the high-pressure stage of the repowered system. These cases include repowering without an additional reheater (case A), with an added single-stage reheater (B) and with an added two-stage reheater (C). In the fourth case (D), the existing intermediate pressure section was replaced by a new high-pressure turbine stage suited to the SMR live steam conditions. While all four repowering options are technically possible and may represent an economic advantage compared to a complete greenfield SMR installation, option D with a new high-pressure stage is clearly the best option available, with significant cost savings, leading to a lower levelized cost of electricity (LCOE) and a higher net present value (NPV) and net present value ratio (NPVR) than the greenfield case and all other repowering. For relatively new coal power plants with equipment in good condition, this type of repowering may present a cost optimal near-term pathway.

Keywords: retrofit decarbonization; steam turbine modernization; small modular reactors; light-water reactors; techno-economic assessment

Citation: Łukowicz, H.; Bartela, Ł.; Gładysz, P.; Qvist, S. Repowering a Coal Power Plant Steam Cycle Using Modular Light-Water Reactor Technology. *Energies* **2023**, *16*, 3083. https://doi.org/10.3390/en16073083

Academic Editor: Flavio Caresana

Received: 1 February 2023
Revised: 20 March 2023
Accepted: 25 March 2023
Published: 28 March 2023

1. Introduction

In many regions of the world, accelerated decarbonization pathways to limit greenhouse gas emissions means existing coal and gas-fired power plants will need be phased out well ahead of their technical lifespans. As plants are phased out of operation, much of the value of the accompanying infrastructure may be stranded. At the same time, decommissioning of fossil-fuel power plants will lead to a reduction in local job opportunities and economic activity, and, as a result, the attractiveness of the location will decrease over time. Social issues in decarbonization processes are important mainly in those regions that are historically and culturally associated with the mining industry. For example, in Poland, in the Silesia region, about 7000 people per 100,000 of those employed are connected with coal mining [1]. A quick closure of mines without creating alternative sources of income can lead to an economic recession.

Over the past decade, wind farms and solar-power plants have dominated new energy investments in Europe. Alongside variable renewables, such as wind and solar, natural gas has been seen as a transitional fuel supporting and balancing these intermittent power sources on a pathway towards climate neutrality. These plans are now being revised in Europe, obviously related to the aggressive policy of Russia, which until recently was the largest gas supplier for Europe. Especially Germany has developed a great dependence on natural gas imports from Russia [2]. With gas no longer being cost-effectively available to balance these systems, the pathway toward higher shares of variable renewables is more challenging. Potentially, the development of renewable energy can be supplemented by implementing energy storage systems, especially large-scale pumped storage power plants, compressed air energy storage systems, and power-to-hydrogen-to-power systems [3]. The approach to the role that nuclear sources are to play in the energy transformation is polarized in Europe. In long-term plans, Germany, Belgium, and Spain have announced a move away from nuclear energy. France, the United Kingdom, the Netherlands, Poland, Romania, Hungary, Slovenia, Ukraine, Finland, Czech Republic, Slovakia, and Bulgaria are planning to increase their nuclear assets, with Sweden now also actively assessing building new nuclear build. In Poland, where no nuclear unit has been commissioned so far, according to the forecasts presented in [4], new nuclear with a capacity of 6 to 9 GW is to be installed by 2043.

As indicated by the Intergovernmental Panel on Climate Change (IPCC) in the report [5], nuclear energy is a very important element of combating climate change. According to [6], the use of nuclear energy may be beneficial from the socioeconomic and environmental point of view. Moreover, production of electricity in nuclear sources may contribute to the reduction of carbon dioxide emissions and waste compared to hydro and wind energy. In [7], it is indicated that, in some countries, nuclear power has a better effect on reduction of carbon emissions than renewable energy. Nuclear technologies, due to the highly diversified sources of fuel [8], offer very low emissions of greenhouse gases and weather-independent operation, which may be an interesting option for Europe, which needs increased energy independence and reduced risks of suffering political blackmail. There are no quick fixes to this situation, with new power capacities of any type taking years to permit and develop. For nuclear, the so-called small modular nuclear reactors (SMR) offer a faster pathway to obtaining new capacity online due to a shorter construction period than large conventional reactors. Companies, such as NuScale and GE-Hitachi, which are looking to enter the European market with first units online in the late 2020s, claim a 24–36-month construction period [9], i.e., within the time period that is also required for the construction of a coal-fired unit.

SMRs are not only a frontrunner technology for new greenfield low-carbon power generation, but could also be used to repower existing fossil fueled assets, such as coal power plants, as has been described extensively in [10]. Assessing the potential of the so-called coal-to-nuclear technology is also the subject of a US Department of Energy (DOE) report [11], which was published in September 2022. The authors of the report indicate that there are 125 locations in the United States suitable for repurposing with SMRs, where until recently there were coal-fired units with a total capacity of 64.8 GW. Additionally, 190 locations were identified totaling 198.5 GW of coal units currently operating, which have favorable conditions for repowering. The potential for the use of coal-to-nuclear technology is even greater in China. The authors of the article [12] estimated that the repowering potential following the coal-to-nuclear pathway is over 850 GW.

The results of the analyses for nuclear repowering of coal plants, using high-temperature 4th generation reactors, are presented in [10,12–14]. In these cases, the adaptation of the steam turbine previously operating as part of a coal-fired unit to supercritical parameters is relatively straightforward, since the steam parameters required by the turbine correspond to the parameters that can be (or will be in the future) produced by certain categories of high-temperature reactors cooled by gas, liquid metals, or salts. This article develops the concept of repowering with the use of conventional light-water-cooled generation III reactor SMR, where the investment involves the construction of a nuclear unit at the site of a currently operation coal-fired unit. To reduce the investment expenditure, the re-use of existing coal power plant site equipment involves not only the elements of auxiliary infrastructure, i.e., transformers, substations, condenser cooling systems, buildings, road and rail infrastructure, but also the turbine island.

In this case, the parameters of the steam for which the steam turbine was designed differ significantly from the parameters of the steam produced by the nuclear reactor system. Therefore, the adaptation of the turbine must be carried out by modernizing and modifying its structure.

2. Methods

This chapter describes the differences in the thermal cycles in power units equipped with steam turbines for supercritical parameters and steam turbines intended to be supplied with steam from pressurized water reactors (PWR). The differences are mainly due to the different temperatures and steam pressures that are generated in a coal-fired steam boiler and in the steam generator of a PWR, respectively. For the purposes of analysis aimed at identifying the required modernization to make a supercritical parameter steam turbine work with a PWR, a turbine with well known characteristics and representative of supercritical steam turbines currently operating in coal power plants in Poland was used. This chapter presents the characteristics of this steam turbine and proposes methods of its modernization, allowing for its adaptation to a steam supply with lower parameters. The methodology for determining the parameters of turbine operation after modernization is presented. The chapter also presents the methodology for determining indicators for the assessment of economic effectiveness for potential investments.

2.1. Selection of the Turbine for Cooperation with SMRs

Figure 1 presents the typical turbine diagram of power plants with PWR-type reactors. Saturated steam from the steam generator flows to the high-pressure section of the turbine. As expansion occurs in the wet steam region, steam at the exhaust of this section of the turbine is characterized by a high content of moisture, which must be removed in the moisture separator before steam is fed to the low-pressure section of the turbine. The steam is then reheated in the steam reheater to a temperature of about 20 °C below the live steam temperature. In the low-pressure section, steam expansion occurs partially in the superheated steam region and partially in the wet steam region. The number of low-pressure turbine modules depends on the turbine power and can be up to four in very large units.

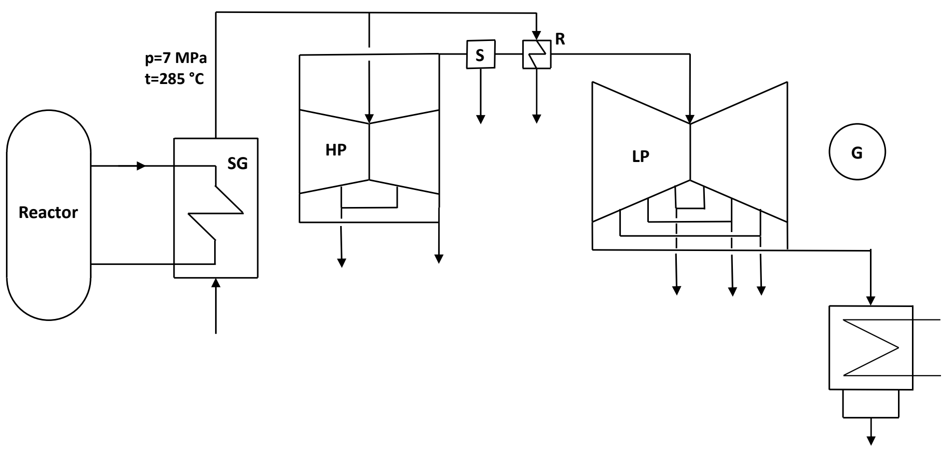

Figure 1. Turbine diagram for a nuclear power plant (SG—steam generator, HP—high-pressure section of a turbine, LP—low-pressure section of a turbine, S—moisture separator, R—reheater, G—generator).

It is assumed for the analysis that the steam pressure at the turbine inlet is 7 MPa with the corresponding saturation temperature of 285.8 °C after repowering. The original and repowered conditions are summarized in Table 1.

Table 1. Main assumptions for the original and repowered plant steam cycle.

Case	Live Steam Pressure	Live Steam Temperature	Reheated Steam Temperature	Inlet Temperature to Boiler/SG	Boiler/SG Thermal Power
Original plant	28 MPa	560 °C	580 °C	290 °C	957.1 MW
Repowered plant	7 MPa	285 °C	Varies	Varies	Varies

Due to these differences, the enthalpy drops in such turbines are about twice that of turbines operating in PWR nuclear power plants. The turbine power output is the product of the steam mass flow through subsequent groups of stages and the associated enthalpy drops in those groups:

$$turbine\ output = \sum_{i=1}^{n} (steam\ flow)_i * (enthalpy\ drop)_i. \quad (1)$$

The steam flow rate to the repowered turbine will be limited by the output of the condenser collecting heat from the steam exhausting from the low-pressure section. Therefore, due to the smaller drop in enthalpy in the turbine after its adaptation for operation with a PWR, it follows from Formula (1) that the turbine power output will always be lower than the nominal value it was designed for.

The turbine of the supercritical 460 MW power unit with a coal-fired boiler operating in the Łagisza power plant since 2009 was selected for the analysis. This power unit is in good condition and could be operated for many decades to come. The analysed machine is a steam reaction turbine with three casings: high-pressure (HP), intermediate-pressure (IP), and low-pressure (LP) (cf. Figure 2). The HP and the IP sections are single-flow structures. The LP section is a double-flow turbine. The LP section outlet cross-section is 2 × 9.6 m^2.

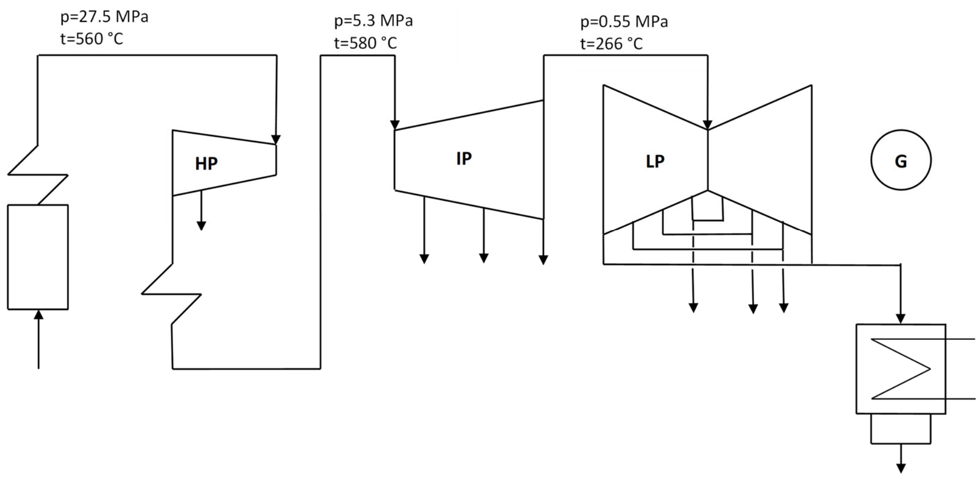

Figure 2. Diagram of the 460 MW condensing turbine (HP—the high-pressure section of the turbine, LP—the intermediate-pressure section of the turbine, LP—the low-pressure section of the turbine).

For nominal conditions of Łagisza power unit the temperature and pressure at the inlet of steam turbine are 560 °C and 27.5 MPa, respectively. The reheated steam is characterized by temperature of 580 °C and pressure of 5.03 MPa. The parameters of steam at inlet of low-pressure section of turbine are 266.7 °C and 0.554 MPa. Live steam flow at the inlet of the high-pressure part and the reheated steam flows are 361 kg/s and 306 kg/s. The steam flows at inlet and at outlet of low-pressure section of turbine are 244.3 kg/s and 208 kg/s, respectively. The total power of the steam turbine unit at 100% load is 460 MW, with the high-, intermediate- and high-pressure parts responsible for the productions of 139 MW, 181 MW, and 150 MW, respectively.

The HP section cannot be utilized for repowering because the pressure at the HP section inlet is almost four times higher than the available pressure supplied by the PWR steam generator. For this reason, it must be disconnected.

The steam conditions assumed for the modernized power unit of p = 7 MPa and t = 285 °C differ also from the steam conditions at the IP section, which is p = 5.03 MPa and t = 580 °C, at reference conditions.

The change in steam conditions has an impact on the steam flow through the turbine. The steam flow rate can be approximately calculated using the Stodola equation:

$$\frac{\dot{m}_1}{\dot{m}_0} = \frac{p_1}{p_0}\sqrt{\frac{T_0}{T_1}}, \tag{2}$$

where $\dot{m}_0, \dot{m}_1$ are flow rates for the nominal load and for the changed operating conditions, p_0, p_1 are pressures at the inlet for the nominal load and for the changed operating conditions, and T_0, T_1 are temperatures at the inlet for the nominal load and for the changed operating conditions.

For the new steam condition, the steam flow rate would total:

$$\dot{m}_1 = \dot{m}_0 \frac{p_1}{p_0}\sqrt{\frac{T_0}{T_1}} = 305.68\frac{7.0}{5.028}\sqrt{\frac{580 + 273.15}{285 + 273.15}} = 526.14\frac{\text{kg}}{\text{s}} \tag{3}$$

The use of the Stodola equation does not require knowledge of the turbine geometry.

However, if the basic geometry of the stages is known, then a one-dimensional flow model can be used based on solving the equations of energy conservation and continuity of the steam flow through the stages of the turbine. According to this model, the determined mass flow rate of steam at the inlet to the IP section would be 563 kg/s. Thus, the steam mass flow rate calculated based on the Stodola formula is approx. 7% too low. These calculations show that, for the steam parameters of 7 MPa/285 °C, the inlet steam mass flow rate to the turbine would increase by approx. 84% compared to reference conditions. This would substantially increase the load of the low-pressure turbine and of the condenser beyond allowable values. As a result, this turbine section could not operate as the HP section of the modernized turbine without changing the pressure condition. To obtain the flow for which this section was designed, the inlet pressure must be lowered from 7 MPa to 4 MPa.

Figure 3 shows the results of the pressure distribution calculations, and Figure 4 shows the temperature distribution in the IP section of the turbine for the rated power of 460 MW (design parameters 5.028 MPa/580 °C) and after modernization for saturated (4.058 MPa/251.2 °C) and slightly superheated (4.035 MPa/285 °C) steam. For these steam parameters, the operating conditions of the LP section of the turbine and the condenser will not change after the unit modernization. These calculations were made using a one-dimensional steam flow model.

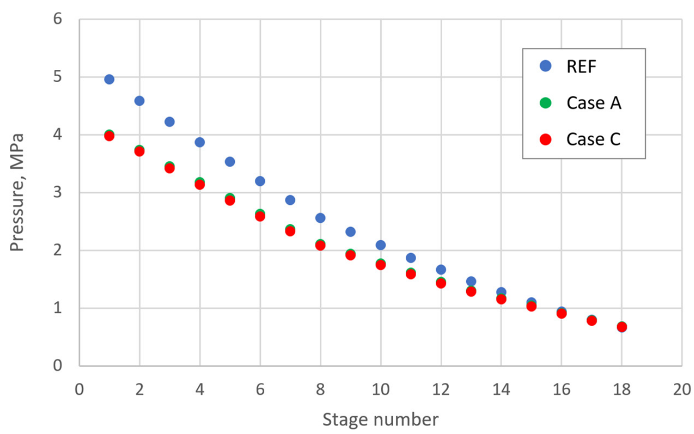

Figure 3. Pressure distribution calculation in the IP section of the turbine.

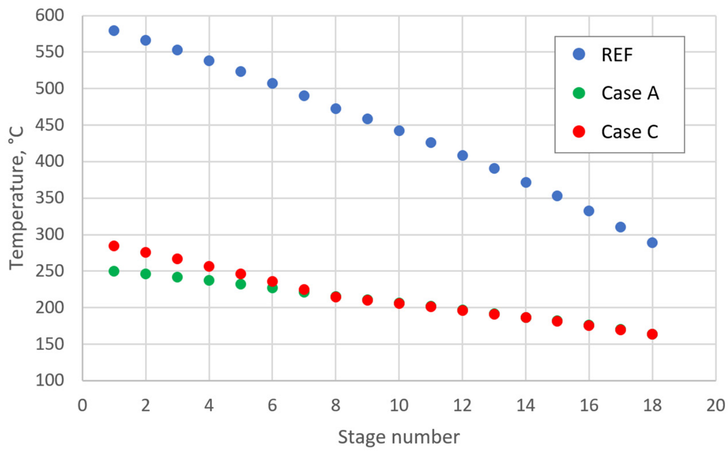

Figure 4. Temperature distribution calculation in the IP section of the turbine.

The inlet pressure is thus much lower than the assumed 7 MPa, which results in a drop in the modernized power unit efficiency. Wet steam expansion in the turbine stages causes a reduction in the efficiency of the stages due to the steam's moisture content.

2.2. Modelling of the Steam Cycle

The answer to the question of whether it is possible to use the existing IP section as the new HP section of the repowered unit must be found through a more detailed analysis based on balance calculations of the steam cycle. A model of the cycle was developed for this purpose to provide a solution in the form of steam and water parameters and the mass flow rate values at the model calculation points. A diagram of the cycle is presented in Figure 5.

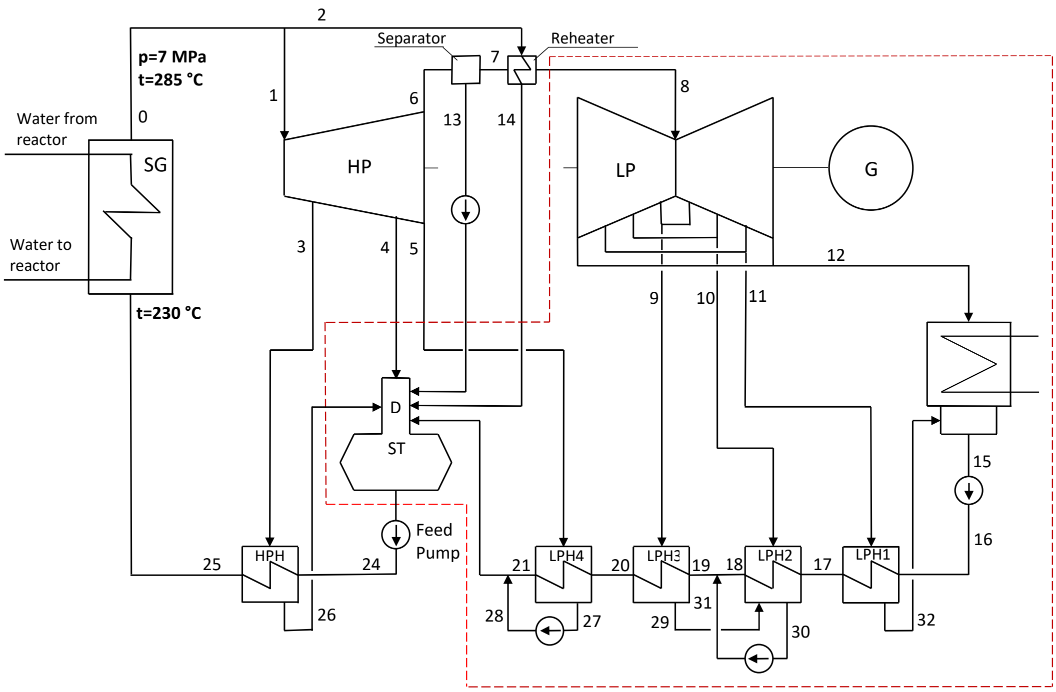

Figure 5. Diagram of the steam cycle with marked calculation points after modernization of the power unit (SG—steam generator, HP—the high-pressure section, LP—the low-pressure section, S—the moisture separator, R—the reheater, G—the generator, (LPH1–LPH4)—the low-pressure feed-water heaters, HPH—the high-pressure feed-water heater, D—the deaerator, ST—the feed-water storage tank). red dashed line—components previously used in the coal-fired power unit.

In the original design, the steam exhausting from the IP section flows directly into the LP section, which means that the IP exhaust and the LP inlet pressure and temperature are identical (cf. Figure 2). Saturated steam from the steam generator must be dried in a moisture separator, and its temperature has to be raised in a heat exchanger whose heating medium is the steam from the steam generator outlet. This means that, in the repowered case, two new components must be added—a moisture separator and a steam reheater. It may also be necessary to install a valve at the inlet of the LP section of the turbine.

The original unit has a feed-water pump driven by the steam turbine fed from the turbine bleed. It is assumed in the analysis that the pump will be replaced with a new one, driven by an electric motor.

2.2.1. Nuclear Retrofit Case with Modernization of the Original IP Section (Case A–C)

Calculations were carried out for two values of steam generator parameters:

- The turbine is fed with saturated steam (4.06 MPa/251.2 °C) (red line in Figure 6).
- The steam generator produces steam with a temperature slightly exceeding the saturation temperature (4.04 MPa/285 °C) (blue line in Figure 6).

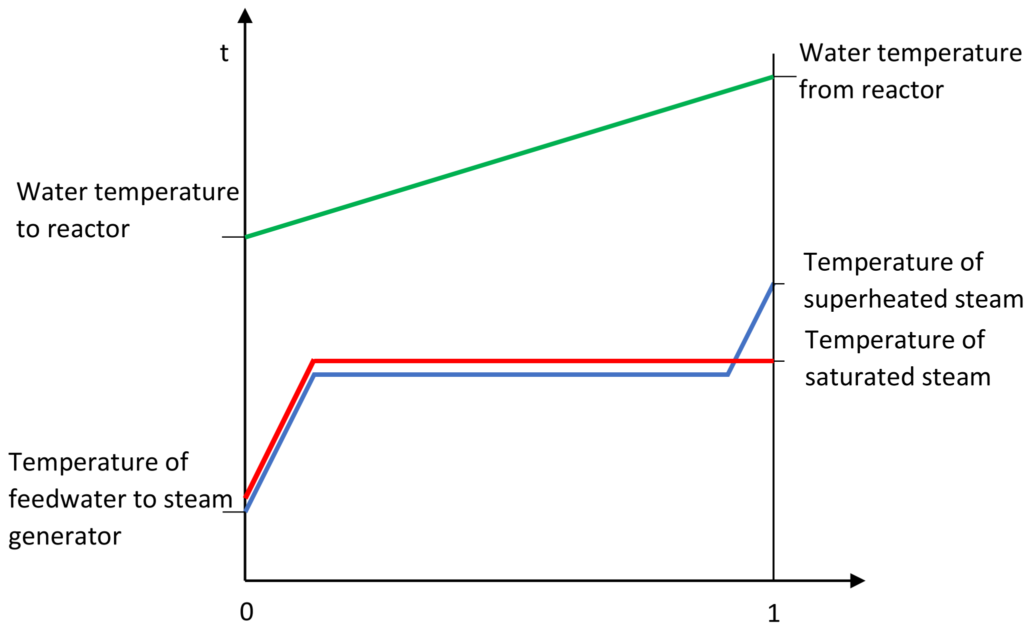

Figure 6. Temperature distribution in the steam generator (green line—temperature of water in the reactor coolant system, red line—temperature of working medium in the steam turbine cycle (case without superheater), bleu line—temperature of working medium in the steam turbine cycle (case with superheater).

The steam parameters at the turbine inlet must be selected so that the steam mass flow rate at the LP section inlet equals the flow rate for the reference load of this turbine section.

Case A in Table 2 presents selected results of the steam cycle calculations performed for saturated steam at the turbine inlet. The saturated steam pressure that maintains the nominal steam flow at the inlet to the LP section is about 4.06 MPa, with the corresponding saturation temperature of 251.2 °C. The unit electric power would total 223 MW, and the thermal efficiency is 32.1%.

Table 2. Parameters at selected points in the cycle are presented in Figure 5.

Calculation Point	Parameters	Case A, No Reheater	Case B, 1-Stage Reheat	Case C, 2-Stage Reheat
0	p, MPa	4.058	4.035	4.035
	t, °C	251.2	285.0	285.0
	x, -	1.0	Superheated steam	Superheated steam
	h, kJ/kg	2800.6	2916.7	2916.7
	$\dot{m}$, kg/s	356.096	337.788	339.281
1	p, MPa	3.997	3.974	3.974
	t, °C	250.2	284.2	284.2
	x, -	0.999	Superheated steam	Superheated steam
	h, kJ/kg	2800.6	2916.7	2916.7
	$\dot{m}$, kg/s	329.5	313.0	313.0
6	p, MPa	0.589	0.589	0.589
	t, °C	158.1	158.1	158.1
	x, -	0.890	0.930	0.930
	h, kJ/kg	2525.7	2609.2	2609.2
	$\dot{m}$, kg/s	272.003	260.257	260.488
8	p, MPa	0.536	0.535	0.539
	t, °C	230.6	230.3	235.6
	x, -	Superheated steam	Superheated steam	Superheated steam
	h, kJ/kg	2919.3	2918.6	2929.6
	$\dot{m}$, kg/s	244.533	244.489	244.706
12	p, MPa	0.006	0.006	0.006
	t, °C	35.9	35.9	35.9
	x, -	0.885	0.885	0.887
	h, kJ/kg	2288.2	2287.8	2294.1
	$\dot{m}$, kg/s	208.924	208.886	209.102
25	p, MPa	4.509	4.483	4.483
	t, °C	212.1	211.5	211.5
	h, kJ/kg	908.2	905.3	905.3
	$\dot{m}$, kg/s	356.096	337.788	339.281
	Gross electric output, MW	223.242	228.788	229.989
	Heat rate, kJ/kWh	10,867.1	10,690.9	10,682.0

However, the turbine operation with such steam conditions would cause unfavorable effects for the LP section. This is because the steam temperature of 230.6 °C at the LP section inlet is about 35 °C lower than the section design temperature. The result would be an increase in the steam moisture content at the LP turbine exhaust, causing a substantial increase in the water droplet erosion of the last stage blades.

Another drawback is that the temperature at the outlet of the high-pressure feedwater heater (water at the steam generator inlet) is lower by 18 °C compared to the assumed temperature of 230 °C.

The temperature at the new HP section inlet (which is the original IP section) can be raised to 285 °C if the steam generator is equipped with a steam superheater. The steam cycle upper temperature of 285 °C is maintained at the steam generator outlet, whereas steam pressure is selected to ensure the nominal mass flow rate of steam at the LP section inlet. For such operating conditions, the required steam superheating totals about 35 °C.

The steam cycle calculations performed for these steam parameters are presented in Case B in Table 2. The working conditions with these parameters of the steam feeding the turbine are more favourable from the point of view of the LP section operation because, in this case, the degree of dryness of the steam outlet from the LP to the condenser increased from 0.89 to 0.93. In addition, the values of turbine power, cycle efficiency, and heat rate are slightly higher than in the previous variant, as well as similar values of water temperature to the steam generator and steam temperature at the inlet of the LP section.

The temperature of the steam at the inlet to the LP section can be increased by 5 °C by using a two-section steam reheater. The calculation results of the cycle with a two-section reheater are shown in Case C in Table 2.

The cycle calculations presented in Table 2 have been made in conjunction with those of the steam flow through the stages of the IP section of the existing turbine. The condition for carrying out such calculations is the knowledge of the basic geometry of this section of the turbine. However, if this geometry is unknown, then the Stodola equation can be used. Table 3 shows a comparison of the results of the cycle calculations made with the accurate modelling of the flow through the IP section (Case B in Table 2) with the results obtained based on the Stodola equation.

Table 3. Comparison of the calculation results.

	Based on the Conservation Equation	Based on the Stodola Equation	Absolute Difference	Relative Difference
Steam pressure at the turbine inlet	4.035 MPa	4.356 MPa	0.321 MPa	7.96%
Electric power	228.8 MW	234.4 MW	5.6 MW	2.45%
Heat rate	10,691 kJ/kWh	10,539 kJ/kWh	152 kJ/kg	−1.42%

For the new operating conditions of the turbine IP section, the steam parameters in this section change significantly. This is shown in Figure 7, which shows the expansion lines in the turbine for the design conditions (REF) and after the modernization for Case A and Case C.

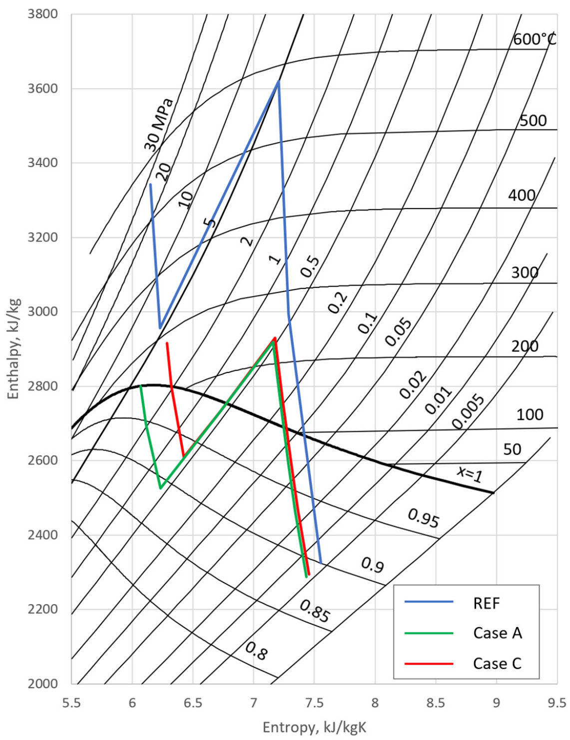

Figure 7. Steam expansion line in the turbine of the 460 MW power unit (REF) and post-modernization state (Casa A and Case C).

Figure 8 presents a comparison of the drops in enthalpy in the groups of the turbine stages for the considered operating conditions and the drops occurring for design conditions of the turbine operation. In the LP section, the differences between the enthalpy drops in each of the four groups of stages are very slight. This is the effect of the adopted assumption that this section of the turbine will operate in conditions close to design parameters. For the IP section, which becomes the HP section of the repowered unit, the enthalpy drops differ considerably from the values they were designed for. This results in a decrease in the efficiency of the section stages. Apart from the losses arising due to the steam moisture content, this is therefore another cause of the decrease in the efficiency of these stages compared to design values.

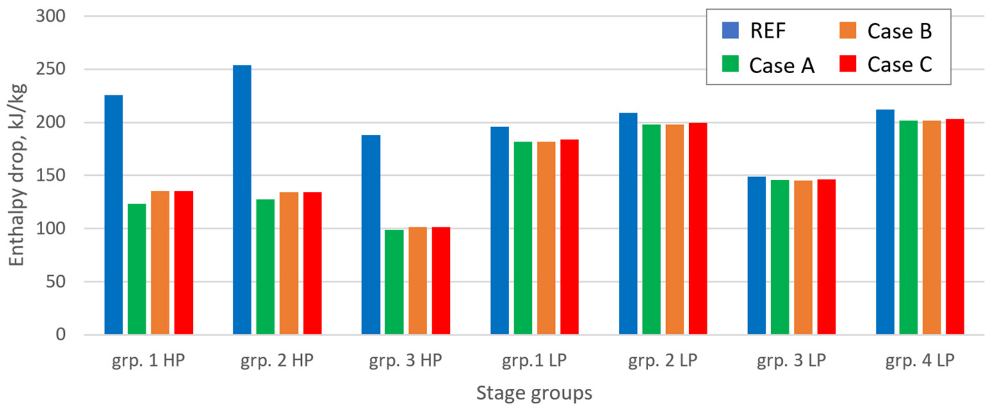

Figure 8. Enthalpy drop in the stage groups of the new HP and LP section of the turbine.

The IP section of the 460 MW turbine was designed for the enthalpy drop of 670 kJ/kg for the reference load with steam supplied by the coal boiler. Whereas, for the working conditions presented in Tables 1–3, the enthalpy drop in this section is much smaller and amounts to approx. 370 kJ/kg. This is a 45% lower enthalpy drop than this turbine section was designed for. Therefore, it seems appropriate to replace the original IP section, which in the above analysis played the role of the HP section, with a new HP turbine section that corresponds to the HP-section of the nuclear plant if built as a greenfield project.

Another consideration is the change in axial forces acting on the single-flow rotor of this section, which is the effect of the change in flow parameters in the turbine stages and for the balance piston. This aspect is not strictly related to the thermo-economic nature of this paper. Therefore, the results of calculations of axial forces acting on the rotor of the IP section are shown in Figure A1 in the Appendix A.

Moreover, due to wet steam expansion, drainage holes would have to be added to the IP section casing to ensure continuous drainage during the process.

Considering the above, the high-pressure section should be designed precisely for the assumed operating conditions.

2.2.2. Retrofit Case with New HP Section (Case D)

The analysis of the steam cycle with the new HP section (Case D) was conducted using the following assumptions:

- saturated steam parameters at the turbine inlet: pressure of 7 MPa and corresponding saturation temperature of 285 °C,
- the LP section operating conditions will not change compared to design values: the steam mass flow and parameters upstream the LP section are the same as for the 460 MW turbine,
- the pressure at the HP section exhaust is higher than the pressure at the LP inlet due to pressure losses in the moisture separator and in the steam reheater,
- the deaerator pressure is equal to the design pressure value at the reference load,
- the steam bleed parameters in the HP section make it possible to heat feed water at the inlet the steam generator to the assumed temperature of 230 °C.

Selected calculation results for this steam cycle are listed in Table 4.

Table 4. Parameters of the steam cycle with the new HP section (Case D).

Calculation Point	*p* [MPa]	*t*/*x* [°C/-]	*h* [kJ/kg]	*m* [kg/s]
0	7.000	285.830	2772.6	406.865
1	6.895	284.531	2772.6	365.100
2	6.930	284.959	2772.6	41.765
6	0.589	0.833	2406.1	290.584
7	0.571	0.990	2733.1	244.428
8	0.554	265.151	2990.9	244.428
12	0.006	0.901	2326.7	209.031
25	7.778	230.000	991.2	406.865
Gross power output			267.018	kW
Heat rate			9771.5	kJ/kWh

Figure 9 presents the expansion line in the turbine of the 460 MW power unit for nominal operating conditions and the expansion line for the modernized turbine with the new HP section. It follows, from Figure 9, that the steam expansion line in the LP section for the upgraded turbine does not differ from the line of steam expansion in the 460 MW turbine. This means that the steam parameters in the LP section did not change compared to the design values and the section can operate within the upgraded power unit keeping its high efficiency. No increased water droplet erosion hazard is also posed to the last stage of the LP turbine.

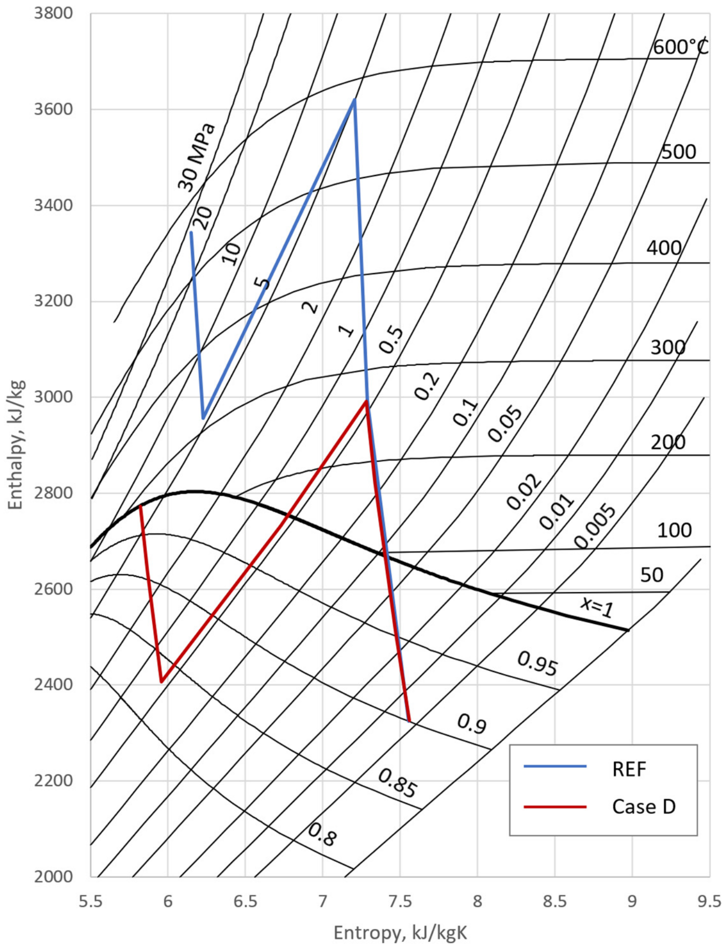

Figure 9. Steam expansion line in the turbine of the 460 MW power unit (REF) and post-modernization state (Case D).

2.3. Economic Assessment

An economic analysis was conducted for five investment cases. Four of them are previously characterized cases, which assumed the use of elements of a steam turbine currently operating in a 460 MW unit. First, three cases (Case A, Case B and Case C) are retrofit cases with modernization of the IP section of steam turbine. The fourth case (Case D) is retrofit case with new HP section of steam turbine. The fifth analyzed case was that of a greenfield investment, where it is assumed that the nuclear system is built using only new components. This investment case was designated as Case GF (greenfield).

2.3.1. Assessment Indicators

Two economic effectiveness assessment indicators were used in the economic analysis. The first one was net present value (*NPV*), which can be calculated as:

$$NPV = \sum_{\tau=1}^{n} \frac{NCF_{\tau}}{(1+r)^{\tau}} - TCIC, \tag{4}$$

where n is the plant lifetime, $NCF\tau$ is the nominal cash flow in year τ, r is discount rate, and *TCIC* is the total capital investment cost over the construction time (including the financia costs).

The second indicator was net present value ratio (*NPVR*), which is defined by the relation:

$$NPVR = \frac{NPV}{TCIC}. \tag{5}$$

The nominal cash flow can be calculated as:

$$NCF_{\tau} = OMC_{\tau} + DEC_{\tau}, \tag{6}$$

where OMC_{τ} are the operations and maintenance costs in year τ, and DEC_{τ} are the decommissioning costs in year τ.

The OMC_{τ} were calculated using the equation:

$$OMC_{\tau} = FOMC_{\tau} + VOMC_{\tau}, \tag{7}$$

where $FOMC_{\tau}$ is fixed part of costs and $VOMC_{\tau}$ is variable part. The following equations were used to determine the cost parts:

$$FOMC_{\tau} = \{[uFOMC(NI) + uFOMC(TI)]N_{\mathrm{elST}}\}_{\tau}, \tag{8}$$

$$VOMC_{\tau} = \{[uVOMC(RC) + uVOMC(SFC) + uVOMC(nnTI)]N_{\mathrm{elST}} \cdot CF \cdot 8760\}_{\tau} \tag{9}$$

where $uFOMC(NI)$ is unit fixed O&M costs for nuclear island, $uFOMC(TI)$ is unit fixed O&M costs for turbine island, $uVOMC(RC)$ is unit refueling costs, $uVOMC(SFC)$ is unit spent nuclear fuel costs, $uVOMC(nnTI)$ is unit non-fuel and non-emission costs for turbine island, $\left(N_{\mathrm{el,g}}\right)_{\mathrm{nom}}$ is nominal gross power of nuclear power unit with using three nuclear reactors, and l_{NR} is number of nuclear reactors in system.

The total capital investment costs can be determined by using the Equation:

$$TCIC = uTCIC \cdot N_{\mathrm{elST}} \tag{10}$$

where $uTCIC$ is the unit total capital investment costs, \$/kW, and N_{elST} is steam turbine gross electric capacity, kW.

The unit total capital investment costs index may be determined for a given technology based on historical data or estimated based on detailed cost analysis. In the analyses that were carried out, the relationship (10) was used to determine the investment costs for greenfield investments, which was a reference point for assessing the economic effectiveness of investments assuming carrying out retrofits. Greenfield investment expenditure has also become the basis for determining investment expenditure for the nuclear retrofit cases analyzed in this article. Equations (11)–(21) were used for this. The total capital investment cost is defined as:

$$TCIC = OCC + TIC \tag{11}$$

where OCC is overnight capital costs, and TIC is total indirect costs. Overnight capital costs can be written as:

$$OCC = \sum_{i} OCC_{i} = \sum_{i} sOCC_{i} \cdot TCIC \tag{12}$$

where OCC_i is overnight capital costs for respective (i) components of investment as detailed in Table 5, $sOCC_i$ is share of the OCC_i in the total capital investment costs.

Table 5. Overall capital costs and total indirect costs for respective components of investment subject [10].

Component of Costs	Category	Symbol of Component	Budgeted Share *, %	Minimal Retrofit Savings, %	Mid-Level Retrofit Savings, %	Maximum Retrofit Savings, %
	-	i	$sOCC_i$ or $sTIC$	$(RS_{OCC_i})_{min}$ or $(RS_{TIC})_{min}$	$(RS_{OCC_i})_{av}$ or $(RS_{TIC})_{av}$	$(RS_{OCC_i})_{max}$ or $(RS_{TIC})_{max}$
Initial fuels inventory	R	IFI	7.0	0.0	0.0	0.0
Other costs (transmission, owner's, etc.)	T	OC	10.0	100.0	100.0	100.0
Land and land rights	R + T	LLR	0(~0)	100.0	100.0	100.0
Structure and improvements	R	S&I	15.0	0.0	12.0	24.0
Reactor plant equipment	R	RPE	18.0	0.0	0.5	1.0
Turbine plant equipment	T	TPE	15.0	0.0	49.5	99.0
Electric plant equipment	T	EPE	5.0	42.0	60.0	78.0
Miscellaneous plant equipment	R + T	MPE	2.0	6.0	48.5	91.0
Main condenser and heat rejection system	T	MCHR	3.0	0.0	50.0	100.0
Total indirect costs	R + T	TIC	25.0	16.0	27.5	39.0

* For greenfield construction.

In turn, the total indirect costs can be written as:

$$TIC = sTIC \cdot TCIC \tag{13}$$

where: $sTIC$ is share of the total indirect costs in the total capital investment costs.

For greenfield investments, the shares for individual components in the investment costs were assumed in accordance with [10]. The values adopted for the analysis are summarized in Table 5. Of course, the relationship applies here:

$$\sum_{i} sOCC_{i} + sTIC = 1 \tag{14}$$

Table 5, also accordingly with [10], shows the potential financial savings in relative terms (minimum, average, and maximum) that for individual investment components can be made by adapting the infrastructure of the coal-fired unit that is subject to nuclear retrofit. Total savings are an important argument for organizing investments in accordance with the coal-to-nuclear pathway. To estimate the amount of investment costs for the analyzed retrofit cases, the individual cost components were first assigned to three categories, i.e., the "T" category, the "R" category, and the "R + T" category. In this way, the components were divided into those whose share in the costs depends on the scale of the installed steam turbine unit (T), on the scale of the installed nuclear reactor (R), or it depends on the scale of both of these elements simultaneously (R + T).

Using the data presented in Table 5, it is possible to write the Equation on the costs (OCC and TIC) for individual components for a nuclear unit that was created through the retrofit:

$$(OCC_{i})_{RET} = (OCC_{i})_{GF} \cdot \left(1 - RS_{OCC_{i}}\right) \tag{15}$$

$$TIC_{RET} = TIC_{GF} \cdot (1 - RS_{TIC}) \tag{16}$$

Conducting economic analysis for investments involving nuclear retrofits requires the determination of financial costs for these investments. For this purpose, the use of the relationships (4)–(10) may be sufficient for the cases of standard retrofits, i.e., for example those analyzed by the authors in [12–14]. For the cases analyzed in this study, this methodology would not be appropriate, which results from the fact that the energy units are characterized by a very different relation of electric power of steam turbine island and thermal power of nuclear reactor island, in relation to the corresponding greenfield project.

It is assumed that the unit resulting from a greenfield investment has a steam turbine optimally adjusted to the parameters of steam produced in a nuclear reactor. This is because it is designed from scratch for operation with a specific nuclear reactor. Thanks to this, it is characterized by the highest thermal efficiency of the cycle among the cases considered. For the purposes of the analysis, it was also assumed that the greenfield investment is characterized by the thermal power of the reactor at the same level as the thermal power of the reactor determined in the framework of thermodynamic analysis for the retrofit with the new high-pressure section of the steam turbine. The retrofits analyzed in this article are unique, since the considered modernization measures lead to a situation in which the thermal efficiency for these units may differ significantly from the thermal efficiency of a greenfield installation. Due to the different thermal efficiencies of the cycles, the steam turbine capacities for Case GF and Case D are different, and more precisely, the electric power of the turbine used in the greenfield investment is higher (which results from the assumption that the thermal powers of the reactors are at the same level). It was assumed that thermal efficiency, as well as electric power for Case GF, are higher than respective quantities for Case D by 5%. Therefore, for the GF power unit, they are, respectively, 38.87% and 280.37 MW. The remaining cases of nuclear retrofits (Case A, B and C) differ from the greenfield unit, both in the electric power of the steam turbine units, as well as the thermal power of the nuclear reactors, which are selected for the specific heat demand of the steam turbine cycle. The different scope of modernization means that, for each of the cases, we deal with different relations between the electric power of steam turbine units and the thermal power of nuclear reactors. Thus, it is not appropriate to use the $uTCIC$ index value, which is provided for standard greenfield investments, when determining the investment expenditure for retrofits. Only using investment costs normalized by the electric power installed in the system could lead to a situation where a unit with a low thermal efficiency, equipped with a nuclear reactor with a certain thermal power, would be cheaper than a unit with a high efficiency, even if this unit was equipped with a reactor with a lower thermal power. This would lead to unrealistic results, since the nuclear component of the plant is typically relatively more expensive than the turbine component.

The method of assigning individual components is shown in Table 5. The performed division allowed determination of the cost components required for the implementation of the retrofit investment as follows:

$$\left(OCC_{\mathrm{i(R)}}\right)_{\mathrm{RET}} = \frac{(Q_{\mathrm{NR}})_{\mathrm{RET}}}{(Q_{\mathrm{NR}})_{\mathrm{GF}}}(OCC_{\mathrm{i}})_{\mathrm{GF}}\cdot\left(1 - RS_{OCC_{\mathrm{i(R)}}}\right) \tag{17}$$

$$\left(OCC_{\mathrm{i(T)}}\right)_{\mathrm{RET}} = \frac{(N_{\mathrm{ST}})_{\mathrm{RET}}}{(N_{\mathrm{ST}})_{\mathrm{GF}}}(OCC_{\mathrm{i}})_{\mathrm{GF}}\cdot\left(1 - RS_{OCC_{\mathrm{i(T)}}}\right) \tag{18}$$

$$\left(OCC_{\mathrm{i(R+T)}}\right)_{\mathrm{RET}} = \left(X\frac{(Q_{\mathrm{NR}})_{\mathrm{RET}}}{(Q_{\mathrm{NR}})_{\mathrm{GF}}} + Y\frac{(N_{\mathrm{ST}})_{\mathrm{RET}}}{(N_{\mathrm{ST}})_{\mathrm{GF}}}\right)(OCC_{\mathrm{i}})_{\mathrm{GF}}\cdot\left(1 - RS_{OCC_{\mathrm{i}}}\right) \tag{19}$$

$$TIC_{\mathrm{RET}} = \left(X\frac{(Q_{\mathrm{NR}})_{\mathrm{RET}}}{(Q_{\mathrm{NR}})_{\mathrm{GF}}} + Y\frac{(N_{\mathrm{ST}})_{\mathrm{RET}}}{(N_{\mathrm{ST}})_{\mathrm{GF}}}\right)TIC_{\mathrm{GF}}\cdot(1 - RS_{TIC}) \tag{20}$$

where X and Y are the indicators determining the impact on the determined costs of the installation of elements related to the nuclear reactor island (X) and the steam turbine island (Y) in the energy unit ($X + Y = 1$).

To finally determine the investment costs for a retrofit unit, the following Equation was used:

$$TCIC_{\mathrm{RET}} = \sum_{\mathrm{i}} \left(OCC_{\mathrm{i(R)}} \right)_{\mathrm{RET}} + \sum_{\mathrm{i}} \left(OCC_{\mathrm{i(T)}} \right)_{\mathrm{RET}} + \left(OCC_{\mathrm{i(R+T)}} \right)_{\mathrm{RET}} + TIC_{\mathrm{RET}} \quad (21)$$

As part of the economic analysis, calculations were carried out for the variable value of the modernization cost index (MCI), which determines the level of costs related to the modernization of the steam turbine unit (C_{modTPE}). Such modernization works would be aimed at adapting the turbine to the functionality appropriate for the analyzed retrofit cases (A, B, C, and D). The *MCI* is the ratio of the cost of the required modernization and the cost that would have to be incurred for the purchase of a new steam turbine unit, providing the same functionality as the turbine unit after a potential modernization:

$$MCI_{\mathrm{TPE}} = \frac{C_{\mathrm{modTPE}}}{\frac{(N_{\mathrm{ST}})_{\mathrm{RET}}}{(N_{\mathrm{ST}})_{\mathrm{GF}}} (OCC_{\mathrm{i}})_{\mathrm{GF}}}. \quad (22)$$

From a practical point of view, the costs incurred for the modernization of the steam turbine unit must be lower than the cost associated with the purchase of a new steam turbine unit, therefore it is not justified to conduct analysis for a value higher than 1. The modernization costs may be treated in the same way as overall capital costs for turbine plant equipment, so we can define the relationship between the modernization cost index and the potential savings resulting from the use of the existing steam turbine unit as part of the investment as:

$$RS_{\mathrm{OCC_{TPE}}} = 1 - MCI_{\mathrm{TPE}}. \quad (23)$$

In this conducted analysis, MCI_{TPE} was a decision variable.

2.3.2. Assumptions

The assumptions used in the economic analysis are shown in Table 6. The total capital investment costs for a nuclear unit resulting from a greenfield investment was determined by using the unit total capital investment costs. The value here is 4000 €/kW$_{\mathrm{el}}$.

Table 6. Base economic parameter assumptions.

Parameter	Symbol	Value (GF = Greenfield, RE = Repowered)	References
Lifetime			
Construction time, years	CT	4	[15]
Time operational in year, hours	τ_a	7884	[16]
Total operation time assumed for the *NPV* analysis, years	TOT	50	[17]
Capital costs			
Unit overnight capital cost (GF investment type), €/kW	$uOCC_{\mathrm{GF}}$	4000	[15]
Variable O&M costs			
Refuelling costs, €/MWh	$uVOMC(RC)$	7	[18,19]
Spent nuclear fuel costs, €/MWh	$uVOMC(SFC)$	5	[20,21]
Electricity average price, €/MWh	C_{el}	85	*
Non-fuel and non-emission costs for turbine island, €/MWh	$uVOMC(nnTI)$	1.50	*
Fixed O&M costs, €/MW/y	$uFOMC$	100,000 (GF)/104,000 (RET)	[15]
Turbine island, €/MW/y	$uFOMC(TI)$	16,000 (GF)/20,000 (RET)	*
Nuclear Island, €/MW/y	$uFOMC(NI)$	84,000	[15]
Others			
Discount rate, %	r	6	*
Tax rate, %	r_t	19	*

*—based on experience and recommendations of authors.

3. Results

3.1. Technical and Energy Performance Assessment Results

The cycle efficiency for the analysed operating conditions is presented in Figure 10. It is defined based on the following formula:

$$Cycle\ efficiency = \frac{\dot{m}_0(h_0 - h_{25}) - \dot{m}_{12}(h_{12} - h_{15})}{\dot{m}_0(h_0 - h_{25})}. \tag{24}$$

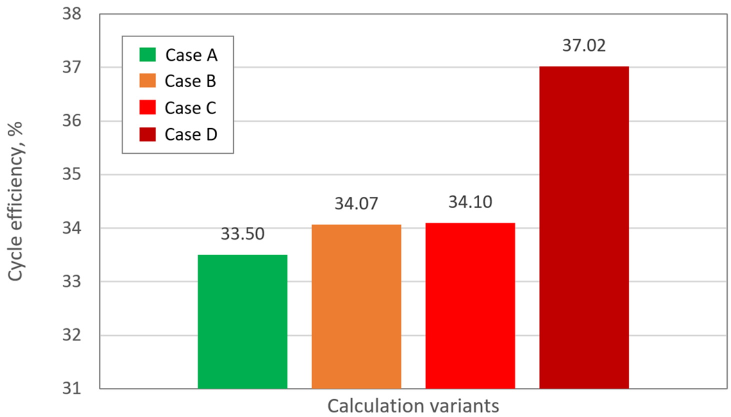

Figure 10. Cycle efficiency for different parameters of steam feeding the turbine.

The highest efficiency was achieved for the upgrade variant with the new HP section. It is by more than 3 percentage points higher compared to the variant that instead uses the IP section of the 460 MW turbine.

The rise in efficiency translates into a reduction in the heat rate, which was determined using the following formula:

$$Heat\ rate = \frac{\dot{m}_0(h_0 - h_{25})}{Gross\ electric\ output}. \tag{25}$$

In the variant with the new HP section, Case D, the heat rate is by about 900 kJ/kWh lower, which is a reduction by about 8.5% compared to the variant using the 460 MW turbine IP section, Case B/C (cf. Figure 11). The obtained values unequivocally recommend selection of the upgrade variant with the new HP section.

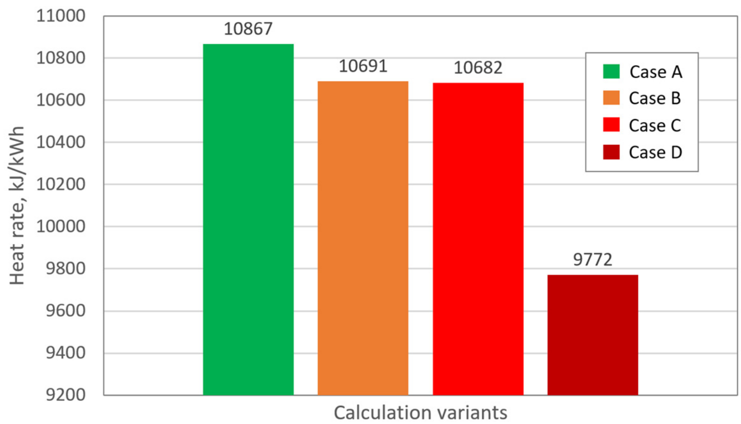

Figure 11. Heat rate for different parameters of steam feeding the turbine.

At the same time, in this variant, the highest achieved gross electric power totals 267 MW, which means an increase by about 16% compared to the operating conditions with the kept IP section of the 460 MW turbine (cf. Figure 12). This also means that the variant meets the maximum power condition specified for small modular reactors.

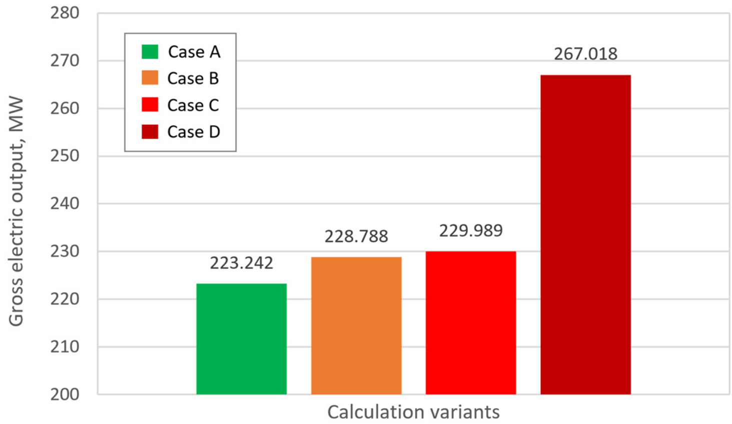

Figure 12. Gross electric power output for different parameters of steam feeding the turbine.

The higher electric power for the new HP section is due to the following factors: higher pressure at the inlet to the turbine, higher efficiency of the turbine, and a larger mass flow rate of steam at the inlet to the turbine (cf. Figure 13).

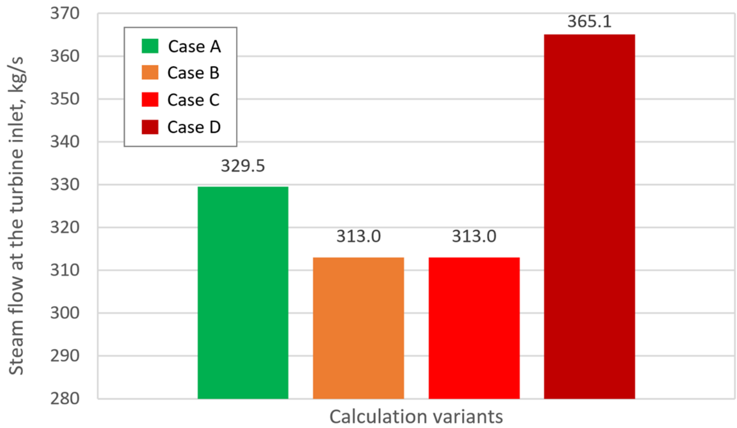

Figure 13. Mass flow rate of steam at the inlet to the turbine for different parameters of steam feeding the turbine.

Figure 14 presents the steam flow rate for low-pressure heaters of feed water, the deaerator and the high-pressure heater for the turbine operating with the power output of 460 MW (reference load conditions) and for the upgraded turbine with the 7 MPa/285 °C steam parameters. Because the post-upgrade operating conditions of the 460 MW turbine LP section will change only slightly, the low-pressure feed-water heaters fed from the LP section steam bleeds (LPH1–LPH3) can also be used in the new power unit. The steam flow to the LPH4 feed-water heater, however, is by 56% larger than for the 460 MW power unit under reference load. The temperature of the superheated steam to this exchanger for the design conditions is 267 °C, while, after modernization, wet steam will flow at a temperature of 158 °C. This reduces the specific volume from 0.441 m^3/kg for design conditions to 0.268 m^3/kg after modernization. As a result of this change, the velocity of inlet steam to this exchanger will be only slightly lower than the design conditions (cf. Figure 15). Thus, the LPH4 feed-water heater can also be used in a new power unit. The mass flow rate of steam to the high-pressure feed-water heater (HPH) is two and a half times greater than for the 460 MW power unit operating conditions. However, due to the change in steam parameters, the velocity in the pipeline at the inlet to this exchanger would be about 160 percent higher for the new operating conditions (cf. Figures 14 and 15). The use of this exchanger in the new power unit would therefore have to be preceded by an analysis of its operation in the new conditions.

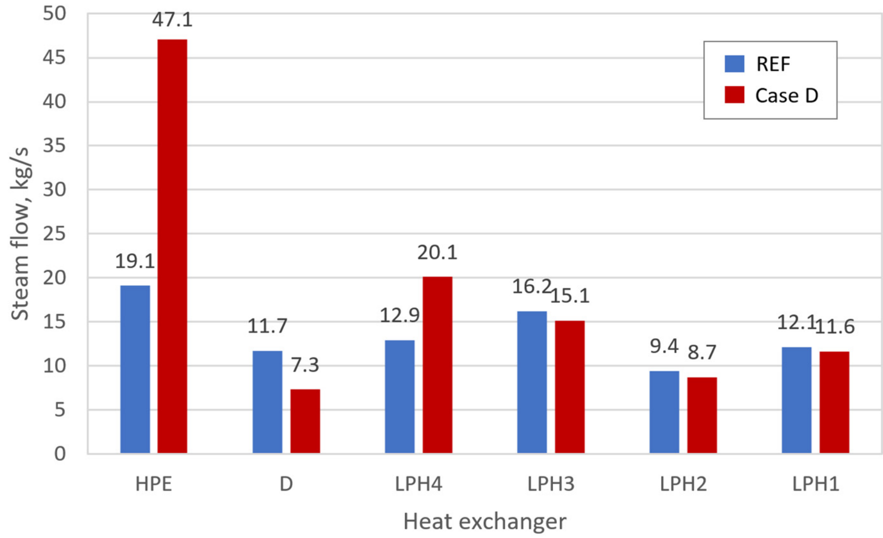

Figure 14. Steam mass flow rate to the feed-water heaters (heat exchanger labels as shown in Figure 5).

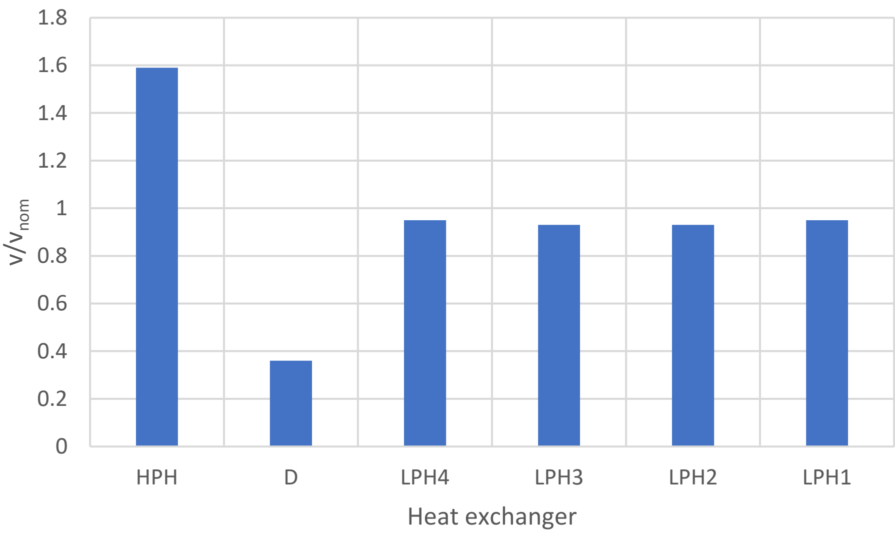

Figure 15. The velocity ratio of the steam flow in the pipeline to the heat exchangers (heat exchanger labels as shown in Figure 5).

If the deaerator pressure is kept at the same level as for the turbine operation with the power output of 460 MW, in the modernized system, the steam mass flow feeding the deaerator will be smaller. The pipeline connecting the turbine bleed to the deaerator will therefore not limit the flow.

In the 460 MW power unit, the feed-water pump is driven by the steam turbine fed from the turbine IP section bleed. Its power for the reference load totals 15.5 MW. Because live steam pressure will drop from 27.5 MPa to 7 MPa, the demand for power needed to drive the pump will also be reduced (cf. Figure 16). Considering such a big difference in the pump delivery head and power, a replacement of the pump should be anticipated with a new one driven by an electric motor.

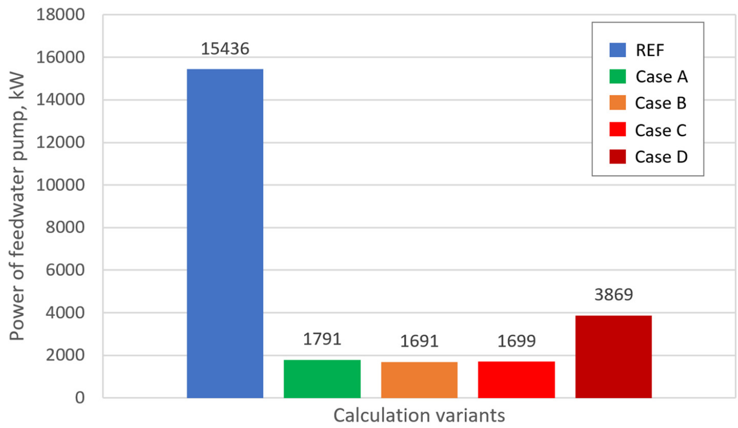

Figure 16. The power of the feed-water pump for different parameters of steam feeding the turbine.

The results of the analysis indicate that, in the upgraded power unit with a light-water small modular reactor, it is possible to use the 460 MW turbine low-pressure section with the condenser and the cooling system, the low-pressure feed-water heaters, and the deaerator with the feed-water storage tank. In the diagram of the upgraded cycle, these components are within the area marked with a red dashed line (cf. Figure 5). The other components, i.e., the turbine HP section with the moisture separator and the reheater, should be designed for the nominal flow through the LP section. A replacement of the feed-water pump should also be anticipated. The possibility of using the existing HPE heater requires more detailed calculations for the changed operating conditions.

Flow through Bypass of the IP–LP Section of the Turbine

For a power unit of 460 MW, after closing the turbine stop valves, 305.68 kg/s of steam with parameters of 5.028 MPa/580 °C flows to the existing bypass valve of the IP–LP section of the turbine. After the modernization of the unit, 406.87 kg/s of saturated steam at a pressure of 7 MPa will flow into the turbine. The volumetric flow and steam velocity in the pipeline to the bypass valve will be about 50 percent lower than the value for which it was designed. To reduce the temperature of the bypass steam at the condenser inlet, the water injection should be 133.34 kg/s for a unit capacity of 460 MW. However, after modernization, water injection into saturated steam will be 34.69 kg/s. Thus, the volumetric flow and steam velocity in the pipeline from the valve to the condenser will not change. It follows that the existing bypass system of the IP–LP section of the 460 MW turbine can be used in the modernized power unit, Figure 17.

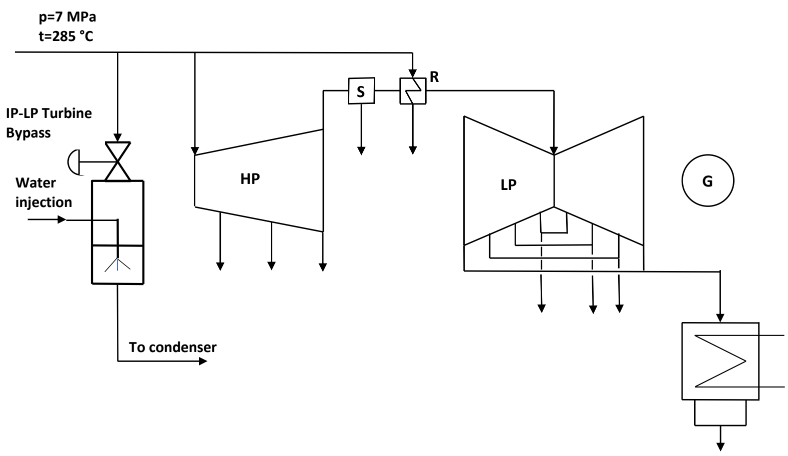

Figure 17. The turbine bypass system.

3.2. Economic Assessment Results

Table 7 presents the results of economic analysis for nominal assumptions. These analyses were carried out for average values of retrofit savings factors resulting from the use of coal-fired infrastructure in the nuclear investment (see Table 5). Other assumptions for the analysis are presented in Table 6.

Table 7. Results of economic analysis for nominal assumptions.

	Case				
	GF	**A**	**B**	**C**	**D**
NPV, M€	1117.75	1062.61	1096.96	1103.12	1328.69
NPVR, M€	0.997	1.556	1.587	1.588	1.759

Figure 18 shows the characteristics of the *NPV* indicator as a function of the project lifetime. Lifetimes for which investments reach 0 for *NPV* are called discounted payback periods (*DPP*). Case D is characterized by the shortest DPP (almost 10 years). Slightly over 10 years were obtained for Cases A, B, and C. For greenfield investment (Case GF), the DPP was almost 15 years. The analysis of the presented characteristics allows for the conclusion that for investments intended to operate for more than 37 years. Case GF is more favorable than Case A. For project lifetimes longer than 44 years, the Case GF is more justified from the economic point of view than Case B and C. The fact that Case D is a high-efficiency variant contributes to the fact that even for very long lifetimes, the *NPV* values obtained for it are higher than for Case GF.

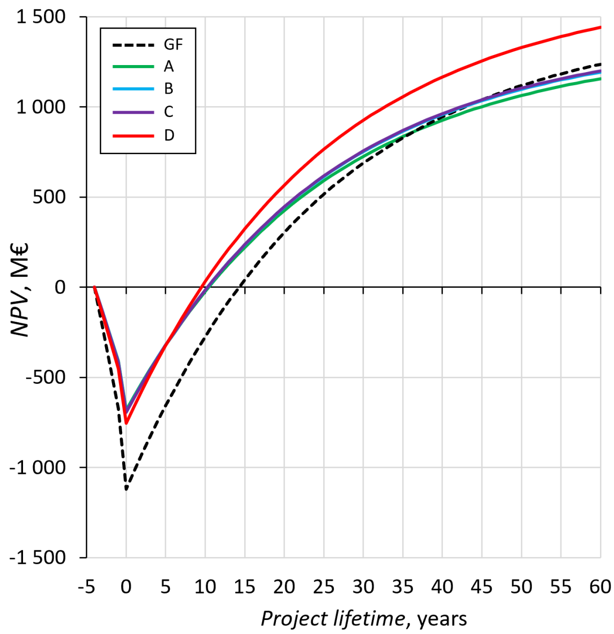

Figure 18. *NPV* as a function of project lifetime for steam cycle modernization cost index MC_{ST} = 0.5 for average level of *RS*.

Figures 19 and 20 show the impact of the value of the steam cycle modernization cost index on the *NPV* and *NPVR* indicators, respectively. The values of the steam cycle modernization cost index for which the *NPV* and *NPVR* indicators were obtained for individual Cases at the same levels as those obtained for the Case GF can be considered the maximum values that are economically acceptable for the modernization of the steam cycle. However, considering the two indicators of economic efficiency assessment, different conclusions can be drawn here. For example, taking into account the *NPV* indicator, analyzing the situation for average levels of retrofit savings factor resulting from the use of the coal-fired unit infrastructure, the acceptable levels of the steam cycle modernization cost index for Cases A, B, and C, respectively, are 0.053, 0.350, and 0.387. For Case D, even if the cost of modernization exceeds the cost of purchasing a new steam turbine unit, the investment will still be more economically justified than the greenfield investment (Case GF). Completely different conclusions should be drawn when the *NPVR* indicator is used as the basis for assessment. Differences in the level of investment costs, appropriate for the cases that assume modernization and Case GF, cause, regardless of the analyzed retrofit case, even if there is a need to engage in the modernization of steam turbine assemblies, higher financial outlays than those required for the purchase of new units, leading to a situation in which it is beneficial to carry out retrofits of coal-fired units. Moreover, such a situation takes place regardless of the analyzed levels of retrofit savings, resulting from the use of the coal-fired unit infrastructure.

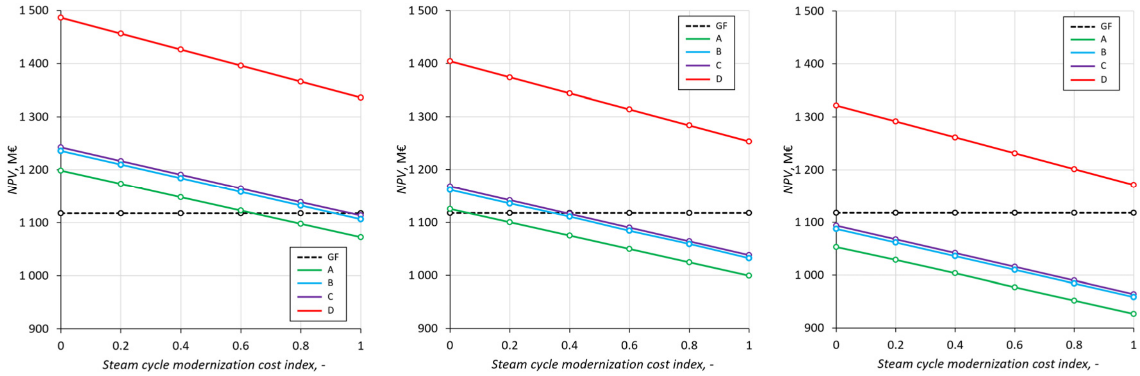

Figure 19. *NPV* as a function of steam cycle modernization cost index for the three values of retrofit savings factor (**left**—maximum, **central**—average, **right**—minimum).

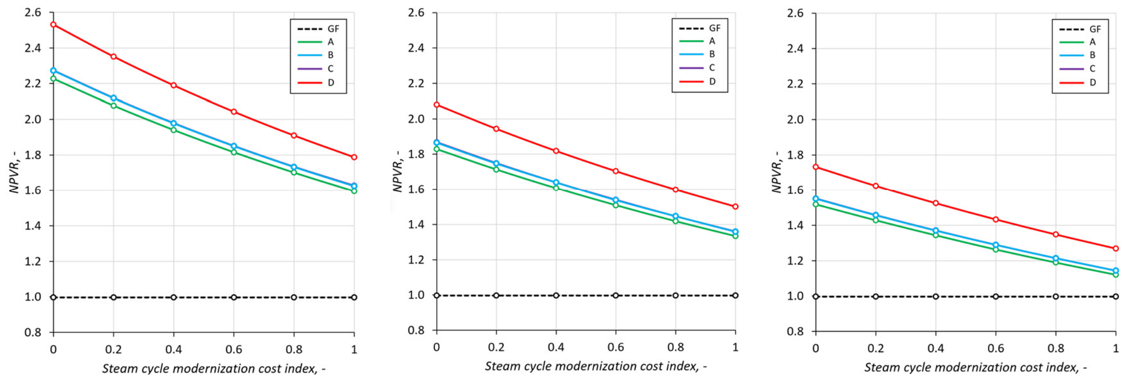

Figure 20. *NPVR* as a function of steam cycle modernization cost index for the three values of retrofit savings factor (**left**—maximum, **central**—average, **right**—minimum).

4. Discussion

The aim of this study was to assess the possibility of adapting a reference steam turbine to new operating conditions resulting from the replacement of a coal-fired boiler with a light-water nuclear reactor. The supercritical 460 MW power unit with the steam parameters of 28 MPa/560 °C/580 °C operating in the Łagisza power plant since 2009 was selected for analysis.

After repowering, the power unit turbine will be fed with saturated steam with the pressure of 7 MPa at the temperature of 285 °C. The assessment of the possibility of adapting the turbine to such a big change in steam parameters required the development of a model of the repowered steam cycle balance calculations.

Two variants of the turbine adjustment to new steam parameters were analysed.

The first assumes utilization of the 460 MW turbine IP and LP sections. Steam from the steam generator is supplied to the existing IP section, which effectively makes it the new HP section, and then this flows through the added moisture separator and the steam reheater to the turbine LP section and further on to the condenser. This variant was analysed for two values of steam parameters at the turbine inlet: 1—the turbine is fed with saturated steam (Case A); and 2—the steam generator produces slightly superheated steam (Cases B and C).

In the second variant, only the LP section of the 460 MW turbine is utilized, whereas the HP section is designed exactly for the assumed steam parameters of 7 MPa/285 °C and the rated parameters of the LP section of the 460 MW turbine with its cooling system (Case D).

In both variants, the original HP section of the 460 MW turbine is disconnected.

The results of the thermal cycle calculations indicate that the second variant is characterized by the cycle efficiency of over 3 percentage points higher, which translates into a decrease by about 8.5% in the heat rate. At the same time, for this variant the gross electric power totals about 270 MW and is about 40 MW higher compared to the first variant. In addition, the target water temperature of 230 °C at the steam generator inlet is achieved only in the turbine with the new HP section.

Another factor in favour of the 460 MW turbine IP section replacement with a new HP section is the avoidance of problems related to the change in the axial forces acting on the rotor. Since the IP section of the 460 MW turbine was designed for the flow of superheated steam, the turbine operation in wet steam would require drains in the bottom casing to carry away water created during steam expansion.

Based on the results of the conducted analysis, it seems that, as part of the investment involving the transformation of a coal-fired unit into a nuclear unit with a LWR reactor, the use of such components of the existing steam turbine as low-pressure section steam turbine, condenser with cooling system (cooling tower, cooling water pumps), low-pressure feed-water heaters supplied from the LP section bleeds (LPH1-LPH4 in Figure 5), deaerator with the feed-water storage tank and bypass of the IP–LP sections of the turbine, is possible. The new components required to adapt the reference unit to the altered operating conditions are HP section of steam turbine, moisture separator, steam reheater, and electrically powered feed-water pump.

The possibility of using the existing high pressure (HPH) feed-water heater requires detailed calculations of its performance under the new operating conditions.

After adding a new HP section, the possible need to install a valve at the inlet of the LP section of the turbine should be considered.

As indicated by the results of preliminary analysis, the recommendations presented above for adapting the turbine of the supercritical 460 MW power unit for co-operation with a light-water SMR will also apply, after slight changes, to turbines of other power units. The following turbines operating in the Polish power sector can be mentioned here: the 360 MW turbines with subcritical steam parameters of 18 MPa/535 °C/535 °C and the 262 MW turbines fed with the 17 MPa/565 °C/565 °C steam. The turbines have one double-flow LP module.

A similar range of changes will also apply to high-power turbines with two or three LP modules.

Although the results of economic analysis do not clearly indicate this, from the economic point of view, it seems that a deep modernization of the steam turbine may be groundless. This is mainly due to the ability of the nuclear unit to operate for a very long lifetime, even exceeding 60 years. In the case of such investments, faster depreciation of costs for units with new steam turbines, i.e., high-efficiency units designed for operation with a specific PWR nuclear reactor, will work in their favor, compared to investments in which modernization of steam turbines is assumed. The results of the economic analysis shows that, in the case of investments aimed at modernization of the steam cycle, the variant where it is assumed that the steam turbine is adapted by installing a new section of the high-pressure turbine, which will ensure the possibility of effective, full use of steam with parameters that can be achieved by a nuclear reactor, is advantageous. Regardless of the scope of the possible modernization of the turbine island, it seems justified from the economic point of view to use the auxiliary infrastructure of the coal-fired unit as part of the nuclear investment. This is due to the possibility of obtaining a very significant reduction in investment costs, in this case without reducing the efficiency of electricity generation.

5. Summary

The coal-to-nuclear transformation path is gaining more and more popularity in the world. This is due to the need to look for new technological solutions that will allow for a faster departure from coal in large power plants. In some countries, for technical reasons, a quick departure from centralized generation cannot take place within the period provided for achieving climate neutrality. Basically, the decarbonisation of these systems can be carried out using two pathways. The first one is the brownfield path, where the investment in the nuclear unit uses land and optionally uses elements of the auxiliary infrastructure previously operating as part of the coal-fired generation system, i.e., cooling systems, power output systems, buildings, water reservoirs, and transport roads. The second path proposed and analyzed by the authors in [10,13,14] is the path where the investment uses the basic elements of the unit's infrastructure, including a steam turbine set. Such modernizations could be relatively simple and thus also economically justified, but only in the case of the possibility of using high-temperature reactors, i.e., constructions classified in the group of 4th generation nuclear reactors. According to the announcements of many companies, their commercialization may take place at the end of the current decade. Their potential use as part of retrofits will be possible only after the technology has been verified as part of greenfield investments. As shown in this article, the use of LWR type reactors for the modernization of coal-fired units (especially the SMRs that are gaining popularity) is also possible, but it is much more difficult due to the need to carry out a deep modernization of the steam turbine units. In the light of the presented results, it should be expected that carrying out such modernizations will not be an interesting option for investors.

The analysis carried out may also, to a large extent, be the basis for assessing the possibility of modernization of coal-fired power units with the use of BWR reactors. However, the use of a BWR reactor for the retrofit of a coal-fired unit would require the addition of biological shields protecting against radiation for the existing turbine, condenser, regenerative heaters, and pipelines. Some of these elements would have to be significantly modernized. However, this would involve high costs. In this case, it would be advisable to install new turbine cycle components.

Author Contributions: Conceptualization, H.Ł. and Ł.B.; methodology, H.Ł., Ł.B., P.G., and S.Q.; software, H.Ł. and Ł.B.; writing—original draft preparation, H.Ł. and Ł.B.; writing—review and editing, P.G. and S.Q.; validation, H.Ł. and Ł.B.; investigation, H.Ł., Ł.B., P.G., and S.Q.; visualization, H.Ł. and Ł.B.; resources, S.Q. All authors have read and agreed to the published version of the manuscript.

Funding: This study was funded by a grant by Founders Pledge, partially based on work previously funded by grants from the Quadrature Climate Foundation.

Data Availability Statement: Data presented in this study relating to the status of Łagisza power unit No. 10 are available in summarized form on request from the corresponding author. However, making this data public requires the consent of the data owner, i.e., Tauron Wytwarzanie SA.

Acknowledgments: We acknowledge the valuable contributions from, and discussions with, Andrzej Brus, Artur Jaszczura, Artur Mermon, Wojciech Przepadło, Łukasz Rybak, Wojciech Smółka, Jacek Śmigielski, Artur Zajchowski, Janusz Zdeb at Tauron Wytwarzanie SA, Mirosław Syta at Tauron Polska Energia SA Baroness Bryony Worthington and Lou Martinez Sancho, Per Peterson, Peter Hastings, Darrell Gardner, Brian Song, Melissa McMorrow and Sean King at Kairos Power and Daniel Cox at QuantifiedCarbon.

Conflicts of Interest: The authors declare no conflict of interest. The funders had no role in the design of the study, in the collection, analysis, or interpretation of data, in the writing of the manuscript, or in the decision to publish the results.

Appendix A.

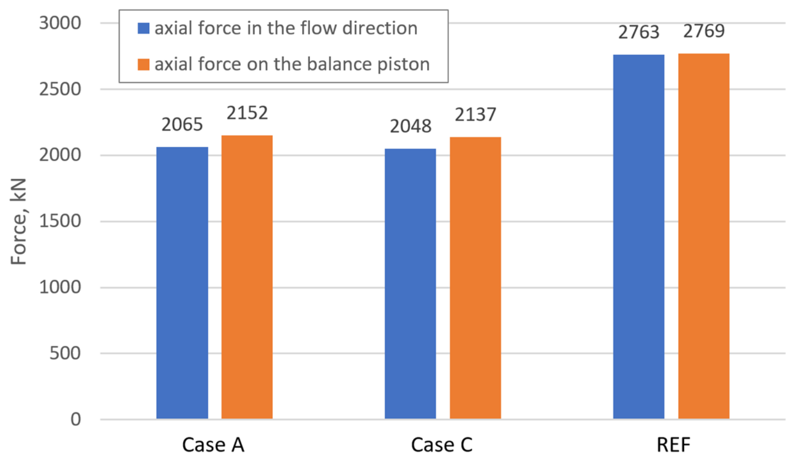

Figure A1. Axial forces acting on the rotor of IP section.

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