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Table of contents

Streszczenia

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THE ECONOMIC OPTIMISATION OF COGENERATION POWER PLANTS

Summary: The aim of this article is to depict the rules of economic dispatch of CHPs working in the Polish regulation environment. Economic dispatch is the basic instrument of preparing the load schedule of individual generation units in CHP for different time intervals (the smallest time interval is one hour). Generally speaking, the economic dispatch of CHPs should depend on the marginal costs of electricity and heat generation by separate production units. The marginal costs of electricity and heat generation by separate units are the basis of the merit order that is the main idea behind economic dispatch. The marginal costs of electricity and heat generation depend on many factors, including the cost of fuels and the efficiency of separate generation units. However the regulation environment, in particular relating to the support of co-generation and renewables development, changes to some extent the typical rules of economic dispatch. In this case the economic dispatch depends not on marginal costs, but rather on the unit gross margins generated by separate electricity and heat production units in CHP.

Keywords: economic dispatch, CHPs.

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1. Introduction

The main goal of every company is the maximization of value generated for shareholders. This goal is also characteristic of companies operating across the energy industry. Subsectors of the energy industry include:
– the mining industry,
– electricity and heat production,
– electricity and heat distribution,
– electricity and heat trade.

Electricity can be produced by the usage of different fuels and technologies including:
– renewables (wind farms, water turbines, photovoltaic etc.),
– thermal power plants and CHPs (Combined Heat and Power) using different fuels:

– coal,
– biomass,
– natural gas,
– nuclear power plants.

In large cities in Poland and in Nordic European countries, heat is delivered to the inhabitants by way of district heating systems that are supplied with heat by Combined Heat and Power plants (cogeneration). In Poland the most popular technologies are based on coal boilers and back pressure or pass – out and condensing turbines. Recently, Polish energy companies have invested heavily in biomass technologies. At present there are also being realized a couple of investments in CCGT.

The aim if this article is to depict the rules of the economic dispatch of CHPs working in the Polish regulation environment. Economic dispatch is the basic instrument of preparing the load schedule of individual generation units in CHP for different time intervals (the smallest time interval is one hour).

2. The rules of economic dispatch

In the everyday exploitation of CHPs, the main problem is the preparation of the electric and heat load schedule of separate cogeneration units. In such a schedule the electric and heat load of separate cogeneration units is envisaged with an accuracy of at least one hour. This schedule is prepared for the day ahead as well as for longer time periods. The schedule should be prepared in a way that will maximize the short-term financial results, in particular the gross margin (revenues less flexible costs). Hence, the goal function of the scheduling process is the maximization of the gross margin generated by the CHP within an assumed time period, taking into account a couple of limitations such as:

– the efficiency of the cogeneration units (boilers and turbines),
– the weather forecast that impacts the demand on heat power in each hour of the day ahead (the heat load required in each hour of the day ahead),
– the signed agreements relating to the electricity sale that determine the position on the electricity market in each hour of the day ahead (the minimal electric load required in each hour of the day ahead),
– electricity and heat sale prices,
– cogeneration and green certificates sale prices,
– fuel prices, CO2 emission allowances prices and other unit variable costs,
– the limitations (bottlenecks) of heat and electric grids,
– the requirements of ancillary services provided for the Power Grid Operator.

Load scheduling is much easier in condensing power plants than in CHPs. To maximize the gross margin generated by condensing power plant within an hour or a day, it is required to schedule the electric load of separate production units in accordance with the marginal cost curve. An example of the load scheduling of a condensing power plant is depicted in Figure 1.

	Unit	Production unit 1 (Capacity - 250 MW)	Production unit 2 (Capacity - 230 MW)	Production unit 3 (Capacity - 220 MW)
Net efficiency of electricity generation (condensing mode)	%	35%	32%	29%
Fuel use per 1 MWh of electricity	GJ/MWh	10,3	11,25	12,4
Unit variable cost per 1 GJ of fuel use (incl. CO2 emission)	PLN/GJ	15,0	15,0	15,0
Unit variable cost of electricity generation	PLN/MWh	154,3	168,8	186,2
Electricity price in a given hour	PLN/MWh	200	200	200
Unit gross margin on electricity sale in a given hour	PLN/MWh	45,7	31,2	13,8

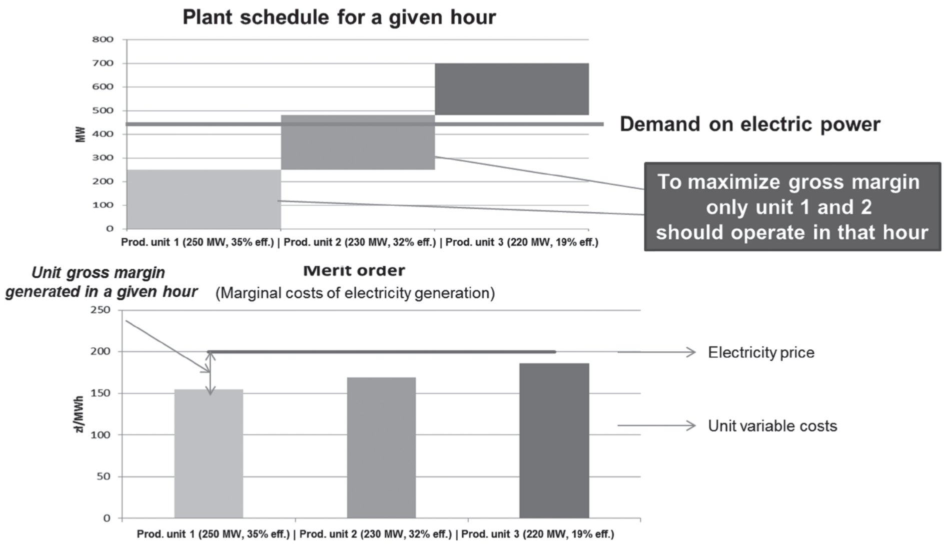

Fig. 1. Load scheduling of condensing power plant

Source: own study.

In this case there are three production units in a condensing power plant. Each production unit is characteristic of the different efficiency of electricity generation. Production unit 1 is the most efficient and production unit 3 is the least efficient. The net electric efficiency is strictly correlated with the size of the unit variable costs of the electricity generated by a given production unit. If the demand on power is at the level of 450 MW in a given hour, then only two production units should be dispatched to maximize the gross margin within that hour. Because of the fact that production units 1 and 2 generate electricity with the least unit variable costs then only these two production units are taken into consideration while load scheduling for that hour. Unit production 2 would operate below its full capacity.

The load scheduling in CHPs is much more complicated because of:
- the prioritization of heat delivery,
- the cogeneration certificates which depend on the total efficiency of production units that is known with 100% certainty after a year,
- the possibility of working in cogeneration or condensing mode which influences the total efficiency of the production units, and as a result of that the quantity of cogeneration certificates gained,
- the possibility of using biomass which translates also into gaining green certificates.

The above reasons change the approach to scheduling CHP's production units. The goal function of scheduling CHP's production units is the same as in the case of condensing power plants. The primary aim of the optimization is the maximization of the gross margin earned on the sale of electricity and heat . However, in contrast with condensing power plants, there are two variables of the goal function:
- the heat load of cogeneration units in each hour,
- the electric load above the minimum that results from heat load (in cases when the production unit can work both in the cogeneration and condensing mode).

Due to the fact that the total efficiency of cogeneration units is known after the year which determines the revenue gained from cogeneration certificates, the scheduling of cogeneration units' load cannot be based on the merit order built on electricity efficiency production, but should be prepared on the basis of the planned total gross margin. A comparison of the scheduling of production units in a condensing power plant and in CHP is depicted in Table 1.

The main reason why cogeneration units cannot be scheduled on the basis of electricity marginal costs is the fact that some of them can work in both condensing and cogeneration mode, which influences not only electricity unit production costs but also the stream of revenue coming from cogeneration certificates. This phenomena is depicted in the below case.

In a CHP there are installed three production units:
- biomass cogeneration unit power of which 30 MWt and 14 MWe while working in cogeneration mode or 18 MWe while working in condensing mode,
- Combined Cycle Gas Turbine (CCGT) power of which 90 MWt and 135 MWe while working in cogeneration mode or 155 MWe while working in condensing mode,
- coal cogeneration unit power of which 200 MWt and 118 MWe while working in cogeneration mode or 135 MWe while working in condensing mode.

Table 1. A comparison of the scheduling of production units in a condensing power plant and in CHP

Power plant	Goal function	Variables of goal function	The tool of optimization
Condensing power plant	Gross margin maximization	Electric load of each production unit	Merit order (marginal cost curve)
CHP	Gross margin maximization	Heat load of each production unit Electric load above the minimum resulting from heat load – operating in condensing mode (if applicable)	Calculation of total gross margin generated within the whole year in different configurations of heat and electric load of each cogeneration unit

Source: own study.

So in that CHP there are used three kinds of fuels: hard coal, biomass and natural gas. Each cogeneration unit is allowed to get cogeneration certificates, the quantity of which depends on total efficiency, PES, and the electricity produced in cogeneration. This CHP can be granted the following cogeneration certificates:

- red certificates – to electricity produced in cogeneration by biomass and coal production units
- yellow certificates – to electricity produced in cogeneration by CCGT.

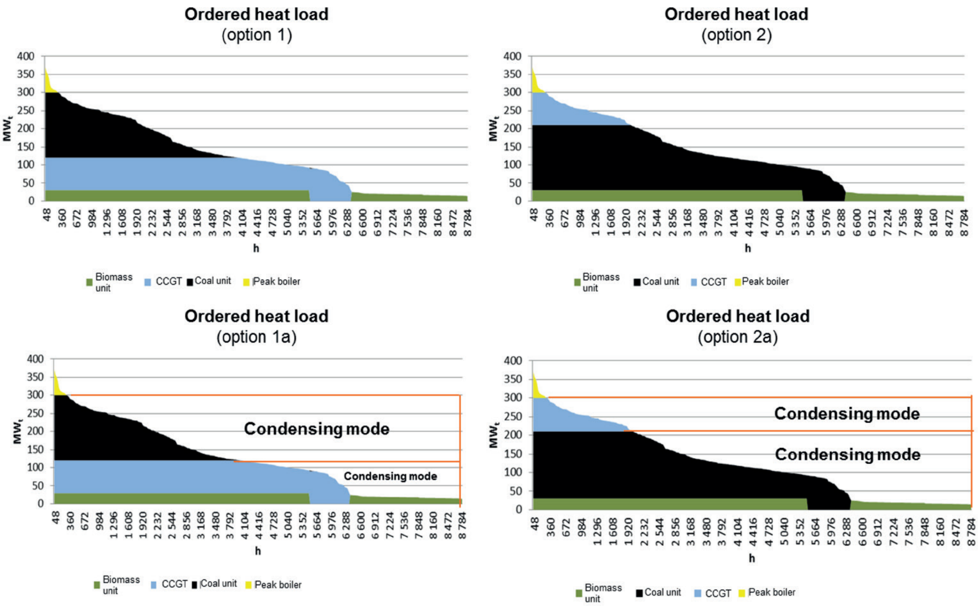

Fig. 2. Potential options of electric and heat load schedule of separate cogeneration units

Source: own study.

Besides this, a biomass cogeneration unit is allowed to get green certificates to all produced electricity. To find the optimal electric and heat load of cogeneration units, four options of the CHP work schedule were set for the next year. These options are depicted in Figure 2.

The horizontal axis represents the number of hours during the year (circa 8,700 hours) and the vertical axis represents the heat power. The figure represents the potential heat load of separate cogeneration units taking into account the ordered heat load for the whole CHP during the next year. The peak heat load amounts to above 350 MW (the heat load for the air temperature below minus 20 degrees C). The base heat load that occurs in summer time does not exceed 20 MW. In all the depicted options of load schedule, the biomass unit works in the base load which is justified by the fact that it yields a large gross margin including green and red certificates. Besides which, the heat power installed in the biomass unit is the closest one to the heat base load. When the demand for heat power exceeds 30 MW then the CCGT (option 1) or the coal cogeneration unit (option 2) is dispatched. When the demand for heat power exceeds 120 MWt in the first option or 230 MWt in the second option, then the last cogeneration unit is dispatched (CCGT or coal cogeneration unit dependending on the option of the load schedule). In the peak heat load the peak boiler is dispatched. We should also take into account that:

- in option 1 and 2 the electric load of coal cogeneration unit and CCGT is adjusted to the heat load,
- in option 1a and 2a the coal cogeneration unit and CCGT work in condensing mode in the summer time (in that time they generate only electricity and the heat is lost in the cooling tower).

The above described options of load schedule determine the production of electricity and the quantity of certificates granted to the electricity produced in cogeneration. However, the heat production is at the same level in all options (3,9 PJ a year) because it is only determined by the demand on heat power and by weather conditions that are the same in all options. The production data regarding the four options of load schedule are depicted in Table 2.

Analyzing the energy balance, one can draw the conclusion that the potential options of heat load and the possibility of working in condensing mode determine the level of electricity production and the level of the total cogeneration units' efficiency which translates into the quantity of cogeneration certificates granted to electricity production. In particular, the differences of production data are characteristic of the coal cogeneration unit and CCGT. In option 1 in which the electric load of CCGT is determined by the demand on heat power, the total efficiency of this cogeneration unit exceeds the threshold of 80%, which means that yellow certificates are granted to the all electricity produced. If the decision is made about dispatching CCGT in condensing mode in summer time, then the total efficiency of that production unit would fall below 80%, which would result in gaining about 300 GWh of yellow certificates less in comparison to option 1. In option 1 and 1a the volume of electricity

Table 2. Energy balance for all the analyzed options

	Unit	Option 1 (excl. condensing mode)	Option 1a (incl. condensing mode)	Option 2 (excl. condensing mode)	Option 2a (incl. condensing mode)
Fuel use					
Forest biomass	GJ	765 274	765 274	765 274	765 274
Agricultural biomass	GJ	814 646	814 646	814 646	814 646
Natural gas	GJ	5 785 548	7 191 546	1 833 910	7 191 546
Coal	GJ	5 400 452	10 402 977	8 369 122	10 402 977
Oil	GJ	8 241	15 874	12 771	15 874
Heat Production	**GJ**	**3 931 214**	**3 931 214**	**3 931 214**	**3 931 214**
Biomass Cogeneration Unit	GJ	751 188	751 188	751 188	751 188
CCGT	GJ	1 928 840	1 928 840	346 658	346 658
Coal Cogeneration Unit	GJ	1 251 186	1 251 186	2 833 369	2 833 369
Electricity Production	**MWh**	**1 448 531**	**2 173 540**	**1 166 088**	**2 175 324**
Inc. Cogeneration Mode	**MWh**	**1 053 806**	**759 296**	**539 549**	**539 549**
Biomass Cogeneration Unit	MWh	126 555	126 555	126 555	126 555
green certificates	**MWh**	126 555	126 555	126 555	126 555
red certificates	**MWh**	**93 898**	**93 898**	**93 898**	**93 898**
CCGT	MWh	**803 510**	**1 013 402**	**262 957**	**1 062 765**
yellow certificates	**MWh**	**803 510**	**508 999**	**91 479**	**91 479**
Coal Cogeneration Unit	MWh	518 467	1 033 583	776 576	986 004
red certificates	**MWh**	**156 398**	**156 398**	**354 171**	**354 171**
Efficiency					
Biomass Cogeneration Unit					
Total Efficiency	%	76,38%	76,38%	76,38%	76,38%
PES		35,11	35,11	35,11	35,11
CCGT					
Total Efficiency	%	**83,34%**	**77,55%**	**70,52%**	**58,02%**
PES		32	32	32	32
Coal Cogeneration Unit					
Total Efficiency	%	57,64%	47,72%	67,16%	61,26%
PES		33,55	33,55	33,55	33,55

Source: own study.

produced by the coal cogeneration unit differs dramatically, but the quantity of red certificates is the same. This results from the fact that in all the options the total efficiency of coal cogeneration unit is below the threshold of 80%, which means that the quantity of red certificates gained depends only on the heat production by this unit. The heat production by coal cogeneration unit is the same in option 1 and 1a.

In option 2 and 2a the work of the CCGT and coal cogeneration unit in condensing mode does not impact the volume of yellow and red certificates gained. In all these options the volume of electricity produced in cogeneration mode is the same, which is determined by the fact that both CCGT and coal cogeneration unit do not attain total efficiency above the threshold of 80%. In that case the quantity of cogeneration certificates depends only on the heat production by separate cogeneration units which is at the same level in option 2 and 2a. In this heat load schedule, the decision about dispatching CCGT or coal cogeneration unit in condensing mode in summer time made during the year will not affect the quantity of cogeneration certificates gained.

The above options of load schedule translate into the gross margin and sale income yielded by the CHP. The calculations of gross margin in particular options are depicted in Table 3.

The calculation of the gross margin indicates option 1a of the electric and heat load schedule as optimal in the assumed conditions of electricity, heat and fuel prices. CHP yields the highest gross margin in that option which means that:

– the biomass cogeneration unit should be dispatched at the heat base load,

Table 3. The gross margin yielded by cogeneration units (in PLN)

	Option 1 (excl. condensing mode)	Option 1a (incl. condensing mode)	Option 2 (excl. condensing mode)	Option 2a (incl. condensing mode)
CCGT				
Revenue	**366 001 798**	**421 474 938**	**102 169 130**	**363 610 805**
Electricity	262 651 793	331 261 589	85 955 676	347 397 351
Heat	67 509 392	67 509 392	12 133 021	12 133 021
Yellow certificates	35 840 613	22 703 958	4 080 434	4 080 434
Variable costs	**261 450 793**	**322 461 531**	**89 976 515**	**322 461 531**
Fuel	217 413 868	267 722 802	76 017 641	267 722 802
CO2 emission allowances	43 775 205	54 413 406	13 875 914	54 413 406
Fees for emissions	261 720	325 322	82 960	325 322
Gross Margin	**104 551 005**	**99 013 408**	**12 192 615**	**41 149 274**
Gross Margin Rate	***28,57%***	***23,49%***	***11,93%***	***11,32%***
Biomass Cogen. Unit	**0**	**0**	**0**	**0**
Revenue	**122 738 393**	**122 738 393**	**122 738 393**	**122 738 393**
Electricity	40 216 709	40 216 709	40 216 709	40 216 709
Heat	26 291 576	26 291 576	26 291 576	26 291 576
Red Certificates	4 188 349	4 188 349	4 188 349	4 188 349
Green Certificates	52 041 759	52 041 759	52 041 759	52 041 759
Variable Costs	**57 231 482**	**57 231 482**	**57 231 482**	**57 231 482**
Fuel	56 111 659	56 111 659	56 111 659	56 111 659
Fees for emission	70 052	70 052	70 052	70 052
Ash utilization	100 062	100 062	100 062	100 062
Other	949 710	949 710	949 710	949 710
Gross Margin	**65 506 911**	**65 506 911**	**65 506 911**	**65 506 911**
Gros Margin Rate	***53,37%***	***53,37%***	***53,37%***	***53,37%***
Coal Cogen. Unit	**0**	**0**	**0**	**0**
Revenue	**212 984 970**	**374 154 172**	**357 939 875**	**423 465 737**
Electricity	162 217 284	323 386 487	242 974 148	308 500 011
Heat	43 791 527	43 791 527	99 167 898	99 167 898
Red Certificates	6 976 159	6 976 159	15 797 828	15 797 828
Variable Costs	**116 937 690**	**258 968 088**	**201 223 406**	**258 968 088**
Fuel	75 694 629	145 811 759	117 304 542	145 811 759
CO2 emission allowances	31 293 455	94 027 598	68 522 050	94 027 598
Fees for emission	1 152 866	2 220 785	1 786 606	2 220 785
Transport of Fuel	3 028 116	5 833 108	4 692 695	5 833 108
Ash Utilization	2 517 390	4 811 935	3 879 052	4 811 935
Other	3 251 233	6 262 902	5 038 461	6 262 902
Gross Margin	**96 047 280**	**115 186 084**	**156 716 468**	**164 497 649**
Gross Margin Rate	***45,10%***	***30,79%***	***43,78%***	***38,85%***
Total Gross Margin	266 105 195	279 706 402	234 415 994	271 153 834
Gross Margin Rate	***37,92%***	***30,46%***	***40,22%***	***29,80%***

Source: own study.

- CCGT should be dispatched before coal cogeneration unit,
- CCGT and coal cogeneration unit should operate in condensing mode in summer time.

The calculation also depicts that the additional gross margin on electricity production in condensing mode in option 1a will be higher than the lost revenue of 300 GWh yellow certificates in comparison to option 1. This means that the electricity price is high enough to compensate for the loss of yellow certificates' revenue by the additional margin on electricity produced in condensing mode. The basic rule of dispatching CCGT or coal cogeneration unit in condensing mode in summer time is depicted in Figure 3.

Of course, the results of the gross margin calculations can change if the electricity price falls and the yellow certificate price goes up. The price changes can occur during

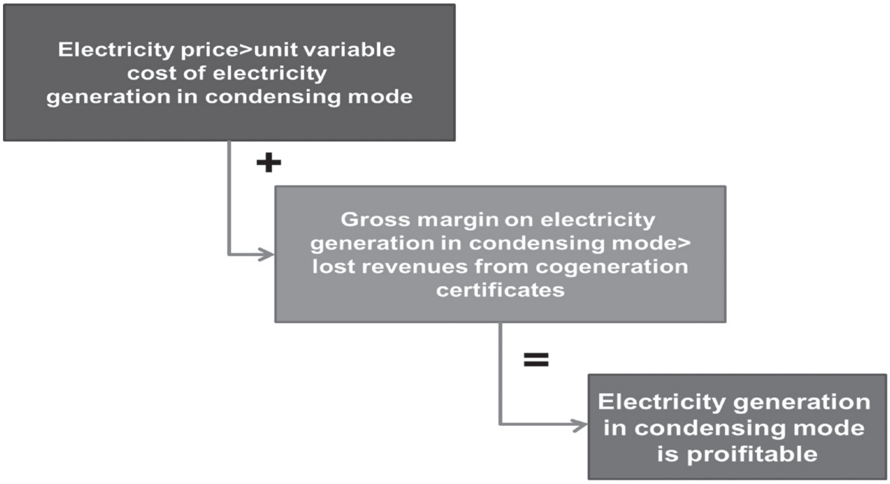

Fig. 3. The rule of dispatching cogeneration unit in condensing mode

Source: own study.

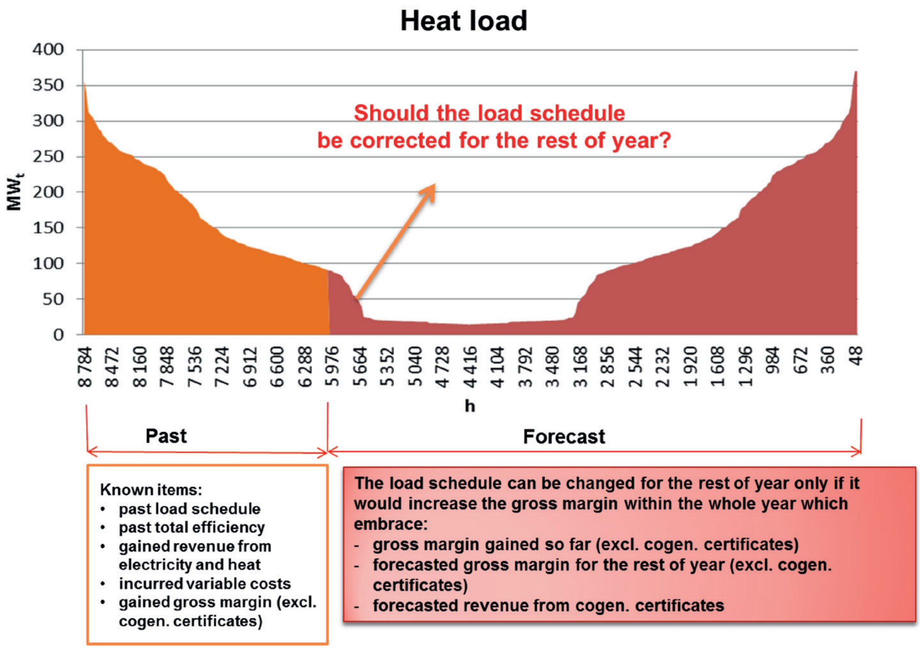

Fig. 4. The rules behind changing the load schedule during the year

Source: own study.

the year, for which there was prepared the load schedule of cogeneration units. Then the dispatcher should correct the load schedule during the year taking into account the price changes and also other circumstances that have occurred like the cogeneration units' failures and new bottlenecks. While changing the load schedule during the year, the dispatcher should calculate the gross margin yielded by CHP in the whole year that includes:

– the real gross margin yielded so far (excluding cogeneration certificates),
– the forecasted gross margin that will be yielded from the moment of making the decision about changing the load schedule to the end of the year (excluding cogeneration certificates),
– the forecasted revenue from the cogeneration certificates that depends on the total efficiency of the cogeneration units – the change of the load schedule during the year can impact the total efficiency and the volume of cogeneration certificates gained for the whole year.

The basic rules relating to changing the load schedule are depicted in Figure 4.

The decision about changing the load schedule is difficult because it is based on the forecasted electricity and cogeneration certificates' prices. The forecasted prices can justify the decision about dispatching of some cogeneration units in condensing mode in summer time but the market circumstances that will occur during the year can make this decision unprofitable. This will happen if the fall of electricity price or the rise of cogeneration certificates' prices causes that the gross margin gained on electricity produced in condensing mode will be below the lost revenue from cogeneration certificates. To avoid such losses, risk management should be introduced in CHPs. The decision about changing the load schedule during the year puts the financial results of CHP at risk. One of the ways to hedge against this risk is to use derivatives (futures or options) that are traded on the electricity exchanges.

3. Conclusions

Economic dispatch in CHPs is a complex issue that should be considered from different perspectives. The optimal dispatch of cogeneration units should maximize the gross margin yielded by the CHP during the whole year. The way of optimizing the cogeneration units' dispatch depends mostly on the system supporting cogeneration. In Poland there are three kinds of cogeneration certificates that are traded on the market and that can yield a huge stream of additional revenue for CHPs. However, the quantity of cogeneration certificates granted to electricity production depends on many conditions, the most important of which is the total efficiency of the cogeneration units. The dispatcher of CHPs can influence the total efficiency by shaping the electric and heat load schedule. This is why the dispatchers in CHPs should be equipped with the tools to optimize the load schedule in real time and to manage the risk depending on the conditions on the electricity market.

References

Ustawa z dnia 10 kwietnia 1997 roku *Prawo energetyczne* [*Energy law bill*, 10.04.1997], DZ.U. nr 54, poz. 348, z późniejszymi zmianami.

Rozporządzenie Ministra Gospodarki z dnia 26 lipca 2011 r. w sprawie sposobu obliczania danych podanych we wniosku o wydanie świadectwa pochodzenia z kogeneracji oraz szczegółowego zakresu obowiązku uzyskania i przedstawienia do umorzenia tych świadectw, uiszczania opłaty zastępczej i obowiązku potwierdzania danych dotyczących ilości energii elektrycznej wytworzonej w wysokosprawnej kogeneracji [The Decree of The Minister of Economy (26.07.2011) on the way of calculating the data in the application for cogeneration certificates and on the obligation of buying and remitting the cogeneration certificates], Dz.U. nr 176, poz. 1052.

EKONOMICZNA OPTYMALIZACJA PRACY ELEKTROCIEPŁOWNI

Streszczenie: Celem artykułu jest prezentacja zasad ekonomicznego rozdziału obciążeń w elektrociepłowni pracującej w polskich uwarunkowaniach regulacyjnych sektora energetycznego. Ekonomiczny rozdział obciążeń jest podstawowym instrumentem przygotowania harmonogramu pracy poszczególnych jednostek wytwórczych w elektrociepłowni dla różnych interwałów czasowych. Ekonomiczny rozdział obciążeń powinien być uzależniony od kosztów krańcowych produkcji ciepła i energii elektrycznej przez poszczególne jednostki wytwórcze. Koszty krańcowe produkcji ciepła i energii elektrycznej zależą od wielu czynników, z których najważniejsze to koszty zakupu paliw i sprawność jednostek wytwórczych. Niemniej jednak otoczenie regulacyjne sektora, w szczególności dotyczące wspierania rozwoju kogeneracji i odnawialnych źródeł energii, zmienia do pewnego stopnia typowe zasady ekonomicznego rozdziału obciążeń, bazujące na kosztach krańcowych. W tych zmienionych warunkach ekonomiczny rozdział obciążeń nie zależy od kosztów krańcowych, ale raczej od marży brutto generowanej na wytwarzaniu ciepła i energii elektrycznej przez poszczególne jednostki wytwórcze.

Słowa kluczowe: ekonomiczny rozdział obciążeń, elektrociepłownia.