RIGA TECHNICAL
UNIVERSITY

Polina Ivanova

THE IMPROVEMENT OF FLEXIBILITY AND EFFICIENCY OF THERMAL POWER PLANTS UNDER VARIABLE OPERATION CONDITIONS

Summary of the Doctoral Thesis

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RIGA TECHNICAL UNIVERSITY
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DOCTORAL THESIS PROPOSED TO RIGA TECHNICAL UNIVERSITY FOR THE PROMOTION TO THE SCIENTIFIC DEGREE OF DOCTOR OF ENGINEERING SCIENCES

To be granted the scientific degree of Doctor of Engineering Sciences, the present Doctoral Thesis has been submitted for the defence at the open meeting of RTU Promotion Council "RTU P-05" on November 22, 2018 at the Faculty of Power and Electrical Engineering of Riga Technical University, 12/1 Azenes Street, Room 306, at 1 p.m.

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DECLARATION OF ACADEMIC INTEGRITY

I hereby declare that the Doctoral Thesis submitted for the review to Riga Technical University for the promotion to the scientific degree of Doctor of Engineering Sciences is my own. I confirm that this Doctoral Thesis had not been submitted to any other university for the promotion to a scientific degree.

Name Surname ……………………………. (signature)
Date: ………………………

The Doctoral Thesis has been written in English. It consists of eight chapters; conclusions; 61 figures; 20 tables; the total number of pages is 103. The Bibliography contains 134 titles.

CONTENT

1 INTRODUCTION

1.1. Topicality of Research

Thermal power plants (TPPs) seem to be an attractive option because they can deliver a variety of energy, environmental and economic benefits. Moreover, thermal power plants produce energy where it is needed, avoid waste heat and reduce losses in transmission and distribution networks [1]–[3].

The implementation of market mechanisms, different support schemes (such as feed-in tariffs) for renewable energy resources (RES) and large-scale integration of intermittent generation (solar photovoltaic (PV) and wind energy) in the energy production process have changed [4]–[7].

- The running conditions of fossil fuel thermal power plants, i.e., the shifting from base load operation to cycling. It is the operation under variable condition, such as variable load of intermittent generation or fluctuation of electricity price. Thermal power plants are partly or entirely not adapted to the cycling operation, which leads to a decrease in their efficiency, more frequent trips and outages.
- The role of fossil fuel thermal power plants, i.e., the secure integration of intermittent generation in energy production process and provision of regulation services to the transmission system operator instead of electrical and heat energy supply in line with its demand. This promotes the mass closing or mothballing of fossil fuel TPPs due to surplus of generation capacity, thus threatening the security of energy supply.

S. Lüdge emphasised in [8] that "Out of the three pillars (environment, cost competitiveness and security of supply) describing the energy sector triangle only one is developing positively. This is the environmental part. … The other two pillars (cost competitiveness and security of supply) are developing in the wrong direction. The economic situation for conventional power plants is so bad that a lot of them will have to shut down permanently in the coming years and naturally there won't be any new projects within this framework. Flexibility especially from fossil fuel fired power plants is not only needed but is the success factor for the whole energy turn around".

The flexibility of fossil fuel TPPs is necessary not only today, but also within the next decades [2]–[10] for the following reasons:

- to adapt existing generation to new running conditions and provide its efficient, flexible and profitable operation;
- to ensure the secure integration of intermittent generation in energy production process and to ensure a stable energy system;
- to achieve the goal of the European Commission concerning renewable energy sources and energy efficiency.

There are different measures to increase the flexibility of fossil fuel thermal power plants from expensive to cost-neutral [4], [11]. First, new running conditions of TPPs should be analysed to evaluate the bottlenecks of a cycling operation. Second, the appropriate measures should be proposed from the technical and economical point of view. Third, the beneficial measures should be implemented and unprofitable ones declined. Thus, the author of the Doctoral Thesis has developed the following new methodologies and mathematical models:

- a mathematical description of transient modes to identify the parameters of transient modes of combined cycle gas turbine (CCGT) power plant and the bottlenecks of cycling operation;
- *EM&OM (Evaluation Model and Optimisation Model) approach* for operation mode optimisation;
- a general algorithm for technical and economic justification of technologies aimed at increasing the flexibility of thermal power plants.

All these developments were approbated on the example of Riga TPP-2 and Latvian site conditions.

1.2. Hypothesis of the Doctoral Thesis

It is necessary and possible to adapt fossil fuel TPPs to new running conditions (cycling) in order to increase their efficiency and operation profitability and prevent them from mothballing.

1.3. The Aim of the Doctoral Thesis

The aim of the Doctoral Thesis is to investigate new running conditions of thermal power plants and propose measures to improve flexibility and efficiency of thermal power plants under variable operation conditions.

1.4. The Tasks of the Doctoral Thesis

To achieve the aim of the Thesis, the following tasks have been set:

1) to investigate the concept of flexibility, as well as significance and necessity of flexibility;
2) to overview the measures to increase the flexibility and efficiency of thermal power plants;
3) to provide the mathematical description (mathematical models) of CCGT power plant transient modes (start-up, shutdown, warm state preservation);
4) to develop an approach to optimise the operation of thermal power plant;
5) to develop a general algorithm for technical and economic evaluation of technologies (air cooling, electric boiler and heat storage system), which are aimed at increasing the flexibility level of the thermal power plant.

1.5. Scientific Novelty

The mathematical description of transient modes of combined cycle gas turbine power plant has been provided.

EM&OM approach has been developed for operation mode optimisation of thermal power plants by shifting start-up *"backward"* and shutdown *"forward"*.

The general algorithm has been developed for technical and economic evaluation of technologies, which are aimed at increasing the flexibility level of thermal power plants. It has been adapted to three technologies (air cooling, electric boiler and heat storage system); as a result, three methodologies for certain technologies have been developed.

The mathematical description of transient modes, the general algorithm for technical and economic evaluation of technologies as well as *EM&OM approach* have been approbated on the example of Latvian site conditions and operation patterns of Riga TPP-2.

1.6. Practical Significance of the Research

The developed *EM&OM approach* and the general algorithm as well as its implementation in different technologies can be adapted to other thermal power plants, which operate under variable running conditions. The developed algorithm has practical application. It has been used for technical and economic evaluation of projects developed by *JSC Latvenergo*. The projects include the installation of thermal storage tank and gas turbine modernisation (*OpFlex* solution) at CCGT-2/2 unit of Riga TTP-2, and the installation of exhaust gas condensing economizer at the heat only boiler of Riga TPP–1. The *OpFlex* solution and exhaust gas condenser economizer have been installed and are in use. The developed algorithm was used to develop the feasibility study for the heat storage system and to submit the application for European Union co-financing (3.75 million €). The co-financing for the construction works of heat storage system at Riga TPP-2 by the end of 2020 was approved. Currently the procurement procedure is conducted to select the candidate for the EPC (Engineering, Procurement and Construction) contractor for the development of technical design and for further construction of heat storage system.

The results of the Doctoral Thesis can be used by *JSC Latvenergo* to evaluate different options for the improvement of flexibility and efficiency of its thermal power plants.

Moreover, the obtained results can be used as input data of power plant optimisation programme developed by the researchers of Riga Technical University.

1.7. Volume and Structure of the Doctoral Thesis

The Doctoral Thesis is written in English. It comprises eight chapters, thirty-three sections, eighteen subsections, conclusions and a bibliography with 134 reference sources. It has been illustrated by 61 figures and 20 tables. The volume of the Thesis is 103 pages. Chapter 1 provides the information about the topicality and hypothesis of the Thesis, formulates the aim of the research and tasks to be fulfilled. Scientific novelty and practical significance of the Thesis are also presented. The author's scientific works are listed. Chapter 2 provides an overview of cycling and flexible operation of fossil fuel thermal power plants. Types of cycling operation, their impact on technical resources of equipment and costs are described. The parameters of flexible operation and measures to increase the flexibility level of fossil fuel thermal power plants are listed. The comparison of the flexibility level of TPPs is performed. The illustration of shifting from based load operation to cycling is presented on the example of Riga TPP-2 (the investigated object). Chapter 3 presents the developed theoretical mathematical models of transient modes and their practical application. Chapter 4 describes the developed approach to optimise the fossil fuel power plant cycling running conditions and provides its practical application. Chapter 5 introduces the general algorithm for technical and economic justification of technologies, which are used to increase the flexibility level of the cogeneration power plant. Chapters 6, 7 and 8 present the adaptation of the algorithm to three technologies (air cooling, electric boiler and heat storage system) with practical application. In the end, the main results of the Doctoral Thesis are summarised.

1.8. Scientific Work

The results of the research have been presented at international scientific conferences in Latvia and abroad.

International Scientific Conferences:

1. 58th International Scientific Conference on Power and Electrical Engineering of Riga Technical University (RTUCON), 12–13 October 2017, Riga, Latvia.
2. 2017 IEEE International Conference on Environment and Electrical Engineering and 2017 IEEE Industrial and Commercial Power Systems Europe (EEEIC / I&CPS Europe 2017), 6–9 June 2017, Milan, Italy.
3. 57th International Scientific Conference on Power and Electrical Engineering of Riga Technical University (RTUCON 2016), 13–14 October 2016, Riga, Latvia.
4. 2016 IEEE International Conference on Environment and Electrical Engineering (EEEIC 2016)", 7–10 June 2016, Florence, Italy.
5. 2015 IEEE 5th International Conference on Power Engineering, Energy and Electrical Drives (POWERENG), 11–13 May 2015, Riga, Latvia.

Local Conference: 4th Practical and Scientific Conference "Energy-efficient Solutions to District Heating" organised by JSC Rigas Siltums, 1 July 2016, Riga, Latvia.

The results of the research have been published in conference proceedings and in scientific and popular scientific journals.

Full-text articles published in the conference proceedings:

1. **Ivanova, P.,** Sauhats, A., Linkevics, O. Cost-Benefit Analysis of Electric Boiler at Combined Heat and Power Plants. In: *2017 IEEE 58th International Scientific Conference on Power and Electrical Engineering of Riga Technical University (RTUCON): Proceedings*, Latvia, Riga, 12–13 October 2017. Piscataway: IEEE, 2017, pp. 1–6, ISBN 978-1-5386-3847-7, e-ISBN 978-1-5386-3846-0, doi:10.1109/RTUCON.2017.8124747.
2. **Ivanova, P.,** Linkevics, O., Sauhats, A. Mathematical Description of Combined Cycle Gas Turbine Power Plants' Transient Modes. In: *2017 IEEE International Conference on Environment and Electrical Engineering and 2017 IEEE Industrial and Commercial Power Systems Europe: Conference Proceedings*, Italy, Milan, 6–9 June 2017.

Piscataway: IEEE, 2017, pp. 61–66, ISBN 978-1-5386-3918-4, e-ISBN 978-1-5386-3917-7, doi:10.1109/EEEIC.2017.7977405.

3. **Ivanova, P.,** Linkevics, O., Sauhats, A. Cost–Benefit Analysis of CHP Plants Taking into Account Air Cooling Technologies. In: *2017 IEEE International Conference on Environment and Electrical Engineering and 2017 IEEE Industrial and Commercial Power Systems Europe: Conference Proceedings*, Italy, Milan, 6–9 June 2017, Piscataway: IEEE, 2017, pp. 55–60, ISBN 978-1-5386-3916-0, doi:10.1109/EEEIC.2017.7977404.
4. **Ivanova, P.,** Sauhats, A., Linkevics, O. Towards Optimization of Combined Cycle Power Plants' Start-ups and Shut-down. In: *2016 57th International Scientific Conference on Power and Electrical Engineering of Riga Technical University (RTUCON 2016): Proceedings*, Latvia, Riga, 13–14 October 2016. Piscataway: IEEE, 2016, pp. 23–28, ISBN 978-1-5090-3732-2, e-ISBN 978-1-5090-3731-5, doi:10.1109/RTUCON.2016.7763081.
5. **Ivanova, P.,** Sauhats, A., Linkevics, O., Balodis, M. Combined Heat and Power Plants Towards Efficient and Flexible Operation. In: *2016 IEEE 16th International Conference on Environmental and Electrical Engineering (EEEIC)*, Italy, Florence, 7–10 June, 2016. Piscataway: IEEE, 2016, pp. 2434–2439, ISBN 978-1-5090-2321-9, e-ISBN 978-1-5090-2320-2, doi:10.1109/EEEIC.2016.7555874.
6. Kunickis, M., Balodis, M., Linkevics, O., **Ivanova, P.** Flexibility Options of Riga CHP–2 Plant Operation under Conditions of Open Electricity Market. In: *2015 IEEE 5th International Conference on Power Engineering, Energy and Electrical Drives (POWERENG)*, Latvia, Riga, 11–13 May 2015. Riga: Riga Technical University, 2015, pp. 548–553, ISBN 978-1-4799-9978-1, doi:10.1109/PowerEng.2015.7266375.

Articles in scientific journals:

1. **Ivanova, P.,** Sauhats, A., Linkevics, O. District Heating Technologies: Is it Chance for CHP Plants in Variable and Competitive Operation Conditions? *IEEE Transactions on Industry Application*, 2018, ISSN 0093-9994, e-ISSN 1939-9367, doi:10.1109/TIA.2018.2866475 (*In press*).
2. **Ivanova, P.,** Grebess, E., Linkevics, O. Optimisation of Combined Cycle Gas Turbine Power Plant in Intraday Market: Riga CHP–2 Example. *Latvian Journal of Physics and Technical Sciences*, 2018, 1, pp. 15–21, doi:10.2478/lpts-2018-0002.
3. **Ivanova, P.,** Grebess, E., Mutule, A., Linkevics, O. An Approach to Optimize the Cycling Operation of Conventional Combined Heat and Power Plants. *Energetika*, 2017, 63 (4), pp.127–140, doi:10.6001/energetika.v63i4.3621.
4. Linkevics, O., **Ivanova, P.,** Balodis, M. Electricity Market Liberalisation and Flexibility of Conventional Generation to Balance Intermittent Renewable Energy – Is it Possible to Stay Competitive?. *Latvian Journal of Physics and Technical Sciences*, 2016, 53(6), pp. 47–56, ISSN 0868-8257, doi:10.1515/lpts-2016-0043.

Articles in popular scientific journals:

1. Stuklis, I., Linkevičs, O., **Ivanova, P.** Ārzemju pieredze siltuma akumulācijas sistēmas izveidei Rīgā. *Enerģija un Pasaule*, 2016, Nr. 6, 44.–49.lpp. ISSN 1407-5911.
2. Balodis, M., Krickis, O., **Ivanova, P.** N-ERGIE siltuma akumulācijas realizācija Nirnbergas centralizētajā siltumapgādē. *Enerģija un Pasaule*, 2016, Nr. 3, 40.–44.lpp. ISSN 1407-5911.

2 OVERVIEW OF CYCLING AND FLEXIBLE OPERATION

2.1. Definition of Cycling Operation and its Main Aspects

The running conditions of fossil fuel TPPs have changed from base load operation to running conditions in cycling modes due to the implementation of market mechanisms, different support schemes for renewable energy resources and large-scale integration of intermittent generation (solar PV and wind energy) in the energy production process [12]–[14]. The cyclic operation means operation with frequent unit load reduction or its full stop, when intermittent generation is available or price of electricity is low (variable running conditions) [15], [16]. The time unit offline or steam turbine temperature determines the type of start-up [17], [15] (Fig. 2.1). The warm state preservation process can be marked in cycling operation. It means that unit is not in operation but the energy is used to hold the unit in the warm state [18], [19].

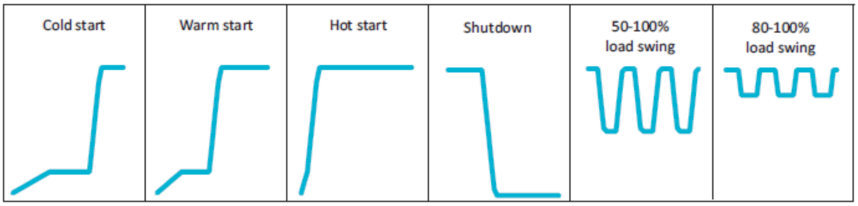


Fig. 2.1. Type of cycling operation [17].

The reason(s), aim(s) and benefits of cycling operation vary according to the geographical location of region, its situation in the energy system and economic development. The comparison of the situation in Latvia and Germany is presented in Table 2.1 [4], [15], [20].

Table 2.1

The Comparison of Situation in Latvia and Germany [4], [15], [20]

Parameters	Latvia	Germany
Reason of cycling operation of TPPs	The fluctuations of electricity price in the Nord Pool market	Intermittent generation variability
Aim of flexibility increase	Adjustment to the situation in the Nord Pool market	Integration of intermittent generation in the energy production process
Benefits of flexible operation	Obtaining additional profit, when electricity price is high. Ensuring profitable operation of the existing thermal power plants	Secure integration of intermittent generation in use. Opportunity to be *"the quickest"* and offer *"the first megawatts"*

The cycling operation with shutdown is more complicated than the operation with load reduction due to a start-up procedure [18], [19]. Operation with load reduction and shutdown followed by hot start-up has less adverse influence on cogeneration unit equipment than the shutdown with warm or cold start-up (Fig. 2.2).

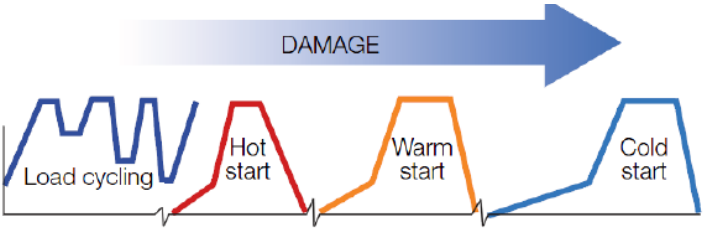


Fig. 2.2. The types of cycling operation [13].

The main damages of cycling mode are creep and fatigue, differential thermal expansion, mechanical shocking, erosion and corrosion, etc. [13], [21].

The factors that contribute to the total costs of cycling are the following [13]: (1) increased fuel consumption due to increased power plant start-ups and operation at part-load levels (efficiency decrease); (2) increased fuel consumption due to loss of plant efficiency arising from increased wear to components; (3) increased operation and maintenance (O&M) costs due to increased wear-and-tear of plant components; (4) increased capital costs resulting from component failures; (5) increased environmental costs resulting from increased emissions; and (6) loss of income due to longer and more frequent forced outages.

In short term the start-up and shutdown costs are calculated taking into account the consumed fuel and produced carbon dioxide emissions [22]. For example, Eq. 2.1 calculates the start-up costs.

$$C_{start} = \sum_{t=1}^{n_{start}} \left[\sum_{i=1}^{n_{CHP}} (B_{it} C_{Fuel}^{t} + E_{it}^{CO_2} \Pi_t^{CO_2}) \right], \tag{2.1}$$

where n_{start} – start-up time, h;

B_{it} – fuel consumption of the unit at the time interval t_n, thous. m^3/h;

C_{Fuel}^{it} – fuel cost, €/thous. m^3;

$E_{it}^{CO_2}$ – CO_2 emission volumes at time period t_n, t/h;

$\Pi_t^{CO_2}$ – CO_2 emission allowance cost, €/t.

In turn, in long term the non-fuel costs (sum of maintenance, repairs, capital expenditure, inspection and wear and tear costs) of start-up and shutdown process are taken into account [23].

Significant attention is devoted to start-up and its costs, because it is more complicated and adverse than shutdown [24]. The start-up costs can vary from a maximum cold start-up value to a much smaller value if the unit has only been turned off recently and it is still relatively close to operating temperature [25], [26].

2.2. Definition and Parameters of Generation Flexibility

Flexibility describes the extent to which an electricity system can adapt the pattern of electricity generation and consumption in order to balance supply and demand [17]. The main parameters of generation flexibility are summarised in Fig. 2.3 [15], [17].

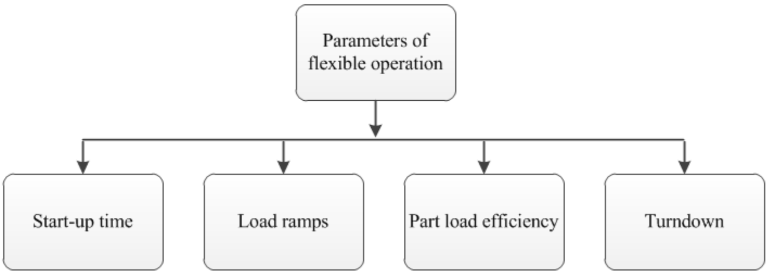


Fig. 2.3. The main parameters of flexible operation (developed by the author according to [17], [27]).

Start-up time denotes the period before the plant achieves stable combustion conditions. Ramping capability characterises TPP ability to respond to changes in demand by ramping up to provide demand during high net loads or by ramping down to ensure grid stability when loads decrease [15], [17]. Part-load efficiency defines improvements, which are able to reduce the short-run marginal costs for electricity generation. Turndown ratio denotes the minimum stable operation load [17].

2.3. Fast Start-up: New Economic Benefits

Fast start-up is an essential feature to ensure economic success under variable operation conditions. Fast start-up ensures the following [28], [29]:

1) reduction of start-up costs (fuel savings, less emissions, flexible operation);
2) additional earnings through participation in ancillary markets (availability and utilization fee, spinning reserve capacity);
3) increased revenue through usage of market arbitrage (seasonal price variation, daily price variation, peak shaving).

2.4. Comparison of TPPs by Flexible Performance Parameters

The comparison of TPPs (conventional/flexible CCGT, open cycle gas turbine (OCGT), internal combustion engine (ICE), and supercritical pulverized coal (SCPC) technologies) flexibility levels is made in this section. The information provided below is based on [17].

1. The efficiency of CCGT, OCGT, ICE rapidly decreases when the load is below 60 % of the installed capacity. Thus, the negative effect of the operation at reduced load is typical of OCGT, CCGT and IEC at a 30 % load. The efficiency of SCPC technology insignificantly changes along with a decrease in its load. That is why the part-load efficiency penalty is less pronounced than in case of CCGT, OCGT, and ICE.
2. The fastest start-up time is demonstrated by OCGT technology, followed by flexible and conventional CCGT technologies. The flexible CCGT power plants have two times shorter start-up time than conventional CCGT power plants. Brown coal cogeneration power plants have the longest duration of start-up, i.e., 150 minutes.
3. The fastest ramp rate up to 25 % of full load (FL) is demonstrated by ICE and OCGT technologies, which are followed by CCGT technology. Coal power plants have the slowest ramping capability. This is the reason for the long start-up of coal power plants.
4. ICE technology has the lowest turndown (10 % of the installed capacity). After OCGT and hard coal power plant follow. CCGT technology has a short start-up time and rapid ramp rate, but this technology is able to reduce load only by 30 % of the installed capacity.

2.5. Flexibility Improvement Measures

The measures to increase the flexibility level of fossil fuel TPPS can be divided into two groups [11]: 1) measures available at the operation stage of the constructed cogeneration power plants; and 2) measures applicable at the design stage of new TPPs. The first group includes two subtypes – related to the necessity of reconstruction of fossil fuel power plants or linked with more complicated usage of their existing equipment features.

More than 30 literature sources have been studied and analysed. As a result, all the possibilities to ensure flexible and profitable operation of TPPs have been divided into five groups (Fig. 2.4).

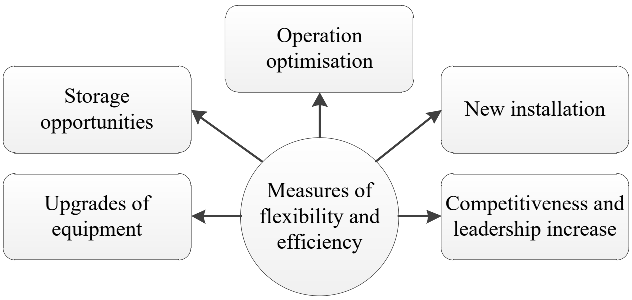


Fig. 2.4. Groups of measures for providing flexible and profitable operation of TPPs [11].

Groups of measures differ by the degree of complexity, investment, time of implementation, sources used, etc., but are united by one goal – to enhance the efficiency and flexibility of fossil fuel TPPs.

2.6. Shifting to Cycling Operation: A Case of Riga TPP-2

Riga TPP-2 plant started to operate in line with electricity market conditions after Latvia had joined the Nord Pool electricity market. In general, the power plant operates if its electricity production costs (marginal costs) are less than the electricity price on the market and it stops if its marginal costs are higher than the electricity price. This makes changes in the operation of the power plant. The following changes are evident in Riga TPP-2 operation when analysing its production data [4], [24], [30]–[32]: shifting from efficient (cogeneration) to inefficient (condensing and mixed) modes; heat only boilers (HOBs) are in operation during the periods of low electricity price and high electricity marginal costs of CCGT cogeneration units (CCGT-2/1 and CCGT-2/2) (mainly at night); the increase in the number of start-ups, etc.

Riga TPP-2 power plant is not fully adapted to the cycling modes [24]. Moreover, taking into account the significance of Riga TPP-2 in the Baltic States, negative consequences may arise [33] if the flexibility and efficiency of a cogeneration power plant are not sustained. The implemented measures, for example, the modernisation of gas turbine and the changes of logic in the distributed control system, are not sufficient; therefore, the developed mathematical models of CCGT power plant transient modes (Chapter 3), the approach to cycling operation optimisation (Chapter 4), and the algorithm for technical and economic justification of technologies (Chapter 5) and its adjustment to certain technologies (Chapters 6, 7, 8) are approbated on the example of Riga TPP-2. It is supposed that the obtained results can show the way how to further improve the flexibility of Riga TPP-2 plant.

3 MATHEMATICAL DESCRIPTION OF TRANSIENT MODES OF CCGT POWER PLANT

3.1. Mathematical Model

Table 3.1 presents the nomenclature used in the methodology to provide the mathematical description of transient modes.

Table 3.1

The Nomenclature Used in Methodology [34]

Sign	Explanation	Sign	Explanation
P_e	Electrical power/electrical energy	*SUIV*	The fourth stage of start-up
P_{eTHmin}	Electrical power at technical minimum	n	Denotes the duration of outage and type of start-up time (if 0 h < n ≤ 12 h => hot start-up, if 12 h < n ≤ 72 h => warm start-up; if n > 72 h => cold start-up)
Q	Heat power/heat energy	i	The start of the shutdown process
t	Time (duration)	$i + z$	The end of the shutdown process
GT	Gas turbine	k	The start of *SUI*
ST	Steam turbine	$k + b$	The end of *SUI*
B	Fuel (natural gas)	k'	The start of *SUII*
SD	Shutdown	$k' + c$	The end of *SUII*
WSP	Warm state preservation	k''	The start-up of *SUIII*

TRM	Transient modes	*k'' + d*	The end of *SUIII*
SUI	The first stage of start-up	*k'''*	The beginning of *SUIV*
SUII	The second stage of start-up	*k''' + e*	The end of *SUIV*
SUIII	The third stage of start-up	$B_{WSP}^{t;n}$	Fuel consumption taking into account the duration of outage *"t"* and start-up time *"n"*

Transient modes of CCGT power plants are complicated and depend on many factors. For the evaluation of transient modes it might be feasible to divide them into three blocks (Fig. 3.1): vertical line bars correspond to shutdown; the area without bars coincides with the preservation of warm state of the unit; the dotted bars correspond to the start-up divided into four sub-blocks (*SUI, SUII, SUIII, SUIV*); the horizontal line bars identify the loading process.

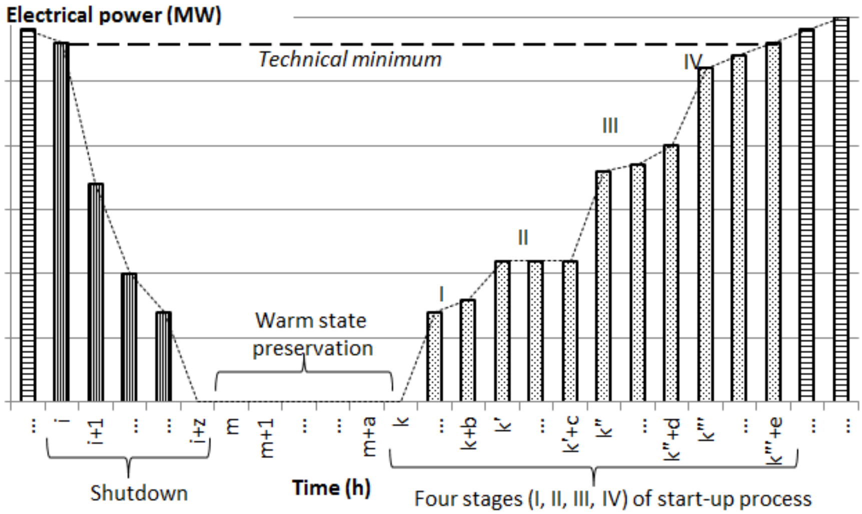


Fig. 3.1. The illustration of transient modes (one cycle) [34].

The shutdown is the process of a decrease in the electrical power of a TPP from $P_{eSD}^{t=i+z} \leq P_{eSD} \leq P_{eSD}^{t=i}$, where $P_{eSD}^{t=I} = P_{eTHmin}$ and $P_{eSD}^{t=i+z} = 0$ ($GT_{SD}^{t=i+z} \leq GT_{SD} \leq GT_{SD}^{t=i}$ and $ST_{SD}^{t=i+z} \leq ST_{SD} \leq ST_{SD}^{t=i}$). The duration of the process is from i to $i+z$. The consumed fuel $B_{SD} = f(P_{eSD})$ and produced heat $Q_{SD} = f(P_{eSD})$. As $P_{SD}\downarrow \Rightarrow B_{SD}\downarrow$ and $Q_{SD}\downarrow$.

During the preservation of warm state, the unit is not in operation, which continues from m to $m + a$. The consumed amount of fuel is determined by the type of start-up *(n)* and the duration of outage *(t)*, i.e., $B_{WSP} = f(t_{WSP}; n)$. If outage is too long (mainly corresponds to cold start-up), then $B_{WSP} = 0$.

The start-up is the process of an increase in the electrical power from $P_e = 0\ MW$ to P_{eTHmin} during the period from k to $k''' + e$. Due to the complexity of the start-up process, it is divided into four stages (*SUI, SUII, SUIII, SUIV*) [34]:

SUI Only gas turbine is in operation ($0 \leq GT_{SUI} \leq P_{eSUI}^{t=k+b}$). The steam turbine is not in operation. The electrical power of thermal power plants is equal to gas turbine output, i.e., $P_{eSUI} = GT_{SUI}$. Heat energy can be produced by district heating economizer (DH ECO) embedded into the heat recovery steam generator. The consumed fuel $B_{SUI} = f\,(P_{eSUI})$ and produced heat power $Q_{SUI} = f\,(P_{eSUI})$. As $P_{eSUI}\uparrow \Rightarrow B_{SUI}\uparrow$ and $Q_{SUI}\uparrow$. The duration of SUI period is from k to $k + b$.

SUII Only gas turbine is in operation at ~ GT_{SUII}, and $GT_{SUII} = const$. The steam turbine is warmed during this period. The electrical power of thermal power plants is equal to gas turbine output, i.e., $P_{eSUII} = GT_{SUII} = const$. Heat energy is produced by DH ECO. As $P_{eSUII} = GT_{SUII} = const$, then $B_{SUII} = const$ and $Q_{SUII} = const$. The duration of SUII is from k' to $k'' + c$.

SUIII Gas turbine is still in operation at approximately $GT_{SUII} = GT_{SUIII}$, but the electrical power output of the unit increases from $P_{eSUII}^{t=k''}$ to $P_{eSUIII}^{t=k''+d}$ due to the loading of steam turbine ($ST_{SUII}^{t=k''} \leq ST_{SUII} \leq ST_{SUII}^{t=k''+d}$). During this process, it is also warmed. Heat energy is produced by district heating economizer (DH ECO). The consumed fuel $B_{SUIII} = f\,(P_{eSUIII})$ and produced heat $Q_{SUIII} = f\,(P_{eSUIII})$. As $P_{eSUIII}\uparrow \Rightarrow Q_{SUIII}\uparrow$, but $B_{SUIII}\downarrow$.

SUIV Parallel loading of the steam ($ST_{SUIV}^{t=k'''} \leq ST_{SUIV} \leq ST_{SUIV}^{t=k'''+e}$) and gas turbines ($GT_{SUIV}^{t=k'''} \leq GT_{SUIV} \leq GT_{SUIV}^{t=k'''+e}$) is taking place. The duration of *SUIV* is from k''' to $k''' + e$. In the end, the electrical power output of a unit increases up to P_{eTHmin}. Heat energy is produced by DH ECO and steam turbine. The fuel consumption $B_{SUIV} = f\,(P_{SUIV})$ and heat production $Q_{SUIV} = f\,(P_{SUIV})$. As $P_{SUIV}\uparrow \Rightarrow B_{SUIV}\uparrow$ and $Q_{SUIV}\uparrow$.

Mathematical models are proposed further for the calculation of the transient modes. They determine the amount of produced electricity and heat energy, consumed fuel and produced emissions and variable expenses of the transient modes.

The necessary input data are the following: hourly production data of a CCGT power plant (electrical power, heat power, fuel consumption in time), the price of fuel (natural gas) and carbon dioxide, the low heat value and the emission factor of fuel.

The duration of the transient mode (t_{TRM}) is the sum of three components: the duration of shutdown ($\sum_i^{i+z} t_{SD}$), warm state preservation ($\sum_m^{m+a} t_{WSP}$) and start-up ($\sum\sum_x^y t_{SU_v}$) (Eq. 3.1):

$$t_{TRM} = \sum_i^{i+z} t_{SD} + \sum_m^{m+a} t_{WSP} + \sum\sum_x^y t_{SU_v}, \tag{3.1}$$

where v – denotes the stage of start-up (I, II,III, IV);

x – denotes the beginning of start-up process stages, which are k; k'; k''; k''';

y – denotes the end of start-up process stages, which are $k+b$; $k'+c$; $k''+d$; $k'''+e$.

The produced electricity (P_{eTRM}) during the transient modes is the sum of two elements. They are the produced electricity during the shutdown ($\sum_i^{i+z} P_{eSD}$) and start-up ($\sum\sum_x^y P_{eSU_v}$) (Eq. 3.2):

$$P_{eTRM} = \sum_i^{i+z} P_{eSD} + \sum\sum_x^y P_{eSU_v}. \tag{3.2}$$

The amount of the produced heat energy (Q_{TRM}) is the sum of the produced heat during the shutdown ($\sum_i^{i+z} Q_{SD}$) and start-up ($\sum\sum_x^y Q_{SU_v}$) (Eq. 3.3):

$$Q_{TRM} = \sum_i^{i+z} Q_{SD} + \sum\sum_x^y Q_{SU_v}. \tag{3.3}$$

The consumed fuel (B_{TRM}) is calculated taking into account the consumed fuel during the shutdown ($\sum_i^{i+z} B_{SD}$), warm state preservation ($B_{WSP}^{t;n} \times \sum_m^{m+a} t_{WSP}$) and start-up ($\sum \sum_x^y B_{SU_v}$) (Eq. 3.4):

$$B_{TMR} = \sum_i^{i+z} B_{SD} + B_{WSP}^{t;n} \times \sum_m^{m+a} t_{WSP} + \sum \sum_x^y B_{SU_v}. \quad (3.4)$$

The emitted amount of dioxide emissions (CO_{2TRM}) during the transient modes is equal to the sum of the produced carbon dioxide emissions in *SD, WSP* and *SU* (Eq. 3.5):

$$CO_{2TMR} = \left(\sum_i^{i+z} B_{SD} + B_{WSP}^{t;n} \times \sum_m^{m+a} t_{WSP} + \sum \sum_x^y B_{SU_v}\right) \times Q_{LHV} \times E_{CO_2}, \quad (3.5)$$

where Q_{LHV} – low heat value of natural gas, MWh/m^3;

E_{CO_2} – a natural gas emission factor, t/MWh.

The costs of the transient modes (C_{TRM}) are the sum of shutdown, start-up and warm state preservation costs (Eq. 3.6):

$$C_{TMR} = \left(\sum_i^{i+z} B_{SD} + B_{WSP}^{t;n} \times \sum_m^{m+a} t_{WSP} + \sum \sum_x^y B_{SU_v}\right) \ldots$$
$$\ldots \times (P_{nat_{gas}} + Q_{LHV} \times E_{CO_2} \times P_{CO_2}), \quad (3.6)$$

where P_{nat_gas} – the price of natural gas, €/thous.m^3;

P_{CO_2} – the price of CO_2, €/t.

3.2. Practical Application of Mathematical Model

The transient modes of CCGT-2/2 unit are calculated. Figure 3.2 illustrates the shutdown of CCGT-2/2 unit. According to Fig. 3.2, the following is obvious [34]:

1. The duration of shutdown (t_{SD}) is 18 minutes: $i = 1$ and $i + z = 18$.
2. The technical minimum (P_{eTHmin}) of CCGT-2/2 is 180 MW. In turn, 187 MW > $P_{SD} \geq 0$ MW: 89 MW > $ST \geq 0$ and 98 MW > $GT \geq 0$ MW. The amount of the produced electricity (P_e) is 1830 MWh.
3. The shutdown of a cogeneration unit in Fig. 3.2 follows after its operation in the condensing mode, i.e., $Q = 0$ MW.
4. The consumed fuel (B_{SD}) is 6460 kg or 9308 m^3 (the density of natural gas: $\rho_{nat\_gas} = 0.6941$ kg/m^3).
5. The produced emission (CO_{2SD}) is 17 t ($E_{CO2} = 0.201$ t/MWh and $Q_{LHV} = 0.00935$ MWh/m^3).
6. The costs of shutdown (C_{SD}) are 2044 € ($P_{CO2} = 5$ €/t and $P_{nat\_gas} = 0.21048$ €/m^3).

The developed mathematical model does not take into account the part of shutdown procedure, which is on the right side from the black dashed vertical line (Fig. 3.2). This period is 15 minutes long: power is not produced; the speed of gas turbine and steam turbine decreases and fuel consumption is 181 kg. It is just 2.7 % of the fuel consumption, when $180 \geq P_{SD} \geq 0$. The author considers that this does not influence the calculation accuracy of shutdown costs.

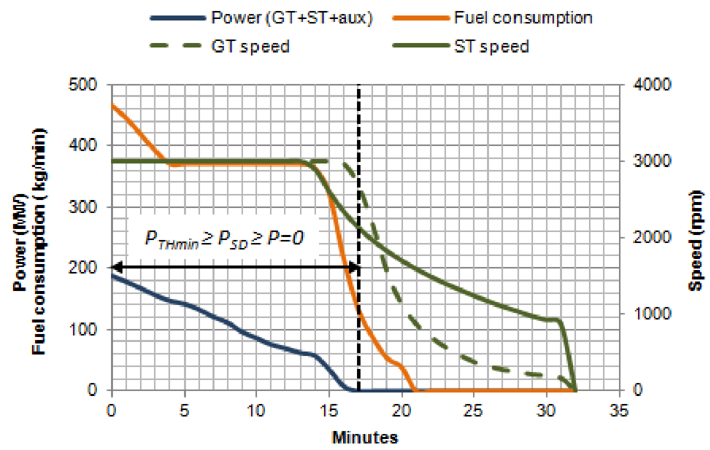


Fig. 3.2. Shutdown of production unit CCGT-2/2 [34].

In this example it is assumed that the warm state is not preserved and the duration of the unit outage *(t_{WSP})* is 72 hours (or 4320 minutes): m = 1 h and m+a = 72 h.

The correct determination of the periods of start-up procedure (*SUI, SUII, SUIII, SUIV*) in line with the proposed methodology requires reflecting the loading process of gas turbine and steam turbine (Fig. 3.3) in addition to the total electrical power.

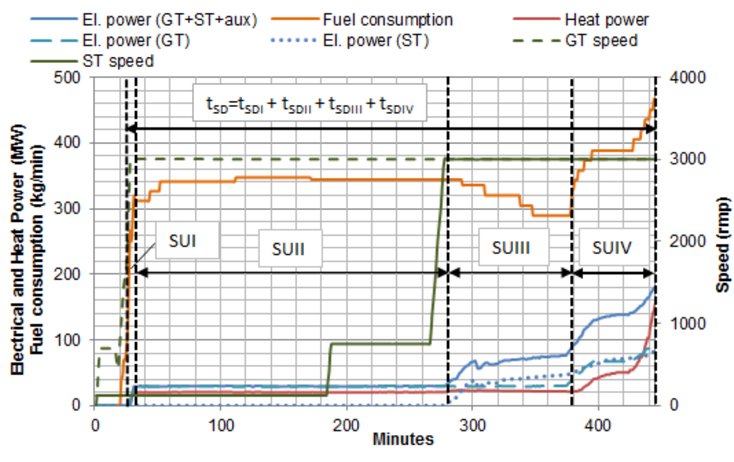


Fig. 3.3. Start-up of production unit CCGT-2/2 [34].

According to Fig. 3.3, the following information on the start-up of CCGT-2/2 unit can be obtained.

- The duration of start-up ($t_{SUI, SUII, SUIII, SUIV}$) is 418 min: k' = 1 and k'''+ e = 418.
- The amount of the produced power ($P_{SUI, SUII, SUIII, SUIV}$) is 22 964 MWh.
- The amount of the produced heat ($Q_{SUI, SUII, SUIII, SUIV}$) is 10 991 MWh.
- The total amount of the consumed fuel ($B_{SUI, SUII, SUIII, SUIV}$) is 143 376 kg or 206 563 m^3.
- The amount of the produced emissions ($CO_{2\ SUI, SUII, SUIII, SUIV}$) is 388 t.

- The costs of start-up ($C_{SUI,\ SUII,\ SUIII,\ SUIV}$) is 45 400 €.

Thus, the total duration of the transient modes (t_{TRM}) with outage of 72 h and cold start-up is 4756 minutes. The amount of the produced electricity (P_{eTRM}) is 24 794 MWh. The amount of the produced heat energy (Q_{TRM}) is 10 990 MWh. In this case, it is equal to the produced heat energy during the start-up. The total amount of the fuel (B_{TRM}) consumed during the transient mode is 149 836 kg or 215 870 m^3. The total emissions producing CO_2 are 405 t. The total costs of the transient modes (C_{TRM}) are 47 444 €.

4 OPTIMISATION OF OPERATION MODE

4.1. Approach to Optimisation of the Operation Mode

EM&OM (*Evaluation Model & Optimization Model*) approach (Fig. 4.1) was developed for a combined cycle gas turbine technology with the aim of optimising its cycling operation under the electricity market conditions. The *EM* processes the production data of a power plant and consequently determines the cycling characteristics of a power plant and input for *OM*. The *OM* ensures the extension of cycling operation range by shifting shutdown *"forward"* and start-up *"backward"* and, hence, the supplementary electricity is produced; the number of cycling periods is reduced and start-ups are replaced with less adverse ones.

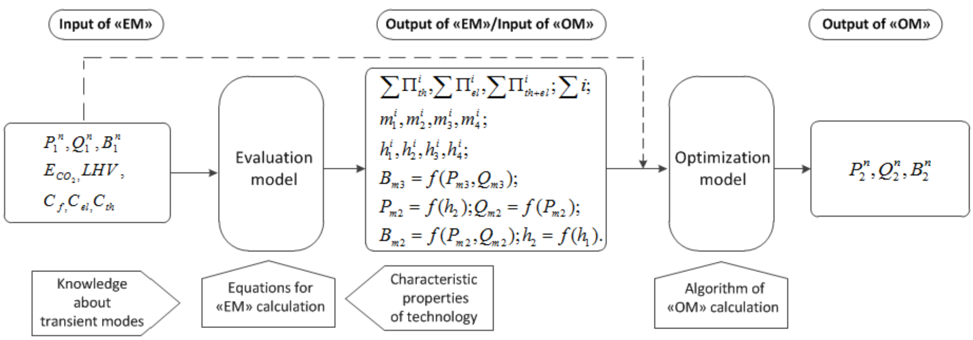


Fig. 4.1. The flowchart of the developed approach [30].

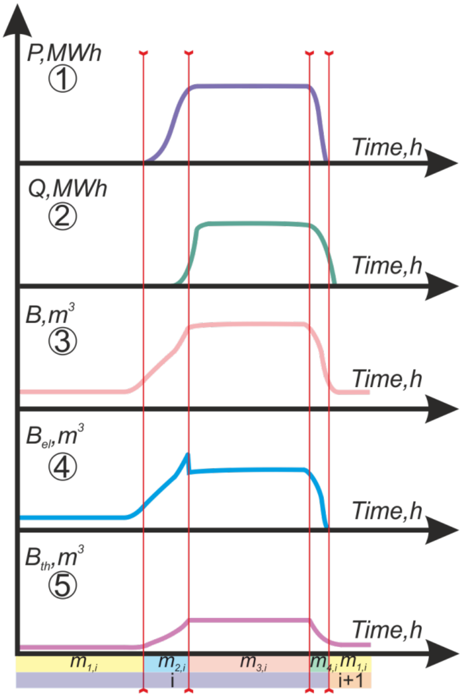
(P, P^n_2 – electrical power; Q, Q^n_2 – heat power; B, B^n_2 – fuel; C_{th} – heat price; C_{el} – electricity price; C_f – fuel price; E_{CO2} – CO_2 emission factor of fuel; LHV – low heat value; m_1 – warm state preservation; m_2 – start-up; m_3 – operation above technical minimum; m_4 – shutdown; h_1 – duration of $m1$; h_2 – duration of m_2; h_3 – duration of m_3; h_4 – duration of m_4; $\sum\Pi_{th}, \sum\Pi_{el}, \sum\Pi_{th+el}$ – profit from electricity and heat production).

Equations (4.1)–(4.9) of *EM* (see Table 4.1) are developed based on information provided in Fig. 4.2 and the previously obtained knowledge about transient modes and characteristic properties of a combined cycle gas turbine technology in [24], [34].

Table 4.1

Equations of the Evaluation Model [30]

Equation	Unit	Explanation	Eq. No
$B^{i}_{th_{n,m\,3...4}} = \dfrac{Q^{i}_{n,m\,3...4}}{0.93 \times LHV}$	[m^3/h]	The consumption of fuel for heat production in periods: operation above technical minimum and shutdown (Coefficient 0.93 describes the efficiency of heat production in the cogeneration mode)	(4.1)
$B^{i}_{el_{n,m\,3...4}} = B^{i}_{n,m\,3...4} - B^{i}_{th_{n,m\,3...4}}$	[m^3/h]	The consumption of natural gas for electricity production in periods: operation above technical minimum and shutdown	(4.2)
$B^{i}_{th_{n,m\,1...2}} = B^{i}_{n,m\,1...2} \times \dfrac{\sum_{m_1}^{m_2}\sum_{n=1}^{n=N} Q^{i}_{n,m}}{\sum_{m_1}^{m_2}\sum_{n=1}^{n=N} P^{i}_{n,m}}$	[m^3/h]	The consumption of natural gas for heat production in periods: warm state preservation and start-up	(4.3)
$B^{i}_{el_{n,m\,1...2}} = B^{i}_{n,m\,1...2} - B^{i}_{th_{n,m\,1...2}}$	[m^3/h]	The consumption of natural gas for electricity production, when the cogeneration unit is in warm state preservation or it starts up	(4.4)
$MC^{i}_{el_{avg\,n,m}} = \dfrac{\sum_{m_1}^{m_4}\sum_{n=1}^{n=N}(B^{i}_{el_{n,m}} \times C^{i}_{f_{n,m}} + B^{i}_{el_{n,m}} \times LHV \times E_{CO_2} \times C^{i}_{CO_{2\,n,m}})}{\sum_{m_2}^{m_4}\sum_{n=1}^{n=N} P^{i}_{n,m}}$	[€/MWh]	The average marginal cost of electricity per cycling operation range	(4.5)
$MC^{i}_{th_{avg\,n,m}} = \dfrac{\sum_{m_1}^{m_4}\sum_{n_1}^{n}(B^{i}_{th_{n,m}} \times C^{i}_{f_{n,m}} + B^{i}_{th_{n,m}} \times LHV \times E_{CO_2} \times C^{i}_{CO_{2\,n,m}})}{\sum_{m_2}^{m_4}\sum_{n_1}^{n=N} Q^{i}_{n,m}}$	[€/MWh]	The average marginal cost of heat per cycling operation range	(4.6)
$\Pi^{i}_{th} = \sum_{m_1}^{m_4}\sum_{n=1}^{n=N}(C^{i}_{th_{n,m}} \times Q^{i}_{n,m} - B^{i}_{th_{n,m}}(C^{i}_{f_{n,m}} + LHV \times E_{CO_2} \times C^{i}_{CO_{2\,n,m}}))$	[€]	The profit of the produced heat in cycling operation ranges per year	(4.7)
$\Pi^{i}_{e} = \sum_{m_1}^{m_4}\sum_{n=1}^{n=N}(C^{i}_{e_{n,m}} \times P^{i}_{n,m} - B^{i}_{e_{n,m}}(C^{i}_{f_{n,m}} + LHV \times E_{CO_2} \times C^{i}_{CO_{2\,n,m}}))$	[€]	The profit of the produced electricity in cycling operation ranges per year	(4.8)
$\Pi^{i} = \Pi^{i}_{e} + \Pi^{i}_{th}$	[€]	The total profit of heat and electricity production in cycling operation ranges per year	(4.9)



① The change in electrical power is taken as a reference point, i.e., the division of cycling operation range into m_1, m_2, m_3 and m_4.
② The heat power falls behind the electrical power in m_2 and m_3. At the end of m_4 and at the beginning of $m_{1,i+1}$ heat power is greater than zero and electrical power is equal to zero. The value of heat power in $m_{1,i+1}$ is shifted to the warm state preservation of a new cycling operation range, i.e., $i+1$.
③ The fuel is consumed, when the unit is out of operation to preserve the warm state of the unit. If outage is too long, then the warm state is not preserved. The total amount of the consumed natural gas for electricity and heat production is also taken as input data in the mathematical model of evaluation of cycling operation range.
④,⑤ Natural gas for heat and electricity production in m_3 and m_4 is calculated using Eqs. (4.1) and (4.2), respectively. Due to short duration of m_4 (less than 30 minutes), the consumption of fuel is calculated for both periods simultaneously. Fuel consumption for heat and electricity production in m_1 and m_2 is calculated proportionally to the produced heat and electricity in m_1 and m_2. It is performed using Eqs. (4.3) and (4.4). $Q_{m1,i} = Q_{m1,i-1}$ due to the fact that at the end of m_4 and at the beginning of $m_{1,i+1}$ heat power is greater than zero and electrical power is equal to zero.

Fig. 4.2. The schematic change in electricity, heat and fuel during the cycling operation range *"i"* [30].

Also the start-up characteristics of CCGT technology ($h_2=f(h_1)$; $Bm_2=f(P_{m2};Q_{m2})$; $P_{m2}=f(h_2)$; $Q_{m2}=f(P_{m2})$) and mathematical relation ($B_{m_3}=a_1 \times P_{m_3}+a_2 \times Q_{m_3}+a_3$), which describe simultaneous change in natural gas consumptions, heat power and electrical power, [30].

The concept of optimisation task (Fig. 4.3) and its calculation algorithm are based on the selection method and principles of the Nord Pool intra-day physical market. The optimisation of cycling operation is achieved through the extension of cycling operation range.

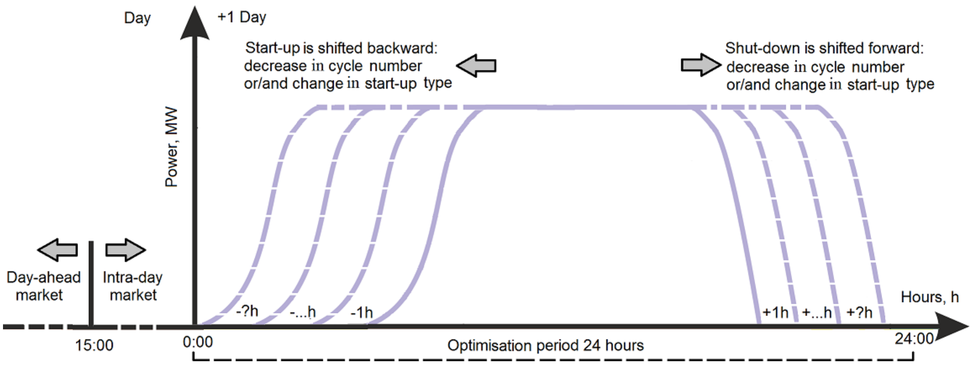


Fig. 4.3. A traditional example of an optimisation task concept [30].

The optimisation task can be implemented in two ways: referring to the maximum profit (Optimisation No. 1 (Eq. 4.10)) or referring to the positive profit and reduction of negative impact of cycling operation on technical resources of the equipment by maximising the hours in operation (n) under condition that the gained profit has to be positive (Optimisation No. 2 (Eq. 4.11)).

The objective function for Optimisation No. 1 is as follows:

$$\sum_i [\sum_{m_1}^{m_4} \sum_{n=1}^{n=N} (C^i_{e_{n,m}} \times P^i_{n,m} - B^i_{e_{n,m}} (C^i_{f_{n,m}} + LHV \times E_{CO_2} \times C^i_{CO_{2\,n,m}}))...$$

$$... + \sum_{m_1}^{m_2} \sum_{n=1}^{n=N} (C^i_{th_{n,m}} \times Q^i_{n,m} - B^i_{th_{n,m}} (C^i_{f_{n,m}} + LHV \times E_{CO_2} \times C^i_{CO_{2\,n,m}}))] \rightarrow \max \Pi, \quad (4.10)$$

Subject to

$i = 1,...,I$, $i \in Z_+$

$n = 1,...,N$, $n \in Z_+$

$N \leq 24$

$P = 0$, $Q = 0$ *if* $m = m_1$

$0 < P \leq P_{m2}$, $0 < Q \leq Q_{m2}$ *if* $m = m_2$

$P^{min} < P \leq P^{max}$, $Q^{min} < Q \leq Q^{max}$ *if* $m = m_3, m_4$

The objective function for Optimisation No. 2 is as follows:

$$\sum_i [\sum_{m_1}^{m_4} \sum_{n=1}^{n=N} (C^i_{e_{n,m}} \times P^i_{n,m} - B^i_{e_{n,m}} (C^i_{f_{n,m}} + LHV \times E_{CO_2} \times C^i_{CO_{2\,n,m}}))...$$

$$... + \sum_{m_1}^{m_2} \sum_{n=1}^{n=N} (C^i_{th_{n,m}} \times Q^i_{n,m} - B^i_{th_{n,m}} (C^i_{f_{n,m}} + LHV \times E_{CO_2} \times C^i_{CO_{2\,n,m}}))] \rightarrow \max n, \quad (4.11)$$

Subject to

$$i = 1,...,I\,,\ i \in Z_+$$

$$n = 1,...,N\,,\ n \in Z_+$$

$$N \leq 24$$

$$\begin{cases} P = 0 \\ Q = 0 \end{cases} \quad if\ m = m_1$$

$$\begin{cases} 0 < P \leq P_{m2} \\ 0 < Q \leq Q_{m2} \end{cases} \quad if\ m = m_2$$

$$\begin{cases} P^{\min} < P \leq P^{\max} \\ Q^{\min} < Q \leq Q^{\max} \end{cases} \quad if\ m = m_3, m_4$$

$$\Pi > 0,\ \Pi \in R_+$$

4.2. Approbation of the Developed Approach

The CCGT-2/1 unit operation was analysed for 2016 in line with the *Evaluation Model*. The number of cycling operation ranges and their duration, the type of start-ups and their number and duration and profit from heat and electricity production were determined. After that the optimization was provided in line with Optimisation tasks No. 1 and No. 2. The situation before and after optimisation is reflected in Table 4.2

Table 4.2

Results of Optimisation Tasks [30]

	Income, [M€]	$\sum i$, [number]	Operation hours, [h]	Number of hot start-ups, [h]	Number of warm start-ups, [h]	Number of cold start-ups, [h]
Before optimisation	6	57	2571	15	19	23
Optimisation No. 1	7.42	57	2799	21	15	21
Optimisation No. 2	7.27	53	2846	17	15	21

Optimisation No. 1 ensures higher income than *Optimisation No. 2*, i.e., 1.42 M€ and 1.27 M€, respectively. The difference is insignificant, approximately 150 k€. In turn, the results of *Optimisation No. 2* have demonstrated the decrease in cycling operation ranges by four cycles, whereas *Optimisation No. 1* have not.

The developed approach is used in intraday market, then the influence of the optimised CCGT-2/1 unit should be investigated on CCGT-2/2 unit (assuming that both cogeneration units form the portfolio) in line with developed algorithm (Fig. 4.4) by checking three scenarios (Table 4.3).

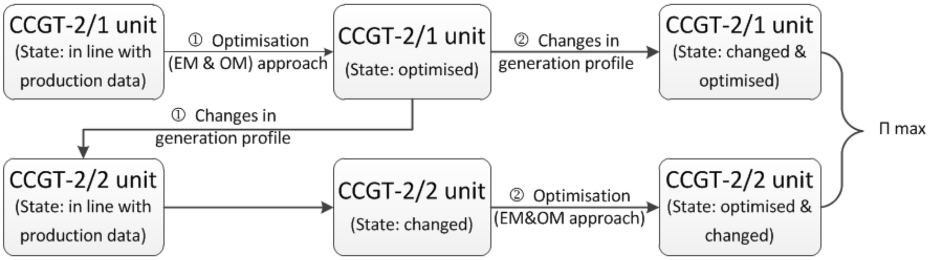


Fig. 4.4. The block scheme of the evaluation algorithm [35].

In case of Scenario No. 1, the additional profit is obtained due to the reduction of time spent in warm state preservation. This has resulted in more efficient start-up. In their turn, Scenarios No. 2 and No. 3 provide negative profit because the optimisation of CCGT-2/1 unit has led to CCGT-2/2 unit's electrical power reduction to the technical minimum. The specific consumption of natural gas of the second cogeneration unit has increased. As a result, the efficiency of CCGT-2/2 unit has decreased (Table 4.3).

Table 4.3

Interpretation of Optimisation Results [35]

Parameters & Scenarios	**The value of parameter before optimisation**	**The value of parameter after optimisation**	**Difference between parameters after and before optimisation**
Scenario No. 1:	**Start-ups are shifted *"backward"***		
Gain/losses, [€]	17.2537×10^6	17.2775×10^6	23 800
Operation hours of both cogeneration units, [h]	5744	5768	24
Scenario No. 2:	**Shutdowns are shifted *"forward"***		
Gain/losses, [€]	17.2537×10^6	17.1511×10^6	- 102 600
Operation hours of both cogeneration units, [h]	5744	5773	29
Scenario No. 3:	**Start-ups are shifted *"backward"* and shutdowns – *"forward"***		
Gain/losses, [€]	17.2537×10^6	17.1751×10^6	- 78 600
Operation hours of both cogeneration units, [h]	5744	5803	59

5 GENERAL ALGORITHM FOR TECHNICAL AND ECONOMIC EVALUATION OF TECHNOLOGIES

The general algorithm for technical and economic evaluation of technologies is presented in Fig. 5.1. The aim of this algorithm is to answer the questions: Is the increased flexibility level of the power plant by technology economically feasible and ensures the additional profit? How different parameters influence the payback of technology (sensitivity analysis)?

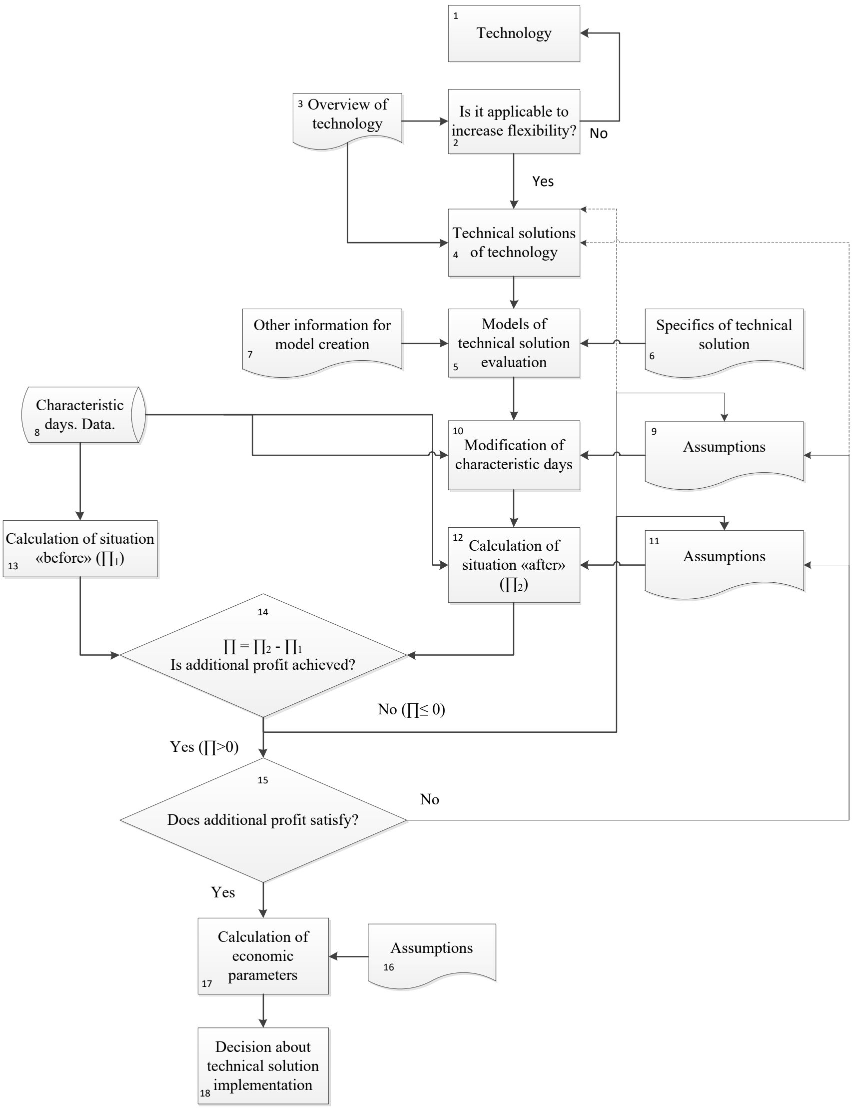


Fig. 5.1. General algorithm for technical and economic evaluation of technologies.

The developed algorithm (Fig. 5.1) is adapted to three different technologies: air cooling, electric boiler and heat storage system (see Chapters 6, 7, 8).

The algorithm (Fig. 5.1) has practical application. It has been adapted to evaluate the feasibility of installation of the exhaust gas condenser economizer at Riga TPP-1 (HOB No. 3) and gas turbine modernisation at Riga TPP-2. Both installation of the exhaust gas condenser economizer and modernisation of the gas turbine have been implemented. For more details see the author's works [36] and [4], [15], respectively. The algorithm has been used to evaluate the feasibility of heat storage system installation at Riga TPP-2. The co-financing was assigned within the framework of programme "Development and Employment" (the second call of 4.3.1. Specific Support Object measure "Promote energy efficiency and the use of local renewable energy sources in district heating system") [37]. Now the procurement procedure is conducted to select EPC contractor for the development of technical design and for further construction of the heat storage tank [38].

6 USE OF AIR COOLING TECHNOLOGY

6.1. Justification and Technical Solutions of Technology

Ambient air temperature has negative impact on gas turbine operation, i.e., with the increase of air temperature the power output and thermal efficiency of gas turbine decrease and heat rate increases [39]–[44]. Traditionally, there are four air cooling technologies: absorption chiller, mechanical chiller, evaporative and fogging cooling [40]. The air cooling systems are mainly installed in the regions with hot and dry climate, such as Iran [39], Saudi Arabia [45], Oman [46], Iraq [47], Brazil [40], etc., with the aim to increase the production of electricity and cover the peak demand of electricity during the periods of high air temperature, thus avoiding power plant extension. Within the framework of the Thesis, the use of air cooling technologies is considered in wet and warm climate conditions to adapt a CCGT power plant to a situation in the electricity market, increase the production of electricity and receive additional income from additionally produced electricity realisation in the market.

6.2. Methodology of Air Cooling Evaluation

The calculation algorithm is reflected in Fig. 6.1. It is used to evaluate the use of air chilling technologies at CCGT power plants to adapt their operation to a variable situation in the electricity market. The fundamentals of the algorithm: the information about a characteristic day (ambient air temperature and electricity price) and gas turbine characteristics (results of simulation) are used as input data; the difference between two situations (*after* air cooling and *before* air chilling) determines the profit of a characteristic day; the yearly profit is calculated by multiplying a characteristic day with its number in a year; the technical solution with the highest profit is chosen.

The gas turbine manufacturers provide the characteristics (power output, heat rate, efficiency) of gas turbines under ISO conditions (ISO: 3977-2): ambient temperature is + 15 ºC; relative humidity is 60 % and pressure is 101.3 kPa [49]. The thermodynamic model of gas turbine is used to obtain the information about GT values within the range of ambient air temperature from + 5 ºC to + 31 ºC.

The algorithm (Fig. 6.1) contains constraints, which limit the use of air cooling technologies (characteristics of technologies) [43].

The objective function ensures the maximisation of benefit (P_y) gained by chilling the air in front of the compressor of GT unit:

$$P_y = \sum_{i=1}^{n} b_i \times a_i = \sum_{i=1}^{n} b_i \times \left(\sum_{j=1}^{m}((W_{N2} - W_{N1} - W_{MC}) \times E)_j\right) \rightarrow max\,, \qquad (6.1)$$

where P_y – profit from air cooling per year, €/year;

b – the number of typical days within a year, number/year;
a – profit of a typical day in 24 h, €/24h;
i, n – the order number of a typical day within a year, [–];
$j,\ m$ – the order number of hours in a typical day, [–];
E – electricity price, €/MWh;
W_{N2} – power after air cooling, MW/h;
W_{N1} – power before air cooling, MW/h;
W_{MC} – the parasitic load of mechanical chiller, MW/h.

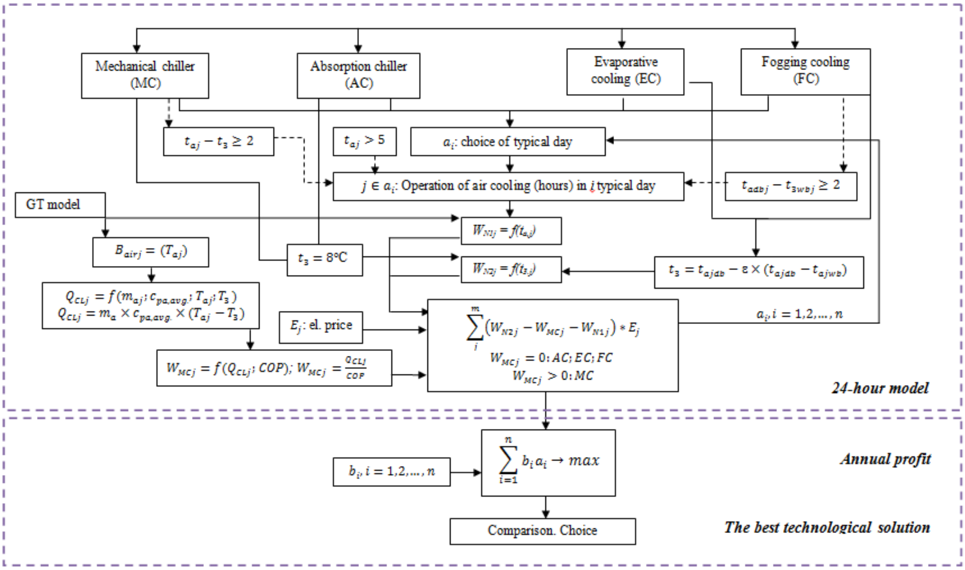


Fig. 6.1. Evaluation algorithm [48].

If cool energy is produced at night for the later use, i.e., during the daytime (energy storage), the objective function is the following:

$$P_y = \sum_{i=1}^{n} b_i \times (\sum_{j=1}^{m}((W_{N2} - W_{N1}) \times E_d - (W_{MC} \times E_n))_j)_i \rightarrow max. \quad (6.2)$$

The parasitic load is multiplied by the electricity price during the night time (E_n) and the additionally produced electricity – by the electricity price during the daytime (E_d) [39].

6.3. Practical Application of Methodology

Figure 6.2 provides the example of CCGT-2/2 unit operation during the summer period in 2015. The cogeneration unit is at full load during the daytime, when electricity price is high at electricity power exchange. The dashed line reflects the range when air chilling can be used to generate additional electricity. It is during the daytime when GT is at full load and the electricity price is high. The profit of air chilling is obtained from selling additionally produced electricity to the market.

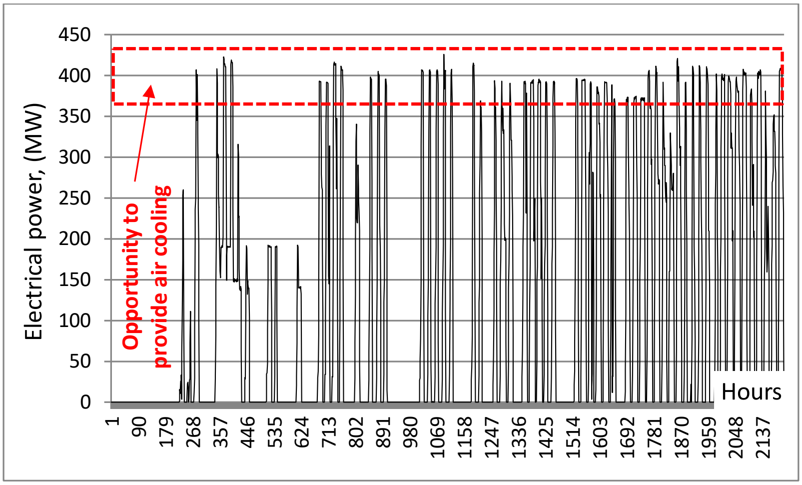


Fig. 6.2. Example of CCGT-2/2 unit operation in summer (June–August) in 2015 [48].

According to the obtained results the benefit of mechanical (€ 511.43 thous.) and absorption (€ 609.80 thous.) chillers exceeds the benefit of evaporative cooling (€ 147.33 thous.) ~ 4 times and fogging cooling (€ 219.06 thous.) ~ 2–3 times. The mechanical and absorption chillers are more appropriate for the climate conditions in Riga (warm and humid [50]) than other technologies.

The benefit from air cooling (P_y) can be represented as a function (6.3) of ambient temperature (t); electricity hourly price (E); number of operated days during a year (n) and operated hours during a typical day (m). In the case of a mechanical chiller, such parameter as coefficient of performance (COP) should be mentioned.

$$P_y = f(t; E; n; m; COP). \tag{6.3}$$

The ambient temperature is taken into account if the calculation of benefit is carried out for different regions.

The sensitivity analysis is carried out for mechanical and absorption chillers (see Table 6.1) as the more appropriate technologies for the climate conditions in Riga (Latvia).

Table 6.1

Results of Sensitivity Analysis [48]

	Mechanical chiller (COP = 2)		Absorption chiller	
	MWh	thous. €	MWh	thous. €
Additionally gained income	($E_{avg.}$ = 54.5 €/MWh; n = 49 days; m = 10 hours/day)			
	9376	511.41	11172	609.81
E decrease by 36 %	($E_{avg.}$ = 34.9 €/MWh; n = 49 days; m = 10 hours/day)			
	9376	327.32	11179	390.27
E increase by 18 %	($E_{avg.}$ = 64.4 €/MWh; n = 49 days; m = 10 hours/day)			
	9376	603.49	11179	719.56
n increase by 85 %	($E_{avg.}$ = 54.5 €/MWh; n = 91 days; m = 10 hours/day)			
	17381	949.77	20748	1132.50

m decrease by 50 %	($E_{avg.}$ = 54.5 €/MWh; n = 49 days; m = 5 hours/day)			
	4813	263.24	5737.78	313.84
COP = 4	($E_{avg.}$ = 54.5 €/MWh; n = 49 days; m = 10 hours/day)			
	10277	560.62	-	-

The decrease in the electricity price (E) and operating hours (m) during the day exerts the most negative impact on the additionally gained income. It is the decrement of additional income by 56 % and 48 %, respectively. The increase in operating days (n) ensures the most positive influence on the additionally gained income.

7 INSTALLATION OF ELECTRIC BOILER

7.1. Justification and Technical Solutions of Technology

District heating system with power generation is integrated in electricity system since TPPs are used for heat supply [51]. This creates new opportunities and conditions for district heating (DH) and power system cooperation through the use of DH flexible technologies, i.e., power-to-heat (P2H) technologies (electric boilers (EB) and heat pumps). They use electricity to produce thermal energy.

In this section the use of electric boiler is considered, because it is more flexible and less expensive than a heat pump [52]–[54]. There are obstacles to use electric boiler in district heating system for heat generation [52], [55]–[57]. A significant obstacle related to the additional use of electricity is the existing legislation supporting a payment system that produces prices from several components that include, apart from market prices, also a fee for network services and taxes. For example, in Latvia the electricity price composes only 30 % of electricity tariff, 70 % is payment for transmission and distribution system services, payment for mandatory procurement and capacity components and value-added tax [58]. This leads to the increase in thermal energy price making impossible for the electric boiler to compete with tax-free natural gas or biomass heat only boilers (HOBs) [52].

Within the framework of the Thesis, it is assumed that the production costs of an electric boiler are equal to the electricity price (the other components of electricity tariff are omitted) in the market. Author would like to demonstrate that electric boiler can be widespread not only in the ancillary market, but can also provide the competitive heat energy and reduce the production costs of a power plant, but it should be supported by authorities.

7.2. Evaluation Methodology of Electric Boiler

The use of electric boiler is evaluated for the following *targets* [31], [59].

1. *Target No. 1:* During the night, the marginal costs of a cogeneration unit (CU) are higher than the electricity price in the market. Thus, HOBs are used instead of CU, whose operation can be substituted with EB in a more profitable way to reduce the production costs of TPP.

2. *Target No. 2:* The appearance of new heat energy sources, such as biomass HOBs (BIO), can offer a lower heat energy price than a fossil fuel TPP, when the electricity price is low in the market. The electric boiler can be used during this period to produce the heat energy and increase the competitiveness of a fossil fuel power plant.

It is sufficient to assess the additionally gained profit of each target to evaluate them. The structure of yearly profit calculation algorithm is depicted in Fig. 7.1.

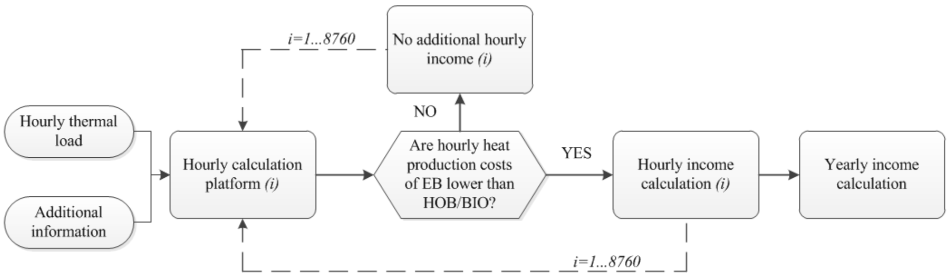


Fig. 7.1. The algorithm of income calculation [59].

Equations (7.5)–(7.9) are used to calculate the hourly and then annual income, expected in line with *Target No. 1* [31], [59].

The substitution of HOBs with EBs is well founded if the inequality is valid, i.e., the heat production costs of EB are lower than HOB heat production costs.

$$P_i^{Q,EB} < P_i^{Q,HOB}. \tag{7.5}$$

The production costs of heat energy produced by natural gas fired HOBs are assumed equal to the variable component of the production costs, i.e., fuel and carbon dioxide costs (7.6). The fuel costs form up to 80 % of heat energy price of natural gas fired units:

$$P_i^{Q,HOB} = \frac{1}{\eta_{avg}^{HOB}} \times \left(\frac{P_m^{NG}}{NG^{LHV}} + E_{CO_2} \times P_i^{CO_2}\right). \tag{7.6}$$

The production costs of heat energy produced by the electric boiler are equal to the electricity price supplied to the electric boiler (in the Thesis, it is assumed that η_{EB} = 100 %):

$$P^{Q,EB}{}_i = P^E{}_i. \tag{7.7}$$

The hourly income is calculated by (7.8), if the substitution of HOBs with EBs is well founded:

$$Q_i^{EB} \times (P_i^{Q,HOB} - P_i^{Q,EB}). \tag{7.8}$$

The income per year is equal to

$$\sum Q_i^{EB} \times (P_i^{Q,HOB} - P_i^{Q,EB}). \tag{7.9}$$

Equations (7.10)–(7.15) are applied to calculate the hourly and then annual income, which are going to be achieved in line with Target *No. 2* [31], [59].

The substitution of HOBs with EBs is profitable, if two inequalities, i.e., (7.10) or (7.11) are true:

$$P_i^{Q,HOB} > P_i^{Q,BIO} < P_i^{Q,EB}, \tag{7.10}$$

$$P_i^{Q,HOB} > P_i^{Q,BIO} > P_i^{Q,EB\prime}. \tag{7.11}$$

In case of (7.11), the modified heat production costs of EB are used. They are calculated in line with Eq. (7.12).

$$P_i^{EB'} = P_i^{Q,BIO} - 1. \quad (7.12)$$

It is assumed that in order to be competitive the modified heat energy production costs of EB are by 1 €/MWh lower than the production costs of biomass heat energy sources.

In contrast to the natural gas fired units, the fuel costs of the biomass heat energy sources form until 50 % of the heat energy price. That is why such additional costs as the costs of auxiliary electricity, taxes and other costs are taken into consideration [60]. Expression (7.13) is applied to determine the production costs (variable component) of heat energy produced from the biomass heat energy sources:

$$P^{F,BIO} + 0.03 \times P^{F,BIO} + 0.06 \times P^{F,BIO}, \quad (7.13)$$

where $P^{F,BIO}$ – costs of biomass (raw materials), €/MWh;

$0.03 \times P^{F,Bio}$ – taxes and other costs, €/MWh;

$0.06 \times P^{F,Bio}$ – costs of auxiliary electricity, €/MWh.

The hourly income of electrical boiler superiority under the biomass boiler can be calculated as follows:

$$Q_i^{EB'} \times (P_i^{EB\prime} - P_i^{Q,EB}). \quad (7.14)$$

The annual income is equal to

$$\sum Q_i^{EB'} \times (P_i^{EB'} - P_i^{Q,EB}). \quad (7.15)$$

7.3. Practical Application of Methodology

The use of electric boiler was evaluated in Riga TPP-2 (Table 7.1). The installed capacity of the electric boiler was assumed 150 MW, due to the unique situation on the right bank of Riga district heating system – the appearance of the new biomass heat energy sources with total thermal capacity of 150 MW. Both *Targets* were calculated in line with evaluation algorithm (Fig. 7.1) and Equations provided in Section 7.2.

Table 7.1

Operation Hours of Electric Boiler in Different Situations [31], [59]

Parameters	Before	Target No. 1	Target No.2
HOB, h	5927	4670	2681
EB, h	-	2663	336
BIO, h	-	-	5647
Income, M€	-	3.3	0.13
Payback period*, years		~ 4	-

* It is assumed that the investment into electric boilers with total heat capacity of 150 MW can be approximately 12 M€ [20]. The payback period is calculated as the capital costs divided by the benefit [39].

According to the operation manner of the power plant in 2015 and provided assumptions it is concluded from Table 7.1, that the use of EB instead of HOBs during the periods of low electricity price ensures more profitable operation of the fossil fuel TPP (*Target No. 1*). However, the installation of electric boiler cannot increase the competitiveness of a thermal power plant due to the low price of biomass and the high price of electricity (*Target No. 2*).

8 INSTALLATION OF HEAT STORAGE TANK

8.1. Justification and Technical Solutions of Technology

Heat storage system decouples the production of thermal energy and electricity. There are three goals of thermal energy storage system: thermal load levelling of heat energy source, increased security of energy supply, increased flexibility of energy source operation [61].

There are different technical solutions of the thermal energy storage system. According to the foreign and local experience, the most common one is the thermal energy system with liquefied storage medium (water), thermal energy displacement (ensuring of stratification) and vertical heat storage tank position [20], [62], [63].

8.2. Evaluation Methodology of Thermal Energy Storage System

The two situations were evaluated before ($\sum_i (m_i \times \Pi_i)_1$) and after ($\sum_i (m_i \times \Pi_i)_2$) heat storage tank system implementation to define the additional income:

$$\Pi_k = \sum_i (m_i \times \Pi_i)_2 - \sum_i (m_i \times \Pi_i)_1 , \tag{8.1}$$

where i – a characteristic day;

m_i – number of characteristic days (i) during a year, number;

Π_i – profit of a characteristic day (i), €/day.

The profit of one characteristic day (i) is calculated taking into account the electricity price in the market, electricity production costs, amount of the supplied electricity and start-up costs (Eq. 8.2).

$$\Pi_j = \sum_j ((C_j - MC_j) \times P_j) - C_{start-up} , \tag{8.2}$$

where j – hour in a characteristic day;

C_j – electricity price per hour €/MWh;

MC_j – electricity production costs per j hour €/MWh;

P_j – the supplied electricity per j hour, MWh;

$C_{start-up}$ – start-up costs, €/start-up.

It was presented at the 4th conference *"From Technical Solution to Efficiency, Flexibility and Competitiveness"* organised by JSC *Rigas Siltums* [64] that the additional income from heat storage system installation can be ensured by the additionally produced electricity and its realisation in the market or by the efficiency increase of the power plant. It is determined by the situation of a characteristic day. In brief, two main outcomes are possible.

1. Thermal power plant is not fully loaded after electrical and heat power. After the installation of heat storage system the electrical power and heat power increase during the daytime. It is necessary to use additional fuel to provide additional electricity production. Thus, there are no natural gas savings and reduction in CO_2 emissions, but additional profit is gained from electricity realisation in the market.
2. Thermal power plant is not fully loaded after heat power, but electrical power is almost equal to the installed one, during the daytime. After the installation of heat storage system the heat power increases during the daytime. The electrical power does not increase (initially is run at maximum) or increases insignificantly (initially is run almost at maximum). The operation of the power plant is shifted to a more efficient operation. Thus, the natural gas savings and reduction in CO_2 emissions ensure additional profit from heat storage system installation.

8.3. Practical Application of the Methodology

It is the first time in Latvia that the installation of a large-scale heat storage system is evaluated (until 20 000 m^3 or 550 MWh) at the fossil fuel TPP (Riga TPP-2).

Two figures below reflect the situation before (Fig. 8.1) and after (Fig. 8.2) heat storage system installation. It is concluded that after heat storage system installation it is possible to obtain the following benefits: operation in mixed mode is replaced with running conditions in cogeneration mode, the competitiveness of TPP increases due to a decrease in power plant production costs; the operation period extends where TPP electricity production costs are lower than the electricity price; it is possible to gain additional profit from realisation of additionally produced electricity in the market.

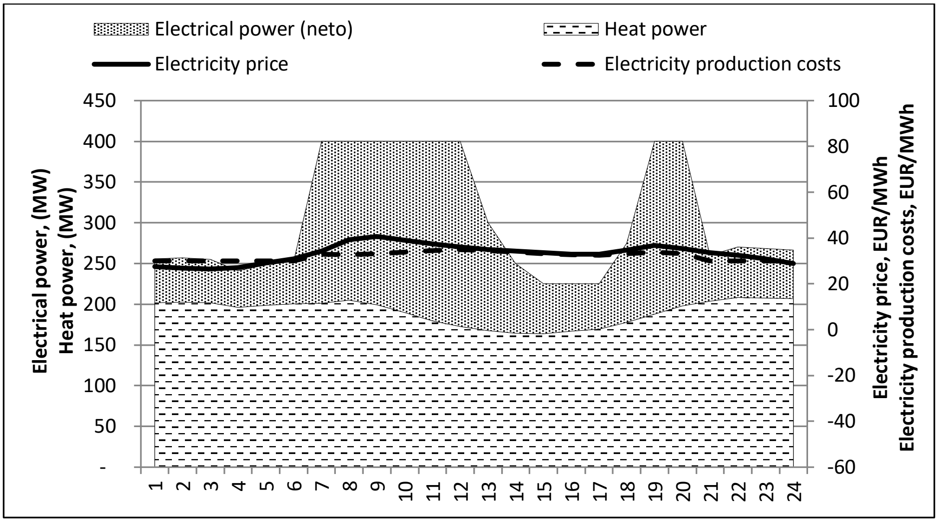


Fig. 8.1. Power of CCGT-2/2 unit before the installation of heat storage system (characteristic day reflects the situation in March).

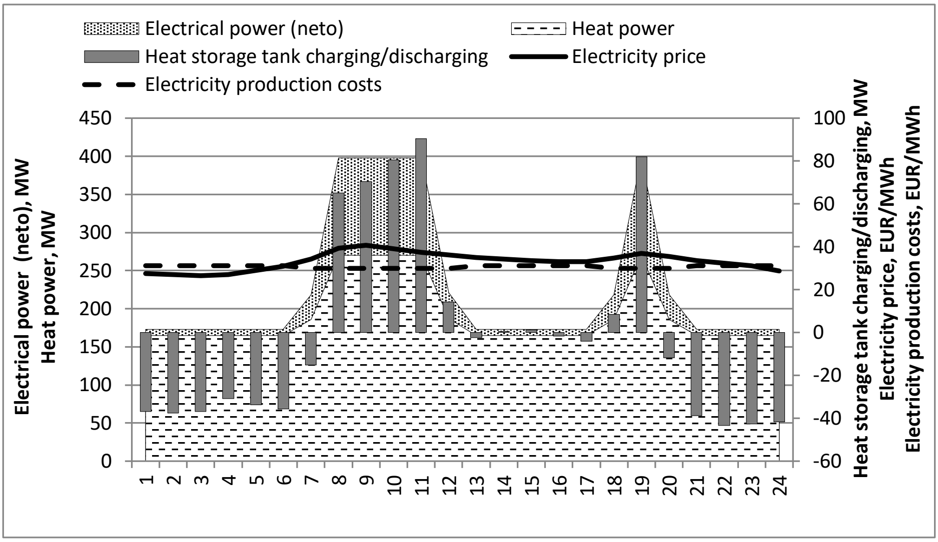


Fig. 8.2. Power of CCGT-2/2 unit after the installation of heat storage system.

The characteristic days are synthesized in line with historical production data of Riga TPP-2 and the appearance of new heat energy sources on the right bank of Riga district heating system. The electricity production costs are calculated in line with the internal order of JSC *Latvenergo* called K260 *"The short-term planning order of primary energy resources produced and supplied in network electricity and heat energy"* taking into account CO_2 price 13 €/t and natural gas price 21.17 €/MWh. The hourly electricity price of typical days is calculated by multiplying yearly electricity price (35.60 EUR/MWh in 2018) by forecast electricity price profiles[1] for working days, which reflect the hourly change of electricity price in % during the typical days.

The accumulated heat energy, CO_2 savings and additional income from the installation of the heat storage system at Riga TPP-2 are summarised in Table 8.1.

Table 8.1

Summary of the Calculated Parameters*

Month	Accumulated heat energy, MWh/24h	Additional income, €/24h	CO_2 emissions, t/24h	Number of typical days	Accumulated heat energy, MWh/month	Additional income, €/month	CO_2 emissions, t/month
January	365	8 171	51	28	10 222	228 796	1 421
February	347	8 893	48	24	8 328	213 432	1 158
March	345	13 024	48	12	4 140	156 290	576
April	550	5 892	76	13	7 150	76 596	992
October	540	12 013	75	18	9 720	216 240	1 351
November	531	10 938	74	21	11 151	229 691	1 550
December	544	6 050	76	28	15 232	169 391	2 118
Year				**144**	**65 941**	**1 290 440**	**9 168**

* The heat storage system will not be used during the months from May to September due to the lack of heat load on the right bank of Riga district heating system.

In turn, the economic parameters are presented in Table 8.2. The implementation of the project is unprofitable without co-financing.

Table 8.2

Summary of Economic Parameters

Economic parameters	Without co-financing	With co-financing
Total investments*, thous. €	12 977.71	12 977.71
Own funding, thous. €	12 977.71	9258.75
Co-financing 30%**, thous. €	0.00	3718.73
Net present value (NPV_{20})***, thous. €	- 1776.98	1515.42
Internal rate of return (IRR_{20})***, %	< Discount rate	7.98
Payback period, years	> 20	15.18

* According to the gained practical experience

** From eligible costs

*** The project is calculated for the period of 20 years

The sensitivity analysis is provided for three price scenarios: low, average, and high simultaneous increase in natural gas, CO_2 and electricity price. In the sensitivity analysis, the forecast price values are for 2028.

- Low price increase scenario: CO_2 price is 8.40 €/t; natural gas – 23.35 €/MWh; electricity price – 35.51 €/MWh. The hourly electricity price is determined by multiplying the electricity price (35.51 €/MWh) by electricity price profiles[1]. Start-up costs are corrected

[1] Data from JSC *Latvenergo*

in line with the low price increase scenario. Thus, the calculated additional income is € 1240.60 thous. per year.

- Average price increase scenario: CO_2 price is 17.70 €/t; natural gas – 25.65 €/MWh; electricity price – 35.77 €/MWh. The hourly electricity price is determined by multiplying the electricity price (35.77 €/MWh) by electricity price profiles[1]. Start-up costs are corrected in line with the average price increase scenario. Thus, the calculated additional income is € 994.15 thous. per year.
- High price increase scenario: CO_2 price is 29.00 €/t; natural gas – 31.85 €/MWh; electricity price – 37.52 €/MWh. The hourly electricity price is determined by multiplying the electricity price (37.52 €/MWh) by electricity price profiles[1]. Start-up costs are corrected in line with the average price increase scenario. Thus, the additional income is not formed in case of the high price increase scenario because the electricity production costs are higher than the electricity price in the market.

The results of sensitivity analysis are reflected in Table 8.3.

Table 8.3

Summary of Sensitivity Analysis

Increase of price	Low price increase		Average price increase	
Availability of co-financing	Without co-financing	With co-financing	Without co-financing	With co-financing
Payback period, years	> 20	14.90	> 20	> 20
NPV_{20}, thous. €	- 1480.68	1537.95	- 3742.16	- 723.52
IRR_{20}, %	4.43	8.13	1.77	4.93

The simultaneous increase in natural gas, CO_2 and electricity price has a negative effect on the heat storage system due to an increase in the electricity production costs above the market price in line with the assumed forecasts of price increase (Table 8.3).

CONCLUSIONS

1. The hypothesis of the Doctoral Thesis has been proven: it is necessary and possible to improve the flexibility and efficiency of fossil fuel thermal power plants in order to achieve the aims (adjustment to variability of electricity price in the market or integration of intermittent generation in the energy production process) and benefits (efficient, profitable, competitive operation of power plants and their prevention from mothballing, secure energy supply) of cycling operation, which vary according to the geographical location of the region, its situation in the energy system and economic development.
2. The literature review reflects that the flexibility level of the fossil fuel TPPs can be increased at the design stage or at the operation stage. The measures available at the operation stage are divided into five groups: upgrades of equipment, storage opportunities, operation optimisation, new installation, competitiveness and leadership increase. They differ by the degree of complexity, investment, time of implementation, sources used, etc.,

but are united by one goal – to enhance the efficiency and flexibility of fossil fuel thermal power plants.

3. The developed mathematical description of transient modes identifies the parameters of transient modes and the bottlenecks of cycling operation, based on which it is possible to decide on necessary measures to increase the flexibility of TPP. Mathematical description of transient modes has been approbated on the example of Riga TPP-2, which proved that the start-up time (especially cold start-up) of Riga TPP-2 should be reduced significantly.
4. The *EM&OM* approach ensures additional electricity production and reduces the negative impact of the cycling operation on the technical resources of the equipment (the number of cycling periods is reduced and start-ups are replaced with less adverse ones). It can be adapted to other thermal power plants and physical electricity markets by changing the characteristics of the considered technologies, principles of market operation and providing additional calculation. The use of *EM&OM* approach in the intraday market is cost-efficient if the generation portfolio consists of various generation units.
5. The developed general algorithm for technical and economic evaluation of technologies has been adopted to three technologies.
   - The *air chilling technologies* ensure additional electricity production in periods of high electricity price, when TPP operates at maximal power. Its realisation in the market provides additional income, which can be shifted to optimise the price of the produced energy. The efficiency of TPP also improves, i.e., less fuel is consumed to generate more electricity.
   - *Electric boiler* can be used to decrease the production costs and increase the competitiveness of the TPP, when the electricity price is low in the market under condition that the electricity price regulated tariff is excluded. However, the economic justification of technology is determined by different components: the price of electricity, fuel, carbon dioxide, the number of operation hours and the size of the electric boiler.
   - The *heat storage system* decouples heat and electricity production. The situation of characteristic days (value of electrical and heat power and equipment content) determines the source of additional income: ensured by the realisation of additionally produced electricity in the market and/or by the increase in the fossil fuel thermal power plant efficiency.

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